MANITOBA HYDRO PUBLIC UTILITIES BOARD

IN THE MATTER OF Manitoba Hydro's 2023/24 & 2024/25 General Rate Application

REBUTTAL EVIDENCE OF MANITOBA HYDRO

WITH RESPECT TO THE WRITTEN EVIDENCE OF:

Darren Rainkie on behalf of the Consumers Coalition (Manitoba Branch of the Consumers' Association of Canada, Harvest Manitoba, Aboriginal Council of Winnipeg) ("COALITION");

Kelly Derksen on behalf of the Consumers Coalition (Manitoba Branch of the Consumers' Association of Canada, Harvest Manitoba, Aboriginal Council of Winnipeg) ("COALITION");

Pelino Colaiacovo on behalf of the Consumers Coalition (Manitoba Branch of the Consumers' Association of Canada, Harvest Manitoba, Aboriginal Council of Winnipeg) ("COALITION");

Chris Oakley and Peter Helland on behalf of the Consumers Coalition (Manitoba Branch of the Consumers' Association of Canada, Harvest Manitoba, Aboriginal Council of Winnipeg) ("COALITION");

Dustin Madsen on behalf of the General Service Small and General Service Medium Customer Classes ("GSS/GSM");

Patrick Bowman on behalf of the Manitoba Industrial Power Users Group ("MIPUG"); and,

Daymark Energy Advisors ("Daymark") Daymark Energy Advisors, Independent Expert Consultant for the Public Utilities Board

Manitoba Hydro

May 5, 2023

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Appendices

1. Introduction

On April 3, 2023, written evidence was filed by Darren Rainkie, Kelly Derksen, Morrisson Park Advisors and Midgard Consulting on behalf of the the Consumers Coalition, Patrick Bowman on behalf of MIPUG, and Emrydia on behalf of GSS and GSM customers. On April 13, 2023, Daymark Energy Advisors filed its Independent Expert Report.

This reply evidence of Manitoba Hydro responds to various aspects of the positions taken by intervenors. The fact that Manitoba Hydro does not address or respond to all statements or positions taken by intervenors, or to any particular assertion or position, should not be taken or construed as acceptance of any intervenor position by Manitoba Hydro.

The Manitoba Hydro reply evidence reflects the understanding that the primary purpose of reply evidence is for the applicant to provide an evidentiary response to new and previously unaddressed matters which intervenors have raised in their written evidence.

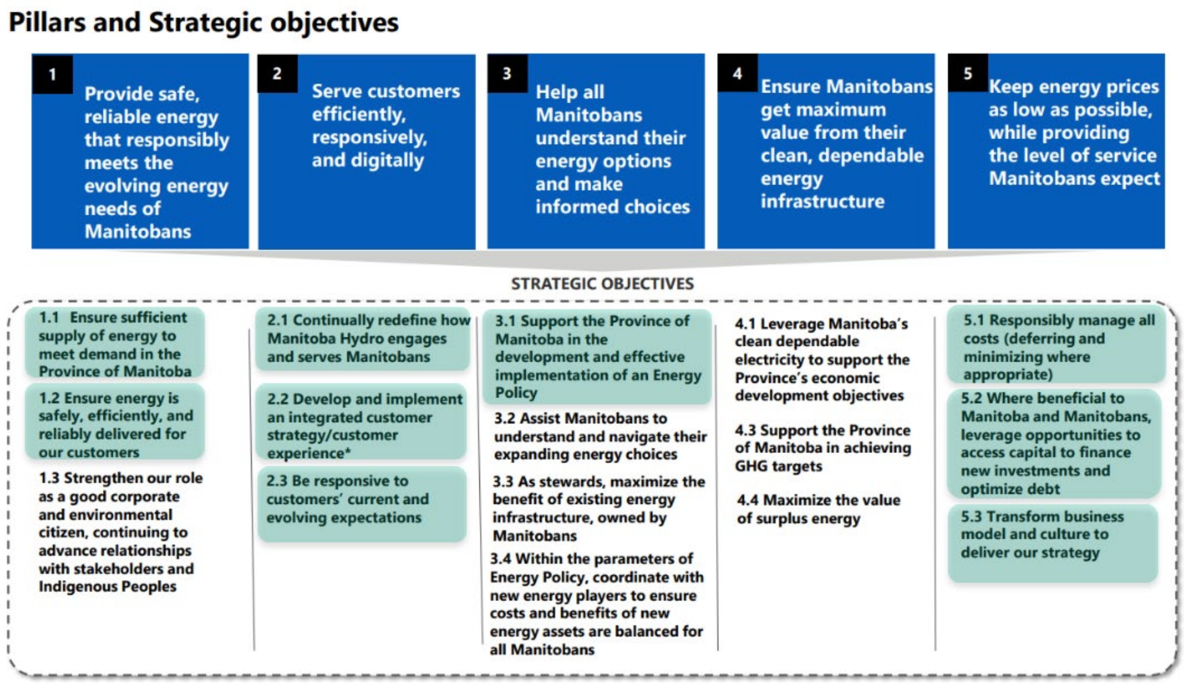
2. Strategy 2040 details Manitoba Hydro’s commitment to Manitobans today and in the future. Ensuring safe, reliable service together with meeting customer service/responsiveness expectations are core components to Strategy 2040

On page 15 of his evidence, Mr. Rainkie suggests that there are too many concerns and unknowns for the PUB to fully accept Strategy 2040 for rate-setting purposes at this time based on his evaluation that that the implementation of Strategy 2040 appears to be premature in advance of Manitoba Energy Policy and the completion of the Integrated Resource Plan (“IRP”).

Mr. Rainkie’s assertion that Strategy 2040 is premature, disregards that core to Strategy 2040 is Manitoba Hydro’s commitment to continuing to provide safe, clean, reliable energy, operating as efficiently and effectively as possible, while being responsive to customers and preparing for changes in the energy landscape that are already occurring.

The core and foundational aspects of Strategy 2040 are highlighted in the pillars and strategic initiatives of Strategy 2040 in the figure below:

Figure 1: Pillars and Strategic Objectives



Mr. Rainkie's assertion that Strategy 2040 is premature also disregards that the development of the IRP is one of the key near-term strategic initiatives outlined in Strategy 2040, as is supporting government policy advancement, such as Energy Policy, which is critical work currently underway to ready Manitoba for the future.

While Mr. Rainkie suggests at page 21 of his evidence that the energy landscape has been under a constant state of evolution for decades, Mr. Rainkie appears not to understand that the energy sector world-wide has seen unprecedented changes in recent years. Consistent with Manitoba Hydro's perspective, the period of rapid transition currently taking place in the US was noted in Daymark's evidence (page 24). The energy transition is already underway in Manitoba. Manitoba Hydro must start preparing for the future now. It would be imprudent not to despite manageable timing issues with respect to IRP and Energy Policy. Planning for and implementing reasonable changes today, including leveraging opportunities to access capital to finance new investments, can be made "without regrets" before the IRP and Energy Policy are finalized.

As noted within the Application, Strategy 2040 is adaptable and will continue to evolve as the landscape evolves.

2.1. The Business Model Realignment Includes Building and Improving Foundational Capabilities

At page 20 of Mr. Rainkie's evidence, he suggests that the magnitude of transformation inherent in Strategy 2040, including business model changes referred to as "restructuring", may be unnecessary depending on the outcome of the IRP and Manitoba Energy Policy.

Mr. Rainkie is overlooking that the business model realignment is being undertaken not only to position Manitoba Hydro to respond to the evolving energy landscape, but to improve and build upon core foundational capabilities that will improve the corporation's overall efficiency and effectiveness through the adoption of an industry best practice process-based model. Examples include the creation of the Integrated Resource Planning Division, leading the development of the IRP, as well as creation of an Asset Management Division combining the asset management functions previously held in the operating groups that were organized around generation, transmission, and distribution assets to a central group, forming a Centre of Expertise. These are both areas that the PUB has found in past proceedings are capabilities that Manitoba Hydro needs to develop and improve.

2.2. Strategy 2040 and Customer Preferences

In Section 3.6 of his evidence, Mr. Rainkie indicates *"It is unclear how customer research and engagement as to customer preferences has influenced Strategy 2040 and the underlying spending priorities and costs."*

Manitoba Hydro disagrees with the assertion that it is unclear how customer research and engagement has influenced Strategy 2040.

Foundational to Strategy 2040 is the commitment to continue to engage with, and learn from, customers. This is outlined in detail in Appendix 2.1, page 15. The underlying spending priorities and costs will continue to be influenced by customer input as stated, “Your input will help us plan for the future and ensure every dollar we invest in the future aligns with Manitobans’ needs and desires.”

The three studies submitted by Manitoba Hydro as evidence in this application – Customer Values and Perceptions Study, Leger Reputation Study, and the Customer Satisfaction Tracking Study – are all examples of Manitoba Hydro’s commitment to continued learning from the customer. Further, customer research efforts are ongoing and continuous. For example, as mentioned in MIPUG/MH I-11 – efforts are underway to create residential customer segments that group Manitobans into segments based on customer attitudes, values, needs, behaviours, and preferences. Manitoba Hydro will continue to refine its understanding of all customers’ needs.

Manitoba Hydro also continues to engage with its Commercial and Industrial customers directly, as well as associations that represent larger customer groups such as the Manitoba Home Builders Association, MIPUG, Manitoba Heavy Construction Association, Association of Manitoba Municipalities and Urban Development Institute.

Together, the insights gained from customer research and engagement direct Manitoba Hydro’s activities, spending priorities, and costs.

2.3. Manitoba Hydro’s customer survey questions were balanced and findings on customer preferences have been fairly interpreted

In Section 3.6 of his evidence, Mr. Rainkie suggests that there is a weak underpinning with respect to Manitoba Hydro’s interpretation of customer preferences involving tradeoffs between reliability and rates, because the Customer Values and Perceptions study was based on leading questions.

Manitoba Hydro disagrees with Mr. Rainkie’s interpretation and related conclusion.

The key questions in the Customer Values and Perceptions study were presented in a format that could be easily understood, and responded to, by the residential Manitoba sample. The survey question style was chosen to present both sides of the decision in a fair and balanced way. Steps taken include:

- All sides of the argument are presented with both the positive and the negative highlighted. For example, when there is increased reliability mentioned (e.g. fewer or shorter outages) it is paired with a rate increase “means higher rates.”
- Anchor labels were chosen to reduce bias by avoiding extreme language. For example, “keep rates lower” is used rather than “cheap.”
- Improvements to reliability were not framed as resulting in perfect reliability. Instead, it was labeled “reduce the number” and “reduce the length” of outages.

Additional considerations included ensuring the questions managed respondent burden and were accessible and high-level, as outlined in COALITION/MH I-128a.

Mr. Rainkie appears to misunderstand that the original objective of the Customer Values and Perceptions study was not to be a fulsome or comprehensive investigation of the stated preferences between rates and reliability. Instead, these questions were asked as part of a broader study that sought to (as stated in the RFP and submitted in COALITION/MH II-64b *“(a) Identify what Manitoba Hydro customers value, need, want and expect from their energy utility for all aspects of its service and interactions.*” The study and questions were written to meet this objective. The methodology and study referenced by Midgard in MIPUG/COALTION I-2 is an example of research that is conducted for the expressed purpose of “measuring stated preference”, a specific objective, different than the Manitoba Hydro study where tradeoffs between reliability and cost were one of many values examined.

Although the Manitoba Hydro study was much broader than the specific tradeoff between reliability and cost, customer responses to the questions provide important and valuable insight into their preferences for cost and reliability tradeoffs.

Similar customer insights were provided within the Leger Reputation study, a second independent study, submitted in Tab 10 MFR 12, Attachment 2. These results are summarized in Tab 10, MFR 12, pg. 3, lines 7-10. The Leger Reputation study used a different methodology and sample yet found similar results; reliability and value are both fundamental to customers’ perceptions of Manitoba Hydro, however, “reliability of products and services” was considered the most important attribute when forming an opinion of Manitoba Hydro.

The results of these two studies are consistent with Manitoba Hydro's understanding of customers' general preference for balancing existing reliability with rate increases, based upon numerous conversations and direct interactions it has with all its customers on a routine basis, including residential, commercial and industrial customers.

With regards to serving larger commercial and industrial customers, a separate research project has investigated the experience of customers who recently completed a Major Work Order. The results of this study show that 33% of customers indicated it was not easy to complete their project and 49% of customers indicated that the project was not completed in a reasonable amount of time. Please see Appendix 1 of this Rebuttal Evidence for a Summary of the Major Work Order Voice of the Customer research.

These low levels of customer sentiment show indications of declining service and an inability to meet customers' expectations for responsiveness with both residential and commercial industrial customers.

3. Increased O&A and BOC Costs are largely related to maintaining reliable service and improving customer service responsiveness and addressing future energy and capacity requirements

Mr. Rainkie concluded in his evidence that "*the $2.3 billion increase in O&A and BOC in the current financial forecast is significantly related to Strategy 2040 and associated initiatives and is inconsistent with and unresponsive to, prior PUB findings and regulatory signaling to MH to control and prioritize its controllable O&A and BOC costs*."

This conclusion and the assertions that attempt to support it are addressed in the following sections.

3.1. O&A Expenses

3.1.1. FTE Increases are primarily related to increases in Operations FTE

On page 55 of his evidence, Mr. Rainkie states that, "*O&A cost increases between 2019/20 and 2024/25 demonstrates that there is a $72 million increase in O&A costs and 116 increase in FTE's in the MH Governance & Services business units.*" And that *"These increases are primarily due to Strategy 2040 and related strategic initiatives…"*

Mr. Rainkie's suggestion that FTE growth is mainly in the Manitoba Hydro Governance & Services business units and that this is driven by Strategy 2040 doesn't properly consider FTE changes since implementation of the Voluntary Departure Program (the "VDP") and takes a narrow view of what is included as part of Strategy 2040.

Through the VDP, Manitoba Hydro committed to reducing its workforce by approximately 15%. As evidenced in Section 6.4.5 of Tab 6 of the Application, Manitoba Hydro has maintained that reduction through the Test Years of this Application.

It is important to note that the VDP was not a targeted reduction of specific positions that were no longer required. Rather, it was a program that provided a financial incentive to those employees that voluntarily chose to leave the company and as such resulted in departures across the corporation. Many of the positions where employees departed needed to be backfilled.

To properly account for the VDP, a more appropriate comparison of the changes in FTEs is to use the 2016/17 FTEs allocated to Governance, Support & Services vs. Capital Construction and Operations and Maintenance[1] with inclusion of the changes from 2016/17 to 2022/23, 2023/24 and 2024/25. The changes in FTEs are illustrated below and highlight that Manitoba Hydro has maintained a reduction in FTEs in all groupings, including the FTEs allocated to Governance, Support and Services.

[1] Previously provided as Figure 3 in PUB/MH I-64c.

Figure 2 FTEs allocated to Governance, Support & Services vs. Capital Construction and Operations and Maintenance

	Straight Time FTEs										
	2016/17	2022/23			2023/24			2024/25			
	Actual	Forecast	Increase/ (Decrease)		Preliminary Budget	Increase/ (Decrease)		Preliminary Budget	Increase/ (Decrease)		
Capital Construction	2,314	1,528	(786)	-34%	1,487	(827)	-36%	1,510	(804)	-35%	
Operations & Maintenance	2,506	2,464	(42)	-2%	2,475	(31)	-1%	2,505	(1)	0%	
Governance, Support & Services*	1,381	1,087	(294)	-21%	1,196	(185)	-13%	1,255	(126)	-9%	
Total	**6,201**	**5,079**	**(1,122)**	**-18%**	**5,158**	**(1,043)**	**-17%**	**5,270**	**(931)**	**-15%**	

In addition to the overall changes in FTEs, the year used to compare changes in FTEs is also important. Mr. Rainkie's use of the 2019/20 year to conduct a comparison does not account for further reductions in FTEs that Manitoba Hydro experienced in 2020/21 when the Trades Trainee Program was paused and an external hiring freeze was put in place to help achieve cost saving measures required during the start of the COVID-19 pandemic. Of the 455 FTE increase between 2020/21 to 2024/25 (from 4,954 to 5,409), 345 FTEs (from 2,253 to 2,598) are related to increases in the Operations business unit. This is highlighted in the figure below:

Figure 3 FTE Changes from 2016/17 to 2024/25 by Business Unit

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

	2016/17 Actual	2017/18 Actual	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Actual	2022/23 Forecast	2023/24 Preliminary Budget	2024/25 Preliminary Budget
President & CEO	14	10	9	8	8	10	19	21	21
Customer Solutions & Experience	475	428	377	373	317	316	355	363	365
Asset Planning & Delivery	1 848	1 776	1 586	1 509	1 352	1 236	1 272	1 282	1 307
Operations	2 804	2 600	2 427	2 407	2 252	2 386	2 533	2 550	2 598
Digital & Technology	288	272	252	249	237	237	246	263	273
HR & Safety, Health and Environment	178	164	150	159	149	154	168	188	209
Chief Financial Officer	465	410	346	352	335	349	364	368	372
External & Indigenous Relations and Comm	129	118	115	116	103	111	122	123	125
Business Unit Total	**6 201**	**5 778**	**5 262**	**5 173**	**4 753**	**4 799**	**5 079**	**5 158**	**5 270**
Other Segments/Corporate Adjustments	210	220	213	220	201	163	96	140	138
Total Corporation	**6 411**	**5 998**	**5 475**	**5 393**	**4 954**	**4 962**	**5 175**	**5 298**	**5 408**

The above assessment is also supported by the evidence of Mr. Madsen where on page 75 of his evidence, he finds "*Overall, for labour costs, I accept that some increase in costs may be reasonable to support continued reliability for Manitoba Hydro. Specifically, Manitoba Hydro provided the following table of* ***FTEs which indicates that a majority of the increase in FTEs relates to operations staff"*** (emphasis added).

Finally, it is important to clarify that the VDP was based on a **reduction of positions**, which is calculated and reported on using FTEs. The VDP was not a reduction of a specific dollar amount. Based on the application of wages and salary increases associated with merit, progression, general wage increases, and other negotiated salary increases, total costs associated with staffing levels will increase over time even if FTE levels are unchanged.

3.1.2. Increases in Operations FTEs can be managed without business disruption

On page 77, Mr. Madsen suggests that "*the ramp up in staffing can be phased in over a longer period of time to match retirements with new positions better and provide a staged approach to training the new staff*" and that "*the forecast increase in Operations FTE could be disruptive to Manitoba Hydro's business. Hiring and training new staff is time intensive and increasing FTE levels by 212 FTEs or 9% in such a short period of time will be difficult to achieve practically. Finding qualified individuals to fill the vacancies, including training new staff, will not be an easy task. Even assuming Manitoba Hydro can identify 212 qualified staff, not accounting for other turnover that is likely to occur, the efforts to onboard those staff will be significant.*"

To clarify, the increase in Operations FTEs will primarily be achieved through Manitoba Hydro's existing Trades Trainee programs. The trainee programs are apprenticeship type programs that provide on-the-job training and formal learning. As outlined in Tab 6, Section 6.4.1, these programs range from two to four years and provide the intake mechanism and skill development required for specialized electrical and gas positions. Regular recruiting into the Trades Trainee Programs ensures that a qualified pool of candidates is available to fill vacant trade and technical positions and address attrition. These core positions support Manitoba Hydro's critical electrical and gas operations and maintenance requirements.

As shown in Figure 6.4 of Tab 6, Manitoba Hydro had slowed down the intake into the Trades Trainee programs over the last several years due to cost constraint measures, and in calendar year 2020 completely halted it due to further cost constraint measures taken during the first year of the COVID-19 pandemic. While this was happening, Manitoba Hydro saw a departure of experienced operational staff that would have typically been backfilled by trained individuals through the trainee programs.

Manitoba Hydro cannot hire fully qualified candidates for many specialized operational positions and requires individuals to go through the trainee programs to be deemed qualified for such positions. The rebuilding of the Trades Trainee programs is essential to ensure a skilled workforce to operate and maintain the electrical and natural gas systems. Having a decrease in the trainee programs, coupled with attrition, has placed Manitoba Hydro in a situation where it is necessary to increase the hiring in the Test Years to rebound to sustainable levels to fill the "gap" that was created.

3.1.3. Increases to FTEs in Other Business Units

Clarification of other FTE increases referenced by Mr. Madsen in his evidence is also required. In Table 5 of Mr. Madsen's evidence, he identifies *"material increases such as the President & CEO which increase 110% to levels not seen historically*".

The increase observed by Mr. Madsen is related to the creation of the Enterprise Excellence Division, which is described fully in Section 2.4.1 of Tab 2 of the Application. For the appropriate context, the cited 110% increase represents the forecasted addition of eleven FTEs within the Enterprise Excellence Division, which report directly to the President & CEO as the focus is on embedding change management, continuous evaluation and improvement, and alignment to strategy across the corporation.

This growth associated with the inclusion of the Enterprise Excellence Division directly in the President & CEO Business Unit was detailed as part of the response to COALITION/MH I-83a, an excerpt of which specific to the President & CEO Business Unit is provided in the figure below:

Figure 4 FTEs in the President & CEO Business Unit from 2019/20 to 2024/25

MANITOBA HYDRO
STRAIGHT TIME FULL TIME EQUIVALENT (FTE) EMPLOYEES BY DIVISION

	2019/20 Actual	2020/21 Actual	2021/22 Actual	2022/23 Forecast	2023/24 Preliminary Budget	2024/25 Preliminary Budget
President & CEO						
Administration	8	8	10	10	10	10
Enterprise Excellence	-	-	0	9	11	11
	8	**8**	**10**	**19**	**21**	**21**

Additionally, on page 78, lines 7-8, Mr. Madsen identifies *"an increase in human resource staff of 55 or 36%".* This increase is for the Human Resource & Safety, Health and Environment Business Unit which includes more than just "human resource staff". A little over half of the increase is for human resources, with the rest pertaining to safety, health and environment. The breakdown for this business unit by Division, as previously provided in COALITION/MH I-83a, is shown below:

Figure 5 FTEs in the HR & Safety, Health and Environment Business Unit from 2019/20 to 2024/25

MANITOBA HYDRO
STRAIGHT TIME FULL TIME EQUIVALENT (FTE) EMPLOYEES BY DIVISION

	2019/20 Actual	2020/21 Actual	2021/22 Actual	2022/23 Forecast	2023/24 Preliminary Budget	2024/25 Preliminary Budget
HR & Safety, Health and Environment						
VP HR & Safety, Health and Environment	5	4	4	3	4	4
Human Resources	94	87	89	101	111	124
Safety, Health & Environment	60	58	61	64	73	81
	159	**149**	**154**	**168**	**188**	**209**

Based on the explanations provided above, Manitoba Hydro does not agree with Mr. Madsen's recommendation to effectively "cut" these required positions thereby reducing labour costs of $7.7 million and $11.1 million in 2023/24 and 2024/25, respectively.

3.1.4. O&A Cost Increases and Ability to Control

On page 55 of his evidence, Mr. Rainkie has stated that, *"MH has shifted its policy orientation from prior regulatory proceedings to pursue cost savings and instead has taken a position that it has little influence over O&A and BOC expenditures."*

Manitoba Hydro has significantly reduced costs over the last several years to levels which are no longer sustainable over time. This is not a shift away from a *"policy of costs savings"* as Mr. Rainkie has suggested. In the 2015/16 & 2016/17 General Rate Application, Manitoba Hydro was signaling that it would not be possible to keep O&A increases below inflation for an extended period of time, stating:

> *"OM&A cost increases have been limited to 1% per year up to 2021/22 (excluding accounting changes and the increases associated with new major generation and transmission projects coming into service). After 2021/22, OM&A is projected to rise at the same level as inflation, despite the increasing cost pressures facing the Corporation from investments required for infrastructure renewal and increased capacity."*[2]

Manitoba Hydro did not, and could not, anticipate the changing economic circumstances that have occurred which have created the cost pressures being experienced by Manitoba Hydro, and globally, that were noted in Tab 6 of the Application.

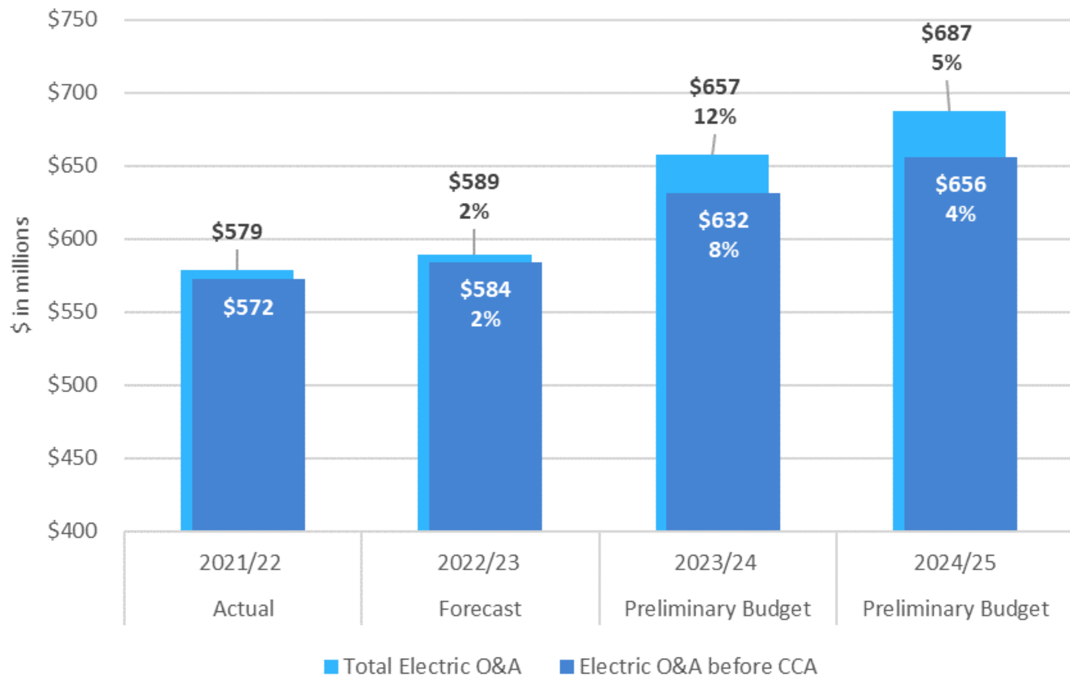
In addition to the impact of the COVID-19 pandemic, there are continued global supply chain challenges that have caused a significant increase on several costs, including materials, contracted services, and transportation. Additionally, Manitoba Hydro has had labour disruptions that have resulted in two of Manitoba Hydro's bargaining units going on strike over the last two years and with resulting salary increases mandated by the Labour Board and a labour arbitrator.

The treatment of cloud computing costs as an O&A expense represents a further example of a change that is impacting Manitoba Hydro's total O&A expenses. On page 60 of Mr. Rainkie's evidence, he observes that the "*MH O&A forecast is increasing in the order of 8% per year in each of the Test Years*". Mr. Rainkie appears to be averaging the increases in those years. It should be noted that the referenced increases would be approximately 6% if cloud computing arrangements were not recognized as an O&A expense.

The figure below highlights O&A increases with and without cloud computing expenditures for 2021/22 to 2024/25.

[2] 2015/16 & 2016/17 General Rate Application, Tab 5 – Financial Results & Forecasts, page 45.

Figure 6 O&A increases with and without cloud computing expenditures for 2021/22 to 2024/25



3.1.5. Caution is Required if Using Fiscal 2022/23 as the Basis for Forecasting Future O&A Expenses

Manitoba Hydro was engaged in negotiations with all four of its bargaining units over calendar years 2021 and 2022 and this overlapped with the development of its 2022/23 budget. As such, general wage increase (GWI) assumptions were not assumed in the 2022/23 budget. In response to PUB/MH I-74a (Updated), Manitoba Hydro indicated that actual wages and salaries for 2022/23 would be higher than the 2022/23 forecast. This was also outlined in response to PUB/MH-I-78a, as summarized in the figure below:

Figure 7 Wages & Salaries Analysis from 2020/12 to 2024/25

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

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

As identified in Manitoba Hydro's Enterprise Plan for 2022/23, the 2022/23 Forecast did not incorporate any wage increases that were not already negotiated within a collective agreement. The preliminary budgets for both 2023/24 and 2024/25 include the negotiated GWI provisions and Manitoba Hydro's assumptions for GWI not yet negotiated.

Since GWI was not included in the 2022/23 budget, Manitoba Hydro does not support Mr. Madsen's recommendation to reduce labour costs of $7.7 million and $11.1 million in 2023/24 and 2024/25, respectively, based on a 1% escalation of expenditures in 2022/23. Additionally, it is highly unlikely to be *"a potential for a positive variance in wages and salaries... in 2022/23"* as Mr. Rainkie has suggested on page 67 of his evidence.

3.1.6. Cloud Computing and Net Movement

Mr. Madsen includes several comments through his evidence pertaining to cloud computing costs and how they are addressed through deferral account treatment.

- Page 65, lines 10-12: "*Some of the increases in consulting costs appear to be driven by software as a service cost, but the increase is unclear given that a portion of these costs are proposed to be addressed through deferral account treatment.*"

- Page 85, lines 15-16: "*Subject to review, I may accept updated 2022/23 consulting fees as the basis to escalate for future years if that level were adjusted for the cloud-computing arrangement costs.*"
- Page 86, lines 10-13: *"I assume that all SAP S/4 HANA costs related to consulting have already been removed and deferred from the consulting fees. If this adjustment has not been made or is made elsewhere in the financial statements for Manitoba Hydro, then my recommendation may differ."*

The treatment of the cloud computing costs and how the SAP S/4 costs are being proposed to be recognized as a regulatory deferral is clarified below.

Under IFRS, regulatory deferred income and expense items are first recognized in the respective income or expense line item to which they pertain and then an adjustment is made in the Net Movement in Regulatory Balances Account (Net Movement) to reverse the initial recognition to eliminate the impact on net income. The cloud computing expenditures recommended for deferral are first recognized as an O&A expense, and then an adjustment is made in the Net Movement line for these expenses which eliminates the impact on net income. This does not include the Phase 0 work for SAP S/4 which is recognized as an Other Expense and is not deferred.

As such, Manitoba Hydro does not support Mr. Madsen's recommendation to reduce consulting costs of $19.8 million and $26.5 million in 2023/24 and 2024/25, respectively.

3.1.7. Inclusion of SAP S/4HANA Costs in the Amended Financial Forecast Scenario

Both Mr. Rainkie and Mr. Madsen have submitted evidence regarding the inclusion of forecasted SAP S/4HANA costs as part of O&A expenses and the establishment of a regulatory deferral account that would subsequently defer SAP S/4HANA costs in the Amended Financial Forecast Scenario. Their recommendations are as follows:

- Mr. Madsen states at page 92 of his evidence that, "*I recommend that the PUB disallow the applied for SAP S4/HANA costs of $12.5 million and $22.9 million in 2023/24 and 2024/25, respectively. Until such time as Manitoba Hydro presents a detailed business case to support the incurrence of the forecast costs as being the* *best option available to Manitoba Hydro, I do not recommend approval of incremental costs*."

- Mr. Rainkie states at page 101 that, "*Considering the lack of justification on the record with respect to the proposed SAP RDA, it is recommended that the PUB leave the establishment of such an RDA to MH's decisioning making, based on its interpretation of IFRS14. MH can make application to the PUB for endorsement and an approved amortization period, once its business case associated with SAP has been developed or alternatively at the next GRA*."

Manitoba Hydro has indicated that it is currently in Phase 0 (pre-planning) of the SAP S/4HANA Project. The final deliverables of this phase include a readiness assessment and business case for SAP S4/HANA and the final decision around adoption of SAP S/4HANA will not be made until after completion of the business case and readiness assessment. That said, Manitoba Hydro was also required by the PUB to provide a long-term financial forecast as part of its Application. To prepare a reasonable financial forecast, Manitoba Hydro must consider both capital and operating costs that it reasonably anticipates spending in the future. Since Manitoba Hydro's current version of SAP ECC will not be supported beyond 2027 and needs to be replaced, Manitoba Hydro considered it reasonable and prudent to include the potential costs for the implementation of SAP S/4HANA in its financial forecast.

Regarding the creation of a regulatory deferral account related to SAP S/4 costs, Mr. Rainkie has suggested that "*the PUB leave the establishment of such an RDA to MH's decisioning making, based on its interpretation of IFRS14*". Manitoba Hydro does not consider there to be previous precedent where the PUB has approved or opined on the deferral of costs like those of SAP S/4 and as such Manitoba Hydro cannot proceed independently to establish a regulatory deferral for SAP S/4 under IFRS 14. The SAP S/4 deferral is recommended to be established based on a potential one-time significant investment that, as a proposed cloud-based system, would be expensed as an operating expense in the year incurred as a result of current account standard interpretations.

3.1.8. Vacancy Management

In Section 4.3.3 of Mr. Madsen's evidence, he states that "*The vacancy rate is designed to measure the number of positions in a year that are vacant as reflected in the full-time equivalents. For example, if there are 100 positions and 95 FTEs throughout the entire year, then the vacancy rate would be 5%. A common practice is to forecast a vacancy rate that reflects standard expectations of vacancies in the business based both on historical experience and forecast needs.*"

Mr. Madsen has described a turnover or attrition rate, which is not completely in line with what Manitoba Hydro has factored into its vacancy rates. As Manitoba Hydro is still in the process of realigning and rebuilding based on the Business Model review that has been described in this Application, the base FTEs included in the budget consider the positions identified through the business model reviews conducted to date. To align with the top-down O&A budget set by executive, the vacancy factor reduced FTEs for both attrition and to maintain FTE levels at an agreed upon increase identified by Manitoba Hydro's executive. As Manitoba Hydro completes all levels of the business model review through the enterprise and prioritizes enterprise initiatives, FTE levels will be budgeted accordingly. Total FTE growth is monitored regularly at various levels within the organization, including management, Finance and HR.

In Section 6.3 of his evidence, Mr. Rainkie states that Manitoba Hydro is using a vacancy management approach in place of a strategy or plan, which is not accurate or reflective of Manitoba Hydro's practice. As described above and mentioned extensively throughout the Application, Manitoba Hydro continues with the business model realignment and is in the process of aligning enterprise priorities with FTE requirements and other O&A costs around those priorities and strategy.

3.1.9. Digital & Technology Costs

In Section 5.2 of Mr. Madsen's evidence, there are some statements that suggest the need for digital and technology related cost is unclear.

On page 89, lines 13-16, Mr. Madsen states: "*While I appreciate that expensing a capital cost would increase O&A costs, it is unclear to me why total operating and capital outlays are increasing at the rate forecast. This appears to suggest that Manitoba Hydro is either forecasting material increases in existing costs, forecasting new software programs and users to be implemented, or a combination of both*."

Further on page 89, lines 21-23, Mr. Madsen states: "*Section 6.6 largely highlights the transition to the cloud, which explains why O&A costs are increasing, but not why overall costs are increasing, except for the proposed transition to SAP S4/HANA.*"

In Section 6.6.2 of Tab 6 of the Application, Manitoba Hydro outlined the reasons for the increases and highlighted that "*the shift in costs are not directly linked, i.e. a dollar increase in O&A will not equate to a dollar decrease in capital*". In addition, not only are there increases in O&A with moving certain costs that were previously deemed a capital expenditure to O&A, but expenditures related to cloud based services, such as subscription costs, are increasing significantly. This is due to both an increase in digital services and for the subscription costs for digital services currently being used. The figure below shows the cost increases for computer services from 2016/17 through the 2022/23 forecast, which reflects an average cost increase of 50% per year and a 758% over that time period.

Figure 8 Computer Services

($000s)	2016/17 Actual	2017/18 Actual	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Actual	2022/23 Forecast	Average Annual % Inc/(Dec)	2016/17 to 2022/23 $ Inc/(Dec)	2016/17 to 2022/23 % Inc/(Dec)
Computer Services	967	817	1 014	1 939	3 096	6 675	8 298	49.9%	7 331	758%

3.2. Capital Expenditure Forecast (C23)

Mr. Rainkie and Midgard have concluded that it is appropriate to reduce Business Operations Capital ("BOC") spending forecasts by 10% for each year of the 20-year forecast. This conclusion appears to be premised on the following conclusions:

- The information provided in CEP22, referred to by Manitoba Hydro and hereafter as C23, is not complete and it therefore should not be relied on for rate-setting purposes on an overall basis;
- C23 differs from CEFs that have been filed in past Manitoba Hydro GRAs, such as CEF16 filed in the 2017/18 & 2018/19 General Rate Application ("2017 GRA"), by providing less detail on forecasted expenditures. C23 only provides project details for 3-years (2022/23 to 2024/25) and 10-year and 20-year sub-totals;
- C23 is inconsistent with and unresponsive to prior PUB findings and regulatory signaling with respect to cost control. In particular, this relates to the need to reduce BOC spending as a result of the cost and rate pressures after the in-service of the major capital projects, consistent with Manitoba Hydro's commitment dating back to the NFAT proceeding; and,
- The primary reason for the 10-year and 14-year increase in BOC relative to CEF16, is the addition of placeholders for the AMI and Grid Modernization Projects, which is a concern based on their close association with Strategy 2040 and their preliminary status.

These conclusions are based on a narrow and inaccurate assessment of C23 compared to CEF16 which are addressed below in the following sections:

- Section 3.3 clarifies that the C23 capital expenditure plan has been developed to the same level of detail as previous capital expenditure forecasts. There is not a lack of detail in C23 compared to previous forecasts that in any way makes it less reliable. Capital expenditure forecasts are rigorously planned, reviewed, and tested, with ultimate approval following Manitoba Hydro's established governance structure.
- Section 3.4 details the C23 forecasted BOC expenditures compared to the CEF16 forecast, addressing 3 aspects:

    1. BOC expenditures in the early years of C23 are lower as compared to CEF16.

    2. Total BOC expenditures in C23 compared to CEF16 over 10 and 14 year-periods, starting in 2022/23, are necessarily higher to address asset sustainment and system capacity & growth requirements, not simply because of AMI and Grid Modernization.

3. Sustainment expenditures remain the focus of BOC expenditures and make up an increasing share of BOC expenditures in the 20-year forecast included in Manitoba Hydro's Amended Financial Forecast Scenario.

In addition to the narrow and inaccurate representation of the C23 capital expenditure forecast, the recommended 10% reduction is an arbitrary amount. Neither Mr. Rainkie nor Midgard have presented any evidence that demonstrates how the recommended 10% BOC reduction was derived. Furthermore, no assessment or analysis of the potential risks and impacts to reliability and system performance that could result from the 10% reduction was provided.

On the other hand, the evidence of Manitoba Hydro demonstrates an upward trend in equipment failures causing increased frequency and duration of customer outages and have shown that Manitoba Hydro's SAIDI and SAIFI measures are increasing at a rate greater than its Canadian peers. These aspects are addressed in additional detail in subsequent sections of Manitoba Hydro's rebuttal.

3.3. Level of Detail and Reliability of the 2022/23 Capital Expenditure Forecast

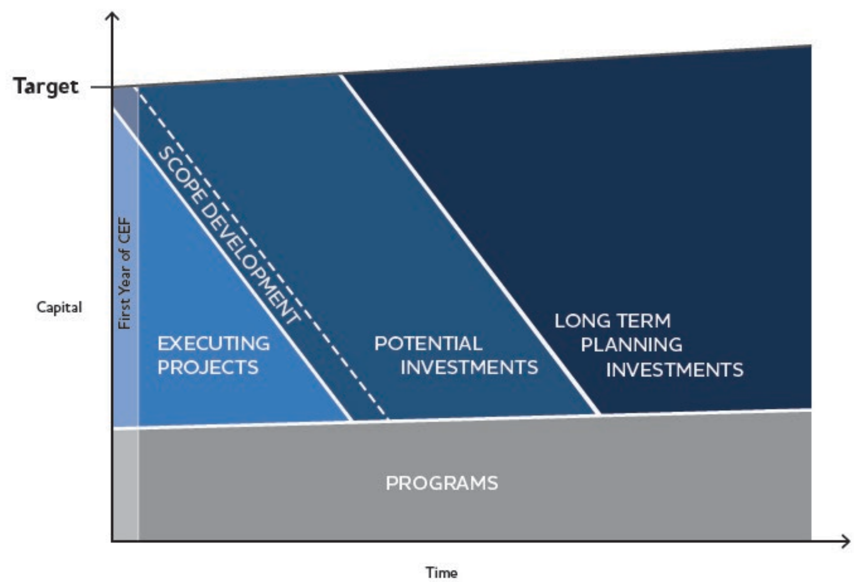
Mr. Rainkie's conclusion that C23 is incomplete and lacks detail compared to CEF16 or other previous Capital Expenditure Forecasts is inaccurate and fails to acknowledge both information that has been filed in this proceeding as well as information filed by Manitoba Hydro in previous proceedings regarding its Capital Expenditure Forecasts.

The C23 forecast was rigorously planned, reviewed, and tested, with ultimate approval following Manitoba Hydro's established governance structure. In fact, Manitoba Hydro's current ability to forecast anticipated capital expenditure requirements is better than it has been previously as Manitoba Hydro has continued to mature its asset management practices.

Despite Mr. Rainkie's suggestion otherwise, the level of detail in C23 is the same as was provided in CEF16. In both forecasts, specific project estimates are provided in the first 3 to 5 years, whereas aggregated data on potential investments and high-level expenditure forecasts are provided in the later years of the forecast. For CEF16, information related to the asset investment planning process was provided as part of Tab 5 – Asset Management and Capital Expenditure Forecast of the Manitoba Hydro's 2017 GRA. On page 4 of Tab 5 of the 2017 GRA, Manitoba Hydro described the asset investment planning process as follows (emphasis added):

> *Manitoba Hydro's capital planning model is depicted in **Figure 5.1** and is also the basis for the Corporation's investment requirements **detailed in the Capital Expenditures Forecast (CEF)**. Certainty in the capital plan is highest in year one where projects have a defined scope, schedule and budget, as well as a start date. Plans become more uncertain and more likely to change the further they are out in time. **Long term planning investments have only a notional definition of scope, schedule and budget.***

Figure 5.1 – Capital Planning Model



In CEF16, and in other previous Capital Expenditure Forecasts, long-term planning investments and programs make up the majority of the forecasted spending in the later years of the CEFs and these amounts are more uncertain than near term project expenditures. This is confirmed when examining a detailed breakdown of CEF16, as provided in Figure 9 below. Planning Investments and Programs make up almost 80% of the total forecasted expenditures over 10 years and 84% of the total forecasted expenditures over 20 years:

Figure 9 – Breakdown of BOC Expenditures in CEF 16

($ Millions)	Total Project Cost	2017 Outlook	2018 Forecast	2019 Forecast	2017 - 2026 10 Year Total	2017 - 2036 20 Year Total
Electric Business Operations Capital						
Executing Projects	2,765	394	325	211	1,375	1,413
Potential Investments	417	0	0	6	351	417
Programs	NA	243	265	290	2,999	6,725
Planning Investments	NA	-	-	26	1,246	4,030
Portfolio Adjustments	NA	(63)	(64)	(16)	(508)	249
Unallocated Year End Outlook Adjustment - Electric		(45)			(45)	(45)
Total Electric Business Operations Capital		**529**	**526**	**517**	**5,418**	**12,790**

This same capital planning process (including the figure outlining the Capital Planning Model), was described on pages 44 and 45 of Tab 7 of the Application as Manitoba Hydro's capital planning model since 2016 and was the approach used to develop C23. Manitoba Hydro further clarified the development process for C23 in response to MIPUG/MH II-90, *"…the 20-year capital expenditure plan included throughout the Application includes both specific projects and programs already approved as part of Manitoba Hydro's capital investment approval process, as well as anticipated capital expenditure requirements in future years to address yet to be approved projects and projected expenditure levels to meet asset renewal and system growth requirements."*

The line items referred to as 'Portfolio Adjustments' in C23 (Appendix 7.7) include the potential capital expenditures related to anticipated but not yet approved projects that would have been referred to as 'Planning Investments' in CEF16. Figure 10 below provides a breakdown of C23 like that provided in Figure 2 for CEF16:

Figure 10 – Breakdown of BOC Expenditures in C23

($ Millions)	Total Project Cost	2022/23 Forecast	2023/24 Preliminary Budget	2024/25 Preliminary Budget	2022/23-2031/32 10 Year Total	2022/23-2041/42 20 Year Total
Electric Business Operations Capital						
Executing Projects	2,291	350	289	228	1,264	1,265
Potential Investments	146	-	-	4	145	146
Programs	NA	265	269	269	2,826	6,233
Portfolio Adjustments	NA	(120)	(21)	58	2,573	8,886
Total Electric Business Operations Capital		**495**	**538**	**559**	**6,809**	**16,530**

‘Portfolio Adjustments’ and ’Programs’ make up just under 80% of the total forecasted expenditures over 10 years and make up approximately 91% of the total forecasted expenditures over 20 years.

It is evident from the above that the capital planning model applied in the development of C23 is the same as applied for CEF16 and other capital expenditure plans. Executing projects represent spending in the near term with longer term spending captured in Programs and Other projects, programs & portfolio adjustments.

Overall, there is an abundance of evidence as part of the Application in relation to C23 compared to CEF16 or other previous forecasts that make it more useful, informative and reasonable for the PUB to rely upon for its rate setting purposes. There is no evidentiary basis to support Mr. Rainkie nor Midgard’s recommendation to arbitrarily reduce Manitoba Hydro’s BOC by 10%.

3.4. BOC Expenditures Since the Last GRA

On pages 75 to 79 of his evidence, Mr. Rainkie indicates that C23 is inconsistent with and unresponsive to prior PUB findings and regulatory signaling with respect to cost control since it forecasts $0.8 billion in additional BOC expenditures in the 14-year period between 2023 to 2036 as compared to CEF16.

Manitoba Hydro’s Amended Financial Forecast Scenario (“AFFS”) incorporates reduced BOC expenditures as compared to CEF16 in each year from 2019/20 to 2026/27. The years 2019/20 to 2026/27 have both actual and forecasted spending for major capital projects and are years where the revenue requirement is significantly impacted by the major capital projects coming into service.

Figure 11[3] below provides a comparison between actual BOC expenditures in the Amended Financial Forecast Scenario (C23) vs. those included in MH Exhibit #93 (CEF16):

[3] This Figure was provided in response to COALITION/MH I-28a-f.

Figure 11 – BOC Expenditures in Amended Financial Forecast Scenario (C23) vs. MH Exhibit #93 (CEF16)

Business Operations Capital (in millions of dollars)								
	Amended Financial Forecast Scenario		MIPUG Scenario December 21, 2017 (MH Exhibit #93)		GREP	MIPUG Scenario (MH Exhibit #93) and GREP included	Change	Cumulative Change
2019/20	Actual	$545	Forecast	$516	$37	$553	($8)	($8)
2020/21	Actual	482	Forecast	511	31	543	(61)	(69)
2021/22	Actual	504	Forecast	499	28	528	(24)	(93)
2022/23	Forecast	495	Forecast	521	28	549	(53)	(146)
2023/24	Forecast	538	Forecast	544	17	561	(23)	(169)
2024/25	Forecast	559	Forecast	616	2	618	(58)	(227)
2025/26	Forecast	617	Forecast	640	2	643	(26)	(253)
2026/27	Forecast	647	Forecast	659	4	663	(16)	(269)
2027/28	Forecast	722	Forecast	671	-	671	51	(218)
2028/29	Forecast	750	Forecast	697	-	697	53	(165)
2029/30	Forecast	788	Forecast	688	-	688	100	(65)
2030/31	Forecast	827	Forecast	727	-	727	100	35
2031/32	Forecast	866	Forecast	734	-	734	131	167
2032/33	Forecast	905	Forecast	748	-	748	156	323
2033/34	Forecast	919	Forecast	760	-	760	159	482
2034/35	Forecast	933	Forecast	835	-	835	98	580
2035/36	Forecast	948	Forecast	852	-	852	96	676

Several findings from the above figure include:

- BOC in the Amended Financial Forecast Scenario (C23) includes investment requirements related to the Gillam Redevelopment and Expansion Project ("GREP") and the Grand Rapids Fish Hatchery project, whereas MH Exhibit #93 (CEF16) included these projects under Major Capital Projects. As a result, the C23 could appear artificially inflated compared to CEF16. Figure 11 adjusts for this difference.
- BOC spending year-over-year is lower in the Amended Financial Forecast Scenario (C23) from 2019/20 to 2026/27 as compared to MH Exhibit #93 (CEF16)
- Cumulative BOC spending is lower the Amended Financial Forecast Scenario (C23) until 2030/31

The reduction in BOC from 2019/20 to 2026/27 is generally the result of the deferral of work into future years. This deferral means that spending after 2026/27 is higher than forecasted in CEF16. This is evident in a 10-year and 14-year comparison of C23 to CEF16, using 2022/23 as the starting point, as shown below:

Figure 12 – Comparison of C23 to CEF 16 Over 10 Year and 14 Year Periods:

Current Forecast vs CEF16 Business Operations Capital ($ millions)	2022/23 - 2031/32 10 Year Total (GREP included in CEF16)	2022/23 - 2035/36 14 Year Total (GREP included in CEF16)
Sustainment		
System Renewal	(282)	(170)
System Efficiency	192	247
Mandated Compliance	(66)	(113)
Decommissioning	24	39
Sustainment Total	**$ (132)**	**$ 4**
Capacity & Growth		
System Load Capacity	170	408
Customer Connections	61	134
Grid Interconnections - Independent Power Producer	6	12
Capacity & Growth Total	**$ 237**	**$ 554**
Business Operations Support		
Town site Infrastructure	68	135
Fleet	130	167
Information Technology	(83)	(122)
Corporate Facilities	14	(8)
Tools and Equipment	72	106
Generation Buildings and Grounds	(46)	(65)
Business Operations Support Total	**$ 155**	**$ 211**
TOTAL	**$ 259**	**$ 769**

In his evidence, Mr. Rainkie has used this 10-year and 14-year comparison to question Manitoba Hydro's concerns about ageing assets since the sustainment category in C23 shows a reduction compared to CEF16 over the 10-year period and to suggest that the primary reason for the 10-year and 14-year increase in BOC relative to CEF16, is the addition of placeholders for the AMI and Grid Modernization Projects.

While amounts for the potential investments in AMI and Grid Modernization have been included in the forecast, they are but one reason for the variances between C23 and CEF16 over the 10-year and 14-year periods. The other reasons for the variance include:

- The Business Operations Support category is higher in C23 than CEF16 for both the 10-year and 14-year periods. Increased fleet spending requirements associated with ageing fleet assets is the primary driver for increases
- The capacity and growth category is also higher in C23 over the 10-year and 14-year periods compared to CEF16. The Capacity and growth category includes

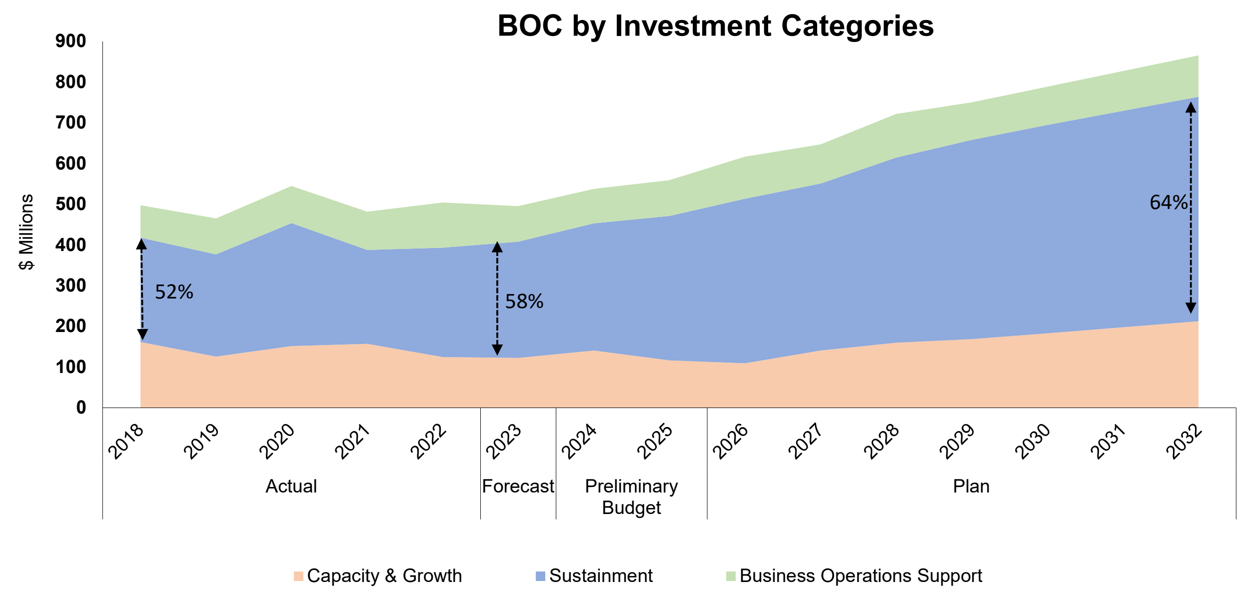
capacity enhancements and system expansion requirements to address specific customer usage requirements & load growth. The specific sub-categories where C23 is forecasted to be higher than CEF16 are:

  - CUSTOMER CONNECTIONS - Addition of new customer-driven connections for domestic service resulting from commercial and/or industrial customer load.
  - SYSTEM LOAD CAPACITY - Addition of new or upgrades to existing transmission or distribution assets for the purpose of increasing the system's capacity to address load growth not driven by one large customer.

- A good example of a project within the capacity and growth category is the Portage Area Capacity Enhancement ("PACE") project. The PACE project is required to increase customers' reliability and allow Manitoba Hydro to respond to increasing load in southwest Manitoba. This is currently one of the most stressed segments of Manitoba Hydro's transmission system.
- The current capital expenditure plan incorporates real escalation in equipment and construction costs associated with the capital expenditures since CEF16 (6 years of real escalation). The primary components that make up the costs of many capital projects (steel, copper and other commodities, construction labour, specialized equipment, etc.) can be volatile and have tended to escalate at a different and higher rate than CPI. The cost of many items has noticeably increased as a result of recent global supply chain challenges that have been experienced. This was outlined in Section 6.9.3 of Tab 6.

While there is a reduction to investments in the sustainment between C23 and CEF16 over the 10-year period identified in Figure 12, it's inaccurate to suggest that Manitoba Hydro has prioritized spending on other areas over addressing the risk of ageing assets. Expenditures on sustaining existing assets continues to be the primary focus of BOC expenditures. In fact, expenditures on sustaining existing assets are anticipated to become a larger portion of BOC expenditures over the forecast period. In 2017/18, 52% of actual BOC expenditures related to the sustainment category. In 2022/23, sustainment related expenditures are anticipated to make up 58% of BOC expenditures and by 2031/32 they will make up 64% of total BOC expenditures. This is shown in Figure 13 below:

Figure 13 – Breakdown of C23 BOC Expenditures by Investment Category



Finally, on the specific matter of AMI, Mr. Rainkie's suggestion that the potential investment in AMI should be excluded or rejected because it is "closely associated with Strategy 2040", should be disregarded as it does not properly recognize the full potential of AMI. AMI is used by the majority of electrical utilities in Canada offering the potential for significant customer benefits and operational improvements for Manitoba Hydro. Independent of any association with Strategy 2040, potential customer benefits of AMI include faster outage response, more accurate billing and better information on energy usage. Potential benefits to Manitoba Hydro's operations include the ability to conduct disconnections and reconnections remotely, better allocation and use of resources in responding to outages, automated and more accurate billing.

4. Manitoba Hydro's Rate Path is based on the balancing of several priorities (including key financial metrics) and acknowledgement of the impending requirements in the Act (Bill 36)

4.1. Planning a rate path and setting rates in compliance with the provisions of The Act is prudent and reasonable

Both Mr. Rainkie and Morrison Park Advisors ("MPA") in their respective written evidence suggest that *The Manitoba Hydro Amendment and Public Utilities Board Amendment Act* ("*The Act*"), particularly with respect to the Rate Cap and Debt Ratio Targets, should effectively be ignored by the PUB when considering Manitoba Hydro's proposed 2% rate path outlined in the amended financial forecast scenario, simply because the new legislated regulatory framework does not become operative until April 1, 2025. On page 7 of his evidence, Mr. Rainkie provides: "*The PUB has ruled that the new legislative framework that includes debt ratio targets is not yet operative for this GRA*." On page 3 of the evidence from MPA, they similarly opine: "*Until Bill 36 is in force, those targets should play no role in rate-setting based on good regulatory principles and practice*."

While Manitoba Hydro acknowledges that the Rate Cap and Debt Ratio Targets in *The Act* do not strictly apply to this Application, the coming into force of those provisions on April 1, 2025, less than two years from now, is a vital consideration impacting Manitoba Hydro's long-term financial forecast scenario and the establishment of a smoothed rate path. It is entirely reasonable and appropriate for Manitoba Hydro to plan now for this legal requirement, as it is obligated to do for all other legal and regulatory requirements that are to become effective at a specified future date. Manitoba Hydro's proposed 2% rate path is an outcome of complying with both the legislative requirements of the Rate Cap and the Debt Ratio Target of *The Act* and other well established regulatory principles such as stable and predictable rates for customers.

4.2. The 2% Rate Path and Rate Smoothing

Mr. Rainkie has argued that the PUB should use traditional financial metrics and targets for rate-setting purposes for the current application vs. the "mechanistic goal-seek" of the 2% rate path recommended by Manitoba Hydro and apply judgment associated with the modified cost of service ("MCOS") model. This argument is summarized in the following statements on pages 41 and 42 of Mr. Rainkie's evidence:

- "*It appears that the MH 2% proposed rate path is determined as a "goal-seek", of the even-annual rate increase that is necessary to obtain the 70% debt ratio (30% equity ratio) by 2039/40, in accordance with the new legislative framework that will not become operative until April 1, 2025.*"
- "*…recommendation that the PUB use its policy determinations from Orders 59/18 and 69/19 and place primary weight on traditional financial metrics and targets for rate-setting purposes. These include net income, net debt, interest coverage ratio and capital coverage ratio, with appropriate weight to the debt to equity ratio, credit rating agency reports and cash flow metrics MCOS method*."
- "*Under the MCOS, not only the forecasts of revenues and expenses in the Test Years under review, but also the forecasts in the MH long-term financial forecast are used to make informed judgements on how the proposed rate increase in the test year(s) impact the longer-term financial outlook and rate trajectory for MH. As such, the MCOS approach is essentially a rate smoothing approach designed to promote rate stability and predictability for customers and balance rate impacts on customers and the financial integrity (financial health) of MH, over the longer-term*."

Manitoba Hydro considered financial metrics, rate smoothing to promote rate stability and predictability for customers, and the balancing of customer considerations vs. the financial health of Manitoba Hydro in arriving at the proposed 2% rate path (the Amended Financial Forecast Scenario or AFFS), as well as considering a reasonable transition to be compliant to the specific requirements of the new legislative framework of *The Act.*[4]

It is inconsistent to represent Manitoba Hydro's recommended 2% rate path as a "mechanistic goal-seek" while suggesting the Coalition's rate path scenarios #10 and #11 (CC10 and CC11 set out below) are a "rate smoothing exercise". All three scenarios (AFFS, CC10 and CC11) were developed by adjusting or '*goal seeking*' the

[4] This is discussed in Section 3.3 of Tab 3.

even annual rate path – in the case of CC10 and CC11 several other forecast assumptions were also adjusted in addition to the rate path - to achieve a specified level for certain financial metrics. The AFFS sought out to achieve the legislated 70:30 debt-to-capitalization ratio by 2039/40 while CC10 and CC11 were the culmination of nine preceding 'goal seeks' via the IR process (CC1 through CC9) that finally produced a combination of adjustments such that the EBITDA interest coverage ratio and capital coverage ratio were in a particular range (not too low but lower than those in the AFFS).

A summary of each Coalition scenario is provided in Figure 14 below. In addition to scenario specific assumptions, all scenarios apply the following assumptions without any analysis or commentary on whether those assumptions are appropriate or achievable:

- Cash flows for regulatory deferrals such as cash paid for DSM expenditures, ineligible overhead, regulatory costs as well as interest costs on the City of Winnipeg perpetual obligation are classified as investing activities;
- O&A escalates at 2% each year over the 20-year forecast period based on the projected 2022/23 O&A of $589 million; and
- Business Operations Capital expenditures that are 10% lower than those projected by Manitoba Hydro in Appendix 7.7 for each year of the 20-year forecast period:

Figure 14 Consumer Coalition Rate Path Scenarios

Scenario Title	Scenario Details (Rates, Financial Targets and other assumptions)	IR Reference
CC1	Confirmation of the 3.6% 2021/22 interim rate increase, 0% rate increase in 2023/24 and even annual rate increases from 2024/25 onward to achieve a 75% Debt ratio by 2041/42	Coalition/MH I-43-a
CC2	Confirmation of the 3.6% 2021/22 interim rate increase, 0% rate increase in 2023/24 and even annual rate increases from 2024/25 onward to achieve a 80% Debt ratio by 2034/35	Coalition/MH I-43-b
CC3	Confirmation of the 3.6% 2021/22 interim rate increase, 0% rate increases in 2023/24 and 2024/25	Coalition/MH I-43-c

Scenario Title	Scenario Details (Rates, Financial Targets and other assumptions)	IR Reference
	and even annual rate increases from 2025/26 onward to achieve a 75% Debt ratio by 2041/42	
CC4	Confirmation of the 3.6% 2021/22 interim rate increase, 0% rate increases in 2023/24 and 2024/25 and even annual rate increases from 2025/26 onward to achieve a 80% Debt ratio by 2034/35	Coalition/MH I-43-d
CC5	CC1 with 50% of the reductions to payments to government between 2022/23 and 2024/25 deferred into the Major Capital Projects deferral account, with the resulting balance to be amortized over 10 years from 2025/26 to 2034/35	Coalition/MH I-43-e
CC6	CC2 with 50% of the reductions to payments to government between 2022/23 and 2024/25 deferred into the Major Capital Projects deferral account, with the resulting balance to be amortized over 10 years from 2025/26 to 2034/35	Coalition/MH I-43-f
CC7	CC3 with 50% of the reductions to payments to government between 2022/23 and 2024/25 deferred into the Major Capital Projects deferral account, with the resulting balance to be amortized over 10 years from 2025/26 to 2034/35	Coalition/MH I-43-g
CC8	CC4 with 50% of the reductions to payments to government between 2022/23 and 2024/25 deferred into the Major Capital Projects deferral account, with the resulting balance to be amortized over 10 years from 2025/26 to 2034/35	Coalition/MH I-43-h
CC9	CC1 with the assumption that that the even annual rate increases from 2024/25 to 2041/42 are set at a constant of 1.5% each year	Coalition/MH II-24-a
CC10	CC1 with the assumptions that: (i) the even annual rate increases from 2024/25 to 2041/42 are set at a constant of 1.21% each year the additions of	Coalition/MH II-24-b

Scenario Title	Scenario Details (Rates, Financial Targets and other assumptions)	IR Reference
	(ii) the Depreciation Method deferral account and Losses of Disposal of Assets deferral account continue for the 20-year forecast period but the accounts are amortized over the amortization periods proposed by Manitoba Hydro (for MH, WPLP and KHLP) and (iii) a level of long-term floating-rate debt of 5% between 2023/24 and 2031/32 and a level of long-term floating rate-debt of 10% between 2032/33 and 2041/42	
CC11	CC10 with the assumption that the even annual rate increases from 2024/25 to 2041/42 are set at a constant of 1.5% each year (instead of 1.21%)	Coalition/MH II-24-c

Several key findings are possible upon reviewing the series of scenarios requested by the Coalition:

- All scenarios in the 1st round IR, COALITION/MH I-43a-h, were structured to "goal seek" for the even annual rate increases required to achieve a specified debt-to-equity ratio in a particular year.
- CC1 was the base scenario on which scenarios CC9, CC10 and CC11 were established in the 2nd round IR (COALITION/MH II-24a-c).
- CC1 requested the application of even annual rate increases from 2024/25 to the end of the forecast period in order to achieve a 75:25 debt-to-equity ratio by 2041/42. This resulted in even annual rate increases of 1.2% from 2024/25 to 2041/42.
- Using the information from CC1, CC9 through CC11 were then developed but the constraint on achieving the 75:25 debt-to-equity ratio by 2041/42 was removed.
- The assumption of reduced O&A and BOC expenditures, applied in the 1st round IR, facilitates achievement of the target debt-to-equity ratio with lower even annual rate increase. However, the Coalition has not conducted any assessment of the potential impacts or risks of these reductions, while Manitoba Hydro has provided evidence that reduction in service levels and reliability has already occurred.

- The reclassification of certain cash flows to investing activities improves the forecasted capital coverage ratio but has no impact on overall cash flow amounts (i.e. the amount of cash generated and spent do not change).

Based on these findings, it is evident that the Coalition was only able to construct its final rate scenarios, CC10 and CC11, based on the results of the first 8 scenarios where a specified debt-to-equity ratio with a target date was set to establish an even annual rate path. The approach to constructing CC10 and CC11 are therefore not discernibly different from the construction of Manitoba Hydro's 2% rate path and one approach does not represent "rate smoothing" while the other represents "mechanistic goal seeking".

The critical difference, however, between the Coalition rate scenarios and Manitoba Hydro's 2% rate path is that the Coalition pretends that the 70% debt ratio target in 2039/40 as enshrined in *The Act* either does not exist or can be ignored because it is pending. Instead, Mr. Rainkie selects the achievement of a 75% debt ratio by 2041/42 as a target.

4.3. The 2% Rate Path Compared to Previous Financial Forecasts:

In addition to arguments related to the "mechanistic goal seeking" and debt-to-capitalization target associated with the 2% rate path, Mr. Rainkie also suggested, as summarized on page 54 of his evidence, that the following concerns exist with the 2% rate path:

- "*A reduction of the absolute levels of net debt by $2 billion despite the forecast that MH's assets will grow by $5 billion over the 20-year financial forecast period*"
- "*The expectation of an improvement in the MH debt to equity ratio of 5%, in the five-year period between 2034/35 and 2039/40, which is quite aggressive*"

In order for the debt-to-capitalization ratio to move from the 85:15 level as forecasted at March 31, 2023 to the 70:30 target by 2039/40, either net debt needs to decrease, equity needs to increase or a combination of both a net debt reduction and increase in equity is required.

Notably, both the reduction of net debt while assets grow and accelerated improvement of the debt-to-capitalization ratio in the last years of a forecast are not items unique to the current long-term financial forecast scenario. These aspects were present in previous Manitoba Hydro financial forecast scenarios and were also present in financial forecast scenario presented in MH Exhibit #93 from the 2017 GRA, which was a scenario that was based on MH16 Update that was requested by MIPUG on December 21, 2017. Manitoba Hydro provided a comparison of MH Exhibit #93 to the Amended Financial Forecast Scenario in response to COALITION/MH I-27a-b. MH Exhibit #93 showed a significant reduction in net debt simultaneous to a growth in assets (staring in 2028/29) as well as accelerated growth in retained earnings near the end of the forecast period. These aspects are shown in the figures below and are compared against the amended financial forecast scenario:

Figure 15 Debt Ratio in Amended Financial Forecast Scenario vs. MH Exhibit #93

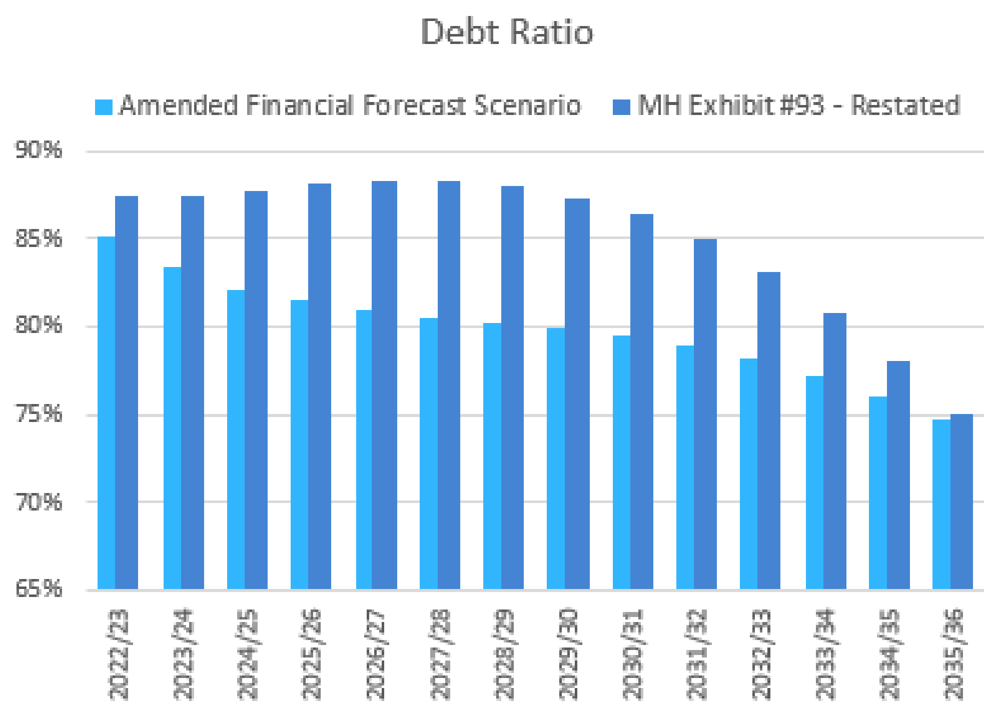


Figure 16 Retained Earnings in Amended Financial Forecast Scenario vs. MH Exhibit #93

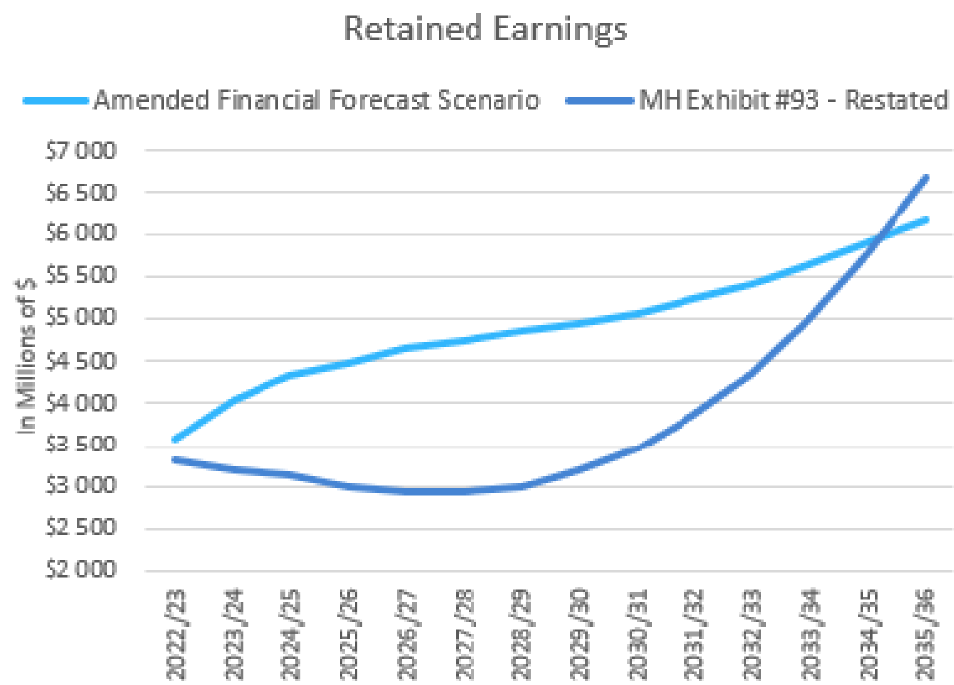
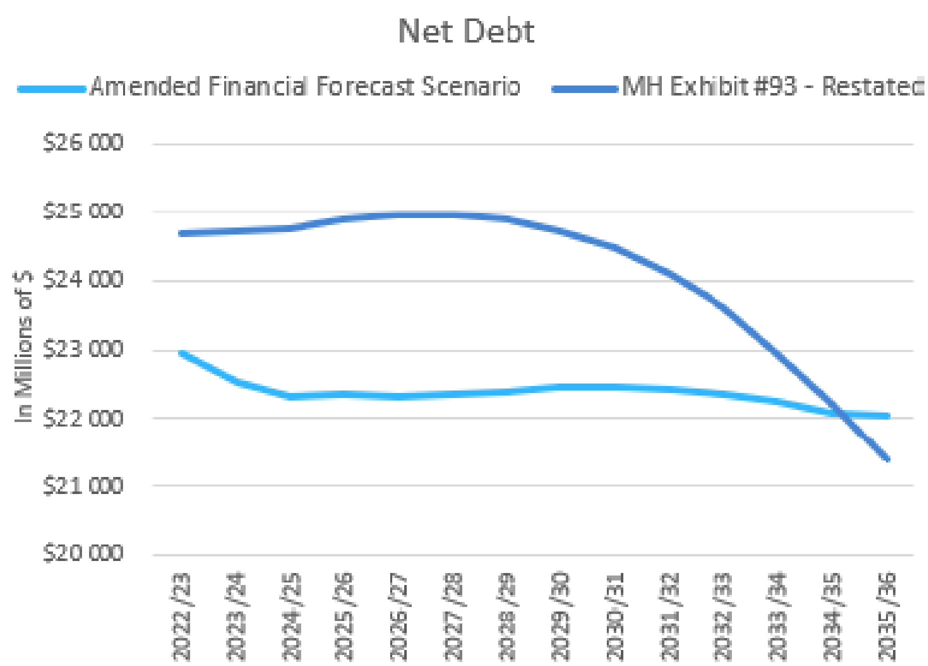


Figure 17 Net Debt in Amended Financial Forecast Scenario vs. MH Exhibit #93



When MH Exhibit #93 is compared further against the Amended Financial Forecast Scenario, the following is also evident:

- The previous, long-standing 75:25 debt-to-capitalization target is achieved in the same year under both forecasts, in 2035/36;
- The average annual rate increase under MH Exhibit #93 was 3.57% compared to the 2% rate path under the current financial forecast scenario; and,
- Average net income for the last 5 years under MH Exhibit #93 was approximately $659 million, compared to average net income of $436 million in the last 5 years under the amended financial forecast scenario.

The significant level of net income and resulting growth in equity at the end of the forecast under MH Exhibit #93 is primarily the result of increased revenue from the compounding effect of 3.57% annual rate increases. Similarly, the compounding effect of annual 2% rate increases under the Amended Financial Forecast Scenario results in increased net income and equity growth in the last 5 years of the forecast, but at a lesser rate of increase compared to MH Exhibit #93.

The above highlights that neither the reduction of net debt while assets grow nor accelerated improvement of the debt-to-capitalization ratio in the last years of a forecast are unique to the 2% rath path as presented in amended financial forecast scenario. In fact, these are expected outcomes associated with the application of even annual rate increases to achieve future financial targets.

4.4. Cash Flow in the 2% Rate Path and the Self-Financing Ratio

On pages 42 to 44 of his evidence (as well as other pages), Mr. Rainkie suggests that Manitoba Hydro has not adequately incorporated other financial targets into the establishment of the recommended 2% rate path and instead has focused only on the debt-to-capitalization targets.

As part of his evidence on those pages, and in support of rate path scenarios CC10 and CC11, Mr. Rainkie has identified the capital coverage ratio as an important financial target to consider and one of the "*long-standing MH financial targets to assess MH's financial health for rate-setting purposes.*" Mr. Rainkie provides the following definition for capital coverage ratio:

> *"**Capital coverage ratio**: a measure of the ability of MH to fund sustaining capital expenditures through cash flow from operations. The longstanding MH target was to maintain a capital coverage ratio of greater than 1.20."*

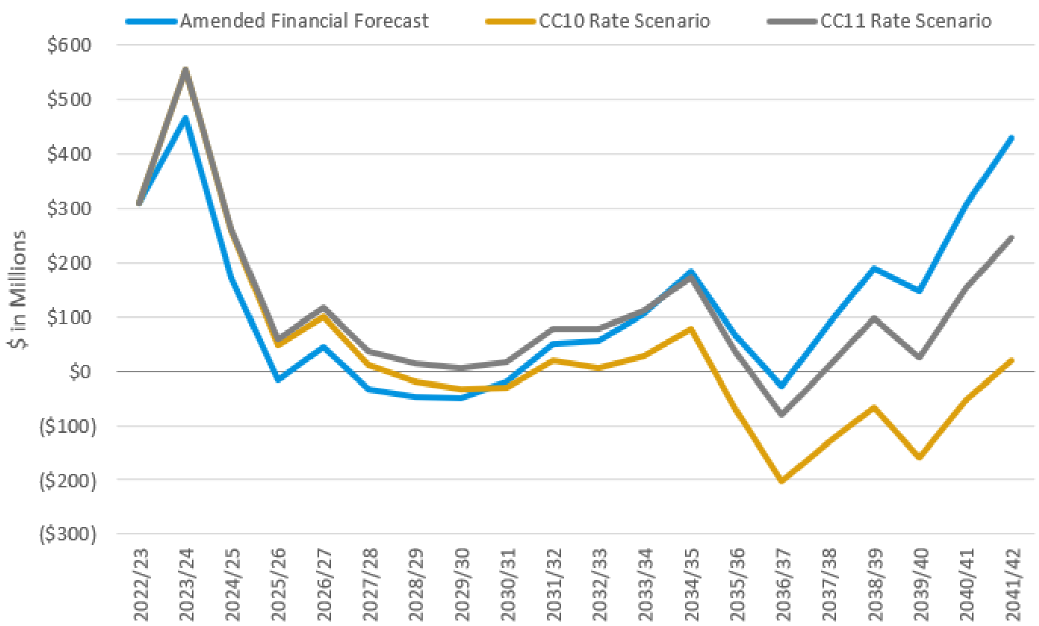
While debt-to-capitalization was highlighted by Manitoba Hydro as the primary metric in establishing the recommended rate path (as a result of the Debt Ratio Targets in *The Act*), other financial metrics considered in establishing the rate path included the cash surplus/deficit measure, the self-financing ratio and net income levels.

The cash surplus/deficit and self-financing ratio both provide a more straightforward view on Manitoba Hydro's cash flows compared to the capital coverage ratio. Whereas the capital coverage ratio excludes certain cash flows from its calculation,[5] the cash surplus/deficit and self-financing ratio both provide information on the overall amount of cash generated from operations and available for use compared to the amount of cash required for investing activities. The cash surplus/deficit and self-financing ratio therefore consider all cash inflows and outflows and the amount of cash remaining that is available to retire debt.

The following figure shows the cash surplus/deficit for Manitoba Hydro's Amended Financial Forecast Scenario with the proposed 2% rate path compared to CC10 and CC11:

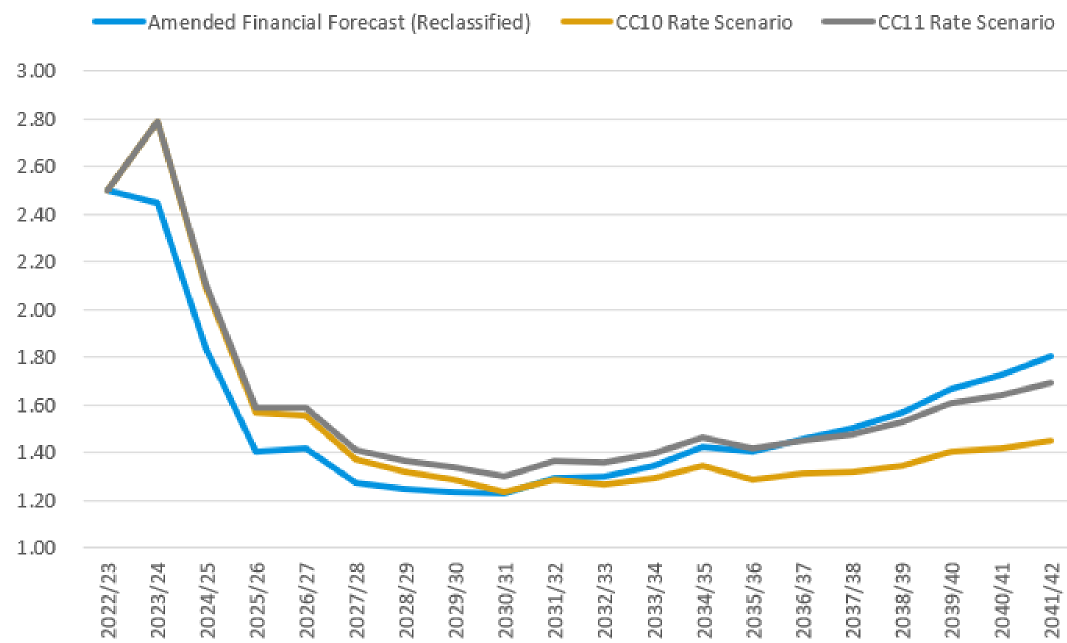
[5] See MIPUG/MH I-87 for a reconciliation of the difference between the capital expenditure amounts used in the capital coverage ratio vs. the total cash for investing activities from the cash flow statement.

Figure 18 Cash Surplus/(Deficit)



While the above Figure 18 clearly shows cash flow deficits under CC10 and reduced cash surpluses under CC11, these yearly differences in cash are not as evident when comparing each scenario using the Capital Coverage Ratio shown in Figure 19 below:

Figure 19 **Capital Coverage Ratio (assuming cash flows for regulatory deferrals as well as interest costs on the City of Winnipeg obligation are classified as investing activities)**



A comparison between the Amended Financial Forecast Scenario with the 2% rate path and the Coalition scenarios is further complicated by the cash flow reclassification (reclassification of certain cash flows as investing activities vs. operating activities) requested by the Coalition. The reclassification improves the capital coverage ratio but has no impact on the annual cash surplus/deficit and the annual change to net debt.

4.5. Consideration of a Cash Flow Metric in Establishing the Rate Path and Divergence Between Consumers Coalition Experts

While Manitoba Hydro and Mr. Rainkie do not agree on the preferred cash flow metric to consider as part the metrics used to establish the rate path, Mr. Rainkie's assertion that the Capital Coverage ratio should be considered as part of establishing a rate path suggests he considers the ability of Manitoba Hydro to fund sustaining capital expenditures through cash flow from operations to be a meaningful measure of financial health for the utility. Manitoba Hydro agrees that the ability to fund sustaining capital expenditures through cash flow from operations is important.

However, the evidence from the Coalition's other independent expert, MPA, challenges the importance of the ability of Manitoba Hydro to fund sustaining capital expenditures through cash flow from operations. On pages 17 through 20 of MPA's evidence they have made several conclusions related to Manitoba Hydro's view on debt and focus on self-financing capital expenditures. The arguments advanced by MPA are that:

- Manitoba Hydro's position around self-financing its capital purchases imply "*that debt is bad, and should be avoided if possible*" (page 17)
- "*Arbitrarily minimizing the use of debt in fact results in deliberately treating customers unfairly over time, and should be avoided unless there is a very good reason to do so*" (page 18)
- "*…use of debt to pay for capital assets should in fact be maximized, except to the extent that it is unavailable or becomes problematic from a financial risk perspective*" (page 18)
- "*The true issue at stake is the relative contribution of Equity and Debt to each year's capital spending, which is what determines the change in the Debt-to-Equity or Debt-to-Capitalization Ratio.*" (page 19)
- "*When Manitoba Hydro argues that **in the normal course of affairs** it believes its Self-Financing Ratio should be greater than one, this is just another way of saying that its total Debt should be falling. However, as discussed above, there is no a priori reason why this should be the case under regulatory principles*." (page 19)

These arguments are in direct contrast with Mr. Rainkie's position around considering the Capital Coverage ratio (a measure of the ability to fund capital investments from cash from operations) as one of the important financial metrics.

Notwithstanding this conflict, Manitoba Hydro's position around increased cash flow from operations to self-finance capital investments should not be interpreted as Manitoba Hydro stating that "*debt is bad and should be avoided*" or as an "*arbitrary minimization of debt*" as suggested by MPA. Manitoba Hydro's debt-to-capitalization ratio is anticipated to be 85:15 as at March 31, 2023 and in order to achieve the target debt-to-capitalization ratio of 70:30 by 2039/40, as required by *The Act,* a reduction in net debt and/or increase in equity over the forecast period is required. This was demonstrated in response to COALITION/MH I-11a-c.

MPA appears to recognize that either net debt will need to decrease, equity will need to increase, or both will need to occur in order to see a reduction in Manitoba Hydro's Debt-to-Capitalization ratio and achievement of the 70:30 target but have suggested this fact be ignored for the time being. On page 20 of their evidence MPA has said, "*Of course, Bill 36 will in fact require that the Debt-to-Capitalization Ratio fall from its current levels, assuming it comes into force as planned. However, it is not law today.*"

As noted above, Manitoba Hydro considers it to be prudent to factor the provisions of *The Act* into the determination of rates in the Test Years and the establishment of a smoothed long-term rate path rather than choose to ignore and defer for the time being that these provisions exist and will take effect in less than two years on April 1, 2025.

4.6. Manitoba Hydro's Current and Target Capital Structure

Manitoba Hydro has stated that once the 70% debt ratio target is achieved it intends to operate around a 70:30 debt-to-capitalization ratio.[6] That means that debt will continue to represent a sizable portion of the funds used for investing activities once the target capital structure is achieved.

Despite this indication, the issue of Manitoba Hydro's long-term capital structure target was also brought up as a concern by the Coalition, as follows:

- On page 46 of his evidence Mr. Rainkie has concluded that "*The third concern with respect to MH's goal-seek to develop the proposed 2% rate path, is that it results in a capital structure approaching that of an investor-owned utility and significantly exceeds the debt ratio targets in the new legislative framework by the end of the 20-year financial forecast.*"
- On page 7, Mr. Rainkie has also stated that Manitoba Hydro has set a rate path "*to attain a 40% debt ratio*[7] *by 2039/40.*"

[6] MIPUG/MH I-25.
[7] Manitoba Hydro has interpreted Mr. Rainkie's statement to mean a 40% equity ratio, not debt ratio.

While Manitoba Hydro's current long-term financial forecast scenario shows continued 2% rate increases (under a 2% rate path) after achievement of the 70:30 target, which results in the debt-to-capitalization ratio reaching 66:34 by the end of the 20-year forecast period, Manitoba Hydro clarified[8] that it intends to manage the capital structure around the 70% target, allowing movement slightly above or below. In the same response, Manitoba Hydro also clarified that the 70% debt-to-capitalization target is well within the range of the target capital structure of other Crown-owned utilities, as shown below:

Figure 20

Crown Owner Utilities	As at 2021/22	Target Ratio
BC Hydro	78:22	60:40
Hydro Quebec	65:35	75:25[9]
Sask Power	72%	60%-75%

The 70% debt ratio target (or 30% equity ratio target) is not like that of investor-owned utilities. The data referenced by Mr. Rainkie shows the following for equity ratios of investor-owned utilities, outlining a Canadian Electric Average of just under 40% equity (or a 60:40 debt ratio) and a U.S. Electric Average of just under 50% equity (or a 50:50 debt ratio):

[8] COALITION/MH II-10-c-d.
[9] The Québec government may not declare, in respect of a given year, a dividend in an amount that would have the effect of reducing the capitalization rate to less than 25% at the end of the year.

Figure 21

Operating Utility	Equity Return	Equity Ratio	Weighted ROE
FortisBC Inc. (existing)	9.15%	40.00%	3.66%
FortisBC Inc. (proposed)	10.0%	40.00%	4.00%
ATCO Electric	8.50%	37.00%	3.15%
Nova Scotia Power	9.00%	37.50%	3.38%
Hydro One Ltd.	8.66%	40.00%	3.34%
Newfoundland Power	8.50%	45.00%	3.83%
FortisAlberta	8.50%	37.00%	3.15%
Maritime Electric	9.35%	40.00%	3.74%
Canadian Electric Average	8.75%	39.42%	3.45%
Canadian Electric Median	8.50%	38.75%	3.36%
U.S. Electric Average	9.50%	49.64%	4.72%
U.S. Electric Proxy Group Average	9.59%	49.76%	4.77%

5. Manitoba Hydro has incorporated an assessment of previous risks into its recommended rate path and has taken a forward view of the risks it faces

Mr. Rainkie has questioned the overall completeness and balance of the risk assessments contained in the Application, the overall effectiveness of the current Enterprise Risk Management Program at Manitoba Hydro compared to the previous risk management framework, inconsistencies in policy and spending and the role of uncertainty analysis modelling. The following sections provide Manitoba Hydro's rebuttal on those matters.

5.1. Manitoba Hydro's Risk Assessments are complete and balanced for rate setting purposes

Pages 29-30 of Mr. Rainkie's evidence asserts that the risk assessments contained in the Application are both incomplete and not balanced.

Manitoba Hydro disagrees with the assertion and believes it has appropriately considered this balance within the risk assessments. As mentioned in response to AMC/MH II-1c, it is important to reference and understand the definition of risk as contained in the Application (Tab 2, Section 2.7.2) – "risk is the *uncertainty* of outcome, whether *positive opportunity* or *negative threat*, of actions or events". Recognizing and speaking to this uncertainty throughout the Application on a variety of different risk areas (i.e. evolving energy landscape) is the acknowledgement that there are multiple potential outcomes and is not indicating any predetermined conclusion on future impact to Manitoba Hydro.

Further, Manitoba Hydro has acknowledged throughout the current regulatory process that it expects the projected growth in its risk universe to include both potential *negative threats* (i.e. downside risk) and potential *positive opportunities* (i.e. upside risk) as these risks being largely driven by the *overall uncertainty* in the evolving energy landscape and federal/provincial considerations to both climate change and emission targets. The pace and breadth of these anticipated changes are unpredictable, and the results are increasing long-term uncertainty.

5.2. Manitoba Hydro has incorporated an assessment of previous risks into its recommended rate path and have taken a forward view of the risks it faces

At pages 31-32 of Mr. Rainkie's evidence, he asserts that proper risk evaluation for rate setting purposes should be based on the differences in risk assessments contained in previous regulatory proceedings and that Manitoba Hydro has not acknowledged that there are certain risks discussed in previous regulatory proceedings no longer impacting the corporation.

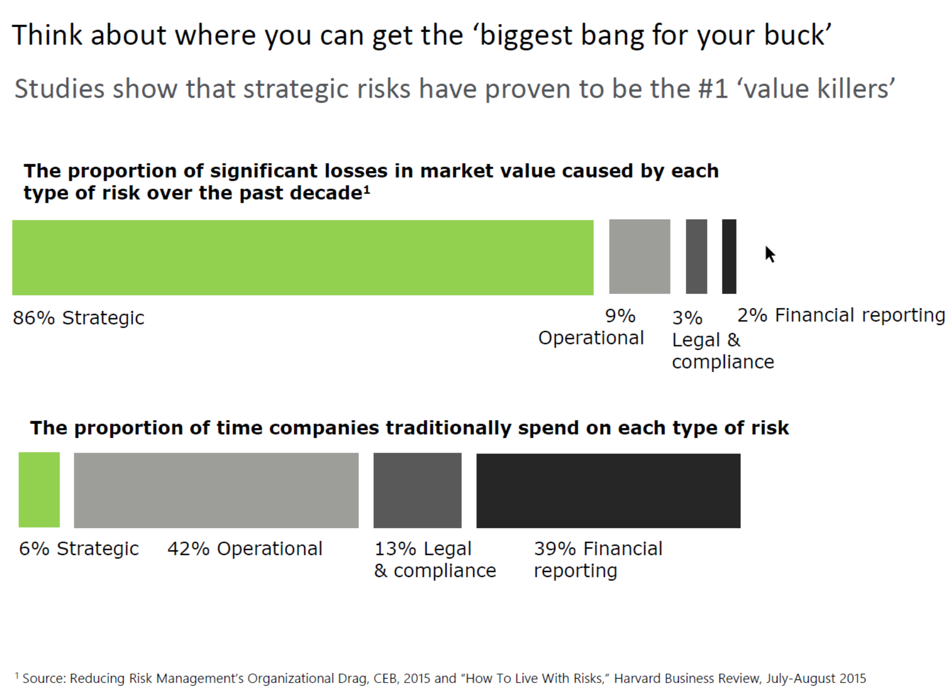
Manitoba Hydro believes Enterprise Risk Management ("ERM") needs to be a forward-looking risk management approach to strengthen an organization's ability to manage both existing and emerging risks.

Further, Manitoba Hydro disagrees that it has not acknowledged or reflected the impacts of certain identified risks from previous regulatory proceedings in its current Application.

A properly built, forward-looking Enterprise Risk Management function provides significant organizational value by identifying both emerging and strategic enterprise-level risks across the business horizon. The longer the horizon, the more lead time an organization will have to prepare and mitigate risk exposure. These risks can include trends in the external environment and may be considered emerging with elevated uncertainty for many years (i.e. evolving energy landscape).

In the illustration below, the Harvard Business Review published research that shows how critical strategic risks are to business value and how traditionally these risks do not receive the commensurate oversight and monitoring that is needed to ensure effective mitigation. These results speak to why best practice based ERM Programs need continued focus and visibility to these forward facing, strategic risks.

Figure 22



Manitoba Hydro's ERM Program will continue to include this proactive, forward-facing view in its approach to enterprise risk management. The results will continue to be valuable for consideration in both current and future regulatory proceedings for rate setting purpose. Section 2.7.5 in Tab 2 of the Application provides greater detail on Manitoba Hydro's ERM Framework and how it is designed and based upon industry best practices, incorporating aspects of both the COSO Enterprise Risk Management framework model and the ISO 31000 Risk Management model.

Further, Manitoba Hydro acknowledged and included the overall effects of the previously identified Major Capital Project risks contained in previous regulatory proceedings when determining its recommended rath path within the Application. As was mentioned in Section 4 above, these aspects, along with other improvements in Manitoba Hydro finances, were present in previous Manitoba Hydro financial forecast scenarios and were also present in the financial forecast scenario presented in Exhibit #93 (MH Exhibit #93) from the 2017 GRA.

This demonstrates that Manitoba Hydro recognized and acknowledged that the potential impacts of these specific risks improved, with the associated impacts being built into these previously noted financial forecast scenarios.

5.3. ERM Program at Manitoba Hydro is not the historical siloed view of Risk Management

On page 31 of the evidence submitted by Mr. Rainkie, he asserts that previous efforts surrounding risk management at Manitoba Hydro would, in today's risk environment, be considered industry standard and best practice based.

It is important to understand that previous efforts of the risk management function at Manitoba Hydro were focused more on a historical, siloed risk management approach rather than enterprise risk management (RM vs. ERM).

The historical siloed approach to risk management is centered on organizations assigning functional areas leadership, with the responsibility and accountability for understanding and managing the risks that an organization faces in attempting to achieve its objectives. Figure 23 below shows the organizational depiction of this approach.

Figure 23 - Historical Siloed Approach to Risk Management

As described by North Carolina State Poole College of Management in its report titled "What is Enterprise Risk Management (ERM)?"[10] the following are limitations of this approach:

- having risks that fall between silos or functional areas;
- reduced organizational understanding of the dependencies between risks;
- lack of shared understanding of how mitigations of one risk may impact other enterprise risks; and,
- inability to successfully connect risk management efforts to strategic planning.

The previous risk management framework at Manitoba Hydro experienced the above noted limitations. Other areas of limitation also included infrequent reporting cycles for internal stakeholders, enterprise level risk assessments only done on an annual basis and varied gaps in ensuring mitigation of risk was occurring.

As stated in Tab 2 of the Application, The Committee of Sponsoring Organizations of the Treadway Commission ("COSO") defines enterprise risk management as "*the culture, capabilities and practices integrated with strategy setting and performance, that an organization relies on to manage risk in creating, preserving, and realizing value through; developing capabilities, applying practices, integrating with strategy-setting and performance, and managing risk to strategy and business objectives*".

[10] Mark Beasley, "What is Enterprise Risk Management?" (2019), NC State University Poole College of Management at 1, online: <[What_is_Enterprise_Risk_Management.pdf (ncsu.edu)]>.

Additionally, the North Carolina State Poole College of Management states "*the objective of enterprise risk management is to develop a holistic, portfolio view of the most significant risks to the achievement of the entity's most important objectives*".

Building off the above best practice principles, Manitoba Hydro's ERM Program will have these updated capabilities and are all being developed and sequenced in a deliberate manner to ensure they are being built the right way and reasonably measured for the enterprise. Additional details on these updated capabilities are included in Figures 2.4 and 2.5 in Tab 2 of the Application.

5.4. The Uncertainty Analysis model and intent for the future

On page 38 of Mr. Rainkie's evidence, he suggests that Manitoba Hydro's decision to not keep its Uncertainty Analysis represents a significant step backwards in terms of its ERM Program and the analysis of risks for rate setting purposes.

The absence of the uncertainty analysis in this rate application is not a step backward but rather a prudent pause while prerequisite initiatives are further developed before the inputs, assumptions and methodologies underpinning the uncertainty analysis are revisited with more fully developed information. In particular, the findings of the IRP must first be studied and understood before the financial modelling inputs can be developed and tested using this information. That is a key first step to producing a meaningful analysis. The usefulness of the uncertainty analysis is dependent on the quality of the inputs used in the model. Other reasons for the pause in development of the uncertainty analysis were also outlined in response to PUB/MH I-21.

Mr. Rainkie's further suggestion on page 38 of his evidence that Manitoba Hydro's "*Uncertainty Analysis is significantly more robust than one-off risk sensitivities*" is not supported with any evidence. A key element of any risk analysis is understanding the potential impact of each identified risk. The sensitivities analysis presented in Section 4.4 of Tab 4 and in Appendix 4.4 is an effective method to isolate the financial impact of each risk and is foundational to understanding any form of combined sensitivity analysis. In fact, a combined sensitivity analysis can be less informative (or less robust) if the underlying risks are not well understood. In many cases, no one form of risk analysis will tell the complete story. Mr. Rainkie's attempt to convey that the extensive body of evidence that is currently on the record is severely lacking due to the absence of the uncertainty analysis is without merit.

On page 53 of Mr. Rainkie's evidence, he suggests that conclusions and recommendations from the 2019/20 Manitoba Hydro General Rate Application with respect to the use of the Uncertainty Analysis to consider rule-based regulation are as applicable now as they were in the prior Manitoba Hydro rate proceeding.

The "*conclusions and recommendations from the 2019/20 MH Rate Application*" that Mr. Rainkie is referencing are conclusions and recommendations made by the Coalition. The PUB made no conclusions and recommendations related to the Uncertainty Analysis in either Order 59/18 or 69/19, and Directive #9 from Order 69/19 neither mentions nor links the Uncertainty Analysis to the technical conference that was to consider the use of rule-based regulation to provide guidance in setting rates. Directive #9 reads as follows:

> **<u>Directive #9 in Order 69/19</u>**
> *Manitoba Hydro participate in a technical conference hosted by Board staff or an external consultant appointed by the Board for the consideration of the use of rule-based regulation to provide guidance in the setting of consumer rates and of the question of the role and sufficiency of reserves in Manitoba Hydro's operations and the Board's rate regulation of the Utility*

In Order 70/22 the PUB varied Directive #9 as follows:

> *Directive #9 in Order 69/19 BE AND IS HEREBY VARIED as the Board now directs Manitoba Hydro to include in its November 15, 2022, General Rate Application, Manitoba Hydro's proposed financial targets together with all underlying assumptions, including financial metrics, in each of the long-term financial scenarios presented*

In compliance with varied Directive #9, Manitoba Hydro has proposed financial metrics as part of the Application and in the presentation of the Amended Financial Forecast Scenario. Interveners were advised they could request limited additional long-term financial scenarios based on different assumptions as part of the MFR and IR processes.

Mr. Rainkie and MPA's suggestion to ignore the new legislative regulatory framework in Manitoba such to re-engage in the debate on rule-based regulation and the setting of appropriate Debt Ratio Targets as part of this proceeding does not align with the direction from the PUB in Order 70/22. Additionally, the suggestion appears impractical given the fast approaching operative date of the new legislative framework in Manitoba which establishes a clear path for rule-based regulation (i.e. Debt Ratio Targets (with target dates) and Rate Caps) for Manitoba Hydro effective April 1/25.

6. Manitoba Hydro continues to consider drought reserve storage requirements in its operations

Daymark Energy Advisors ("DEA") discusses Drought Reserve Storage ("DRS") at pages 80-81 of its report:

> *"Three significant improvements in MH hydrology forecasting warrant discussion. First, MH now uses physically-based inflow forecasting (PBIF) to forecast short-term hydrology. Second, MH now utilizes the Drought Reserve Storage (DRS) concept for ensuring sufficient water supplies into the future. And finally, MH now performs a "cold snap" analysis to stress test DRS to ensure the resulting water supply target can withstand a "[redacted][90][90 GRA Filing Appendix 5.3 – Manitoba Hydro's Drought Management Planning Document, p. 25.]* **4a & 4b**
>
> *…*
>
> *With respect to drought reservoir management, MH now tests for sufficient energy supply over time by constraining the modeling using the DRS value rather than a simpler volume target. According to MH documentation, "The DRS is the minimum potential energy in Manitoba Hydro's major reservoir storage that is needed at the start of the next water year (i.e., Y2), such that firm demand can be met assuming the most severe single year drought of record is repeated.*

> *Finally, the inclusion of a "cold snap" test provides for a conservative plan for meeting domestic and firm export energy under a reasonable "worst case scenario." This test provides a check on the economic optimization model that might lead to energy being sold due to high short term value when that energy is needed for other policy purposes."*

DEA has implied that Manitoba Hydro's practice of protecting Drought Reserve Storage is a new practice in stating, "**MH now utilizes the Drought Reserve Storage (DRS) concept** for ensuring sufficient water supplies into the future." (emphasis added). Conserving storage to protect for drought is not a new practice for Manitoba Hydro. Although the terminology "Drought Reserve Storage (DRS)" may be relatively new, having been used by Manitoba Hydro for about 10 years, Manitoba Hydro's operations have always considered storage requirements for drought.

This has been discussed in depth at prior PUB proceedings. For example, during the 2004 GRA hearing, Mr. Cormie explained how storage was conserved through the 2003-04 winter to protect for the possibility of severe drought in 2004/05:

> *"MR. DAVID CORMIE: We were serving the -- primarily the Manitoba load. I believe through the winter season we bought down the vast majority of our export obligations.*
>
> *And so this operation was designed to ensure that the Manitoba load could be met as well as maintain our reservoir -- our energy in storage targets for the end of the fiscal year so that we would be able to continue to meet the power demand should the drought --continue in 2003/04 -- in 2004/05."*

DEA has also implied that the improvement to the DRS analysis is a new practice where they state, *"MH now tests for sufficient energy supply over time by constraining the modeling using the DRS value rather than a simpler volume target*". As discussed above, Manitoba Hydro has always defined its storage requirements based on energy needs and planned its energy operations accordingly. The improvement referred to by DEA is better characterized as one that is based on additional water volume analyses. With the addition of the Manitoba-Minnesota Transmission Project, Manitoba Hydro's firm import capability has doubled. Considering energy needs alone and other supply and demand factors it is possible to meet Manitoba Hydro's firm power requirements for periods in the year when Manitoba load is lower, such as in spring, with Lake Winnipeg outflows operating below the minimum required by licence.[11]

To ensure Manitoba Hydro can reliably meet energy demands and maintain minimum Lake Winnipeg outflow, Manitoba Hydro's reservoir storage target also considers the minimum total volume of water required in Lake Winnipeg and Cedar Lake, which is upstream of Lake Winnipeg. This was explained on pages 17-18 of Appendix 5.3 Drought Management Planning:

> *"Generally, once per year, Manitoba Hydro undertakes an evaluation to define its Drought Reserve Storage (DRS) requirement. The DRS is the minimum potential energy in Manitoba Hydro's major reservoir storage that is needed at the start of the next water year (i.e., Y2), such that firm demand can be met assuming the most severe single year drought of record is repeated along with other assumptions described in this section. The evaluation of DRS is typically carried out in early spring using the Energy Security Planning Assumptions and may be updated periodically through the year depending on conditions. The Drought Reserve Storage requirement must satisfy all operating licenses, including reservoir level limits and minimum outflows that impact Manitoba Hydro's storage flexibility, as well as minimum flow requirements determined through a detailed assessment of short-term severe loading conditions."*

7. Debt Management Strategy and Treasury Risks

7.1. Treasury Risk Tolerances

Mr. Rainkie repeatedly suggests that treasury risk tolerances are heavily influenced by the $23 billion level of net debt and the $1.1 billion annual projected refinancing requirements over the next decade, prompting policy changes from Manitoba Hydro

[11] Manitoba Hydro's Water Power Act Licence for the Lake Winnipeg Regulation project requires that the total outflow from Lake Winnipeg shall not be less than 25,000 cubic feet per second.

to reduce tolerances for interest rate risk and levels of floating rate debt.[12]

Manitoba Hydro does not agree that it has reduced its absolute risk tolerance to interest rate risk as suggested by Mr. Rainkie.

7.1.1. Absolute Interest Rate Risk Exposure Remains at Similar Levels

Although the level of Manitoba Hydro's debt of approximately $24 billion at March 31, 2023, has influenced the strategy of reducing the proportion of floating rate debt as well as amending the interest rate risk policy and guidelines to lower the proportion of floating rate debt, Manitoba Hydro's interest rate risk guidelines and risk profile allow for similar levels of absolute interest rate risk exposure.

As indicated in the response to COALITION/MH I-44b-j pages 30-31, the maximum floating rate debt that Manitoba Hydro has historically held is $2.1 billion (in 2013/14) which would equate to approximately 9% floating rate debt in today's debt portfolio, or approximately the mid-point of the revised guideline range of 0%-20%. When this floating rate debt was outstanding in 2013/14, it represented 19% of the debt portfolio, or approximately the mid-point of the guideline range of 15%-25% at that time. This is summarized in the following figure:

Figure 24

In Billions of $	2013/14		2022/23
Hist. Max Floating Rate Debt Level	$2	→	$2
Total Debt Level	$11		$24
Floating Proportion	19%	midpoint	9%
Floating Rate Guideline Range	15-25%	of range	0%-20%

The independent National Bank Financial ("NBF") model suggests that the higher the total debt level, the lower the recommended floating (variable) rate percentage when holding all other variables constant.[13] The analysis suggests that a debt portfolio with a high proportion of floating rate debt will result in higher interest expense volatility. Intuitively, as the absolute debt level grows, so too does the interest expense

[12] Revenue Requirement Evidence Prepared by Darren Rainkie On Behalf of The Consumers Coalition, dated April 3, 2023, pgs. 4, 8, 80-82, 92, 112 and 117.
[13] See response to Coalition/MH II-25d.

volatility. To maintain the same interest expense volatility, all other things being equal, a lower floating rate proportion would be required.

Manitoba Hydro has not reduced its absolute interest rate risk tolerance, it has simply amended the policy and guidelines to adjust the proportion of floating rate debt to allow for similar levels of interest expense volatility.

As indicated on page 5 of the Debt Management Strategy, in the near term, Manitoba Hydro will maintain the percentage of floating rate debt within the debt portfolio to below 10% of the debt portfolio. At current debt levels of approximately $24 billion, this would equate to $2.4 billion, thus maintaining a similar level of maximum interest expense volatility as it has historically**.**

7.2. Peer Group Comparatives

Mr. Rainkie repeatedly states that Manitoba Hydro's floating rate debt assumptions in the Amended Financial Forecast Scenario (referred to by Mr. Rainkie as MH22) of 1.3% in the early years, building to 7.0% at the end of the forecast, are materially lower than peer group analysis (6% to 16%) would suggest.[14]

Manitoba Hydro does not agree that its floating rate percentages are materially lower than its peers particularly when comparable information and pertinent risk factors are considered.

7.2.1. Beyond Selective Comparisons

Mr. Rainkie asserts that the peer group maintains between 6-16% floating rate debt; however, several peers were not represented in the one year selected (2022) from the table in COALITION/MH II-25a, as annual reports were not available. In 2021, when all peers have reported data, the peer range is 1%-19% which is very similar to the new Manitoba Hydro target guideline for floating rate debt of 0%-20%. In fact, Newfoundland and Labrador Hydro reported between 1%-3% floating rate debt in the reported periods, lower than Manitoba Hydro's 1%-5%.

[14] Revenue Requirement Evidence Prepared By Darren Rainkie On Behalf of The Consumers Coalition, dated April 3, 2023, pgs. 4, 8, 80, 85-88, and 92.

Figure 25 Peer Group Historical Floating Rate Debt %

Peer Group Historical Floating Rate Debt %

	2018	2019	2020	2021	2022
Manitoba Hydro	4%	5%	3%	1%	1%
BC Hydro	10%	13%	12%	11%	11%
SaskPower	17%	14%	13%	6%	11%
Hydro Quebec	9%	5%	7%	7%	6%
NB Power	17%	16%	13%	11%	16%
Nfld. & Labrador Hydro	2%	2%	3%	1%	n/a
Emera Inc.	14%	18%	18%	19%	n/a
Fortis Inc.	10%	13%	10%	9%	10%
Canadian Utilities Limited	11%	8%	8%	10%	n/a

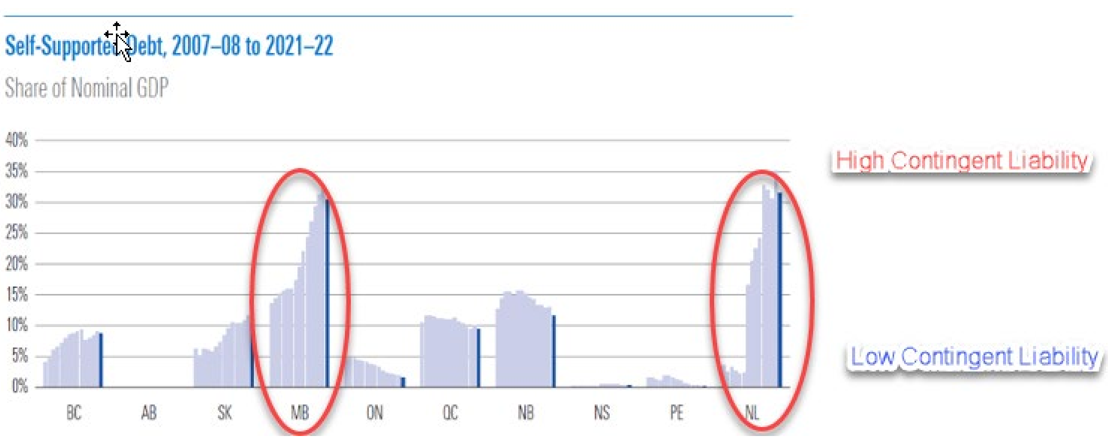
Note: Floating Rate Debt = Long Term Floating Rate Debt + Short Term Debt
Sources: Annual Reports
n/a: Reports not yet available

7.2.2. Pertinent Risk Factors Differentiating Manitoba Hydro from Peers

1) High Debt to GDP Ratio and Contingent Liability to Province

Interestingly, as seen in Figure 4.37 in Tab 4 of the Application, DBRS shows that Newfoundland and Manitoba have the distinction of having Government Business Enterprises with the highest debt relative to GDP of any province which means Manitoba Hydro and Newfoundland & Labrador Hydro represent the highest contingent liabilities to their respective provinces as compared to their peers.

Figure 26

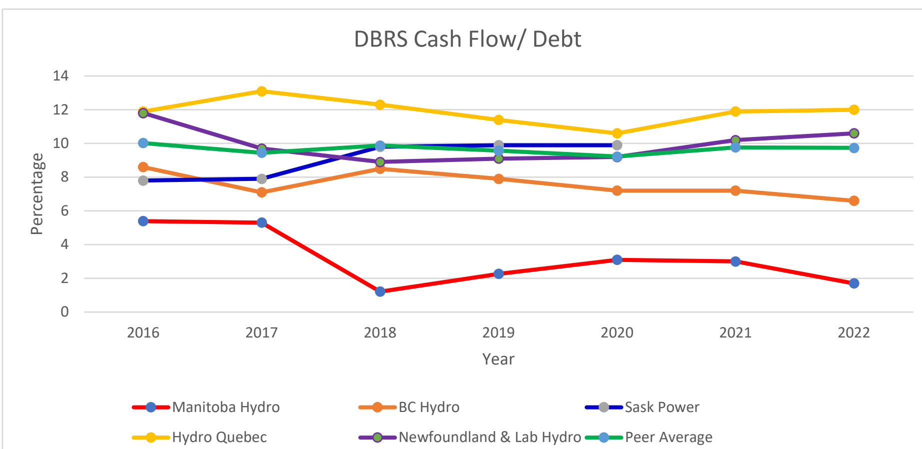


Confirming this, Moody's comments on the Province of Manitoba's top credit challenge as being the elevated debt burden and contingent liability risk of Manitoba Hydro in its most recent July 7, 2022 Credit Opinion on the Province of Manitoba.[15]

2) Low Cash Flow to Debt Ratio

Manitoba Hydro's peer utilities have an average cash flow to debt ratio of over 9% over the period 2016-2022 as indicated in Figure 4.38 in Tab 4 of the Application. Borrowing to fund the construction of major new generation and transmission projects increased Manitoba Hydro's total debt portfolio by 3.25 times from 2005 to 2022. During this time, Manitoba Hydro's Cash Flow to Debt ratio has decreased from approximately 9% (2005-2009) which was similar to its peers, to approximately 2% (2018-2022) as rates collected from customers have not kept up with the debt growth (MFR 78). As a result, Manitoba Hydro has less financial flexibility to increase its interest expense volatility as compared to most peers.

Figure 27 Utility Comparison of DBRS Ratio of Cash Flow to Total Debt



3) Legislative Framework Limiting Rate Increases and Increasing Business Risk

The Manitoba Hydro Amendment and Public Utilities Board Amendment Act ("*The Act*") limits annual rate increases effective April 1, 2025 to 5% or the rate of inflation, whichever is less. This limitation is recognized by credit rating agencies

[15] See Tab 4 of the Application, Appendix 4.6, pg. 7.

as an increase to business risk. As indicated in COALITION/MH I-6i, S&P downgraded Nova Scotia Power following legislation by the Province of Nova Scotia to limit the utility's rate increases to the end of 2024. S&P viewed the rate cap as significantly increasing Nova Scotia Power's business risk and indicated the utility must maintain a Funds from Operations (Cash Flow) to Debt ratio above 10% to avoid further downgrades.

7.2.3. Treasury Risks Not Overstated

Manitoba Hydro does not agree with Mr. Rainkie's suggestion on page 80 of his evidence that Manitoba Hydro has purposely overstated its treasury risks to support its proposed 2% rate path.

Manitoba Hydro has an elevated risk exposure as compared to peers as a result of both the level of debt which needs to be serviced, and limited cash flow with which to service the debt. This is clearly demonstrated by the fact that Manitoba Hydro's cash flow to debt ratio is not expected to exceed 5% in the first decade of the Amended Financial Forecast.

Despite this elevated risk exposure, Manitoba Hydro will continue to employ appropriate debt management strategies which do not pose undue risk to itself and its stakeholders including maintaining an interest rate risk profile which is manageable in the risk context.

7.3. Updated Independent National Bank Financial ("NBF") Analysis

Mr. Rainkie repeatedly opines that Manitoba Hydro's floating rate debt assumptions in the Amended Financial Forecast Scenario (1.3% in the early years, building to 7.0% at the end of the forecast) are materially lower than updated independent analysis (8% to 15%).[16]

Manitoba Hydro does not agree that its interest rate risk profile is materially lower than the updated NBF independent analysis suggests when considering the following

[16] Revenue Requirement Evidence Prepared by Darren Rainkie on Behalf of The Consumers Coalition, dated April 3, 2023, pgs. 4, 8, 80, 85-88, and 92.

limitations of the model.

7.3.1. Limitations of the NBF Model

1) Does not Consider Complete Interest Rate Risk Profile

   A significant limitation of the NBF model is that it does not take into consideration the interest rate risk to refinance debt maturities on new debt borrowings. While Manitoba Hydro still considers the model to be of value, the corporation is mindful of this limitation when considering the interest rate risk profile. Rather than considering the suggested range for simply the short-term debt and floating rate debt, Manitoba Hydro includes the fixed rate long-term debt maturing in the next 12 months as well.

2) Does not Consider the New Legislative Framework Limiting Rate Increases

   The NBF model does not consider Manitoba Hydro's limited ability to request higher rate increases as a result of *The Act.* Limited rate increases reduce Manitoba Hydro's capacity to absorb interest rate risk volatility.

3) Does not Consider Manitoba Hydro's High Debt to GDP Ratio and Contingent Liability Status to Province

   The NBF model does not consider the elevated risk resulting from Manitoba Hydro's debt levels being a high contingent liability to the Province of Manitoba. Being a high contingent liability to the Province has the potential to impact cost of debt should Manitoba Hydro be deemed to be not self-supporting.

When considering and factoring in these limitations of the NBF model, it is appropriate for Manitoba Hydro to remain at the lower end of the optimal floating rate range calculated in the independent analysis (8%-15%) to avoid elevating risk beyond manageable levels.

7.3.2. Current and Forecast Interest Rate Risk Profiles are Not Materially Lower than the Updated Floating Rate Range from the NBF Model but at the Lower Boundary of the Range

As indicated on page 17 of the Debt Management Strategy, at September 30, 2022 Manitoba Hydro had $1.9 billion or 8% of the existing debt portfolio subject to interest rate risk. Looking at the forecast years from 2023-2042 in the Amended Financial Forecast Scenario, the interest rate risk profile including floating rate debt, short term debt and fixed rate long term debt maturing in the next 12 months is forecast to be in the range of 5%-10% with an average of 8% over the 20-year timeframe (COALITION/MH I-44 pages 6-12) putting the interest rate risk profile at the lower boundary of the updated independent analysis.

With respect to Mr. Rainkie's assertion on page 83 of his evidence that, "*Over the first 10-years of the forecast period the average of floating rate debt and debt to be refinanced is 7.6% compared to the new guideline of 25% and the debt to be refinanced is 4.4% as compared to the new guideline of 10%*", Manitoba Hydro clarifies that the <u>25% is the policy limit,</u> not guideline for the aggregate of floating rate debt, short term debt, and fixed rate long term debt to be refinanced within the subsequent 12-month period within the total debt portfolio. Manitoba Hydro clarifies that <u>10% is the guideline limit</u> for debt maturing within 12 months, not a target. Amounts that exceed these limits would indicate non-compliance with policy and guidelines and to maintain risk at manageable levels, Manitoba Hydro must be below the limits.

7.4. Concentration Risk and Interest Rate Risk Management

Mr. Rainkie repeatedly suggests that it is Manitoba Hydro's own assessment that its debt maturities of $1.1 billion or 5% on an annual basis is well within its interest rate risk guidelines and does not represent concerns over debt concentration risk. However, then Mr. Rainkie implies that these treasury risks are overstated by Manitoba Hydro to support Manitoba Hydro's proposed 2% rate path.

Manitoba Hydro does not agree with Mr. Rainkie's suggestion that maintaining concentration risk within guideline levels is evidence that Treasury risks are being overstated by Manitoba Hydro.

7.4.1. Concentration Risk is Only One Part of Managing the Interest Rate Risk Profile

Refinancing risk cannot be looked at in isolation. While having $1.1 billion or 5% of the debt portfolio maturing each year for the next decade is significant, Manitoba Hydro actively manages its interest rate risk profile. For example, during the past decade, there was significant interest rate risk on new borrowings so Manitoba Hydro accordingly responded by reducing the percentage of floating rate debt within the existing debt portfolio to lower interest rate risk. Manitoba Hydro also chose longer dated debt maturities that extended the debt portfolio's weighted average term to maturity and kept the concentration risk manageable.

7.4.2. Manitoba Hydro is Responsive to its Interest Rate Risk Profile

Despite Mr. Rainkie's assertions otherwise (page 86 of his evidence), Manitoba Hydro did respond in COALITION/MH-I 44 (page 32), that as interest rate risk from new borrowings has abated, Manitoba Hydro expects to gradually raise the percentage of floating rate debt. In the near term, Manitoba Hydro will continue to manage the interest rate risk profile to maintain the aggregate of short term, floating rate long term debt and fixed rate long term debt maturing in the next 12 months below 10% of the debt portfolio.

7.4.3. Simplifying Forecast Assumption Understates Concentration Risk in the Forecast

As noted in PUB/MH I-27a, the forecast has a simplifying assumption that new forecast issuance has a term to maturity of 20 years. In practice, Manitoba Hydro will likely issue in the 5-year, 10-year, 30- year and ultralong terms with some medium-term notes of varying maturity dates. This simplifying assumption will result in the forecast concentration risk being understated as at least 50% of the debt that will be refinanced in the next decade, will be refinanced again in this 20-year forecast period.

7.4.4. Interest Rate Risk is an Elevated Risk for Manitoba Hydro

The large exposure to interest rate risk in the refinancing of this maturing long-term debt in the coming decade, while manageable, is subject to an interest rate environment which has changed dramatically within the space of a year. From March 2022 to January 2023, the Bank of Canada raised its target overnight rate from 0.25% to 4.5%. With the tightening of monetary policy having occurred at a record pace, it is anticipated the interest rate outlook will be subject to extraordinary uncertainty. Even when the Bank of Canada is able to get inflation under control, keeping it there may be more difficult than in the past. To do so, the bank may have to keep interest rates higher and adjust them more frequently, on average, than before the COVID-19 pandemic. These higher rates and the uncertain environment keep interest rate risk elevated for Manitoba Hydro. The trajectory of debt servicing costs remains a focus for credit rating agencies monitoring Manitoba Hydro's ability to service its debt obligations.

7.5. Layers of Liquidity Protection

Mr. Rainkie states that Manitoba Hydro is planning multiple layers of liquidity protection (cash, sinking funds, short and long-term debt) and has not forecast any significant use of the larger $1.5 billion short term debt facility in the Amended Financial Forecast Scenario, resulting in finance costs that are overstated for rate-setting purposes. Mr. Rainkie asserts that each of these layers of protection has an associated cost for ratepayers.[17]

Manitoba Hydro emphasizes that each of these 'layers of liquidity protection' have been used for decades. Manitoba Hydro will address each 'layer' to disprove Mr. Rainkie's position that they are resulting in finance costs that are overstated, for rate-setting purposes.

[17] Revenue Requirement Evidence Prepared By Darren Rainkie On Behalf of The Consumers Coalition, dated April 3, 2023, pgs. 80, 82, 89-91.

7.5.1. Sinking Fund Reserve

1) <u>Required by *The Manitoba Hydro Act* to be Funded from Revenues of the Corporation</u>

   Manitoba Hydro is required by legislation to set aside a sinking fund reserve out of the funds of the corporation each year for the repayment of moneys borrowed by the utility. As described in detail on page 8 of the Debt Management Strategy, during the capital expansion, Manitoba Hydro had to resort to borrowing to make the legislated sinking contribution; however, with the capital assets now in service, it intends to make the sinking fund contributions with internally generated funds where possible.

2) <u>No Cost to Manitoba Hydro's Forecast Sinking Fund Strategy</u>

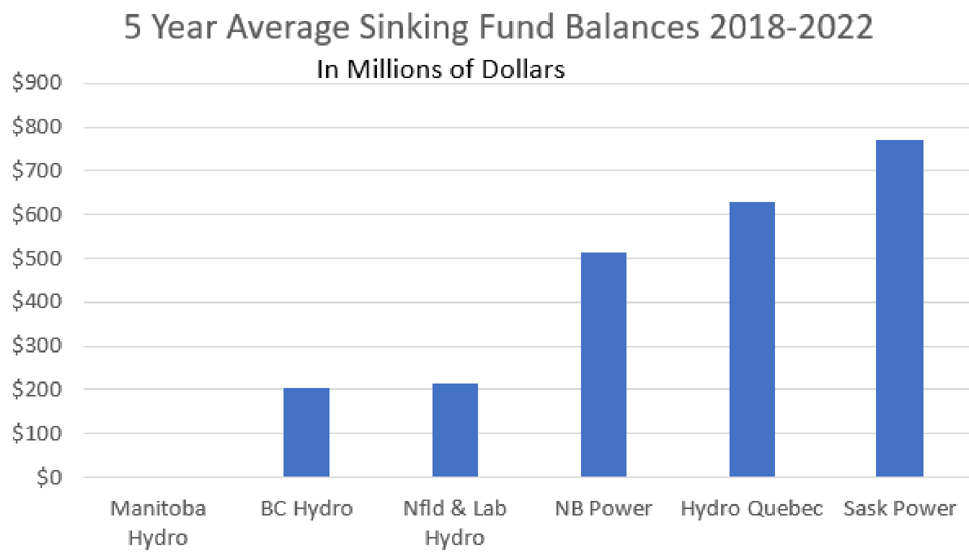
   Manitoba Hydro intends to make the sinking fund contributions and withdrawals to retire debt on the same day to avoid having any costs in finance expense related to holding sinking fund balances. Mr. Rainkie admits that this layer of liquidity protection comes at no cost to Manitoba Hydro.[18]

3) <u>Active Peer Use of Sinking Fund Reserves</u>

   Many of the Manitoba Hydro's peers have sinking fund reserves outstanding on a regular basis as a source of liquidity for debt repayment. The following graph shows the five-year average of the year end balances sourced from their annual reports:

[18] Revenue Requirement Evidence Prepared By Darren Rainkie on behalf of the Coalition, dated April 3, 2023, pg. 89.

Figure 28



7.5.2. Long term debt

1) <u>Access to Long Term Borrowing Authority has Been Reduced as a Result of Recent Legislative Amendments Increasing Liquidity Risk</u>

The Appropriation Act, grants Manitoba Hydro borrowing authority to meet the corporation's projected new long term debt financing requirements. This was formerly provided by the annual *Loans Act.* Where the *Loans Act* provided for rollover of unused new borrowing authority which the utility could draw upon for unplanned new requirements, *The Appropriations Act* does not. Manitoba Hydro has historically maintained carryover borrowing authority. As Manitoba Hydro has not forecast any new borrowing for 2023/24 and 2024/25, it has not been granted any new long-term borrowing authority for these years. The only long- term borrowing authority that is available during this time, is refunding authority for maturing long term debt which is provided through *The Financial Administration Act*. It should be noted that when debt is retired by means of a sinking fund withdrawal, the refunding authority for the associated debt lapses. Manitoba Hydro has seen its access to long term borrowing reduced as a result of these legislative changes increasing liquidity risk.

2) Reduced Provincial Guarantee Fee Payments Lower Finance Expense Related to Borrowings

The reduction of the Provincial Guarantee Fee that was announced on November 23, 2022 results in direct savings to finance expense of approximately $110-$115 million per year reducing the finance expense needing to be recovered through rates.

3) Debt Reduction Helps Ensure Manitoba Hydro Remains Self-Supporting to Keep Borrowing Costs from Increasing

The reduction in payments to government contributes greatly to the forecast $0.9 billion of debt retirement in 2022/23-2024/25, which reduces Manitoba Hydro's debt levels as well as the contingent liability to the Province of Manitoba. This debt reduction helps to ensure that Manitoba Hydro remains self-supporting to continue enjoying the low-cost financing available by virtue of the Province's high credit quality.

7.5.3. Short Term Promissory Note Program

Mr. Rainkie claims that the Amended Financial Forecast Scenario only assumes that $50 million of the borrowing facility is outstanding in each of the 20 years of the financial forecast resulting in increased levels of finance expense (page 91). He acknowledges that Manitoba Hydro has indicated that it will not change planned levels of short-term borrowing until the provincial guarantee is granted on a larger short-term facility.

1) Inconsistent Considerations of Forecast Assumptions

Mr. Rainkie asserts that Manitoba Hydro should forecast an assumption which has not been approved by the Province (provision of the guarantee on a larger Manitoba Hydro promissory note program), but should not consider the limited annual rate increases stipulated in *The Act* because they do not become operative until April 1, 2025.

2) Further Amendments to Legislation Impacting Approved Short Term Borrowing Authority

Beyond the legislative amendments noted in Coalition/MH I-46c, *The Manitoba Hydro Act* has recently been amended to remove the reference to the increased limit of $1.5 billion and instead is silent on a temporary borrowing limit. Currently, section 30(1) of *The Manitoba Hydro Act* states:

> Authority for temporary borrowing
> 30(1) With the approval of the Lieutenant Governor in Council, the corporation may, from time to time, borrow or raise money for temporary purposes by way of overdraft, line of credit, or loan, or otherwise upon the credit of the corporation in such amounts, upon such terms, for such periods, and upon such other conditions, as the corporation may determine.

As a result of this recent legislative amendment, a $500 million promissory note program remains in place as approved by a 1992 Order-in-Council which also approved the guarantee of the $500 million promissory note program.

3) Uncertain Future for Manitoba Hydro Short Term Borrowing

Manitoba Hydro cannot increase its short-term borrowing in any significant manner or reasonably plan for its increase as suggested by Mr. Rainkie until such time as it is provided assurance and certainty from the Province of Manitoba that a provincially guaranteed short- term borrowing facility greater than $500 million will become available. Manitoba Hydro currently does not know when or if this facility will be available.

As such, any savings to finance expense that Mr. Rainkie has calculated based on increasing short-term borrowing levels are not available and overstated savings at this point in time.[19]

[19] Revenue Requirement Evidence Prepared by Darren Rainkie on Behalf of The Consumers Coalition, dated April 3, 2023, pgs. 88.

4) No Cost for this Layer of Liquidity

As the $50 million of short term debt outstanding throughout the forecast is reinvested at the same forecast interest rate, this layer of liquidity has no cost in the forecast.

7.5.4. Cash

1) Unencumbered Cash Balances Required for Liquidity Purposes not Contested by Mr. Rainkie

Mr. Rainkie states on page 89 of his evidence that "*MH indicates that as part of its revised DMS that it plans to maintain average unencumbered cash balances of approximately $400 to 500 million in the first decade of MH22 and approximately $200 million in the second decade of the forecast, to mitigate liquidity risk and ensure financing flexibility*." He does not appear to take issue with this 'layer of liquidity', which as indicated in Coalition/MH I-46f, is forecast to cost the utility on average $4 million per year over the 20-year forecast timeframe.

As indicated in the Debt Management Strategy, Manitoba Hydro maintains cash balances equivalent to approximately six months of cash requirements in line with the Province of Manitoba's practices. Manitoba Hydro has followed the same practices as the Province of Manitoba with respect to pre-funding since the Great Financial Crisis in 2008. This layer of liquidity does not overstate costs in the Amended Financial Forecast Scenario.

2) Restricted Cash is not a Layer of Liquidity

Mr. Rainkie questions the increasing cash balances more than a decade into the future which result from the Manitoba Hydro-Electric Board ("MHEB") being required to fund a Cash Call pursuant to the Keeyask Hydropower Limited Partnership Agreement to satisfy the 75% debt covenant. As indicated in Coalition/MH II-26 a), this cash is considered restricted, therefore not available for MHEB operating requirements. Manitoba Hydro points out that this is not a 'layer of liquidity protection', but the result of the MHEB being projected to be the only remaining common equity unit holder and, as such, required to fund the cash call.

7.6. Interest Rate Forecasting Assumptions

Mr. Rainkie opines on page 92 of his evidence that Manitoba Hydro's floating rate debt assumptions are more risk averse than necessary resulting in finance costs that are overstated, for rate setting purposes, as floating rate debt is forecast to be lower cost than fixed rate debt by the independent consensus forecasters that Manitoba Hydro uses to forecast interest rates in the Amended Financial Forecast Scenario.

Manitoba Hydro does not agree that its levels of forecast floating rate debt are overstating finance costs.

7.6.1. Long Term Debt of the Same Term is the Same Cost at Time of Issuance in the Marketplace

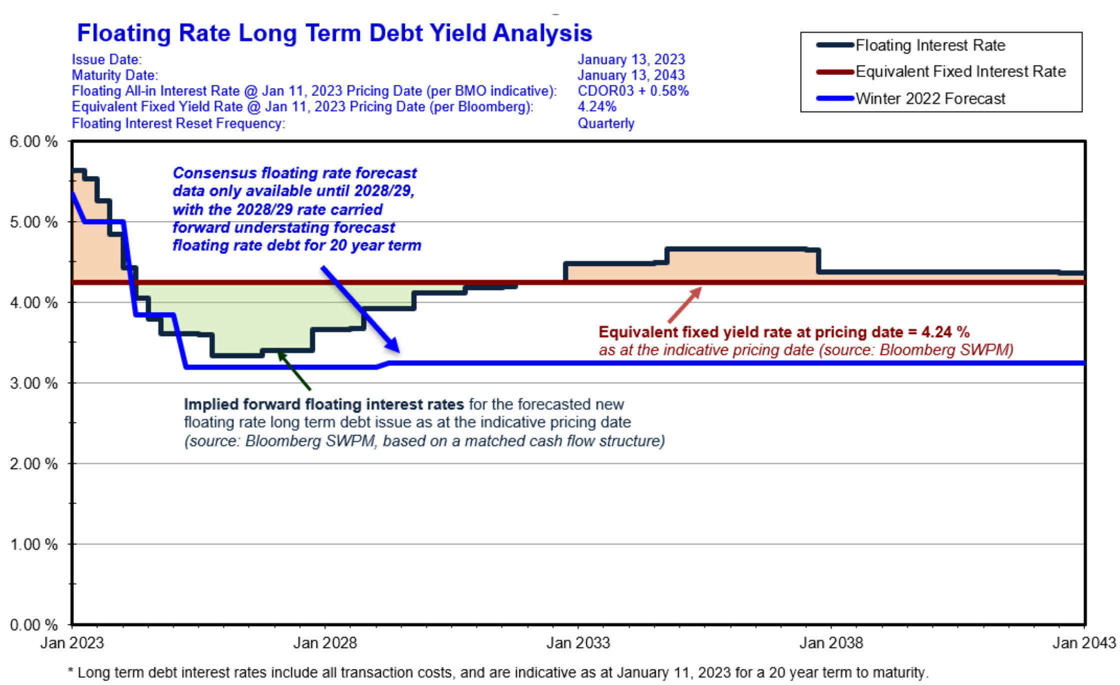
As Manitoba Hydro indicates in COALITION/MH I-44i and further clarified in COALITION/MH II-25e, at the time of actual issuance in the marketplace, floating rate long-term debt is priced to be indifferent over the term of the bond as compared to fixed rate long-term debt. With no differential between fixed and floating long- term debt in the marketplace at time of issuance, there are no cost savings to be realized.

Mr. Rainkie states on page 85 of his evidence that NBF concluded that its analysis implied that by increasing the floating rate debt mix, positive gains could be made in net income since floating interest rates tend to be lower than fixed interest rates. This comment implies that the switch to floating rate debt would require a move down the yield curve, i.e. taking on debt with a shorter term to maturity. It is the term to maturity differential that makes this cheaper, but with a tradeoff of greater refinancing risk.

7.6.2. Interest Rate Forecast Cost Differentials Result in Understated Finance Expense

Over the 20-year forecast, the forecast cost differentials between long-term floating-rate debt and long-term fixed rate debt shown in COALITION/MH 44i are a result of the averaging in the consensus forecasting process and lack of extended interest rate forecasts, making it difficult to replicate market conditions with forecast data for a 20-year term forecast debt issue. The following chart shows the implied forward floating interest rates (green line) which were priced in the market on January 11, 2023 for a 20-year debt issue with an equivalent fixed yield rate of 4.24% (red line) and adds the Manitoba Hydro Winter 2022 forecast floating rates (blue line). This market pricing reflects the expectation that the bond issuer would initially pay a higher floating rate in the first couple of years, pay a lower floating rate coupon than fixed in the medium term and then pay a higher floating rate coupon than fixed in the latter part of the debt's term. The Winter 2022 forecast floating rates remain close to the implied floating rates in the first few years, however, the carry forward of the 2028/29 floating interest rate forecast clearly understates the market expectation of interest rates with respect to a 20- year debt issue resulting in understated floating rate long term debt interest expense.

Figure 29



Manitoba Hydro could eliminate the discrepancies to replicate market conditions and match the forecast long-term floating rate debt yield to fixed rate long-term debt yield with the same 10+ year term. This would eliminate the incorrect 'floating rate savings' to which Mr. Rainkie refers. With 15% of all new long-term debt issued at floating rates in the forecast, Manitoba Hydro expects that the Amended Financial Forecast Scenario has understated finance expense costs as a result of these discrepancies.

7.6.3. In the Current Interest Rate Environment Short Term Debt has a Higher Yield than Long Term Debt

As of May 1, 2023, the yield curve is inverted as yields of short-term government debt are higher than longer-dated government bond yields. The Bank of Canada overnight rate is 4.5% and the 10-year Government of Canada benchmark bond yield is 2.89%.

7.7. Manitoba Hydro's Debt Management Strategy and Treasury Risk Policies and Guidelines are reasonable and do not unnecessarily increase the Finance expense

Mr. Rainkie has overstated his claims pertaining to Manitoba Hydro's Debt Management Strategy and Treasury Risk Policy and Guidelines increasing finance expense. Any rates that are established by the PUB according to Mr. Rainkie's suggestions will not result in cost recovery. The following rebuts Mr. Rainkie's conclusions set forth on page 92 of his evidence.

Manitoba Hydro has not reduced its absolute interest rate risk tolerance, it has simply amended the policy and guidelines to adjust the proportion of floating rate debt to allow for similar levels of interest expense volatility.

The peer range is 1%-19% which is very similar to the new Manitoba Hydro target guideline for floating rate debt of 0%-20%. Upon broader inspection, Manitoba Hydro is not an outlier, Newfoundland and Labrador Hydro reported between 1%-3% floating rate debt in the reported periods, lower than Manitoba Hydro's 1%-5%. Current and forecast interest rate risk profiles are not materially lower than the updated floating rate range from the NBF independent analysis model but at the lower boundary of the range of 8% - 15%. Given Manitoba Hydro's risk context, the interest rate risk profile is not more averse than necessary.

Concentration risk cannot be looked at in isolation. $1.1 billion or 5% of the debt portfolio maturing each year for the next decade is significant, however Manitoba Hydro actively manages its interest rate risk profile within the risk context. Higher interest rates and the uncertain interest rate environment keep interest rate risk elevated for Manitoba Hydro.

Each of the 'layers of liquidity protection' have successfully been used for decades, including under Mr. Rainkie's direct management while CFO at Manitoba Hydro, and do not result in finance costs that are intentionally overstated for rate-setting purposes as implied by Mr. Rainkie throughout his evidence.

Savings to finance expense from increasing short term borrowings as alleged by Mr. Rainkie are not available as the short-term borrowing facility has not been expanded.

Pre-funding with short-term borrowing has no cost in the forecast as it is reinvested at the same rate as making sinking fund contributions with internally generated funds has no cost in the forecast as contributions and withdrawals occur on the same day. Long term borrowing will remain at the low cost as the debt levels have reduced the contingent liability to the Province.

Pre-funding with long term debt is being reduced in 2023/24 and will remain at lower levels as compared to previous years.

Long term debt of the same term is the same cost at the actual time of issuance in the marketplace. To achieve savings by switching to floating rate debt, would require taking on debt with a shorter term to maturity. Interest rate forecast cost differentials result in understated finance expense in the amended financial forecast scenario, <u>not</u> overstated.

Increasing short term debt at the moment would mean an increase in finance expense in 2023/24 as short-term debt currently has a higher yield than long term debt.

Any rates set according to Mr. Rainkie's observations may not result in cost recovery and could result in higher finance expense in the test years 2023/24 and 2024/25.

8. Outage Implications and the System Approach

8.1. Generation Outages Typically Have Revenue Impacts and Can Cause System Outages

The Midgard Evidence states at page 51: "*Consequently, evidence indicates that MH has sufficient surplus generation resources such that at least some, or all, of its generation assets can be permitted to degrade further before intervention is warranted from a ratepayer risk and system impact standpoint*". The Midgard Evidence further quotes Manitoba Hydro's response to COALITION/MH I-96a: "*Confirmed. A **<u>single</u>** [emphasis added] forced generator outage will not normally result in an outage to domestic customers...*". The Midgard Evidence then goes on to make an incorrect extrapolation of logic at page 51 that "*the above confirmation that generation outages do not cause system outages".* This demonstrates a fundamental misunderstanding by Midgard of the potential impact of generation forced outages on Manitoba Hydro's revenue ("customer risk") and the potential for system outages in the event of multiple outages during high system loading conditions.

Manitoba Hydro cannot achieve the revenues projected in Figure 4.2, Electric Operations Statements, of the Application (initial years Forecast Extraprovincial revenues of $1.283 billion for 2022/23 and a Preliminary Budget projection of $1.153 billion for 2023/24) if its revenue- producing generation assets are "permitted to degrade further". Even if forced generation outages do not cause loss of load events ("system outages"), they are likely, under most water conditions, to result in some sort of negative impact to net export revenue through lower hydro generation. Under above average water conditions, the hydro generation outages can result in spilled energy and associated loss of export revenue. Under high load conditions when hydro generation is required to meet obligations, generator outages can result in costs for the purchase of replacement energy. Under average flow conditions, hydro generation outages can result in a shift of generation from the higher valued on peak period to the lower valued off-peak period. In all these situations, increased forced generation outages reduce net export revenue below that projected in the financial scenario, which impacts electricity rates customers pay.

Manitoba Hydro tracks indicative estimates of the lost revenue (opportunity costs) or increased purchase costs resulting from generation and HVDC outages. In 2022/23 alone, the estimated lost opportunity cost of forced outages was estimated to be more than $70 million. This figure excludes any impacts of reduced future capacity surpluses related to degraded performance and/or the need to increase Manitoba Hydro's capacity Planning Reserve Margin if increased forced outages rates are sustained.

The fact that a single generating unit outage does not normally result in Manitoba Hydro being unable to serve domestic load or firm export contracts does not in any way imply that multiple forced generation outages do not have the potential to cause domestic loss of load events, particularly under very high system loading conditions. For example, on June 10, 2021, MISO had a reliability event in which "*a Maximum Generation Event Step 2a was triggered by forced generation outages, above normal temperatures and near all-time peak loads.*"[20] As the number of units that are concurrently on outage increases, the ability to serve load decreases, and at some point, demand cannot be met. To suggest otherwise shows a serious lack of understanding or disregard of the fundamentals of resource adequacy analysis in the Midgard Report.

As stated in Appendix 5.5 of the Application, "*Manitoba Hydro's capacity criterion requires that the corporation carry a minimum reserve which is intended to protect against capacity shortfalls resulting from breakdown of generation/transmission equipment or increases in winter peak load due to extreme weather conditions. The reserve is calculated as 12% of the Manitoba forecast peak winter demand in effect at the time for each year that is forecasted*." A sustained increase in the forced outage rate will result in a corresponding increase in the 12% planning reserve margin. New operable capacity resources would be required to replace the ones that Midgard suggests be allowed to "degrade further", at significant cost to Manitoba customers.

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[20] https://cdn.misoenergy.org/20210708%20MSC%20Item%2006%20Review%20of%20Max%20Gen%20Event%20-%20June%2010567565.pdf, Slide 4

8.2. HVDC Outages Have Customer Impacts and Can Cause System Outages

Midgard also has a fundamental misunderstanding about the potential impact of HVDC-forced outages on Manitoba Hydro's load-serving ability and on Manitoba Hydro revenue and customer impacts. For example, the Midgard Evidence at page 56 states that Manitoba Hydro "*provides figure and explanatory text that shows with one Bipole failed (in this case Bipole II) all domestic load could be served, and even with two Bipoles failed [emphasis in original], MH could still supply domestic load in most cases*". Further, the Midgard report goes on to say at page 57, "*As a result, the ratepayer impact of a single Bipole failing is near zero, because there is sufficient redundancy in the DC and AC transmission systems to meet domestic loads even at peak times. And consequently, the criticality of the increased failure rates of Bipole I and Bipole II is lower than indicated by Manitoba Hydro when focusing on impacts at a system rather than asset level because it would take more than one Bipole failure, and typically more than two Bipole failures to result to result in an impact to domestic ratepayers*".

The Midgard Evidence analysis and conclusions are incorrect. Manitoba Hydro's three High Voltage Direct Current ("HVDC") Bipoles are generation outlet transmission which mean they provide the <u>only</u> means (save 200 MW of non-firm AC transmission) to move the hydro generation from the four Lower Nelson River generation stations (Keeyask, Kettle, Long Spruce and Limestone), with a combined capacity of approximately 4,200MW (as per COALITION/MH I-99b, to southern Manitoba. Other than the 200 MW non-firm AC transmission provision, there is no ability for the Lower Nelson River generating stations to utilize the AC network to deliver their output to the major load centers in southern Manitoba. Should two Bipoles fail as postulated in the Midgard Evidence, only 2,000 MW[21] of north to south HVDC transmission would remain. Up to 2,200 MW[22] of hydro generation would be stranded (or "bottled") in northern Manitoba- and serving the Manitoba load would require imports of large volumes of replacement energy, from markets outside of Manitoba, if available to dispatch. A single Bipole outage, depending on when it occurred, would also result in

[21] Based on Bipole capacity as per Coalition/ MH I-99 and assuming there are no outages on the remaining Bipole or restrictions on the northern collector transmission which carries generation from the Lower Nelson River generating stations to the northern HVDC converter stations.
[22] This would apply to peak load conditions and other times when water conditions support maximum generation and assuming no generation is on outage.

a lesser degree of bottled hydro generation in Northern Manitoba (see for example PUB/MH I-61a-b) and also has the potential for bulk power system outages.

Power systems often have unique characteristics. For Manitoba, the unique characteristics are that it is a predominately hydro system and over 70% of its generation is located on the Lower Nelson River connected to southern Manitoba through generation outlet transmission – the three Bipoles. This is different than in Alberta where Midgard has performed consulting services. Alberta's predominately thermal power system added two HVDC Bipoles to the existing AC transmission system between the Calgary and Edmonton areas in 2014 and 2015.[23] The AC transmission system between Edmonton and Calgary was reinforced to avoid reliability issues for consumers in southern and central Alberta, to improve the efficiency of the transmission system and to allow lower cost wind generation to supply northern loads. The existing AC transmission system in Alberta provides redundancy to the new Alberta Bipoles. No such firm AC transmission redundancy exists in Manitoba for the Lower Nelson River generation – if a single Bipole fails, power must flow on the other Bipoles or hydro generation will be restricted (and energy potentially spilled) in northern Manitoba. As such, redundancy for the generation carried on the HVDC transmission must be carried on the HVDC system itself. The complexity and the lead times for component replacement or modernizing of these assets is long (multiple years). Hence, in the event of a catastrophic failure of the Bipole(s), it could also take years to either replace that capacity with generation in southern Manitoba or replace major HVDC system components. Therefore, the effect of the lost capacity is long lasting and would likely extend through the winter peak demand months when the HVDC system is typically most heavily relied on.[24]

The need for Bipole III has been reviewed since the original commitment decision more than a decade ago. For example, Boston Consulting Group ("BCG") reviewed Keeyask, Bipole III and the Minnesota Manitoba Transmission Project in 2016. Some 615 pages of review documents were filed in the 2017/18 & 2018/19 General Rate Application as PUB MFR 72. The BCG review concluded at page 15 of 615 that "Mitigating the risk of Bipole I&II and Dorsey was a necessity" as they "represent

[23] https://www.altalink.ca/projects/view/168/western-alberta-transmission-line-watl; https://electric.atco.com/en-ca/community/projects/eastern-alberta-transmission-line.html
[24] The HVDC system is most heavily utilized during periods of high load and high hydraulic flow.

unusually large contingencies" with "significant and real risk of catastrophic failure" and there is "~$4-20B societal impact of prolonged outage." These are very significant impacts to Manitoba customers.

Since the completion of Limestone generating station approximately 30 years ago, and the resultant increase in HVDC system loading, there have been at least half a dozen events which had the potential for large scale and even multi-day loss of load events:

- September 1996 – tornado force straight line winds destroyed 19 steel towers a few kilometres north of Dorsey Converter Station; It took five days to put one of the HVDC transmission lines back in operation on temporary structures while Manitoba Hydro maximized imports. Manitobans were asked to reduce their non-essential load. Had this event not occurred in early September when loadings are relatively low – multiple days of rotating outages would have been required.
- August 2007 – storm event that destroyed HVDC equipment at Dorsey converter station and, one minute later, loss of the 500 kV transmission to the US; total loss of 1,750 MW.
- June 2008 – forest fire along the HVDC corridor resulted in tripping of 3 of 4 HVDC Poles and the loss of 1,985 MW in less than two minutes.
- March 2009 – HVDC icing resulted in loss of approximately 1,500 MW in less than 20 minutes.
- Winter 2010/11 – Extreme high flow conditions combined with complex ice processes along the Nelson River resulted in ice movement in the vicinity of the HVDC towers, where dozens of HVDC towers were compromised at remote locations over a 100 km long stretch of the HVDC corridor. Manitoba Hydro implemented conservative operations to limit the impacts of towers collapsing and the sudden loss of power. This event had a high potential for multi-day loss of load events in a Manitoba winter.
- February 2017 – One HVDC tower (equivalent to one Bipole or about 2,000 MW) was knocked out of service when a farmer drove into one of the HVDC tower with a tractor. No system outages resulted as the event coincided with a period of mild weather/ reduced Manitoba load.

Despite Midgard's unfounded assertions otherwise, the foregoing examples clearly demonstrate the potential impact to customers of major HVDC outages.

8.3. Manitoba Hydro is focussed on the System Approach

At Page 52 the Midgard Evidence states: "*despite its asset management policy of focusing on system impacts rather than individual assets, MH continues to justify generation asset investments on an asset focused basis rather than a system focused basis. Moreover, the asset focus is continuing even though MH staff appear to understand at some intuitive level that surplus exists to support a successful strategy of utilizing already available surplus generation to maintain existing levels of service*."

Manitoba Hydro does not agree that it does not focus on the system when justifying generation asset investment. Manitoba Hydro operates an integrated system in which all available generation resources are operated as required to meet Manitoba load, while considering its market interactions on a least cost basis. For this reason, the incremental or marginal generation resulting from any single project is not individually allocated to serving domestic load or export and import market interactions.

8.4. Hypothetical Minimum System Analysis Provides no Value

Section 9 of the Midgard Evidence is titled *"Ratepayers need to understand the minimum system"*. The Midgard Evidence goes on to state at page 77, "Without knowing the Minimum System, the magnitude of the surplus bulk transmission and generation system cannot be quantified, which eliminates the possibility of calculating associated benefits net of all-in costs and prevents customers from knowing if planned incremental investments are surplus to the Minimum System required to provide reliable domestic service."

The Midgard Evidence notes at page 80 the "*Minimum System analysis has been recently applied in Alberta for rate design purposes for a Provincial-scale transmission system".* Thus the concept of the "*minimum system*" was borrowed from a Rate Design Application (i.e., a cost of transmission service application and <u>not</u> a revenue requirement application) before the Alberta Utilities Commission (AUC). After 19 months of review including eight engagement sessions, two technical information sessions, and one written consultation, the AUC denied the Alberta Electric System Operator's (AESO) rate design application in a November 10, 2022 decision.[25] This decision stated at paragraph 83 that *"The proposed rate design included an all-hours energy charge [emphasis added] that was used to recover approximately 30 per cent of the costs of the bulk and regional transmission system [emphasis added]. The AESO defended the use of an all-hours charge on the basis that the costs that it was designed to recover related to the avoidance of congestion that could occur at any time. However, as discussed above, the Commission has found that the application of cost causation principles to costs that consumers cannot influence is not useful."*

The "minimum system" concept was discussed in Alberta in a July 3, 2013 report titled "Alberta Transmission System Cost Causation Study" by London Economics International.[26] The first line of this report states "London Economics International ("LEI") was retained by the Alberta Electric System Operator ("AESO") to perform a transmission cost causation study." The scope of work for the study did not include review of revenue requirements or have anything to do with generation or distribution.

The "*minimum system*" methodology has been used in cost causation/ cost of service methodologies for distribution systems: "In the minimum system approach, a minimum standard conductor size is selected and the minimum system is obtained by pricing all of the distribution conductors at the unit cost of this minimum size. The minimum system determined in this manner is then classified as customer-related and allocated on the basis of the number of customers in each rate class. All costs in excess of the minimum system are classified as demand-related. The theory supporting this approach maintains that in order for a utility to serve even the smallest customer, it would have to install a minimum size system. Therefore, the costs associated with the minimum system are related to the number of customers that are served, instead of the demand imposed by the customers on the system."[27]

[25] https://www.auc.ab.ca/featured/aeso-bulk-and-regional-rate-design-application/

[26] https://www.aeso.ca/assets/Tariff-2021-BR-Application/Appendix-N-2013-LEI-ATS-Cost-Causation-Study.pdf

[27] The Prime Group LLC | Overview of Electric Cost of Service Studies, Section 2

As noted in the LEI report "A criticism of the minimum system approach is that the actual minimum [conductor] size can be subjective, which in turn affects the classification results." The LEI report goes on to state on p. 1617:

> *"In order to perform the minimum system approach, a minimum line and optimized line must be identified. In defining minimum and optimum lines, LEI takes into account that the minimum system in a transmission system is not necessarily the minimum size conductor that can be constructed. The transmission system is inherently not serving minimum loading requirements like the distribution system, and TFOs are required to perform a conductor optimization study to determine the most economic conductor size, considering both capital costs and line losses, for all lines above 100 kV and longer than 10 km. All 240 kV lines greater than 50 km in length must conduct a "full bulk transmission line optimization study" which includes costs of structures.* ***<u>Therefore, in a practical sense, it can be argued that there is no minimum system for a transmission line.</u> [Emphasis added]*** *However in LEI's analysis, in order to approximate demand versus energy related costs, LEI has defined "minimum" and "optimal" conductor sizes as comparable lines that TFOs would consider, where the optimized line minimizes losses over the minimum line."*

In other words, the "minimum system" test, as applied to transmission, is arbitrary and hence any resulting minimum system is hypothetical and without value. Manitoba Hydro is not aware of examples of the "minimum system" being applied to a predominately hydro generation system.

8.5. Including Opportunity Revenue in Economic Analysis is Appropriate

The Midgard response to Information Request MIPUG/Coalition I-7 stated "*Therefore, ratepayers are already paying for the insurance to cover an unplanned generation outage should it occur. As a result, it is inappropriate to carry both planning reserve margin for an unplanned outage and justify surplus generation investments on the basis of avoiding suboptimal generation dispatch when unplanned outage are already covered by the planning reserve margin.*"

This statement is wrong for several reasons.

First, insurance generally provides financial compensation for a specified loss in exchange for premiums. The customers of Manitoba Hydro do not pay for generator outage insurance in exchange for compensation payments in the event of forced generation outages. The purpose of planning reserve margin is to provide a margin against forced generation outages and extreme weather so that there will be a high degree of likelihood that the lights will stay on even on the coldest days of winter.

Second, it is entirely appropriate and consistent with industry practice for generators which are available and in economic merit be used to provide net revenue to the generation owner when they are not needed to meet capacity/reliability obligations. For a hydro generator with surplus water beyond load requirements, this additional revenue comes at almost no incremental operating costs save water rentals. Manitoba Hydro's all-time peak load is over 4,900 MW, and its minimum load is under 2,000 MW. That means, depending on current Manitoba load and water conditions, there may be up to 3,000 MW of hydro generating units available to turn surplus opportunity energy into energy for sale in extra-provincial markets. Manitoba Hydro should plan to use this opportunity revenue to reduce overall revenue requirements from domestic customers.

Third, it is common practice in the industry to consider a number of value streams in justifications for resources. For example, battery energy storage system ("BESS") use the concept of value stacking: "BESS can maximize their value to the grid and project developers by providing multiple system services. As some services are rarely called for (i.e., black start) or used infrequently in a given hour (i.e., spinning reserves), designing a BESS to provide multiple services enables a higher overall battery utilization. This multi-use approach to BESS is known as value-stacking."[28]

Fourth, revenue from opportunity energy is a significant source of revenue for Manitoba Hydro. Manitoba Hydro classifies hydro energy into dependable hydro energy (that hydro energy which can be expected during the worst drought on the hydraulic record), and opportunity hydro energy (the additional and variable hydro

[28] National Renewable Energy Laboratory, Grid Scale Battery Storage https://www.nrel.gov/docs/fy19osti/74426.pdf, Page 4

surplus above dependable hydro energy). MFR 42 provides a break-down of Water Supply and Export Revenues. Total opportunity revenue (Canada plus USA) was as high at $187 million in 2019/20. The opportunity revenue is a revenue that does not come from Manitoba customers. To arbitrarily exclude opportunity revenue would distort an economic analysis and result in flawed valuations being used in asset planning decisions.

8.6. Capital Additions in the Financial Scenario are Driven by Existing Obligation

The Midgard Evidence states at page 75 that *"MH demonstrates that it continues to perpetuate its historical surplus philosophy as evidenced by its recent capital additions such as Keeyask, Bipole III and MMTP, assets which have been justified or advanced ahead of domestic need to enable MH to satisfy or expand its export market activities*". This statement has factual errors.

These investments are not recent decisions – the regulatory process for Bipole III began in 2011 and public hearings were held more than a decade ago in October/ November 2012 and March 2013. The Terms of Reference for the Need for and Alternative for Keeyask, associated AC transmission and a new Canada – US interconnection was assigned to the Public Utilities Board in an Order-in-Council issued more than a decade ago – on April 17, 2013. The NFAT Application was filed on August 16, 2013.

Capital additions in the Financial Forecast Scenario are planned in consideration of export revenue but are not driven by a Manitoba Hydro need to expand its export market activities. As detailed in Section 4.2.5, the Application is supported by the Amended Financial Forecast Scenario that contains no new hydro generating stations or new interconnections. As explained in the response to COALITION /MH II-99a-b, "*The additional resources in the financial scenario are being added for the increasing Manitoba load, recognizing that the existing predominately hydro system will continue to interact with export markets over the scenario horizon. Manitoba Hydro notes that due to the uncertainty of the New Energy Investment project schedules, individually sized project additions, load forecast and emerging energy policy uncertainties, new energy investments cannot exactly match demand to avoid small nearer term surpluses of dependable energy and capacity*."

To the extent the Amended Financial Forecast Scenario includes projects that increase capacity or dependable energy at existing hydro generating stations, including Kettle, Long Spruce and Pointe du Bois, the vast majority of the capacity and dependable energy from these projects will serve Manitoba Hydro's existing obligations (Manitoba load growth and existing firm export contracts). The flow dependent opportunity energy, when available, will continue to be sold on extra provincial markets providing export revenue – as they have for more than 50 years as this is an inherent property of the interconnected Manitoba Hydro system.

A single generator or hydro plant can serve many roles. Specific generators are not designated for export vs. domestic energy/ capacity, or dependable vs. opportunity hydro energy. Rather a single generator can serve all these roles even within the same day and over the seasons. Further, those roles can change over longer periods of time – as capacity and dependable energy is consumed by an increasing Manitoba load. That is why, as explained in response to COALITION/MH II-104b-c:

> "*Manitoba Hydro uses a single approach to the evaluation of generation investments, which recognizes the obligation to serve Manitoba load, and the value obtained from interaction with external markets (both exports and imports). Manitoba Hydro operates an integrated system in which all available generation resources are operated as required to meet Manitoba load while considering its market interactions on a least cost basis. For this reason, the incremental or marginal generation resulting from any single project is not individually allocated to serving domestic load or export and import market interactions."*

8.7. The Enabler of Manitoba Hydro's Development

The Midgard Report missed the point of what the enabler of the development of hydro resources in Manitoba were with its comment, "At Least We're Doing Better than the Neighbours".

In the 1960s, the Province of Manitoba and Manitoba Hydro made the decision to begin large scale hydro development on the lower Nelson River. This decision was explained in Manitoba Hydro's response to COALITION/MH II-102a-b:

"… for the study of large hydro development on the lower Nelson River stated in the first paragraph "WHEREAS Manitoba has represented to Canada that the Nelson River has a power potential of in order of 4 million kilowatts of firm power, approximately 2 million kilowatts of which would be surplus to Manitoba's requirements for a considerable period and that, **if any part of this potential is to be made available at economic rates in the near future, it must be developed for large markets outside Manitoba to take advantage of economies of scale in which long distance transmission of electric energy could play a vital role.**" [emphasis was in original].

The point that Midgard missed was bolded in the original. The economic development of the lower Nelson River required large scale development which included transmission to large markets outside of Manitoba. Hydro development is not very scalable- the optimal size of a hydro station is based primarily on the characteristics of the site and river conditions – i.e., available head, river flow and reservoir storage considerations, – not domestic load. A large portion of the financial cost to develop hydro stations are related to the civil works which cannot be developed incrementally. The scale of the lower Nelson River development seen in the 1960s was too large to serve Manitoba only. An initially large portion of the installed capacity as well as the surplus opportunity energy was sold on export markets while the Manitoba load "grew into" the output of the large hydro plants. Subsequent large hydro development also involved optimization of investments with new interconnections as explained in Section 5.2.2 "Manitoba Hydro's Transmission Interconnections Overview" of Chapter 5 of Manitoba Hydro's August 2013 Needs For and Alternatives To application.

In commenting on Manitoba Hydro's statements regarding the benefits to Manitoba customers of historic investments and comparison to rates in Saskatchewan, Midgard states at page 77 that Manitoba Hydro ignores the most critical factor underlying the prevailing rate differential is that Saskatchewan does not have Manitoba's Hydro resource potential. According to Waterpower Canada, Saskatchewan has 3,955 MW of undeveloped hydro potential, while Alberta has 11,775 MW of undeveloped hydro potential.[29] Manitoba had larger sites to develop hydro – but was only able to develop

[29] https://waterpowercanada.ca/wp-content/uploads/2015/09/2008-hydropower-past-present-future-en.pdf, Page 6

these larger sites by using export markets to optimize the investments.

9. Asset Management

9.1. Essential asset management principles

9.1.1. Midgard Recommends Assets to be in Service "As Long as Possible", Contrary to Modern Asset Management Practices which target Assets' Optimum Economic Life

Page 29 of Midgard's evidence states: "*Utilities must decide if aging assets near the end of their service lives should be replaced or maintained in service as long as possible to provide the best value to ratepayers. In answer to this fundamental question MH recommends building new assets rather than continuing to extract low-cost value from its current assets by increasing its operational resources (e.g., reducing callout times, as discussed previously)*".

The assertion by Midgard equates "in service as long as possible" to "best value to ratepayers" overlooking the essential asset management concept of "optimal economic life". This is a fundamental and core principle on which modern asset management relies. Obtaining optimal economic life for a given asset requires that the asset is utilized until its lowest average lifecycle cost of ownership is achieved, but not beyond. Lifecycle costs must consider the increased cost to resource and to maintain assets of advanced-age, the rise in risk carried through the probability of in-service failure as assets approach advanced-age, and the impacts of such failures, including the costs of repair, collateral damage, employee and public safety, customer outages, revenue losses, and other factors as considered in the Corporate Value Framework.

This concept of economic life is something that Midgard indirectly suggests is an important concept to Manitoba Hydro (through inclusion of an excerpt from the ISO 55000 standard), while implying that Manitoba Hydro needs to shift strategies, in order to adequately consider the concept. What Midgard fails to acknowledge is that this concept is already well understood and applied in the Corporation, being central to Manitoba Hydro's existing Asset Management foundations, including its Asset

Management Policy, Corporate Value Framework, and Whole-Life Cost Modelling.

Page 28 of Midgard evidence states: "*Manitoba Hydro, like all other mature North American utilities, needs to better manage the trade-off between investing in its fully or mostly depreciated existing asset base versus replacing it with new assets. As a consequence, transitioning from a "high growth build it and we will quickly growth into it strategy" (e.g., MH's pre-1985 strategy) to an asset sustainment and optimization strategy (i.e., a mature lower growth utility strategy) is a major driver for the North American continent-wide transition to modern asset management practices which focus on extracting more value from assets:*" Midgard continues to reference ISO 55000 "*Asset management enables an organization to realize value from assets in the achievement of its organizational objectives... Asset Management supports the realization of value while balancing financial, environmental and social costs, risk, quality of service and performance related to all assets.*"

The text Midgard provides with respect to ISO 55000 summarizes the principles already used in Manitoba Hydro's approach to determining the economic life of its assets through its "Asset Whole-Life Cost Model" process, as discussed in Tab 7 of the Application (specifically, section 7.2.6.2).

Whole-Life Cost Models accept all lifecycle costs as inputs, including risk costs, in order to output the optimal economic life to be used in decision-making such as determining intervention timing. Whole-Life Cost Models are a key component of the Manitoba Hydro Asset Class Strategies and one that Manitoba Hydro has implemented over recent years in its asset management journey, following the implementation of the Asset Management Policy which states such an approach (Appendix 7.1 of the Application).

Figure 30 - Asset Lifecycle Whole Life Cost Formula

Manitoba Hydro

Asset Whole-Life Cost Models
Technical Guide

2. MATHEMATICAL MODEL

The optimum asset life-cycle investment strategy is the option which provides the lowest average annual costs that delivers the required service over the required period.

2.1 Average Annual Cost

Average annual cost is the main component of asset life-cycle decision making. Through optimization of this value, the total cost of ownership for a single asset or a fleet of assets can be minimized. The value takes into account all asset life-cycle activity costs, risk costs, equipment reliability curves as the asset degrades over time, and financial rates to incorporate the impact of the time value of money.

The high-level governing equation to determine average annual costs is:

$$Cost_{av.ann.} = \frac{Cost_{Renewal} + \sum_{n=1}^{Period}\left[Cost(n)_{Life-Cycle\ Activities} + Cost(n)_{Risk}\right]}{Period} \tag{1}$$

The above excerpt in Figure 30 from Manitoba Hydro’s technical guide for Asset Whole-Life Cost Models, demonstrates a standardized, repeatable, and transparent process which considers the growing maintenance costs and risks associated with an aging asset. The aim is to make value-based decisions which go beyond the declining “average annual replacement cost” alone suggested by Midgard.

Importantly, Midgard does not provide any specific evidence or example of the expected risk that Manitoba customers will carry by extending the life of an asset class “…as long as possible”. Manitoba Hydro understands that the annual replacement cost declines when asset replacement is deferred, however, the Corporation also appropriately takes the increasing risk costs and life-cycle activity costs into consideration.

With respect to Manitoba Hydro’s response to COALITION/MH II-98, Midgard states on page 69 of its evidence that: “*To balance the expected increases in asset failure rates due to aging out, MH should commensurately increase maintenance crew resources available to respond to asset failures in a timely manner, thus both maximizing asset value extraction (i.e., thereby minimizing rates) and minimizing response times (i.e., managing SAIDI in a cost-effective manner)*”

Manitoba Hydro agrees with the need to increase maintenance crew resources and had identified this as a requirement to sustain and provide optimum life of the assets. The associated evidence can be found in Tab 7, Section 7.2.3.1 *"We are Projecting a Need for Increased Human Resources"*. This section of Manitoba Hydro's Application clearly identifies the need to perform a higher percentage of preventative maintenance tasks to mitigate the rates of asset degradation and corrective maintenance.

Although Manitoba Hydro agrees with the need to increase maintenance crew resources, Manitoba Hydro rejects the claim that a general approach of instituting a large workforce is optimal to sustain the planned maintenance program while reactively responding to failures. Further, this approach is not aligned with the asset management principle of optimal economic life, discussed above, nor is it sustainable economically, as it does not appropriately manage a growing risk. By allowing a risk to continually grow to include an increasing number of assets experiencing advanced age, an appropriate balance of cost, risk and performance is not maintained, and significant rate increases and performance decreases become unavoidable in the future as the risk materializes and mitigation becomes more costly. This is not an optimal strategy for the customers of Manitoba Hydro.

9.1.2. Manitoba Hydro's Asset Intervention Strategy and the Relationship Between Cost, Performance and Risk

Page 28 of Midgard evidence states: "*However, MH is not facing an unexpected or unique situation with an aging asset base, nor is a "continuously degrading asset base" a surprise. In fact, the asset base has been continuously degrading since it was installed because that is what the passage of time does to assets. As a result, the fact that MH's asset demographics are aging and have always been aging does not justify an asset replacement strategy. Instead, Manitoba Hydro, like all other mature North American utilities, needs to better manage the trade-off between investing in its fully or mostly depreciated existing asset base versus replacing it with new assets. Consequently, transitioning from a "high growth build it and we will quickly growth into it strategy" (e.g., MH's pre-1985 strategy) to an asset sustainment and optimization strategy (i.e., a mature lower growth utility strategy) is a major driver for the North American continent-wide transition to modern asset management practices* *which focus on extracting more value from assets*"

While Manitoba Hydro is not “surprised” that the passage of time causes degradation to its assets, Manitoba Hydro rejects Midgard’s assertion that a replacement strategy is not justified. There is large-scale degradation of Manitoba Hydro’s asset base as many have currently reached (or will be projected to reach) the end of economic life in the coming decades. Good asset management requires such strategies be in place.

Allowing the aging asset risks to grow without addressing the root cause through asset replacements and refurbishments, would have negative impacts to Manitobans. Replacing assets well beyond the end of their economic life would result in markedly decreased performance and greater costs, which would translate to future rate increases and unacceptable negative consequences (such as safety, environmental and reliability) for Manitobans.

Asset interventions which optimize costs, risk and performance cannot be achieved with ad-hoc replacements, nor with a blanket approach of increasing operations staff as suggested by Midgard (page 69 Ref C). This strategy would lead to the increasing materialization of failure-related risks such as human injury or death, environmental impacts (such as spills), public property damage, collateral equipment damage, increased asset downtime resulting in increased loss of service to customers and financial loss to the company. Further, eliminating strategic and proactive replacements, where economic, would result in an inability to optimally replace assets, including challenges and delays related to the availability of replacement assets. In today’s market, it can take years to adequately prepare for an optimal asset replacement or refurbishment due to technological changes, availability of equipment and specialized asset consultants and contractors, and skilled internal labour. With a “replacement strategy”, Manitoba Hydro can determine investment methods and timing which consider the constraints and risks while leveraging opportunities and economies of scale in order to maximize value for customers.

A very straightforward and common example of the need for a replacement strategy can be demonstrated by considering the station transformer asset class. At the end of the service life for these assets, the options for planned intervention are limited after failure, as the asset cannot be fixed in the field. Replacing a station transformer once it fails (reactively), as opposed to a proactive replacement strategy, will result in a prolonged outage to associated equipment due to long lead time delivery currently trending upwards between 100 to 200 weeks, depending on the manufacturer specification.

To ensure reliable energy supply to Manitobans, replacement strategies are essential to eliminate the potential of wide-spread failures. Some of the strategic considerations necessary are as follows:

- Quantity: Predict and plan for other transformer replacements to understand risk, funding, and level of effort;
- Staff: Establishing appropriate workloads to manage the procurement, installation, commissioning of the equipment;
- Design: Considerations for obsolescence of current design, materials, equipment and the need to interface with associated equipment;
- Considerations for current load and future growth; and,
- Procure: Establish contracts of appropriate size and scope to cover all transformer needs and mitigate supply chain risks such as significant delivery delays and cost increases.

9.1.3. Manitoba Hydro's projected intervention rates

Midgard evidence at page 69 states: "*In short, it is expected that due to aging asset demographics distribution asset renewal investments will increase, but not a step increase of unnecessary pre-emptive replacements, but rather a moderate risk-informed increase coupled with increased numbers of reactive replacement as the assets naturally age out at the end of their lives (i.e., after maximum asset value has been extracted rather than premature replacement).* "

Midgard appears to misinterpret the projected sustainment capital increase discussed in Tab 7 and, more specifically, Appendix 7.5, pages 2 and 3, which identifies the requirement to continuously plan for an increased workload immediately and executing an annual investment increment, as opposed to a "step increase". This demonstrates Manitoba Hydro's intentions to continue to replace assets based on actual condition, as opposed to assumed condition based on age or other indicators.

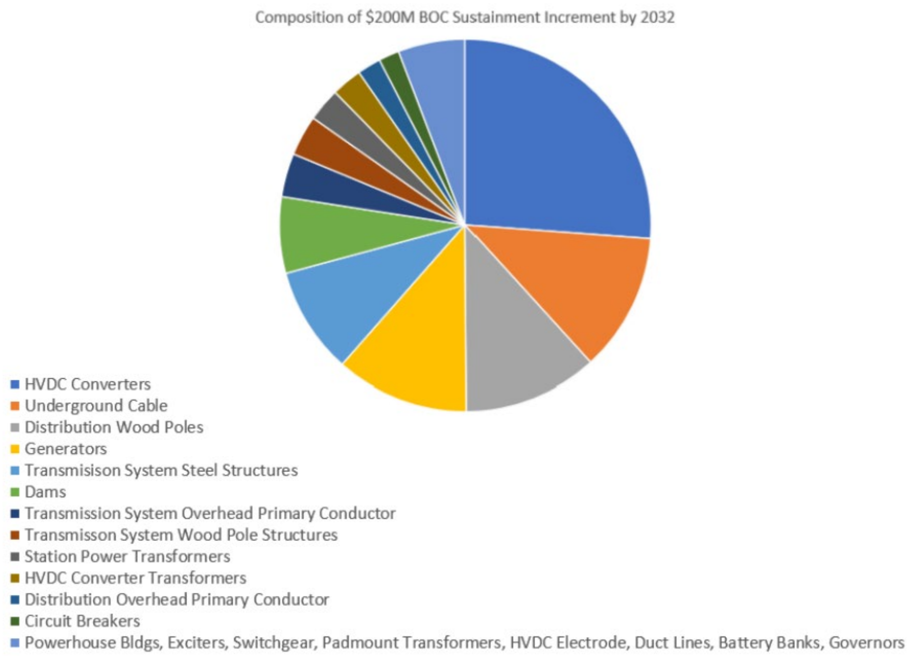
This includes waiting for failure to occur to replace assets with an established intervention strategy of “run-to-fail".

- Midgard’s statement that risk-informed replacements would be moderate with the balance being reactive replacements is not an appropriate characterization or strategy for the asset renewals Manitoba Hydro is projecting. Figure 31 below displays the pie chart representation found in Figure 7.13 - Appendix 7.5, representing the asset populations that contribute to the projected sustainment capital (asset renewal) increase. Not one of the listed asset classes support a reactive replacement plan as the sole strategy (and in very few cases the primary strategy) employed to economically manage the risks associated with in-service failure. Specific examples are given with respect to the asset strategy applied to the top 4 asset populations contributing to sustainment projection increments: HVDC Converters – End of life challenges with this asset class include technology obsolescence and compatibility, vendor availability, design and manufacturing timelines, among other factors contribute to an extended lead time to react to in-service equipment failures. Failure modes may result in outages lasting several years and resulting in significant reliability and financial impacts. Section 8.2 details the impacts caused by HVDC system outages.
- Underground Cable – This asset type is not solely managed by reactive maintenance triggered through failure. A proactive program to rejuvenate/extend life of a percentage of eligible cable type is accomplished through silicon injection, which may be applied to 2000 – 3000 kilometres of buried cable across the province. This is a capital sustainment activity, as opposed to a reactive maintenance activity, and is a very economic option to pursue.
- Distribution Wood Poles – These assets are proactively inspected and consideration is given to capital sustainment investments to prolong the pole’s life, risk-based replacement to replace prior to failure, and full line replacement to take advantage of cost-saving opportunities such leveraging mobilization and increasing capacity in the area without adding additional lines.
- Generators - technology obsolescence and compatibility, vendor availability, design and manufacturing timelines, among other factors contribute to an extended lead time to react to in-service equipment failures, with many failure modes resulting in outages lasting several years and causing a reduction in the ability for Manitoba Hydro to maximize export revenue through a reduction in

what can be considered “firm power”. Section 8.1 details the impact critical generation asset failure can have on customers.

Figure 31 Capital Sustainment Projection Excerpt Appendix 7.5

Figure 7.13 Composition of $200M Business Operations Capital Sustainment Increment Projected by 2032



9.2. Manitoba Hydro has the appropriate Tools and Data to make objective, short and long term planning decisions

On page 7 of Midgard’s Evidence, Midgard suggests Manitoba Hydro has a lack of data, tools, and decision-making frameworks to adequately support its proposed investments.

Midgard’s Evidence makes numerous statements regarding Manitoba Hydro’s data quality, tools, and decision-making frameworks characterizing them as “not good”,[30] “lacking”,[31] “not sufficiently mature”[32] or “deficient”.[33] Midgard suggests that Manitoba Hydro’s decision-making is “impaired”[34] and that the BOC should be

[30] Pages 7, 61, 84
[31] Pages 7, 71, 72, 73, 85
[32] Page 42, 43
[33] Page 57, 60
[34] Page 7, 35, 62, 65, 68, 84

reduced by an arbitrary 10% as a result, despite an aging asset base.

Manitoba Hydro acknowledges that improvements to asset information, risk and review and decision-making are needed to further mature Manitoba Hydro's Asset Management System which is common to comparable electric utilities. Despite this acknowledgement that there is room for improvement, there is no basis to support Midgard's characterization that Manitoba Hydro's level of data quality, tools and decision-making frameworks is poor. Furthermore, Manitoba Hydro disagrees with Midgard's conclusion that the decision-making supporting the analysis presented in this Application (see Appendix 7.5) is impaired as a result.

Midgard makes this characterization based on the following incorrect assertions and assumptions presented as part of their evidence:

- AMCL's maturity assessment included an assessment on current asset information quality and asset information system capabilities;
- Data quality issues are representative of the entire asset base;
- Manitoba Hydro's use of asset age and economic life is an impaired form of long-term investment planning; and,
- Manitoba Hydro does not have an adequate framework or tool capable of making short-term investment planning decisions.

For reference, Manitoba Hydro differentiates long and short-term planning. Long-term planning is defined as judgements made on the whole population of asset classes to determine future spending needs. Short-term plans are decisions made on specific assets or investments, typically with a three-to-five-year outlook, that become the optimized portfolio.

Each incorrect assumption made by Midgard in its evidence as noted above is rebutted in Sections 9.2.1 through 9.2.4

9.2.1. Midgard's assertion that AMCL's maturity assessment included an assessment on current asset information quality and asset information system capabilities

On page 61, Midgard summarizes the findings of the AMCL report regarding asset information as follows:

> *"In more direct terms, MH is firmly at an "Awareness" stage (Score = 1.32[107]) with its asset information, record keeping, its ability to manage its asset data, and analytics to track progress. In the future an Asset Information Strategy will improve these areas of deficiency. However, as of today, MH's asset information is of poor quality, lacks the necessary information systems to store, access and utilize the data effectively, and is absent metrics to track and plan improvement."*

Midgard asserts from its interpretation of the AMCL maturity assessment that Manitoba Hydro's asset information is of poor quality and lacking information systems to leverage asset data to enable effective decision making when no such information or findings was presented in the AMCL report. This interpretation is an inaccurate reflection on Manitoba Hydro's current ability to make good decisions using current information system capabilities.

The AMCL maturity assessment report recommends improvement initiatives to mature the Asset Information domain. However, it is important to note that AMCL did not equate the need for improvement to conclude that Manitoba Hydro's current capabilities is deficient in supporting Asset Management decision making.

9.2.2. Midgard's assertion that the noted data quality issues are representative of the entire asset base

On pages 70-73, Midgard presents examples of distribution specific asset data quality issues and generalizes that the *"pervasive lack of asset [data] means that MH does not know what assets it is managing"*. From this generalization, Midgard further asserts that Manitoba Hydro cannot plan the associated sustainment activities, because of this lack of data and applies this assertion on the same scale across

Manitoba Hydro's entire asset base.

Manitoba Hydro disagrees that there is a "pervasive lack of asset [data]" and that the level of data quality issues noted prevent Manitoba Hydro from planning sustainment activities. Midgard's evidence also fails to recognize that Manitoba Hydro possesses and uses professional subject matter experts to make informed decisions using the available data. When data quality is in question, further analysis and or investigation is taken to appropriately address the uncertainty.

Midgard inappropriately characterizes asset inventory and age quality issues found within one of its largest asset populations, the distribution wood pole class with 1,000,000+ assets, across the entire asset base. Most asset classes have much smaller populations, where such data quality issues do not uniformly exist.

For many asset classes noted within the Asset Management Sustainment Spending Projection Analysis, Manitoba Hydro presents a complete and specific asset inventory with age demographics. This includes the generator, valve groups, circuit breaker, and medium voltage switchgear asset classes to name a few.

9.2.3. Manitoba Hydro appropriately uses asset age and economic life in long-term investment planning

On page 65, Midgard states: "*without effective AHI, MH's investment decision-making, long-term spending targets, and asset intervention planning is impaired and non-optimized, which leads to higher average lifecycle costs.*"

Midgard makes this assertion based on Manitoba Hydro's response to COALITION/MH I-100a-b, where Manitoba Hydro notes missing Asset Health Index ("AHI") information can influence sustainment capital investment planning from an optimization perspective. However, Manitoba Hydro does not agree that using asset age and economic life as a proxy for asset condition to estimate long term capital sustainment investments is a significant impairment to decision making. This was noted as such within Manitoba Hydro's response to COALITION/MH I-100a-b as found below.

"*Long-term capital investment planning stands to have potential for optimization by the availability of a complete AHI data inventory. Though the current method of using asset age and economic life to estimate long-term level-of-investment is appropriate, given the available information and when applied to the entirety of each asset population, additional insights and planning efficiencies and abilities would come with a complete AHI inventory*."

9.2.4. Manitoba Hydro has an adequate framework and tools capable of making short-term investment planning decisions

Page 43 of Midgard evidence states: *"Presumably the overall capital spending targets are therefore determined in discussions between the senior management team, the MHEB and the Government. How the overall capital envelope is then allocated between projects in the Generation, Transmission & Distribution business groups is not clarified in evidence, but the implication is that the group that lobbies most effectively for its cause will be allocated the biggest envelope. The negative portfolio adjustment values are then established to balance the "too large" cumulative capital portfolio costs within the envelope set for each business group."*

Manitoba Hydro does not agree with Midgard's assumption that it does not value the bottom up needs of its assets and that priority is based on the group that lobbies hardest for the need within their respective energy group. Asset Management practices translate engineering information into business case valuation further detailed above in Section 9.1.1 and the valuation tools described below in Figure 32.

On page 23, Midgard states that, *"it is challenging to accept MH's asserted confidence that …a blanket increase in asset renewal spending is the optimal approach to maintaining or improving ratepayer Service (reliability) outcomes.*"

Manitoba Hydro wholly disagrees with Midgard's interpretation of how Manitoba Hydro oversees asset renewal spending. As explained in Tab 7 Section 7.4.1.1 and expanded on in multiple Information Requests (COALITION/MH I-122, MIPUG/MH I-79,) the "do-nothing" option is always considered as a capital investment alternative.

All potential needs are thoroughly verified through inspection and assessment, proceed through numerous approval gates, and are executed based on the value it brings to Manitoba Hydro and its customers.

Midgard has also confused long and short-term decision making, and the tools available to Manitoba Hydro. Midgard further expands their argument suggesting on pages 44 through 48 that Manitoba Hydro should adopt a decision-making framework like Enwin Utilities.

Since 2016, Manitoba Hydro has had a similar, if not more robust, decision-making tool than Enwin, in its Corporate Value Framework ("CVF") for evaluating and ranking the risk of projects (see Tab 7). The CVF is Manitoba Hydro's framework for short-term decision-making. Decisions are made by evaluating specific asset needs within the CVF to wholistically understand the risks(s) being mitigated or the benefit(s) gained by an investment.

In addition, there are currently 26 value measures in 5 categories used in the CVF that were aligned to corporate strategic objectives when established (see Figure 32 on page 97). The consequence and probability levels for each value measure have been aligned to facilitate evaluation and comparison of different types of investments across Manitoba Hydro (see excerpt of consequence tables Figure 33 on page 97 and probability levels Figure 34 on page 98). As shared in Tab 7 (see SAMP Objective #5), Manitoba Hydro is undertaking a CVF re-calibration initiative to ensure the tool is properly aligned to its new corporate strategy.

Manitoba Hydro's investment prioritization is more advanced than Enwin, because it establishes an optimized portfolio that factors in other portfolio constraints like resource availability, and planned outage requirements to ensure that the necessary generating capacity reserve for resource adequacy is maintained consistent with industry practices and as reviewed by NERC and industry peers.

Copperleaf is the tool Manitoba Hydro has selected to facilitate valuation, comparison, and assembly of investments into an optimized portfolio. Copperleaf is recognized as a leader in asset investment planning and management, and value-based decision making. It is used by utilities across North America and the world including BC Hydro, Ontario Power Generation, Bonneville Power, Tennessee Valley Authority, Alectra Utilities and National Grid.

Manitoba Hydro uses the advanced features of Copperleaf to not only compare investments and build a portfolio, but to also select the investment alternatives (ex. repair or replace) that bring Manitoba Hydro the highest value within known constraints.

Manitoba has provided numerous Capital Investment Justification documents (see MIPUG/MH I-82, COALITION/MH I-122 and COALITION/MH II-124) that demonstrate the application of the CVF.

On page 62, Midgard states, "MH has plans to improve its risk and review frameworks and tools, but they are often ineffective, absent or siloed in a manner than renders them ineffective for improving asset management practices." Manitoba Hydro disagrees with Midgard's broad categorization that risk and review tools are ineffective for improving asset management practices. Manitoba Hydro uses the CVF tool for ad-hoc risk analysis to quantify the valuation for asset decision making and justification of investments. Other recent examples of risk analysis include investigation and reporting on the state of the SCFF Cables and Subsurface Utility Chamber Explosion Concerns. The conclusion from these risk studies drive investment decision making for these respective asset classes.

Figure 32 Manitoba Hydro CVF Value Measures

Value Measure Categories	Value Measures	Conversion Factor	Polarity	Organizational Goals
• Financial	• Capital Financial Benefit	0.001	+	• Maximize cost savings and increase efficiency
	• O&M Financial Benefit	0.001	+	
	• O&M Costs	0.001	-	
	• Financial Risk	Risk Matrix	+	
	• Technology Obsolescence Risk	Risk Matrix	+	
	• Lost Generation Risk	Risk Matrix	+	
	• Export Transfer Capacity Risk	Risk Matrix	+	
	• Working Conditions Benefit	1	+	
	• Varying Cost or Revenue Benefit	0.001	- or +	
	• Generation Revenue Benefit	0.001	- or +	
	• Investment Cost	0.001	-	
• Reliability	• Transmission Reliability Risk	Risk Matrix	+	• Maintain customer service reliability
	• Electrical Delivery Capacity Risk	Risk Matrix	+	
	• Gas Delivery Capacity Risk	Risk Matrix	+	
	• Import Transfer Capacity Risk	Risk Matrix	+	
	• Blackstart Delay Risk	Risk Matrix	+	
	• Distribution Reliability Benefit	1	+	• Increase customer satisfaction
	• Distribution Outage Recovery Benefit	1	+	
	• Gas Distribution Reliability Benefit	1	+	
• Environmental	• Environmental Benefit	1	+	• Environmental stewardship
	• Environmental Risk	Risk Matrix	+	
• Safety	• Safety Risk	Risk Matrix	+	• Safety first for employees & community
	• Security Risk	Risk Matrix	+	
• Corporate Citizenship	• Compliance Risk	Risk Matrix	+	• Stakeholder Perception
	• Stakeholder Perception Risk	Risk Matrix	+	
	• Customer Service Benefit	1	+	

1

Figure 33 Manitoba Hydro CVF Consequence Table

Consequence	Consequence 100,000	Consequence 30,000	Consequence 10,000	Consequence 3,000	Consequence 1,000	Consequence 300	Consequence 100	Consequence 30	Consequence 0
Financial	>$50 million annually	>$15 million annually	>$5M annually	>$1.5 million annually	>$500K annually	>$150K	>$50K annually	<$50K annually	None
Electrical Delivery Capacity	N/A	Unable to service a new load	Can supply all load but exceeding thermal limits	Can supply all load but exceeding planning limits or some customers experiencing power outside of required range for distribution supply system	Can supply all load but exceeding planning limits or some customers experiencing power outside of required range for distribution feeder mains	Can supply all load but exceeding planning limits or some customers experiencing power outside of required range for distribution feeder taps	N/A	Able to supply load without exceeding planning limits.	None
Environ-mental	Severe environmental impact (calculated at 15 as per EMS Risk Ranking Criteria)	Severe environmental impact (calculated at 13-14 as per EMS Risk Ranking Criteria).	Severe environmental impact (calculated at 11-12 as per EMS Risk Ranking Criteria).	Moderate environmental impact (calculated at 9-10 as per EMS Risk Ranking Criteria).	Moderate environmental impact (calculated at 7-8 as per EMS Risk Ranking Criteria).	Moderate environmental impact (calculated at 5-6 as per EMS Risk Ranking Criteria).	Limited environmental impact (calculated at 3-4 as per EMS Risk Ranking Criteria).	N/A	None
Safety	Community destruction and multiple fatalities or serious injuries	Multiple fatalities where no workaround is possible	Serious injury (e.g. permanent disability) or fatality where no workaround is practicable	Injury requiring hospitalization	Injury requiring medical attention	Injury requiring first aid	N/A	N/A	None

2

Figure 34 Manitoba Hydro CVF Probability Levels

Almost Certain	Once in 3 years	Once in 10 years	Once in 33 years	Once in 100 years	Once in 333 years	Once in 1000 years	Once in 3333 years	Once in 10000 years	None
Imminent (>95% chance of occurring this year)	Approximately 30% chance of event occurring this year (e.g. 1 in 3 year event)	Approximately 10% chance of event occurring this year (e.g. 1 in 10 year event)	Approximately 3% chance of event occurring this year (e.g. 1 in 33 year event)	Approximately 1% chance of event occurring this year (e.g. 1 in 100 year event)	Approximately 0.3% chance of event occurring this year (e.g. 1 in 333 year event)	Approximately 0.1% chance of event occurring this year (e.g. 1 in 1,000 year event)	Approximately 0.03% chance of event occurring this year (e.g. 1 in 3,333 year event)	Approximately 0.01% chance of event occurring this year (e.g. 1 in 10,000 year event)	Event unlikely to occur in next 10,000 years

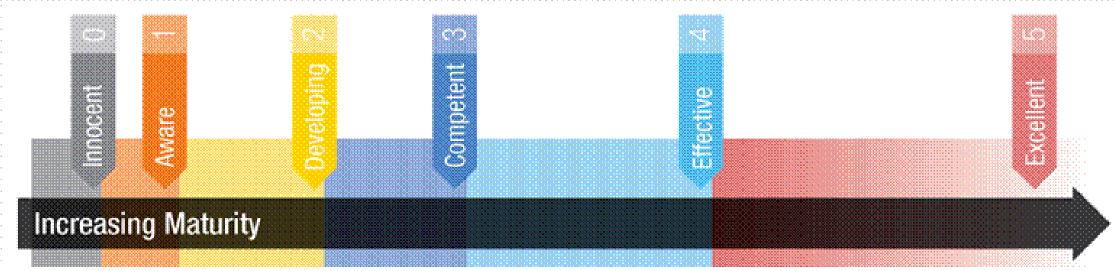
On page 7 of Midgard's evidence, it is recommended that *"A BOC budget reduction of at least 10% is warranted until such time as MH can demonstrate its decision-making."* Manitoba Hydro strongly rejects this conclusion based on the incorrect assertions/assumptions around AMCL's maturity assessment, data quality issues, Manitoba Hydro's use of asset age and economic life for long-term planning and the adequacy of its CVF tools used to make short-term investment planning decisions that populate the BOC. Furthermore, aside from the incorrect assertions/assumptions that underpin Midgard's recommended decrease, Midgard has not provided any evidence or basis to support such a conclusion. No particular project or initiative has been identified or recommended by Midgard to be cancelled by Manitoba Hydro.

The Asset Management Sustainment Spending Projection Analysis provided in Appendix 7.5 is considered to be in customers' best interest.

9.2.5. Manitoba Hydro has made progress on its Asset Management Maturity and is well positioned to make further advancements

In Midgard evidence, Section 7.1: Manitoba Hydro is (Still) Beginning its Asset Management Maturity, Midgard states: *"In the AMCL Report, AMCL finds that MH has advanced its overall maturity from 1.5 to 1.81 (i.e., still in the "Awareness" Category)"*. The range between 1 and 2 is known as the "developing" band, as shown on the diagram below from the AMCL Maturity Assessment report. Midgard incorrectly states Manitoba Hydro is in the Awareness stage, but Manitoba Hydro is in fact at the upper end of the Developing band, with an average score of 1.81.

Figure 35



While progression from an average of 1.5 to 1.81 is not a large numerical progression in maturity, AMCL determined that Manitoba Hydro has made good progress, especially given the circumstances, citing the size and complexity of Manitoba Hydro, a reduction in staffing, the reorganization (which Mr. Rainkie called a full restructuring in his evidence) and the COVID 19 pandemic. While these noted circumstances have temporarily delayed progress on further Manitoba Hydro's asset management maturity, it was designed around an asset management functional model, which will facilitate further maturity improvements in the future.

9.3. SAIDI/SAIFI – Customer Desire for Reliability/Rates

On page 20 of Midgard's evidence, it states that, "*The problem with including these external events is that as an asset manager, MH has negligible control or influence over these external events, and therefore should not be basing its investment decision making upon these external events. For example, if MH has a wood pole transmission line that a forest fire burns, the SAIDI/SAIFI impacts are not due to poor asset management nor asset condition, because regardless of the asset condition the line would have burned and the act of burning was independent of the asset condition that MH managers*."

Additionally, Midgard appears to incorrectly assume that asset management and investment decision making is only about asset condition.

Furthermore, on page 21, Midgard states that, "*uncontrollable changes in system SAIDI and SAIFI results shown in Figure 3 are not a justification for increased asset investment, because the SAIDI/SAIFI results under MH's direct control are stable as confirmed and shown in Figure 4.*"

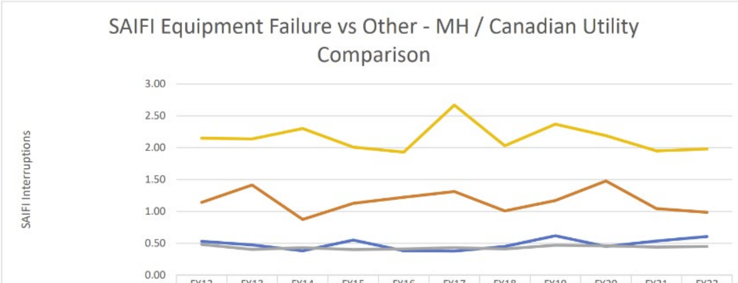
While Manitoba Hydro agrees that an external event's contribution to SAIDI/SAIFI is not necessarily related to asset condition, Manitoba Hydro disagrees that it has negligible control or influence over the impact of external events as investments can be used to mitigate the impact of external events. In addition, Manitoba Hydro disagrees that changes in system SAIDI and SAIFI are uncontrollable and are therefore not a justification for increase asset investment. Manitoba Hydro can and has decided to invest in assets to reduce the impact of external events. Examples of this include:

- Design considerations for steel lattice structures for wind and ice loading;
- Geotechnical slope stabilization to prevent underground cable or structure failure;
- Underground cable or structure relocation away from a geotechnical slope failure; and,
- The re-design or replacement of wood pole lines with steel lattice structures to prevent burning.

On page 23, Midgard states that, *"Since MH has such superior performance when compared to its Canadian utility peers, it is challenging to accept MH's asserted confidence that its overall equipment failure rates are too high and that a blanket increase in asset renewal spending is the optimal approach to maintaining or improving ratepayer Service (reliability) outcomes."* Additionally, on page 27, Midgard states that, "*In summary, although the equipment failure trend is graphically observable in isolation, when viewed in the larger context of the overall SAIDI/SAIFI performance that ratepayers actually experience, the equipment failure trend is not material in the context of MH's stable overall SAIDI/SAIFI trend.*"

Midgard appears to be asserting that Manitoba Hydro's performance is superior to others and it is only the resultant SAIDI/SAIFI performance that impacts customers. To the contrary, Manitoba Hydro's response to Coalition/MH I-92a provides evidence that its SAIFI with equipment failure compared to other utilities is performing worse than its peers.

Figure 36



	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
SAIFI Equip Fail	0.53	0.47	0.38	0.55	0.38	0.38	0.45	0.62	0.45	0.53	0.61
SAIFI - excl Equip Fail	1.14	1.41	0.87	1.13	1.22	1.31	1.01	1.17	1.48	1.05	0.99
CDN-SAIFI-Equip Fail	0.48	0.40	0.43	0.4	0.41	0.43	0.41	0.47	0.46	0.44	0.45
CDN-SAIFI-excl Equip Fail	2.15	2.14	2.30	2.01	1.93	2.67	2.03	2.37	2.19	1.95	1.98

Manitoba Hydro recognizes the increasing trend in equipment failure as an indication of assets reaching their end of life. In response to COALITION/MH II-78, Manitoba Hydro has shown that equipment failures in terms of customer minutes and outages is trending upwards. The response shows that outages due to equipment failures have increased from 2,085 in 2012 to 3,368 in 2022, or a ~4% increase each year in that period.

While Midgard asserts that Manitoba Hydro believes this to be "too high," Manitoba Hydro regards this increase as an indication that age-related deterioration is increasingly resulting in outages and this supports its Asset Management Sustainment Spending Project Analysis in Tab 7.5, notably for intervention rate on underground cables and distribution wood poles given the age demographic of these assets. On page 73, Midgard recognizes this approach and states, "The currently planned replacement rates for some assets (e.g., 5000 distribution wood poles per year, 37 km/year of underground cables) are expected to be inadequate over the longer term as these assets age." Therefore, it appears that Midgard supports Manitoba Hydro's determination that an increased investment rate is required.

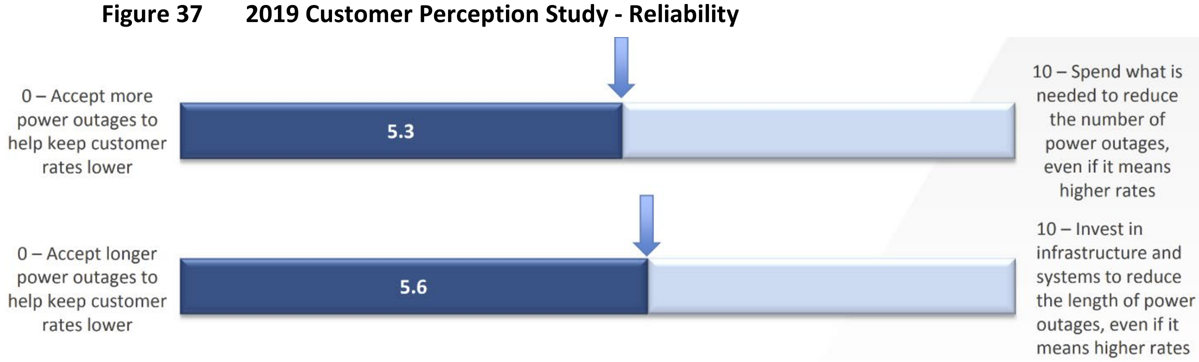
On page 41, Midgard states that, "*the evidence indicates that MH is not basing its Performance (Reliability) targets on a customer- driven tradeoff, and it does not intend to use customer feedback to modify its reliability targets, but rather intends to continue basing its reliability target on a 5-year historic average of its superior performance relative to its Canadian utility peers*."

Midgard is not considering the practical logistics associated with Manitoba Hydro's plans to consult with customers to establish the desired balance of level of services and cost. While Manitoba Hydro is committed to consulting customers, it recognizes the need to adequately prepare and execute upon customer consultation. As a result, Manitoba Hydro has used historical performance in its Strategic Asset Management Plan objective 7 issued in 2019.

On page 26, Midgard states that, "*Although Midgard does not dispute the graphical upward trends shown in the above figure, Midgard questions the materiality of those trend in the context of MH's overall SAIDI and SAIFI trends, which are not increasing*." From the increasing SAIFI, Manitoba Hydro estimates that an additional 5,000 customer interruptions have occurred year over year between 2011/12 and 2021/22. Additionally, in terms of the SAIDI upwards trend, 5,000 customer interruptions are approximately 4 hours of interruption duration. Therefore, between 2011/12 and 2021/22, approximately 5,000 additional customers were interrupted each year for 4 hours due to equipment failures. Manitoba Hydro considers this increase to be of material impact.

On page 85, Midgard states that, "*Ratepayers have not clearly indicated they want to pay for a superior reliability system*." Manitoba Hydro disagrees with Midgard's assertion and has provided contrary information in its response to Minimum Filing Requirement 12. In 2019, Manitoba Hydro gathered survey responses from 1,000 respondents living within Manitoba. Overall, Manitobans lean slightly over the midpoint in favour of spending what is needed to reduce the number of power outages versus keeping rates as low as possible, based on the following survey results.

Figure 37 2019 Customer Perception Study - Reliability



This survey result, in conjunction with other insights from customer research and engagement, shows support for the decision to maintain historical reliability.

AMCL's reply evidence to Midgard's Written Evidence is found at Appendix 2 of Manitoba Hydro's Rebuttal Evidence.

10. Cost of Service & Rates

10.1. Manitoba Hydro's Rate Proposals are Fair, Reflective of the Current Circumstances, and Give Appropriate Weight to Rate Objectives

At page 34 of her evidence, Ms. Derksen states,

> *"The over-emphasis on cost causation as based on the mechanical output of PCOSS24 has resulted in MH proposing rate differentiation by class that ignores the highly unstable cost basis resulting from a culmination of a number of profound changes including the addition of significant generation and transmission investment, record high net export revenue, and the significant reduction to payments to government, at the great expense of other critical criteria of efficiency and fairness.*
>
> *This is a striking dichotomy compared to its past ratemaking perspectives."*

Ms. Derksen provides no evidence to support these positions, and in fact, her conclusions are incorrect.

The major capital projects are now fully in-service and provide certainty on the costs of the significant investment in generation and transmission and can hardly be viewed as providing a "highly unstable cost basis". These assets have average service lives in the range of 50-100 years which will translate into relatively fixed amounts of depreciation and finance expense in the upcoming years.

Similarly, the reduction in payments to government are expected to continue in perpetuity; as a result, beyond the initial impact in the test year which reduced costs for all classes and resulted in a reduction in proposed rate increases from 3.5% to 2%, there is no instability created as a result of this reduction. In fact, water rentals are one of the few true variable costs in Manitoba Hydro's system and the substantial reduction in the water rental fee will actually result in greater cost stability. In the case of net export revenue, Manitoba Hydro concurs that the very high levels forecasted do contribute to more variability than has historically been experienced. However, this factor was explicitly recognized in Manitoba Hydro's rate proposals as discussed in Section 8.4.2 of Tab 8.

Most problematic, however, is the assertion that Manitoba Hydro's rate proposals are *"at the great expense of other critical criteria of efficiency and fairness".* With regard to the criteria of fairness, Ms. Derksen's evidence generally leaves the impression that any change in costs that results in an increased revenue to cost coverage ratio ("RCC") for the GSL >100 class (which could translate into necessitating a lower than average rate increase) is unfair and requires some form of remedial action at the ratemaking stage. One such example can be found on page 39 of her evidence:

> *"In the current ratemaking framework directed by the Board in Order 164/16 of recognizing Ratemaking Objectives other than cost causation in Rate Design, it is expected that MH's rate differentiation proposals give consideration to the asymmetric benefit to some customer classes, notably the largest GSL classes as a result of the significant reduction in Water Rental Fees and the PGF payments to the Manitoba Government. No such consideration by MH has been provided."*

Manitoba Hydro does not agree with the suggestion that the on-going water rental fees, which will continue to be treated as a generation cost and represent a proportionately greater share of total costs for GSL customers than for customers served from the distribution system, should be theoretically viewed differently than the one-time reduction in water rental fees.

The PUB directed in Order 164/16 that rate making objectives should not be considered in the determination of the cost of service methodology and if required, should be considered at the rate design stage. However, it should not follow, nor does Manitoba Hydro believe, that it was the PUB's intention in 164/16 that rate design should ignore all changes in cost responsibility produced within the PCOSS.

At page 37 of her evidence Ms. Derksen states:

> *"there appears to have been a profound change in perspective regarding rate philosophy in the past couple of years."*

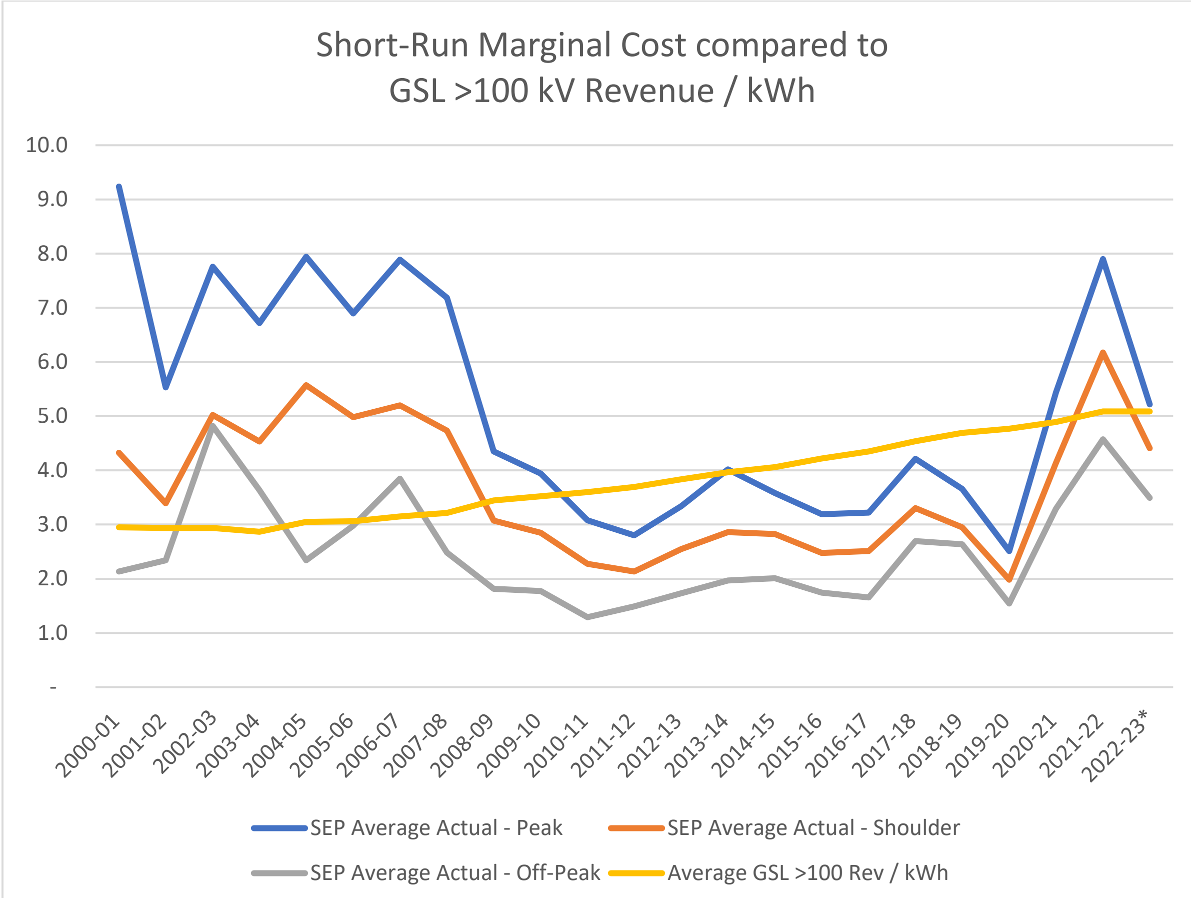
While there is some discussion of the history that gave rise to Manitoba Hydro's earlier proposals in Ms. Derksen's evidence, there is no consideration to the more contemporary, and therefore more relevant, changes that have arisen and influenced the current rate proposals being sought in this application.

The primary considerations that led to past proposals by Manitoba Hydro were well explained as part of the 2004 General Rate Application:

> *"A key concern raised by Manitoba Hydro in the context of the allocation of export revenues is that current levels are so high relative to the embedded costs of Generation and Transmission that their allocation is contributing to inappropriately low price levels, particularly for the largest customers. Manitoba Hydro raised this concern in the 2002 Status Update proceeding and continues to be concerned about rates that are based on embedded costs falling below short term marginal cost of energy." (Rebuttal Evidence of Manitoba Hydro, June 11, 2004, page 18)*

Using Manitoba Hydro's Surplus Energy Program (SEP) prices as a proxy for short-run marginal costs, Figure 38 below shows the discrepancy that existed in the early 2000s that resulted in Manitoba Hydro's earlier positions regarding fairness and efficient prices signals.

Figure 38 **Short-Run Marginal Cost Compared to GSL >100 kV Revenue / kWh**



In 2000-2001 the short run marginal costs were more than three times higher than the average revenue per kWh being collected from GSL >100 kV customers. With export revenues expected to continue at similar (or increasing) levels and no major additions on the horizon that would increase embedded generation and transmission costs, Manitoba Hydro began to explore other potential mechanisms for sharing export revenue as a means to reduce this gap. This led to significant debate in the regulatory forum over the next decade and a half with various different cost allocation methods related to Manitoba Hydro's export revenues being implemented along the way.

However, as shown in Figure 38 the export price trend did not continue and short-run marginal costs and embedded costs started to converge. Short-run marginal costs (using most recent SEP prices as a proxy) and even long-run marginal costs (as noted in COALITION/MH II-57d) are now at levels that are not materially different compared to average revenues based on embedded costs and may continue to narrow with short-run marginal costs currently on a downward trajectory. These differences are certainly not substantive enough to warrant special consideration which, in Manitoba Hydro's view, would disregard the latest PUB direction.

Order 164/16 the PUB provided their most current view of the appropriate treatment of export revenues:

> *"The Board finds that the revenue from export sales is linked to the assets that give rise to export sales revenues, which are Generation and Transmission assets only, not Distribution assets. To use Distribution costs to credit export revenue of any kind would be a disconnection to cost causation and thus inappropriate.*
>
> *The Board concludes that export revenues are not a "dividend" that can be assigned or based on considerations other than cost causation."* 164/16 page 39
>
> *"the Board determines that, in part, the creation of the Export class was based on ratemaking goals and not cost of service principles. As discussed above, Manitoba Hydro's purpose for including an Export class in the COSS is to achieve fairness and equity between the rates paid by domestic customer classes. The Board's view is that these concerns are more appropriately considered* ***and, if necessary****, addressed in the context of ratemaking in a GRA"* 164/16 pages 31-32 [emphasis added]

And while noting that Manitoba Hydro proposed to expand the zone of reasonableness ("ZOR") in the 2017 GRA in response to some of the Board findings in Order 164/16, Ms. Derksen's evidence does not provide the corresponding direction from the Board from Order 59/18[35] in relation to that proposal:

> *In evaluating class Revenue to Cost Coverage ratios, the Board does not accept that the zone of reasonableness should be expanded to 90% to 110% and finds*

[35] Order 59/18, page 197

the zone of reasonableness should remain at 95% to 105%. While rate-making principles may justify accepting Revenue to Cost Coverage ratios that are outside of the zone, those principles do not support broadening the zone itself. A 95% to 105% range recognizes the sophistication of Manitoba Hydro's Cost of Service Study and departure from this range has not been justified.

In addition to retaining the ZOR at the 95-105% level, the PUB also directed Manitoba Hydro to differentiate rates based on the results of Manitoba Hydro's most current PCOSS, in each of Orders 59/18, 69/19, and 137/21. As noted in Tab 8, Manitoba Hydro's proposals in this application are guided by this direction from the PUB in addition to the consideration of historic RCC levels by class and the overall level of net export revenue. None of this amounts to Manitoba Hydro being "slavishly bound" to the results of an embedded cost of service study as implied by the Coalition, but rather recognizes that in the current circumstances, with the level of recent additions of new major generation and transmission facilities that came with some expectation of increased export revenues, coupled with the trends of decreasing marginal costs and increasing embedded costs, the same concerns that gave rise to Manitoba Hydro's position in the late 90s and early 2000s do not currently exist.

10.2. Changes in class cost responsibility are largely due to changes in class consumption

In Section 4.2 of her evidence, Ms. Derksen provides analysis and discussion that *"is intended to assist in understanding the shifts in cost responsibility between customer classes and resultant RCCs driven by the significant additions to generation and transmission investment related to Bipole III, GNGT*(sic)*, MMTP and Keeyask."*

On page 23, Ms. Derksen overstates the impact that these major Generation and Transmission projects have had on the revenue requirement in PCOSS24 in the following observations:

3. As shown in Table 4, despite the increase in cost of $566 million between PCOSS21 and PCOSS24 almost all a result of the addition of Keeyask, there has actually been a decline in total allocated cost to the GSL>100kV ($282 million vs. $283 million);

4. As shown in Tables 5&6, not surprisingly, there are sizable increases in the allocation of generation and transmission costs to the classes, including the Residential class. However, there is a fairly sizable decrease in the allocation of generation and transmission costs to the GSL>100kV class. Between PCOSS18 and PCOSS24, the GSL>100kV class's allocation of generation and transmission cost has declined by 4% and 24%, respectively. The reduction in the GSL>100kV class's allocation of generation cost of -23% is even more pronounced between PCOSS21 and PCOSS24. This is particularly counterintuitive given the nearly $1.1 billion (60% increase) in costs associated with Bipole III, GNGT (sic), MMTP, and Keeyask;

The assertion that the $566 million increase in total costs is almost entirely due to the addition of Keeyask is incorrect. The revenue requirement for Keeyask, excluding any net export revenue ("NER"), increased by $302 million between PCOSS21 and PCOSS24 and is therefore only responsible for slightly more than one-half the increase in gross revenue requirement. Similarly, the gross revenue requirement for Keeyask, Bipole III, MMTP and GNTL was already largely included in PCOSS21, and the increase for these projects between PCOSS21 and PCOSS24 was only $357 million and not the $1.1 billion as referenced.

It is correct that the costs for GSL>100kV decreased between PCOSS21 and PCOSS24 despite increases in the overall revenue requirement, although the cost decrease for the class of only 0.4% ($283 million vs $282 million) was clearly insignificant. However, Ms. Derksen's interpretation of Table 4 does not consider the impact due to changes in class load between studies.

In the case of the GSL>100 kV, the slight reduction in allocated costs for the class in Table 4 occurs despite increases in total costs due to the significant decrease in GSL >100kV load used to allocate those costs. The reduction in load was primarily driven by a reduction in the mining sector,[36] and is evident in the figure below which provides the changes in GSL >100kV energy consumption between studies. The 19% decrease in load between PCOSS21 and PCOSS24 was sufficient to keep costs for the class flat

[36] COALITION/MH I-157a

despite overall increases in the gross generation and transmission costs.

Figure 39 Changes in GSL >100kV Energy Consumption Between Studies

	E20 Energy (MWh)			Change in Energy		
	PCOSS18	PCOSS21	PCOSS24	PCOSS21 vs PCOSS18	PCOSS24 vs PCOSS21	PCOSS24 vs PCOSS18
GSL >100 kV	4,505	3,997	3,249	-11%	-19%	-28%

Tables 5 and 6 on pages 22 and 23 of Ms. Derksen's evidence provide a comparison of the changes in functionalized costs by class between COS studies. While it may seem reasonable to expect that the comparison will show sizable increases in allocated generation and transmission costs for PCOSS24 compared to earlier studies, it is not borne out by the evidence provided. Table 5 provides a comparison of PCOSS18 to PCOSS24 that shows increases for only 10 of the 16 generation and transmission data points, while the comparison of PCOSS21 to PCOSS24 provided in Table 6 shows that the generation or transmission costs have actually increased for only 3 of the 16 data points.

The reason for this anomaly is the choice of the data source used in Ms. Derksen's analysis. Tables 5 and 6 have been prepared using the functionalized costs provided in Table A3 of the PCOSS (Appendix 8.1). Costs in Table A3 are net costs that have been reduced by the allocation of net export revenue and are not appropriate to use in an attempt to analyze the impact of changes in G&T costs in isolation. The change in GSL >100 kV costs may appear 'counterintuitive' if you fail to also consider the $525 million increase in NER between studies that significantly offsets the expected increases in G&T costs.

The allocation of net costs in Tables 5 and 6 will also be affected by the same decreases in GSL >100kV energy consumption that impacted gross costs in Table 4 (28% reduction in load in Table 5 and a 19% reduction in Table 6).

10.3. The allocation of NER in the PCOSS is proportional to the related G&T costs allocated to each class and offsets a smaller portion of G&T costs than prior studies

Ms. Derksen has incorrectly and significantly overstated the extent that NER offsets Generation and Transmission costs in PCOSS24.

In response to PUB/Coalition 16b Ms. Derksen claims:

> *"Secondly, NER is offsetting 94% of total generation and transmission investment, almost offsetting the entire annualized generation and transmission investment cost in PCOSS24, of approximately $1.2 billion, as shown in the Table below:*

PCOSS24	Total Generation	Total Transmission	Total G&T	Total NER	Total NER Offset
	(Billion)	(Million)	(Billion)	(Billion)	(%)
	$1,041	$152	$1,193	$1,116	94%

> *In comparison, in past years when MH was expressing significant concern about the reliability of the results of COS, NER was offsetting order of magnitude of 50% of total generation and transmission investment. The magnitude of this issue has doubled compared to past cost of service results on this basis."*

This claim is reiterated in Ms. Derksen's response to AMC/CC 1-4:

> *"In terms of providing comments on the fairness of allocating a greater percentage of export revenues to non-residential customers who are the least impacted by Manitoba Hydro's electric facilities, it has been a long-standing issue before the PUB since at least 1995. The results of PCOSS24 serve to demonstrate that this issue has only been amplified as **NER is now large enough to nearly offset the entire annualized generation and transmission revenue requirement** in PCOSS24. MH's inaction is not only disappointing but concerning for the captive Residential class. (emphasis added)"*

In fact, NER offsets approximately 50%[37] of the generation and transmission related revenue requirement in PCOSS24. The high level of exports in the current study is also accompanied by the revenue requirement for the increased generation and transmission investments which in combination results in a ratio that **<u>is actually lower</u>** than previous results which ranged from 54-61% for the PCOSS04 to PCOSS10 studies. This offset ratio is expected to continue to decline in future studies since these generation and transmission assets will continue to be significant components of future revenue requirements while export revenues are forecast to decline.

The reason for this incorrect conclusion in Ms. Derksen's evidence is, again, the choice of the data source used in the analysis. The table provided to support the 94% offset claim has been prepared using the functionalized costs provided in Table A3 of the PCOSS (Appendix 8.1). Costs in Table A3 are net costs that have already been reduced by the allocation of net of export revenue. Comparing NER to costs that have already been reduced by NER will result in double-counting the NER and dramatically overstating the costs offset by export revenues.

Table 9 of Ms. Derksen's evidence shows the share of total allocated costs that are offset by net export revenue for each customer class and demonstrates that the share of total costs offset by NER will vary depending on the amount of non-G&T costs for each class.

In this case the costs and NER used in the calculation are appropriate, but the conclusion is misleading. This variation does not demonstrate that the allocation of NER is at all inequitable. Rather, all classes receive precisely the same benefit when only the relevant costs are included as demonstrated in the following figure. The net export revenue that is allocated to each class offsets the same portion of the costs (48.7%) of the generation and transmission facilities that the PUB found supported export activities in Orders 164/16 and 59/18.

[37] COALITION/MH II-60b

Figure 40

	Net Export Revenue ($ million)	Allocated G&T (Excluding Non Tariffable Transmission) ($ million)	Percent of Allocated G&T Offset by NER
Residential	471.2	967.5	48.7%
GSS ND	106.9	219.4	48.7%
GSS D	86.9	178.4	48.7%
GSM	144.0	295.6	48.7%
GSL 0-30 kV	87.2	179.0	48.7%
GSL 30-100 kV	82.3	168.9	48.7%
GSL >100 >100 kV	134.8	276.8	48.7%
ARL	3.0	6.1	48.7%

10.4. RCCs before NER Inherently Incorporate an Allocation of NER on Total Cost

On page 46, Ms. Derksen notes concern that Manitoba Hydro continues to rely on RCCs that incorporate Net Export Revenue for rate differentiation as directed in Orders 164/16 and 59/18 rather than adopt RCCs prior to Net Export Revenue as proposed by Ms. Derksen.

> *"It is concerning that MH has not acknowledged that RCCs prior to incorporation of NER is a valid and reasonable consideration in the assessment of the responsibility of the outcome of PCOSS24 and rate differentiation. The issue of NER, the impact to RCCs, and rate differentiation is a live issue, one that is not dissimilar to that in many past years whereby Manitoba Hydro was not even prepared to accept the results of its COS, let alone be slavishly bound by the results of PCOSS24.*
>
> *Order 164/16 directed a number of significant foundational changes in COS philosophy. What Order 164/16 did not find is that these issues were to be ignored. Very clearly, Order 164/16 found these types of issues are to be addressed in Rate Design, which MH has failed to do. At the very least, RCCs*

prior to NER are a valid consideration in the assessment of the outcome of the PCOSS in the translation to revenue to class as part of the Rate Design phase. The results further support an across-the-board rate change if a rate change is approved by the Board."

The approach being advocated for by Ms. Derksen is inconsistent with the PUB's findings and directed treatment of NER included in Order 164/16. This is revealed by examining the true nature of RCCs prior to the allocation of NER.

Since RCCs prior to NER are well below unity they must be adjusted or normalized for use in cost differentiation by restating the RCC for each class against the overall RCC. In PCOSS24 the Residential RCC prior to NER of 61.5% is not meaningful by itself so it needs to be evaluated against the average overall RCC of 62.6%, yielding a normalized RCC of 98.2% for the class. The following figure provides the RCCs prior to NER[38] after normalization for each class.

The figure also provides an alternate calculation of RCC after NER, where NER has been allocated in proportion to total costs rather than exclusively Generation and Transmission costs.

A comparison of the RCCs shows that the RCC prior to NER after normalization are equivalent to the RCC with NER allocated on total costs.

[38] Appendix 8.1, Table A1

Figure 41

(a)	(b)	(c)	(d) (c / b)	(e) (d/total d)	(f) (b/total b)	(g) (f x Total NER)	(h) (b – g)	(i) (c / h)	(j) (i – d)
	Total Cost ($ million)	Class Revenue ($ million)	RCC % (Prior to NER)	**Normalized RCC % (Prior to NER)**	Class Share of Total Cost	NER on Total Cost ($ million)	Net Cost ($ million)	**RCC% (NER on Total Cost)**	RCC Difference
Residential	1,352.4	831.6	61.5%	**98.2%**	45.3%	506.1	846.3	**98.3%**	0.1%
GSS ND	298.7	210.3	70.4%	**112.5%**	10.0%	111.8	186.9	**112.5%**	0.0%
GSS D	234.9	150.7	64.2%	**102.6%**	7.9%	87.9	147.0	**102.5%**	-0.1%
GSM	378.9	235.6	62.2%	**99.4%**	12.7%	141.8	237.1	**99.4%**	0.0%
GSL 0-30KV	214.8	125.0	58.2%	**93.0%**	7.2%	80.4	134.4	**93.0%**	0.0%
GSL 30-100KV	177.5	107.0	60.3%	**96.3%**	6.0%	66.4	111.1	**96.3%**	0.0%
GSL >100KV	282.0	166.6	59.1%	**94.4%**	9.5%	105.5	176.5	**94.4%**	0.0%
SEP	2.8	3.0	106.2%	**169.6%**	0.1%	1.1	1.8	**169.8%**	0.2%
A&RL	27.6	26.7	96.6%	**154.3%**	0.9%	10.3	17.3	**154.4%**	0.1%
Diesel	13.0	9.9	76.4%	**122.0%**	0.4%	4.9	8.1	**122.2%**	0.2%
Total	2,982.7	1,866.5	62.6%	**100.0%**	100.0%	1,116.2	1,866.5	**100.0%**	0.0%

Allocation of NER on total costs is not consistent with views on cost causation and the direction provided by the PUB in Orders 164/16 to credit export revenue based on exclusively Generation and Transmission since these are the only assets that facilitate export sales.[39]

Any decision to use RCCs prior to NER must recognize that this RCC inherently incorporates an allocation of NER on total costs, and consider the extensive regulatory review of this topic in previous GRAs and the 2016 Cost of Service Methodology Review hearing that led the Board to reject this approach.

In response to PUB/COALITION I-16b, Ms. Derksen states that the range of class RCCs demonstrates that the results of PCOSS24 have been distorted due to the level of NER included in the study:

> *"Further, as discussed below, the distortion that led to MH's conclusions in past years that class RCCs were not reliable for purposes of rate differentiation, continue to exist and in fact, have been amplified significantly in the current 2023/24 Test Year.*

[39] Order 164/16 pages 9-10

PCOSS24 includes Net Export Revenue of approximately $1.1 billion. There are several important points to raise regarding this level of NER…………

Third, if the RCC distortion did not exist, it is expected that class RCCs prior to NER, would be similar in their range to each other. This is not the case. What we see is a significant variation in the class RCCs and their range as shown in the Table below. Class RCCs before NER range from 59% - 97% and with NER range from 94% - 113%.

	PCOSS24	
	As Filed Dec 2022	
	RCC (no NER)	RCC
Residential	61.5	94.4
GSS ND	70.4	109.7
GSS D	64.2	101.8
GSM	62.2	100.3
GSL 0-30	58.2	97.9
GSL 30-100	60.3	112.4
GSL>100	59.1	113.2
ARL	96.6	108.2

Based on the above, it is clear that distorted RCCs persist, and in fact are much more pronounced in PCOSS24 than in past years."

Unfortunately, it is not clear what evidence has been provided or relied upon to support the claim "*that distorted RCCs persist*".

It appears that Ms. Derksen's concern may be that the difference between the RCC prior to NER and the RCC including NER is larger for some classes than it is for others. If so, this is entirely expected due to the relative differences in the generation and transmission costs incurred by each class which is used as the basis of allocating a share of NER to the class.

This type of variation in pre and post NER RCCs by customer class will occur under all methodologies, other than the allocation of NER on total cost approach which has already been rejected by the PUB in Order 164/16.

10.5. Modification to the PCOSS methodology for ARL is entirely consistent with the principles established in 164/16

On page 48, Ms. Derksen compares the Area & Roadway Lighting ("A&RL") RCC from the PCOSS14 study filed for the 2016 Cost of Service Methodology Review to the revised version of PCOSS14 filed in response to Directives 1 and 2 of Order 164/16:

> *"A review of the ARL RCCs flowing from the COS methodology changes in Order 164/16 as it relates to the treatment of DSM and the LED conversion are not apparent. The RCC results do not indicate any discernible issue of concern (i.e approximate RCC of 99.7% vs. 99.5%) despite previous expectations;"*

The version of PCOSS14 compliant with 164/16 included the change in the allocation methodology for DSM, however neither version of the study included any costs related to the LED conversion program as these costs were not part of the revenue requirement used for PCOSS14. In absence of any A&RL specific programs, there were no expectations that the methodology change for DSM would have any notable effect on A&RL in that study.

On page 49, Ms. Derksen states that:

> *"The proposed COS methodology change by MH is clearly a result of an RCC outcome that it did not believe represented a reasonable depiction of class cost of service for ARL. It elected to address it through the adjustment of COS than through Rate Design as directed by the Board in Order 164/16."*

The fact that the justification of the LED conversion program was based, in part, on benefits that are specific to lighting plant is clearly a question of cost causation and is relevant information that was not available to the Board in making its determination in Order 164/16. The proposal by Manitoba Hydro to make a slight modification to the PCOSS methodology is entirely consistent with the principles established by the Board in 164/16 to determine matters relevant to include in the cost of service process rather than the rate design phase:

"The Board accepts and applies the principle of cost causation in establishing the appropriate method of allocating Manitoba Hydro's financial costs to the various customer classes. The Board finds that other ratemaking principles for setting just and reasonable rates should be considered in a GRA, and not a cost of service process." Order 164/16, page 6

10.6. Manitoba Hydro has no concerns regarding the adequacy of the level of G&T costs allocated to the ARL class

On page 49, Ms. Derksen notes the sensitivity of A&RL to changes in the level of Generation, Transmission and Net Export revenue, and goes on to clarify that this sensitivity is actually due to the class's minimal use of generation and transmission resources:

"Based on the above table, it is clear that the RCCs of the ARL class are highly impacted by the addition of generation and transmission investment, and high levels of export revenue, recognizing their disproportionately low allocated cost of generation and transmission."

To ensure the record is clear, Manitoba Hydro has prepared the following figure that provides the functional breakdown of net cost by class from PCOSS24[40] that demonstrates the atypical cost structure for A&RL compared to all other customer classes, namely that only 11.3% of the net costs for A&RL are Generation related and 1.5% are Transmission related. This is a significantly lower share of the total costs than any other class due to the additional costs related to the dedicated street lighting plant that are unique to the A&RL class. Net export revenue allocated on the basis of Generation and Transmission costs will also be dramatically different than all other classes.

[40]Table A3, Appendix 8.1

Figure 42

Class	Generation	Transmission	Subtransmission	Distribution Service	Distribution Plant
Residential	49.0%	8.1%	5.4%	9.0%	28.5%
GSS ND	51.8%	7.6%	5.1%	8.3%	27.3%
GSS D	54.8%	7.8%	5.2%	4.7%	27.6%
GSM	57.5%	7.8%	5.1%	4.2%	25.5%
GSL 0-30 kV	64.4%	8.2%	5.4%	2.4%	19.5%
GSL 30-100 kV	82.2%	9.6%	6.2%	1.7%	0.3%
GSL >100 kV	87.3%	10.8%	0.0%	1.7%	0.2%
A&RL	11.3%	1.5%	1.0%	4.4%	81.8%

10.7. In the zero-sum realm of Cost of Service, a class with lower than average cost increases will experience a RCC decrease

In the response to PUB/Coalition I-17a, Ms. Derksen expresses concern that the RCC of the A&RL class has increased despite the addition of new generation and transmission assets:

> *"Both interestingly and concerningly, the ARL class <u>benefits</u> to a significant degree by the addition of new generation and transmission, as well as NER. In other words, despite the significant addition of generation and transmission that has added more than $13 billion of cost to MH's rate base, the result of the COSS is to significantly increase the ARL RCC such that MH is proposing for a much lower than average differential rate increase for the ARL class. […]*
>
> *At the very minimum, it is counterintuitive to expect that the significant addition of generation and transmission cost would lead to a cost allocation reduction to the ARL class, and significantly lower than average rate differential. Further, the reduction in NER anticipated by MH is expected to further benefit this class."*

To understand changes in class RCCs it is critical to understand that an asset addition will have different impacts on the overall revenue requirement than it will have on the results of the Cost of Service.

The impact on the revenue requirement as a result of adding a new asset is entirely intuitive. The asset addition will result in increases in finance and depreciation expense, which will subsequently require an increase in overall revenues to recover the increased revenue requirement.

On the other hand, because the Cost of Service is a net-zero process that allocates revenue requirement once it's determined, any increases in class RCCs will be fully offset by decreases in RCCs of other classes, so that the overall RCC of the study remains at 100%. The overall RCC is never allowed to depart from 100% since this would suggest the need for increases or decreases in the overall level of revenue – this is the role of the revenue requirement phase and not the COS. Maintaining an overall RCC of 100% means that an increase in costs will lower the RCCs of some classes as expected, but will also have the seemingly counter-intuitive effect of increasing the RCC for other classes. Similarly, some classes will experience an RCC decrease despite decreases in costs or increases in export revenue which would be unanimously considered a beneficial change in the revenue requirement phase.

This is not a unique phenomenon that is specific to the A&RL class. It is a fundamental aspect of the cost of service study that utilizes the revenue requirement as an input and accepts that it represents the appropriate level of costs that need to be recovered. In this regard the RCCs in the COS provide a neutral portrayal of the utility's financial position, continuing to yield an overall RCC of 100% under all financial conditions regardless of any significant increases or decreases to the revenue requirement.

In the specific case of A&RL, the class RCC increases despite the addition of significant generation and transmission assets due to its uniquely low proportion of generation and transmission costs as a proportion of its total net costs (13%) compared to all other classes (57% - 98%). The RCC increase for A&RL is not due to a reduction in costs, but rather that the addition of new G&T assets increases the costs for all other classes much more significantly than for A&RL. In the zero-sum realm of Cost of Service, a class with lower than average cost increases will experience a RCC decrease – a result that may not be intuitive to those unfamiliar with the rate making process.

The same response to PUB/Coalition I-17a includes seemingly contradictory statements that suggest that A&RL benefits from a higher RCC in response to either <u>additional</u> export revenues or <u>decreases</u> in export revenue:

> *"Both interestingly and concerningly, the ARL class <u>benefits</u> to a significant degree by the addition of new generation and transmission, as well as NER….*
>
> *Further, the reduction in NER anticipated by MH is expected to further benefit this class."*

To clarify the record Manitoba Hydro refers to the response to Coalition/MH II-61a that provided RCCs for PCOSS24 assuming reduced export revenues of $1.0 billion, $900 million and $800 million.

Figure 43

	PCOSS24	**PCOSS24 (Exp Rev of $1B)**	**PCOSS24 (Exp Rev of $900M)**	**PCOSS24 (Exp Rev of $800M)**
Area & Roadway Lighting	108.2%	111.4%	113.5%	115.7%

The scenarios clearly show that the RCC of A&RL is negatively correlated with changes in export revenues due to the below average amount of export revenues allocated to the class.

10.8. Manitoba Hydro is Continuing to Target the ZOR for the A&RL Class

On page 49 Ms. Derksen states that:

> *"MH's proposal to benchmark an RCC for the ARL class to 108% does not address the substantive issue that the ARL may not be adequately allocated the cost of generation and transmission through COS as it is the result of the direct assignment of LED fixture costs and an unrelated issue."*

Manitoba Hydro is not proposing to benchmark the "RCC for the ARL class to 108%". The appropriate benchmark for the A&RL class continues to be unity and the associated 95 to 105% zone of reasonableness. Manitoba Hydro proposes to continue moving the overall A&RL class into the ZOR using class average revenue increases of 1.0% for 2023/24 and 2024/25.

The use of the 108% benchmark is also entirely unrelated to the adequacy of allocated generation or transmission costs or DSM costs.

After determining the appropriate differentiated rate increase for the class as a whole, any additional differentiation to individual lighting rates within the A&RL class must be done on a revenue neutral basis to avoid increasing or decreasing the proposed 1.0% increase. By comparing the RCC for each lighting rate to the overall RCC for the A&RL class of 108%, this second level of rate differentiation can be determined for each lighting rate to ensure the overall 1.0% increase once applied will continue to achieve the proposed amount of total revenue for the A&RL class.

10.9. The impact of the reduction in Water Rentals and Provincial Guarantee Fee on class RCCs is Intuitive, Predictable and provides clear benefits to the Residential Class

Ms. Derksen provided a table on page 31 of her evidence which was intended to demonstrate the impact that the amended reduction in Water Rental and debt guarantee fees would have on class RCCs:

"Table 11:

	PCOSS24 RCC	PCOSS24 RCC Without Water Rental & PGF Reduction	PCOSS24 Benefit of Lower Water Rentals & PGF
Residential	94.4%	94.8%	0.4%
GSS ND	109.7%	109.9%	0.2%
GSS D	101.8%	101.8%	0.0%
GSM	100.3%	100.1%	0.2%
GSL 0-30	97.9%	97.4%	0.5%
GSL 30-100	112.4%	110.7%	1.7%
GSL>100	113.2%	111.2%	2.0%
ARL	108.2%	110.9%	2.7%

The sensitivity demonstrates the disproportion benefit provided to some customer classes. In PCOSS24, the Residential Class RCC benefits by 0.4%, while the RCC of the GSL>100kV and the ARL classes benefit by 2.0% and 2.7%, respectively."

By way of information request, Ms. Derksen was invited to correct Table 11 to distinguish between positive and negative RCC changes and modify any conclusions as needed. In the response to MH/Coalition I-8, a partially corrected table was provided that still failed to correctly identify the impact on A&RL. The following observation was also provided:

*"Please see the updated Table 11 below. As indicated in Ms. Derksen's evidence, there is **a counter-intuitive disbenefit of 0.4% to the Residential class** as a result of the reduction of the Water Rental and PGF payments of approximately $180 million annually. Conversely, most other classes benefit, with the GSL classes benefitting between 1.7% - 2.7%."* (emphasis added)

The IR response incorrectly claimed that the benefit for the GSL classes due to the fee reduction ranged from 1.7 to 2.7%, rather than the actual estimated RCC increases for the GSL classes of 0.5% to 2.0%, as shown in the table.

To clarify the record Manitoba Hydro has corrected the RCC change shown for A&RL in the following version of Table 11.

Figure 44

	PCOSS24 RCC	PCOSS24 RCC Without Water Rental & PGF Reduction	PCOSS24 Benefit of Lower Water Rentals & PGF
Residential	94.4%	94.8%	-0.4%
GSS ND	109.7%	109.9%	-0.2%
GSS D	101.8%	101.8%	0.0%
GSM	100.3%	100.1%	0.2%
GSL 0-30	97.9%	97.4%	0.5%
GSL 30-100	112.4%	110.7%	1.7%
GSL>100	113.2%	111.2%	2.0%
ARL	108.2%	110.9%	-2.7%

With this correction, the RCCs demonstrate the typical pattern of changes that consistently and predictably occurs with any change in generation or transmission related costs. RCC impacts due to changes in G&T costs will vary depending on the relative amount of generation and transmission costs for the class. In this case, the reductions in generation-related Water Rentals and the largely G&T related[41] provincial guarantee fee increases the RCC for the General Service Large classes whose costs are almost exclusively Generation and Transmission related. Meanwhile the RCCs for classes that are served off the distribution system, including Residential and ARL, will decrease. The claimed *"counter-intuitive disbenefit of 0.4% to the Residential class"* is in fact entirely predictable and fully consistent with how costs are allocated in the Cost of Service Study.

The response to PUB/Coalition I-18 noted one part of the impact that the reduction in water rentals and provincial guarantee fees had on the Residential class:

> *"Not confirmed. It is not clear this is true. As can be seen in response to MH/Coalition I-8, there is a sizable difference in RCC impacts, with the Residential class actually disbenefitting. In order (sic) words, despite a nearly $180 million reduction in Water Rental and PGF costs, the Residential class'*

[41] COALITION/MH I-138e (Revised)

RCC declines and their rates would have to increase, all else equal. ***Surely, the sizable reduction in payments to government shouldn't result in Residential customers having to pay more****." (emphasis added)*

Manitoba Hydro would like to ensure the record is clear. Since Cost of Service is the second phase of rate making, it begins with the costs and revenues having already been determined in the revenue requirement phase. A thorough consideration of the entire rate making process reveals that the claim that the reductions in water rentals and provincial guarantee fees will "***result in Residential customers having to pay more***" is unsubstantiated. The reduction in fees clearly provided an initial benefit to all classes as demonstrated by the Amended Financial Forecast Scenario which includes projected 2.0% rate increases for September 1, 2023 and March 31, 2024 compared to the initial 3.5% rate increases projected for each year prior to the announced reductions in fees.

These 1.5% reductions in the projected rate increase for each of the test years in the revenue requirement phase must be considered in conjunction with the class specific RCC changes that result from the reduction in G&T costs in the PCOSS. Considering both types of changes, the Residential class is expected to pay 1.1% less in 2023 and 2.6% less cumulatively in 2024 than they would have in absence of the fee reductions.

10.10. GSL Classes do not benefit due to higher net income in PCOSS24

On page 57 and 58, Ms. Derksen claims that the GSL classes benefit as a result of being assigned lower amounts of Net Income than other classes:

"The issue for the largest GSL classes occurs as a result of:

1. *The record level of NER which based on the mechanics of the COS study, disproportionately benefits these classes;*
2. *The significant Net Income assumed in the current Test Year, which is a cost in COS recoverable from all classes, and which is assigned to a lesser degree to these classes as it is spread based on total assets, including Distribution and which are not allocated to these classes; and*

3. *The windfall reduced payments to government for Water Rental Fees and the PGF, which as discussed in Section 4.4, also disproportionately benefits these classes.*

The result is a dichotomy. The results of PCOSS24 show that the Residential class is effectively paying its share of costs. On this basis, the question becomes why should the fact that the largest GSL classes who significantly benefit from high NER in the current year, lower allocated Net Income, and a higher benefit from lower government payments, result in a material 1% rate differential spread from the Residential class? This really has nothing to do with class cost responsibility, but simply a result of the mechanics of the COS study."

In fact, the amount of Net Income allocated to the GSL classes in comparison to the total costs for the class is actually higher than any other classes and not lower as claimed by Ms. Derksen.

The following figure provides the gross costs for each class from PCOSS24 broken down into the cost categories of Interest (which includes Finance Expense, Net Income and Capital Tax), Depreciation and Operating. The subsequent figure shows these amounts as shares of the total cost for each class, which confirms that Net Income costs represent 16.1% of the gross cost to serve the largest GSL classes compared to 11.7-15.6% for the other classes.

The claimed benefits of "lower allocated Net Income" for the largest GSL classes is simply not correct.

Figure 45

Class	Interest ($ million)			Depreciation ($ million)	Operating ($ million)	Total Class Costs ($ million)
	Finance Expense	**Net Income**	Capital Tax			
Residential	403.2	**201.1**	55.3	280.6	412.4	1,352.4
GSS ND	89.6	**44.7**	12.3	62.1	90.0	298.7
GSS D	71.9	**35.9**	9.9	50.2	67.1	234.9
GSM	116.9	**58.3**	16.0	79.5	108.2	378.9
GSL 0-30 kV	67.3	**33.6**	9.2	44.9	59.9	214.8
GSL 30-100 kV	57.2	**28.5**	7.8	36.5	47.5	177.5
GSL >100 kV	91.3	**45.5**	12.5	57.6	75.2	282.0
A&RL	6.5	**3.2**	0.9	6.6	10.5	27.6

Figure 46

Class	Interest			Depreciation	Operating	Total
	Finance Expense	**Net Income**	Capital Tax			
Residential	29.8%	**14.9%**	4.1%	20.7%	30.5%	100.0%
GSS ND	30.0%	**15.0%**	4.1%	20.8%	30.1%	100.0%
GSS D	30.6%	**15.3%**	4.2%	21.4%	28.5%	100.0%
GSM	30.8%	**15.4%**	4.2%	21.0%	28.6%	100.0%
GSL 0-30 kV	31.3%	**15.6%**	4.3%	20.9%	27.9%	100.0%
GSL 30-100 kV	32.2%	**16.1%**	4.4%	20.6%	26.8%	100.0%
GSL >100 kV	32.4%	**16.1%**	4.4%	20.4%	26.6%	100.0%
A&RL	23.4%	**11.7%**	3.2%	23.8%	37.8%	100.0%

10.11. Nothing has changed since DSM was determined to be a system resource

At page 50 of his evidence, Mr. Bowman states:

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

> *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 Bo*ard 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*[106]*:*

> *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)"*

By referencing these excerpts, Mr. Bowman appears to suggest that there has been a fundamental shift in how energy efficiency programming is valued since the establishment of Efficiency Manitoba. However, this is not the case. The relative values of these marginal costs may have changed but the underlying methodology for evaluating efficiency programming has remained relatively consistent.

Despite the direction given in 164/16 to treat DSM as a generation resource, the PUB also acknowledged and considered the potential for deferring transmission and distribution assets: "*DSM investments reduce customer energy consumption and, in most instances, the peak demand of the Manitoba Hydro system*. *These reductions in energy consumption and peak demand can provide benefits to the Manitoba Hydro system by delaying Manitoba Hydro's investment in generation, transmission or distribution. These reductions in energy consumption and peak demand can also free up hydraulic generation for export, thus increasing export revenue." (Order 164/16, page 82)*

Mr. Bowman is suggesting that the PUB's finding in the Efficiency Manitoba hearing is evidence that it is no longer appropriate to functionalize DSM costs entirely to the generation function and recommends at page 53 of his evidence that *"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."*

In support of his recommendation, Mr. Bowman provides tables of marginal values depicting the split by function to be roughly 76% generation, 10% transmission and 15% distribution and states, *"This means that Efficiency Manitoba's programs, contrary to the earlier PUB finding, are not only avoiding generation, they are also designed and justified specifically on the basis that they will avoid material transmission and distribution costs."*

While the PUB is not bound by previous decisions, Manitoba Hydro notes that there has been no change to the marginal value assumptions underlying the evaluation of DSM based on whether the programming is being undertaken by Manitoba Hydro or Efficiency Manitoba. This is demonstrated by the marginal values used in the evaluation of DSM programs at the time of the cost of service methodology review which led to the Board's decision in Order 164/16. These costs were provided in response to COALITION/MH-I-19a at the 2015 Cost of Service Methodology Review:

> *The levelized marginal value used for the analysis in the 2015 DSM Plan is 7.67 cents per kW.h (at meter). A breakdown of the value is as follows:*
>
> *Generation 6.23 ¢/kW.h*
> *Transmission 0.66 ¢/kW.h*
> *Distribution 0.78 ¢/kW.h*
>
> *The levelized marginal value used for the analysis in the 2012 DSM forecast that was included in the PCOSS14 is 7.74 cents per kWh (at meter). A breakdown of the value is as follows:*
>
> *Generation 6.32 ¢/kW.h*
> *Transmission 0.65 ¢/kW.h*
> *Distribution 0.77 ¢/kW.h*

Furthermore, while it is expected that DSM will result in some deferral of transmission and distribution, the method Mr. Bowman recommends of apportioning costs to the individual functions is neither indicative nor reflective of the value of savings realized by efficiency programming being undertaken. This is evident in the following excerpt which can be found in Section 5 page 6 of Efficiency Manitoba's 2020/23 Efficiency

Plan:

> *"Due to the detailed energy savings and capacity savings associated with each program bundle, the marginal value realized will vary depending on the specific electric energy and demand savings profile of the program or bundle. Therefore, the representative portfolio weighted marginal value is not directly comparable to prior representative marginal values provided by Manitoba Hydro as* ***the value depends on the individual savings magnitudes and profiles of the programs found within the electric profile****." (emphasis added)*

10.12. Recognition of the capacity component of Wind Is Not Required

On Page 49 of his evidence Mr. Bowman states that "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". Mr. Bowman then recommends that wind should be classified as 20% Demand and 80% Energy rather than the 100% Energy classification directed in Order 164/16 and reaffirmed in Order 59/18.

Mr. Bowman appears to have disregarded the findings in Order 59/18, where the PUB recognized wind's limited contribution to winter peak but found that refinements to address the now-recognized capacity benefit of wind would add complexity to the COS with minimal benefit.[42]

The Supply and Demand Summary reviewed during the 2017/18 & 2018/19 GRA included 52MW of wind capacity for each year between 2016/17 to 2025/26.[43] The current Supply and Demand table shows that what Mr. Bowman characterizes as "a material capacity value to wind" actually starts with the same 52MW in 2022/23 and declines to 31MW by 2027/28. The wind capacity in question is equivalent to or lower than the amount that was considered and dismissed by the Board in Order 59/18 so the benefit associated with Mr. Bowman's proposed revisions to the classification of wind remains minimal.

[42] 59-18.pdf (pubmanitoba.ca) page 187
[43] Tab 7 Electric Load Forecast, Demand Side Management and Energy Supply (hydro.mb.ca) page 13

The COS methodologies used at the other utilities noted by Mr. Bowman highlight the additional complexity that may be required to recognize the wind capacity. Manitoba Hydro currently classifies all generation in one of two manners, as either 100% Energy or split between Energy and Demand based on the system load factor (SLF). In contrast, Newfoundland and Labrador Hydro uses a variety of methods to classify generation including: 1) 100% Energy 2) 100% Demand 3) SLF 4) Station Capacity Factor and 5) 22% Demand and 78% Energy Wind.[44] Nova Scotia Power classifies generation using 1) 100% Energy 2) Load factor 3) 18% Demand and 82% Energy Wind and 4) In proportion to total costs of Port Hawkesbury biomass plant.[45]

The increased reliance on wind generation starting in 2033/34 may require a re-evaluation of the treatment of wind when additional wind may be included in the COS revenue requirement, but it does not justify a modification to the COS methodology at this time.

[44] Microsoft Word - P.U. 37(2019) (pub.nf.ca) Schedule A page 3.
[45] Nova Scotia Power, Cost of Service Study SR-01, January 27, 2022, pdf page 10 and 20.

Voice of the Customer - Major Work Order

April 2023

Manitoba Hydro

Key Findings

Customers that found completing a project with Manitoba Hydro difficult reported **unmet** and **unclear timelines** as a major reason for the difficulty.

75% of customers who found it difficult to work with Manitoba Hydro identified timelines as the reason why.

Customers with low levels of relationship satisfaction report **communication** as a major issue.

Customers are looking for direct contact information and a central point of contact.

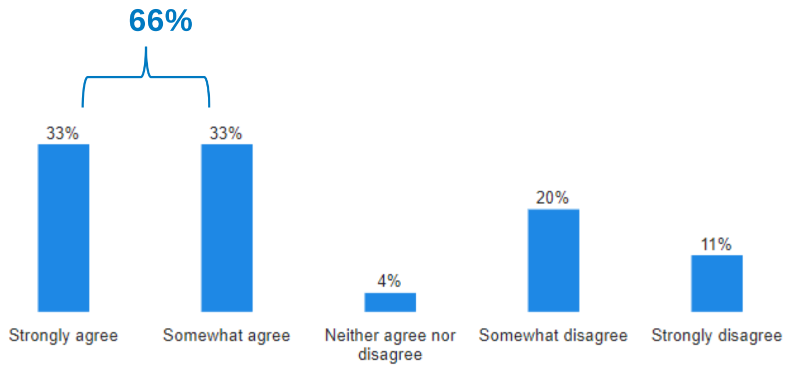
Almost a quarter of customers disagree that Manitoba Hydro is **responsive** to requests.

Many customers suggested more internal co-ordination between Manitoba Hydro teams.

Key Customer Experience Metrics

Customer Effort

Q:Thinking about the whole experience from beginning to end, to what extent do you agree or disagree with the following statement: Manitoba Hydro made it easy for me to complete my project. (n=55)



What makes it difficult?

- Timelines are not met.
- No clear contact for progress updates and lack of communication.
- Too much red tape and paperwork required.
- Concerns about quality of clean-up on work sites and damage caused by Manitoba Hydro crews.

Customer Satisfaction

Q: Thinking about your project from beginning to end, rate your overall level of satisfaction with the experience.

(n=55)

Customer Satisfaction (CSAT)

★★★★☆

Per cent of customers with a rating of 4 out of 5 stars or higher.

62%

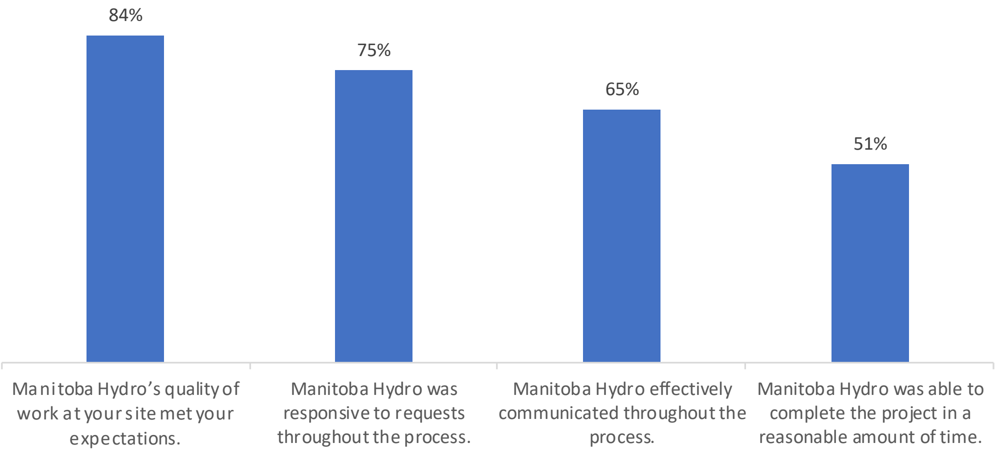
Why Dissatisfied:

Approximately 16% of customers reported they were dissatisfied with their overall experience. When asked why the following themes were identified:

- Timelines provided were not met.
- Customers did not know what to expect next in the process.
- Inadequate communication related to detail and progress on the project.

Detailed Findings

Q: Thinking about your project as a whole, please rate the extent to which you agree or disagree with the following statements. (n = 55)



Navigating the Major Work Order Process

What Could We Do Better?

- Customers want to see clearer timelines that are aligned internally among Manitoba Hydro teams.
- Timelines are a significant pain point for Major Work Order customers with 35% disagreeing that Manitoba Hydro was able to complete the project in a reasonable amount of time.
- Almost a quarter of customers disagree that Manitoba Hydro effectively communicated throughout the major work order process.

> "I would certainly have chosen another service provider if one was available for this service."

Detailed Findings

Q: Thinking about your interactions with Energy Services Advisors and other Manitoba Hydro representatives. How would you rate the overall quality of service provided?

(n=55)

ESA Satisfaction

★★★★☆

Per cent of customers with a rating of 4 out of 5 stars or higher.

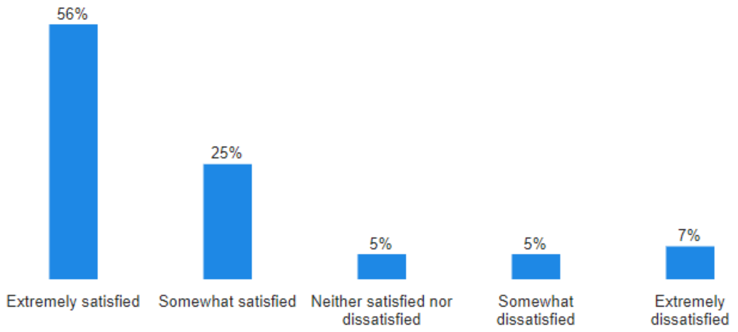
73%

"Staff were helpful and generally did their best to accommodate the project."

"Very happy with the work that was done. Very disappointed it wasn't done on time and we had to use a genset for harvest."

Detailed Findings

Q: How satisfied were you with the relationship between Manitoba Hydro and your organization during the project? (n=55)

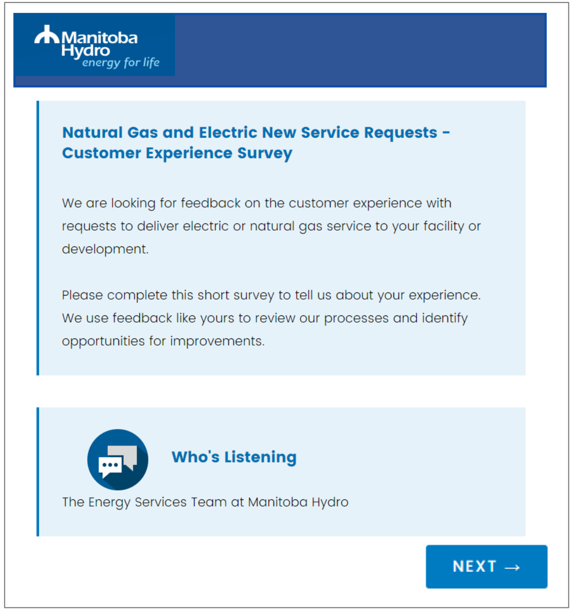


What Could We Have Done Better?

- Communicate more effectively.
- More timely communication.
- More accurate cost estimates and timelines.

Survey Methodology

Survey Structure



What questions are included?

Respondent Characteristics	• Role of respondent • Organization size • Industry
Corporate KPI's	• Customer Effort Score • Overall Customer Satisfaction • Note: both include open-ended "Why?"
Evaluation Criteria	• Effective communication • Responsive to requests • Reasonable completion time of projects • Quality of work
Relationship	• Energy Service Advisor • Manitoba Hydro and your organization
Communication Channel Preference	• Preferred channel for communications

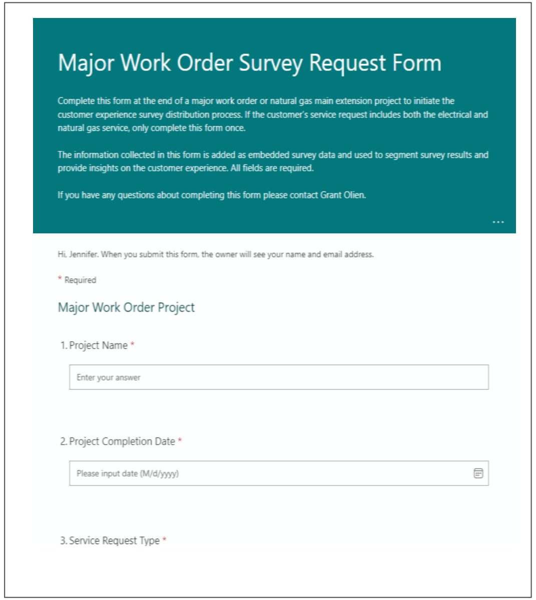
Survey Distribution

Who do surveys go to?

- Completed Commercial O/H and U/G projects
- Completed Residential O/H and URD projects

When and how are they sent?

- At the end of each month the Energy Services team generates a report of completed major work order projects.
- From this report ESA's are sent an email and asked to complete an intake form to request survey distribution to customer contacts from their completed projects.
- The Customer Data, Analytics and Research team generates personal links from the completed intake forms and sends these to the Energy Services Admin team for email distribution.


Major Work Order Survey Request Form

Complete this form at the end of a major work order or natural gas main extension project to initiate the customer experience survey distribution process. If the customer's service request includes both the electrical and natural gas service, only complete this form once.

The information collected in this form is added as embedded survey data and used to segment survey results and provide insights on the customer experience. All fields are required.

If you have any questions about completing this form please contact Grant Olien.

Hi, Jennifer. When you submit this form, the owner will see your name and email address.

* Required

Major Work Order Project

1. Project Name *

Enter your answer

2. Project Completion Date *

Please input date (M/d/yyyy)

3. Service Request Type *

Survey Distribution

Survey Invitations

- Invitations are personalized and include embedded data.

What customer information is included?

- Project name
- Project completion date
- Service type request
- Energy service provided
- Industry
- Service region of project
- Customer service centre
- Customer contact name and email
- ESA Contact name

Dear [Customer name],

My name is Colleen Galbraith and I am the Manager of the Customer Energy Services Department at Manitoba Hydro. I understand you have recently worked with [ESA Name] to receive a new service(s) installation or upgraded your existing service.

In an effort to identify improvement opportunities I am seeking feedback on your experience through a short online survey. This feedback is invaluable, reviewed by myself and provides insights on better ways to serve you, our customer, in the future.

The survey takes approximately 5-10 minutes to complete and all survey responses are confidential.

COMPLETE SURVEY

If you have any questions or concerns about this survey or Manitoba Hydro's service process, please reach out to me.

Best Regards,

Colleen Galbraith | Customer Energy Services Manager
Customer Solutions & Experience
Manitoba Hydro
Email: sm-ColleenGalbraith@hydro.mb.ca

Contact Email

Manitoba Hydro
energy for life

Prepared by the Customer Data, Analytics and Research Team.

For more information contact:

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Manitoba Hydro

AMCL+
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Date: 5th May 2023

By Email Only
Krista Halayko

18 - 360 Portage Ave
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Re: Manitoba Hydro 2023/24 & 2024/25 General Rate Application PUB

Evidence For The Consumers Coalition
Document Number: P0649-D013-RPT-R00-EXT
Submitted By: Midgard Consulting Incorporated
Date: April 3, 2023

Dear Krista

Following a detailed review of the above document, we have a few observations and comments on the content and some recommendations. Rather than repeat comments on the Summary of Evidence (Section 2.2), we have restricted our feedback to the main body of the report, Sections 3 through 10. We have also focussed our comments, such that our silence on any particular point should not be interpreted as agreement.

Our observations and comments are as follows:

Section 3
The quote on page 14 from Hydro's response to COALITION/MH II-109d: "*Manitoba Hydro will require additional resources to reliably supply firm load, including the domestic load and firm export sales*" lacks some context. The additional resources required to supply load from existing assets reliably are the same regardless of whether the supply is used for domestic use, export sales or both; the resource requirements for operational, maintenance and lifecycle renewal activities are driven by the assets and system configuration, not by the end consumer.

Furthermore, there is an impairment cost to the business and ratepayers resulting from under-maintaining fixed assets; this is a loss in economic benefit or service potential of an asset over and above its loss through depreciation. This results in the real value of the assets being less than the depreciated asset value reported in the financial accounts, compounded by the loss of opportunistic export revenue.

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Section 4
Page 18, Paragraph 3
"MH's strategy of overinvesting in assets made sense when electricity growth rates were high, but in today's mature electrical grid environment with low growth rates a different strategy is warranted when evaluating asset investments." (Midgard Consulting Incorporated, 2023)
This seems to imply that Manitoba Hydro is overinvesting in asset sustainment. As noted in the previous section, capital spending on asset sustainment is required to maintain the current book value and capacity of the existing fixed asset base, referred to as capital maintenance.

Systematic underinvestment in capital maintenance creates intergenerational problems. Given that previous generations of ratepayers have financed the initial investment in capacity, it is inequitable for current ratepayers to benefit from the resulting resilient infrastructure resulting from historic investment whilst passing the disbenefits of under-investment to future generations who would have to finance a bow-wave of deferred capital risk.

The impact of this historical approach of 'sweating' assets to achieve short-term capital benefits without considering future risk is becoming better understood as the effects of those decisions are becoming apparent to the current ratepayers. If we consider the planet's natural resources as an asset, which it is, it has been the subject of poor asset stewardship for generations; now we are seeing the impact of climate change and the financial burden of mitigating this impact on the current generation.

Sections 5 and 6
"Manitoba Hydro electrical infrastructure assets are aging, and their condition is degrading. The overall performance of the asset portfolio has shown a declining trend in the last several years." (Manitoba Hydro GRA Tab 07, 2022)
SAIDI and SAIFI measures are outcome performance measures which provide a useful lagging indicator of asset condition. Distribution systems are usually configured to be resilient and minimize single points of failure. When we observe the poor performance of an asset system manifest in a general declining trend in outcome measures, this is a good indicator of systemic deterioration of the system, and significant investment is required to stabilize performance. A more modern approach is to monitor trends in leading indicators, manage overall system resilience and take a risk-based approach to target interventions. Further guidance on asset decision making is available in the Institute of Asset Management[1] .

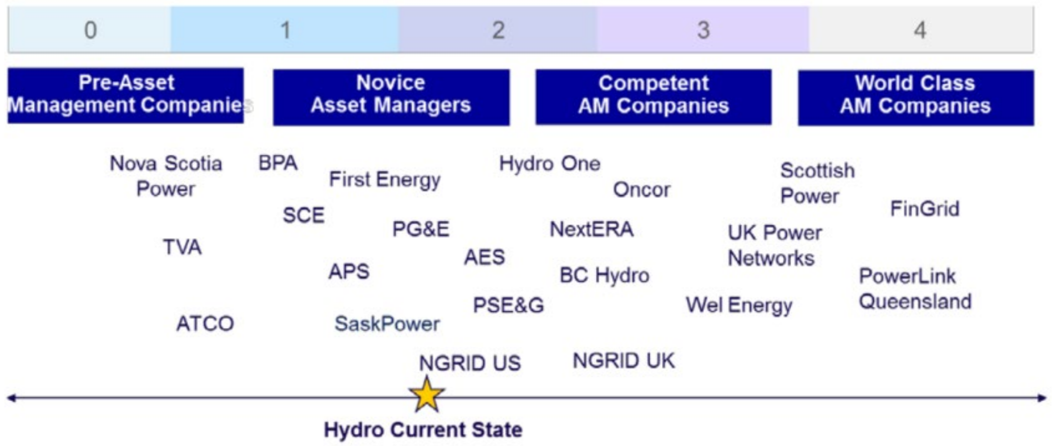
Hydro response to COALITION/MH II-77a "Confirmed, excluding major event days, Manitoba Hydro's SAIDI and SAIFI performance is not materially trending either positively or negatively since 2012."
There is a general acceptance worldwide that extreme weather events are becoming more frequent. Customers pay for reliable service; service providers should ensure their asset systems are resilient enough for extreme conditions. Resilience is not just about the ability to respond to interruptions; it includes resistance to external threats (flood defence, fire protection systems, buildings) and system redundancy. System redundancy relates to factors beyond spare capacity, such as the number of customers dependent on single points of failure and the extent to which system configuration provides operational flexibility. Further guidance on the principles of resilience is available in The Institute of Asset Management[2].

[1] https://theiam.org/knowledge-library/subjects-6-and-7-capital-investment-operation-and-maintenance-decision-making/
[2] https://theiam.org/knowledge-library/ssg-32-contingency-planning-resilience-analysis/

Section 7

Section 7.1 Manitoba Hydro Is (Still) Beginning Its Asset Management Journey

One minor point of clarification on Page 33 is that the diagram inserted from the UMS report excludes the footnote from the image, indicating that this is an opinion of relative asset management maturity and, therefore, not based on objective assessment data.



Note: The above positions reflect UMS' opinion of the relative AM maturity of each company based on a range of source information.

Regarding progress in asset management maturity, consideration should be given to the impact of a global pandemic; many organizations have had to transition to remote or hybrid working environments. The size and complexity of Manitoba Hydro, the recent reorganization of the business centred around Asset Management as a discipline, alongside headcount constraints and the impact of COVID-19, is essential context when providing opinion on maturity progression. This is a substantial change in the organizational context that will impact an organization's ability to progress concurrently in asset management maturity.

7.2 Asset Management Decision Making

Typical planning horizons for public infrastructure are outlined in Figure 1 below; the methodology for each planning horizon varies as appropriate, with the level of detail increasing in the near term.

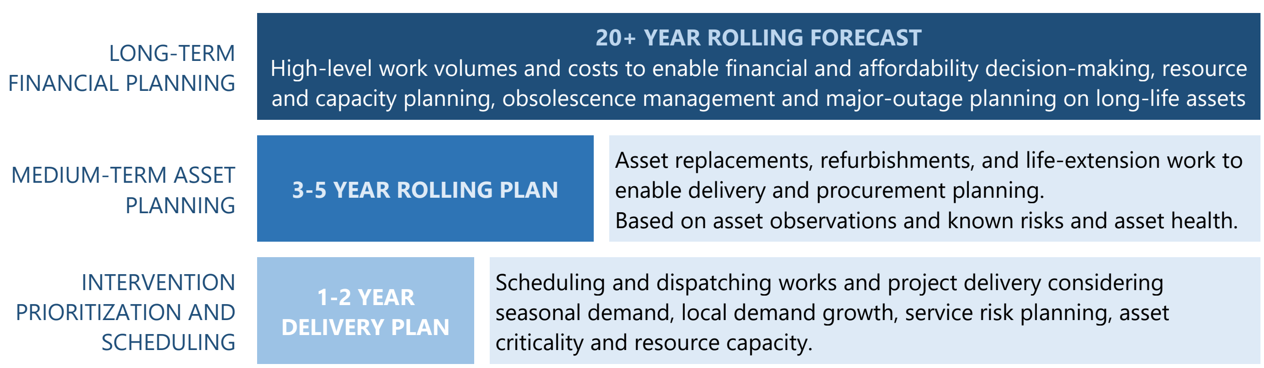


Figure 1 Typical Planning Horizons

Long-term financial planning for assets is ideally based on deterioration models built from historical data, observed and captured, following a consistent methodology over a statistically relevant period for each asset type to derive the asset's Economic Life (EL). Without sufficient observed data for developing its deterioration models, the EL of a given asset population has been estimated based on industry research and Manitoba Hydro data.

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Manitoba Hydro's approach of using asset Turnover Rate using industry-available EL data to supplement Manitoba Hydro's own observed data is reasonable. It will likely give an adequate level of accuracy for long-term financial planning; the normal variances in observed asset life, shorter or longer than the EL, will balance out across a large asset base.

Manitoba Hydro has assumed that asset age is reset to zero years following an intervention or refurbishment, which is a conservative assumption that may result in a low estimate of work volumes; by contrast, common practice is to carry a Residual Asset Life (RAL) following a refurbishment of 60% of the original EL of the asset. Furthermore, data provided by Manitoba Hydro in Appendix 7.5 (Manitoba Hydro GRA Tab 07, 2022) indicates that current asset turnover rates are in excess of the expected life for many of the asset types. That is, the data shows that the rate of reinvestment may already be too low. More data is required to assess the risk of extending the turnover rate further; making an uninformed decision to reduce funding levels at this stage may be imprudent.

In the interim, improving medium-term asset planning capabilities using Asset Health Indices (AHI) will ensure that available capital is directed effectively. Throughout Appendix 7.5 (Manitoba Hydro GRA Tab 07, 2022), Manitoba Hydro has stated its commitment to improve data capture and refine its medium-term asset planning capabilities in the forthcoming AMP.

Section 7.2.3 How Others do Asset Management and Capital Planning
Enwin Utilities
Enwin Utilities Ltd is a small distribution utility with two distinct 'value streams', electricity and water.
Non-corporate Decision Support Tools (DST) are adequate methodologies, assuming the appropriate level of governance is applied to the control of data and proper controls are in place to ensure the integrity of algorithms and parameters embedded in the tools.
Midgard (Midgard Consulting Incorporated, 2023) has provided a caveat on page 48 *"Midgard has cited the Enwin case because it provides a simple, clear example of how using modern asset management and risk management processes enables more transparency of the value being added by proposed capital spending….."*

The example cited is not based on mature asset investment decision-making techniques, such as MCDA[3] and AHP[4]. It appears to be top-down prioritization based on value but does not optimize over time and will not select between solution options for the same needs statement. It does not provide the granularity required to adequately differentiate one investment need over another across multiple value streams for a capital program the size and complexity of Manitoba Hydro's.

Manitoba Hydro has invested significantly in Copperleaf's C55 software, a modern and sophisticated corporate decision support system suitable for large organizations with diverse portfolios such as BC Hydro, National Grid, Hydro One and Enmax. Manitoba Hydro would be better served by improving its asset decision-making processes to maximize the capability and functionality of the software to make asset planning a business-as-usual activity.

Section 7.2.5 System Versus Individual Asset Focus
There is a balance of how much of today's customers' money should be spent on mitigating future risk. Although this is usually associated with resilience and climate change mitigation, the same principles apply. Generally, the term 'redundancy' concerning assets refers to spare capacity and underutilized assets. Service risk is driven by system configuration, operational flexibility within the system and system resilience, of which redundancy is one component. There is a trade-off between consuming current spare capacity and future security of supply.

---

[3] Multi Criteria Decision Analysis
[4] Analytic Hierarchy Process

Unlike many of the smaller distribution companies that effectively have one system, Manitoba Hydro operates a system of systems where each system has a distinct purpose and contributes value to the organization in very different ways.

Generation

If the generation system performance were impacting outages for domestic customers, it would indicate a total failure to manage the system. Manitoba Hydro needs to understand how much overall system redundancy exists based on the individual systems and their contribution to overall service risk; this will support mature risk-informed decision-making.

The distribution system predominately drives SAIDI/SAIFI performance. Reducing investment in asset sustainment of the generation system until it deteriorates to such an extent that it impacts SAIDI/SAIFI performance would significantly increase the capital cost risk to future customers; these customers would also be facing prolonged periods of degraded performance as the investment backlog is being addressed.

Transmission

Extreme events are increasing in frequency and are expected to continue to increase. Customers have reasonable expectations for a service outcome; therefore, systems must be resilient. While capital solutions are not always the answer, minimizing single points of failure within the system and asset protection are part of the solution. Midgard appears to advocate a reactive or run-to-fail approach to transmission system management.

A more appropriate direction would be risk and resilience profiling on the transmission system, considering the assets' condition (probability of failure) and the ability to recover service to customers. The ability to recover service to customers due to a transmission line failure depends on non-asset related factors such as proximity of nearest depot, access constraints, ground conditions, number of customers impacted and temporary supply logistics.

7.3 Asset Information

Manitoba Hydro's top-down budget envelope approach discussed in Section 7.2.2 (Midgard Consulting Incorporated, 2023) is appropriate for long-term (~20 years) financial planning and affordability management. Better data and data systems will enable the development of asset health indices (AHI), which can improve the targeting of spend, within that budget envelope, for short to medium-term (2 ~ 5 years) asset decision-making.

7.4.1 Asset Health Indices

Asset Health Indices tend to be dynamic, dependent on several variables and are derived at the asset level; these characteristics make them unsuitable for long-term financial planning in most cases. When AHIs have been in place for a sufficient number of years, they can be used to develop meaningful deterioration models appropriate for long-term financial planning; in the interim, AHIs support short to medium-term asset decision-making.

8.1 Distribution Asset Equipment Failures

Midgard and AMCL acknowledge that run-to-failure and run-near-to-failure strategies are suitable, cost-effective strategies for low-consequence assets that can be quickly replaced. However, Manitoba Hydro must ensure that sufficient maintenance crews and spares are available to deliver this strategy.

AMCL+
LEADING ASSET MANAGEMENT

Section 10

"A BOC budget reduction of at least 10% is warranted until such time as MH can demonstrate its decision-making is based upon quality data, tools and decision-making frameworks." (Midgard Consulting Incorporated, 2023)

There appears to be no basis for a 10% reduction in BOC budget; reducing BOC by an arbitrary amount without understanding the associated risk creates potential problems for the future, especially for the distribution network, where an increase in failure becomes a logistics problem rather than a financing problem, in that the number of concurrent planned system isolations and outages make it impossible to maintain levels of service to customers.

Yours sincerely,

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