PUB/COALITION I-1 Reference: Midgard Evidence pp.23,24; PUB/MH I-87(a),(d)
Capital Spending Versus Vegetation Management

Preamble:

In the response to PUB/MH I-87(a), MH states:

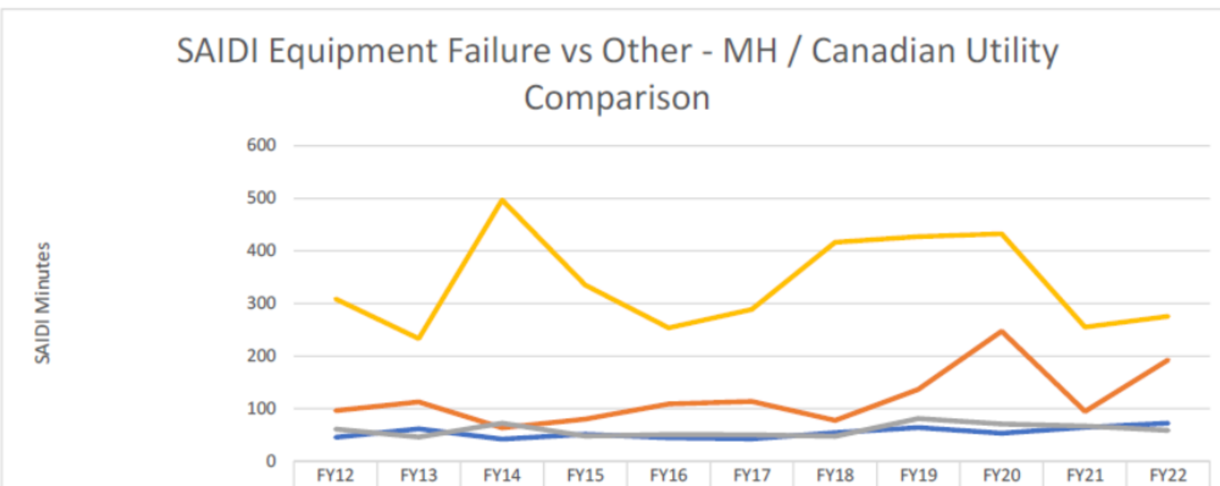
> Manitoba Hydro's current capital expenditure plan is designed to provide the most value within the spending targets. Reliability is included as a part of the value calculation; however, it is not specifically designed to achieve a certain performance target (5 year average) as Manitoba Hydro's current asset management maturity does not allow for precise mapping of capital expenditures to performance at this time.

In the response to PUB/MH I-87(d), MH states:

> Manitoba Hydro's asset management maturity is not sufficient to be able to adjust business operations capital investment to achieve target levels of performance.

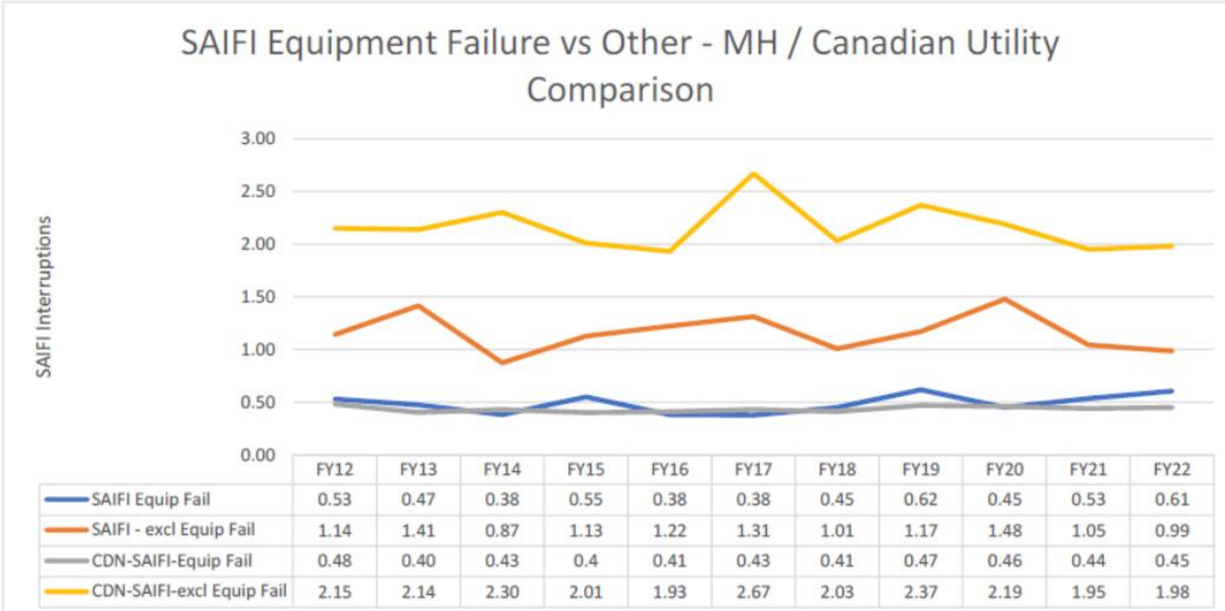
On page 24 of its evidence, Midgard reproduces MH's graphs of SAIDI and SAIFI:

Figure 5: SAIDI Equipment Failure vs. Canadian Utility Peers[33]



	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
SAIDI - Equip Fail	46	62	42	51	45	43	54	64	53	65	72
SAIDI - excl Equip Fail	96	113	64	80	109	114	78	137	247	95	193
CDN-SAIDI-Equip Fail	61	46	73	48	51	50	47	81	71	67	59
CDN-SAIDI-excl Equip Fail	309	233	497	335	254	289	416	427	433	255	275

Figure 6: SAIFI Equipment Failure vs. Canadian Utility Peers[34]



	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

Request:

a) Please explain how MH would be able to compare benefits of an increased vegetation management budget to an increased capital investment budget to determine which investment would result in the greatest improvement in reliability or reduction in risk.

b) Considering MH is not yet able to adjust capital investments to achieve target levels of performance, please explain how MH could accomplish this.

c) Please explain how a regulator could review and assess this trade-off for a utility with the asset management maturity of MH.

d) Considering MH's SAIDI and SAIFI excluding the impact of equipment failures as shown in Figures 5 and 6 on page 24 are substantially superior to the Canadian average, does this indicate that MH's vegetation management approach is delivering satisfactory results?

e) How would MH go about determining whether this the optimal level of vegetation management spending?

Response:

a) The benefit of increased capital investment budgets can be measured on the basis of expected reduction in outages due to asset condition (i.e., reduced probability of failure due to improved asset condition). As a poorer condition asset is replaced with a new asset, there is a reduction in probability of failure due to asset condition, but the consequence of asset failure remains unchanged. As a result, the risk reduction is driven solely by the reduced probability (risk = probability x consequence).

   The benefit of increased vegetation management can be measured on the basis of expected reduction in tree contact events due to removing vegetation growing in close proximity to transmission and/or distribution lines. As vegetation that poses a risk to transmission and distribution is removed, the vegetation event risk is reduced by both probability (e.g., probability of contact) and (in some cases) consequence (e.g., since treefalls can damage or destroy assets).

b) The long-term answer is that Manitoba Hydro should mature its asset management program so that it can determine the impact of changing capital investment levels and strategies on system performance, and so that it can determine the impact of changing vegetation management budgets and strategies on system performance due to risk reduction. Other utilities in Canada can determine, or are well on their way to being able to determine, these impacts.

   In the short term:

   (1) Vegetation Management: Manitoba Hydro could correlate vegetation inventories (ROW vegetation and off-ROW danger/hazard trees) to vegetation-caused outages. Based on an assessment of the vegetation inventories, and vegetation management costs, Manitoba Hydro could develop a simplified model to determine performance benefit per dollar spent.

   (2) Capital Investments: Manitoba Hydro could correlate asset condition demographics to asset condition caused outages. Based on an assessment of asset condition demographics, Manitoba Hydro could develop a simplified model to determine performance benefit per dollar spent.

(i) NOTE: Midgard acknowledges that Manitoba Hydro does not have asset health indices that are fit for intended purpose for many asset classes. However, at a high level, until more comprehensive asset health index information is available, known (or estimated) asset age can be used as a proxy for asset condition for assets with large populations.

c) The regulator cannot assess the trade-off for a utility with the asset maturity of Manitoba Hydro because the required quantitative evidence is not available on the record. However, even if adequate evidence was available on the record, the responsibility for performing and reporting on the assessment should lie with Manitoba Hydro as the entity seeking to build an evidence-based case before the regulator.

In the present case, review cannot be based on adequate evidence supporting Manitoba Hydro's performance risk mitigation claims. The regulator must therefore base its review on other factors that are supported by evidence, for example, the superior SAIDI and SAIFI performance of the Manitoba Hydro system.

d) No, it indicates that Manitoba Hydro's vegetation management program is delivering results, but the efficiency and effectiveness of the spending is undetermined, since the value of the marginal vegetation management dollar spent is unknown. Vegetation management (like all risk management investments) is subject to the law of diminishing returns. It is possible that reducing spending will not materially degrade the results, or that increasing spending will either negligibly or not materially improve the results. Additionally, there is no way to compare the effectiveness of a dollar spent on vegetation management to an equivalent dollar spent[1] on capital.

In summary, Manitoba Hydro has not provided evidence demonstrating that its overall spending, which includes both O&M (of which vegetation management is a component) and capital investments, has been optimized. Without an analysis of the optimization of overall spending of which vegetation management is a component, it cannot be determined if the current vegetation management approach is satisfactory.

[1] An equivalent dollar spent allows for a full-lifecycle evaluation of spending and its impact using Net Present Value analysis.

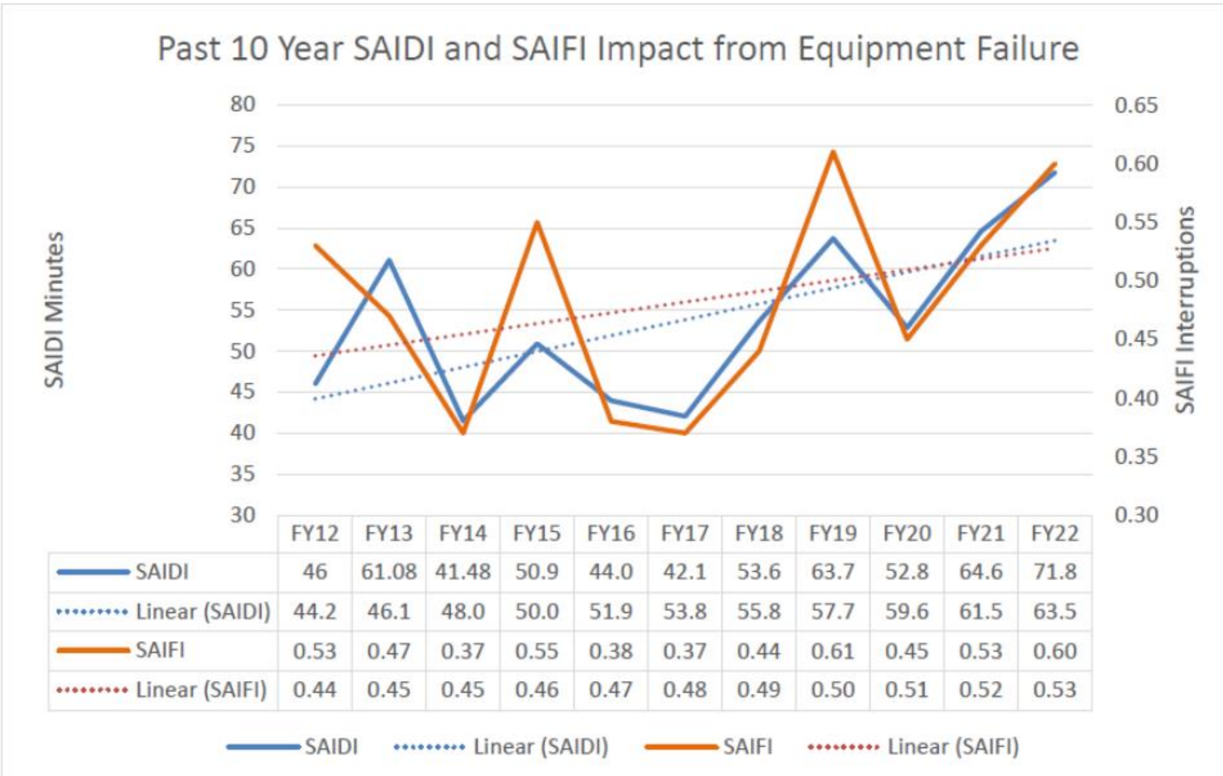
e) As discussed above, Manitoba Hydro would compare the value to ratepayers of a marginal dollar spent on vegetation management to an equivalent marginal dollar spent on other O&M activities or capital investments.

PUB/COALITION I-2 Reference: Midgard Evidence pp.26-27

Preamble:

On page 26 of its evidence, Midgard reproduces MH's graph of SAIDI and SAIFI from equipment failures:

Figure 7: 10 Year SAIDI and SAIFI Impact from Equipment Failure



	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
SAIDI	46	61.08	41.48	50.9	44.0	42.1	53.6	63.7	52.8	64.6	71.8
Linear (SAIDI)	44.2	46.1	48.0	50.0	51.9	53.8	55.8	57.7	59.6	61.5	63.5
SAIFI	0.53	0.47	0.37	0.55	0.38	0.37	0.44	0.61	0.45	0.53	0.60
Linear (SAIFI)	0.44	0.45	0.45	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53

On page 27 of its evidence, Midgard states:

> As shown in Figure 4, MH's F22 overall SAIFI was 1.46 – a change of 0.01 interruptions/year is trivial in comparison to the natural variability of SAIFI from year to year, which has a standard deviation of 0.12 interruptions/year[38], and it isn't clear why customers should be required to pay higher rates to mitigate an imperceptible performance change.

Request:

a) Please plot a version of this graph (or separate graphs for SAIDI and SAIFI) showing the Canadian averages and their trend lines along with MH's SAIDI and SAIFI and their trend lines.

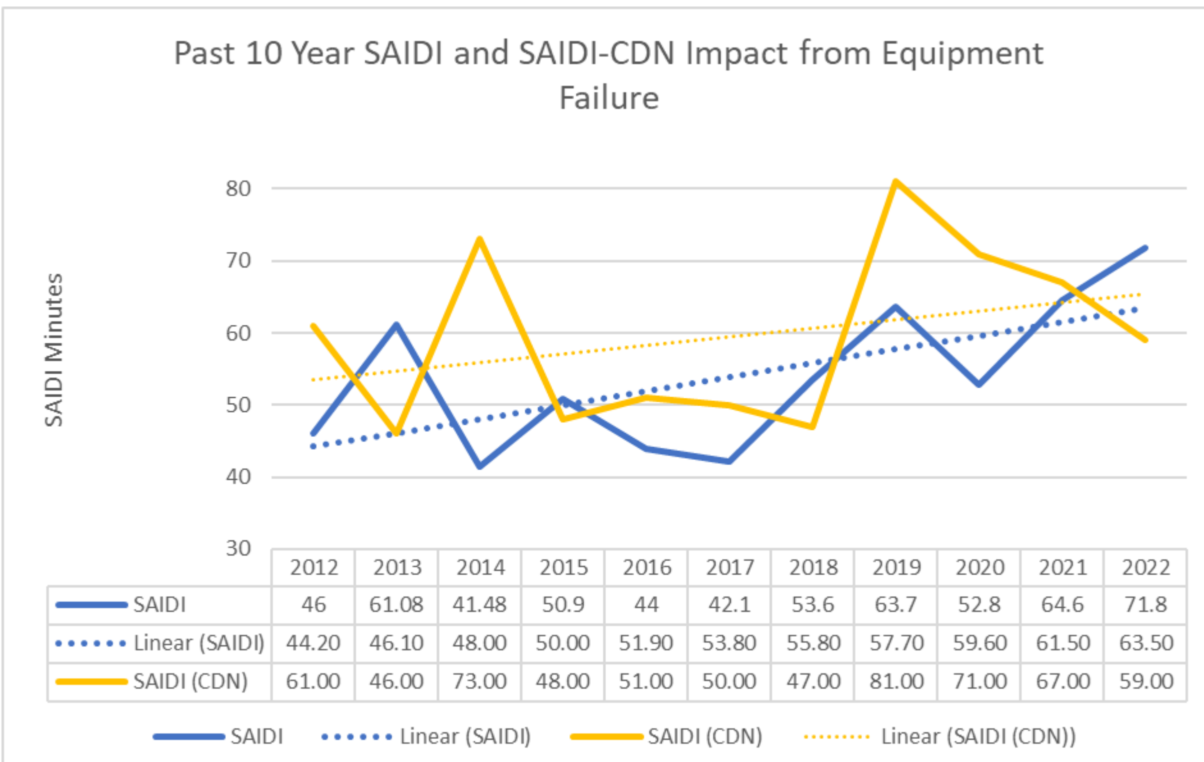
b) Please explain whether Midgard considers the increase in SAIDI from 44 minutes in FY2012 to 64 minutes in FY2022 to be material and whether this is a performance change that would be noticeable to customers.

Response:

a) Midgard has prepared the requested plots, provided below. Figure 1 shows SAIDI and CDN-SAIDI averages and trendlines, while

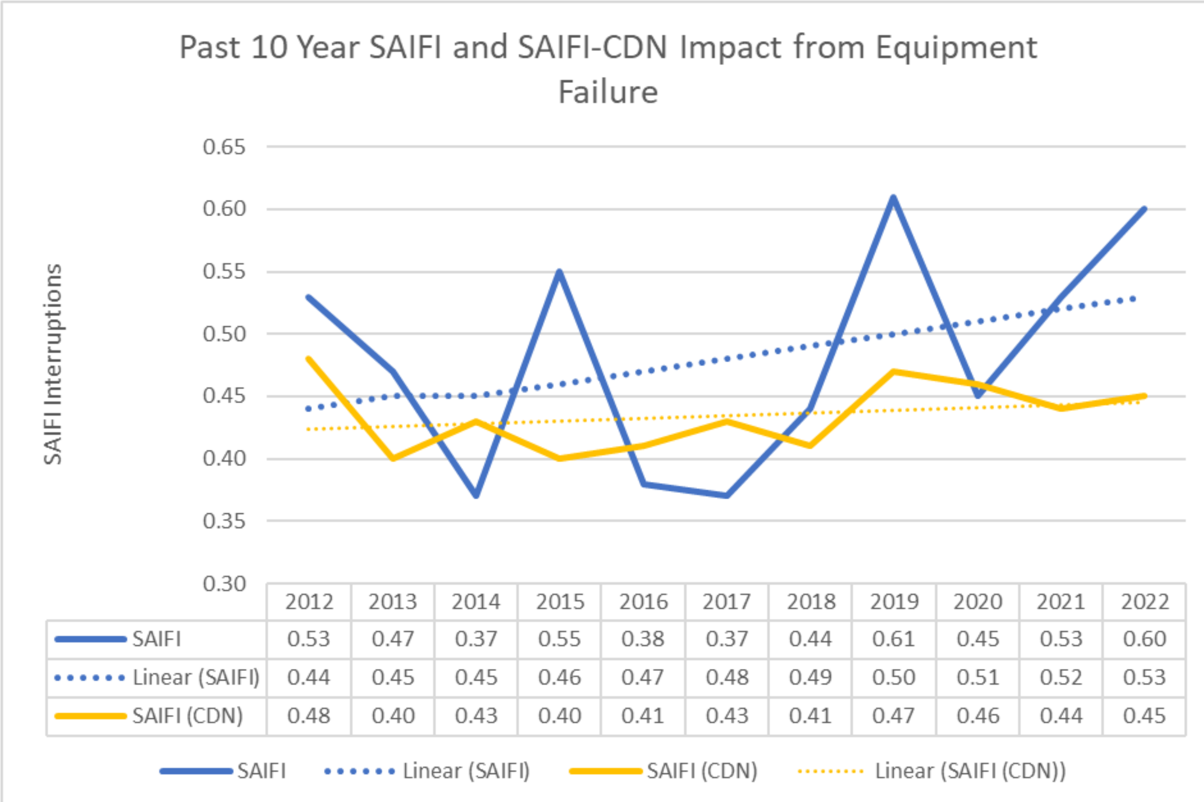
b) Figure 2 shows SAIFI and CDN-SAIFI averages and trendlines.

Figure 1: SAIDI & CDN SAIDI Reproduction[2]



[2] Please refer to the attached .xlsx file PUB/COALITION I-2 Attachment 1 (P0649-D022-MDL-R00-EXT - SAIDI-SAIFI Analysis).xlsx which includes data citations.

Figure 2: SAIFI & SAIFI-CDN Reproduction[3]



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
SAIFI	0.53	0.47	0.37	0.55	0.38	0.37	0.44	0.61	0.45	0.53	0.60
Linear (SAIFI)	0.44	0.45	0.45	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53
SAIFI (CDN)	0.48	0.40	0.43	0.40	0.41	0.43	0.41	0.47	0.46	0.44	0.45

At face value:

- Figure 1 shows a higher average SAIDI impact for Canada (59 minutes) relative to Manitoba Hydro (54 minutes). The linear trendlines indicate a lower rate of change (i.e., minutes per year) for Canada (approximately 1.2 minutes per year) relative to Manitoba Hydro (approximately 1.9 minutes per year).
-
- Figure 2 shows a higher average interruption rate for Manitoba Hydro (0.5 interruptions) relative to Canada (0.4 interruptions). The linear trendlines indicate a lower rate of change (i.e., interruptions per year) for Canada (approximately 0.002 interruptions per year) relative to Manitoba Hydro (approximately 0.01 interruptions per year).

This information is summarized in

[3] Please refer to the attached .xlsx PUB/COALITION I-2 Attachment 1 (P0649-D022-MDL-R00-EXT - SAIDI-SAIFI Analysis).xlsx which includes data citations.

Table 1.

Table 1: Summary of Plotted Metrics

Metric	Average	Trendline Slope[4]
SAIDI (Manitoba Hydro)	**54 minutes**	**1.2 minutes per year**
SAIDI (Canada)	**59 minutes**	**1.9 minutes per year**
SAIFI (Manitoba Hydro)	**0.5 interruptions**	**0.01 interruptions per year**
SAIFI (Canada)	**0.4 interruptions**	**0.002 interruptions per year**

However, when comparing short duration datasets (i.e., when comparing 10 years of Manitoba Hydro metrics with nationwide metrics), it is also relevant to consider the endpoint context of the data being presented. While its common to compare metrics when evaluating the impact or influence of a particular variable, one must consider to what extent the selected endpoint influences observed changes or effects. To demonstrate this effect, Midgard has reproduced the same plots as Figure 1 and

Figure 2 omitting the 2022 SAIDI and SAIFI metrics (see

[4] The slope of a linear trendline represents the rate of change of the dependent variable (SAIDI or SAIFI) with respect to the independent variable (Year), calculated as Δy/Δx.

Figure 3 and

Figure 4 below).

Figure 3: SAIDI & CDN SAIDI Reproduction; 2022 Data Omitted[5]

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[5] Please refer to the attached .xlsx file PUB/COALITION I-2 Attachment 1 (P0649-D022-MDL-R00-EXT - SAIDI-SAIFI Analysis).xlsx which includes data citations.

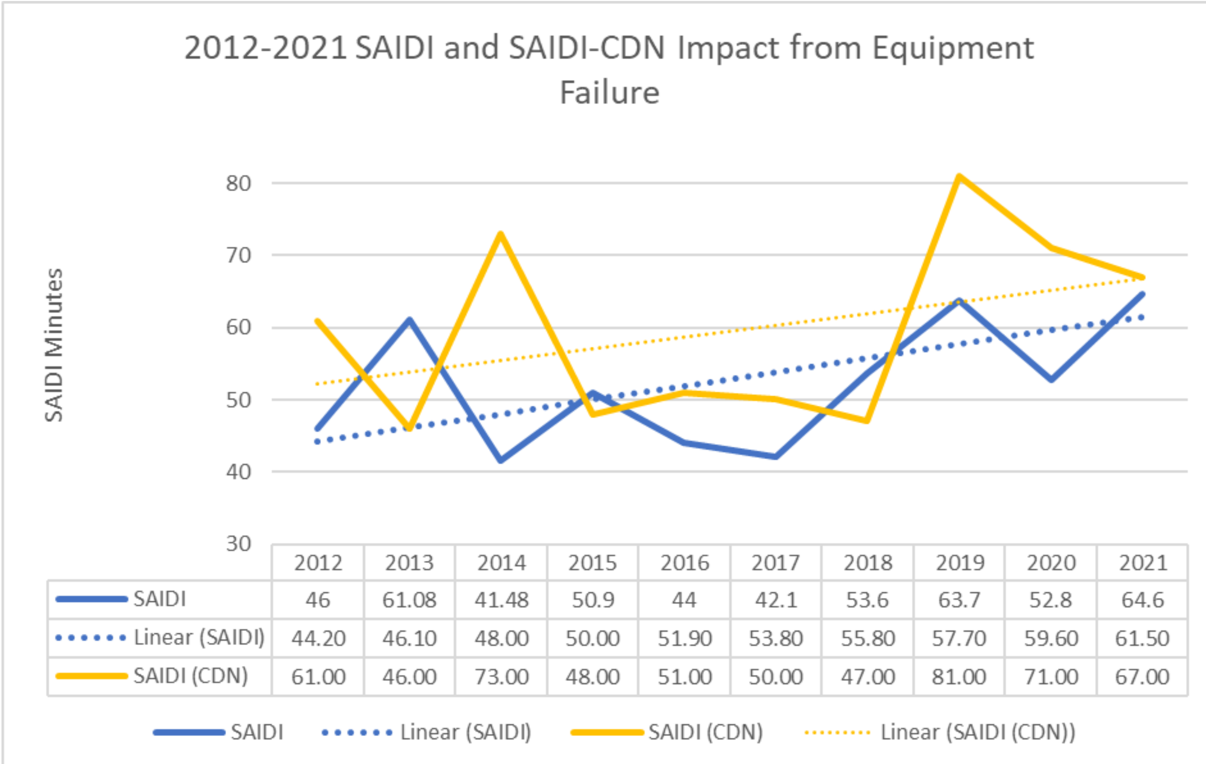
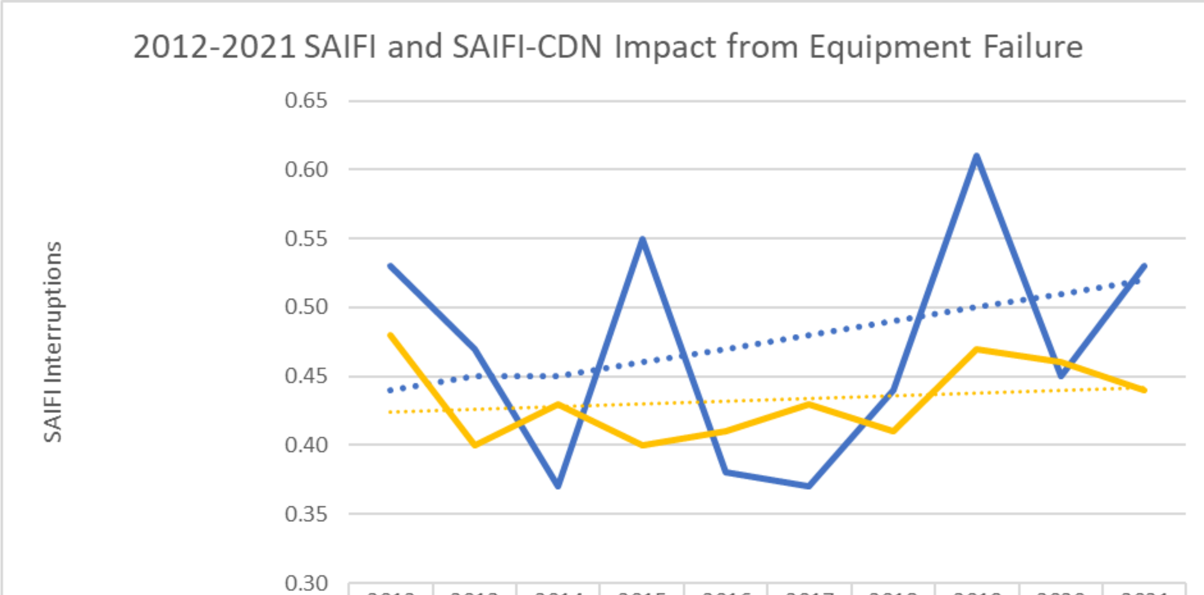


Figure 4: SAIFI & CDN SAIFI Reproduction; 2022 Data Omitted[6]

[6] Please refer to the attached .xlsx file PUB/COALITION I-2 Attachment 1 (P0649-D022-MDL-R00-EXT - SAIDI-SAIFI Analysis).xlsx which includes data citations.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
SAIFI	0.53	0.47	0.37	0.55	0.38	0.37	0.44	0.61	0.45	0.53
Approx. Linear (SAIFI)	0.44	0.45	0.45	0.46	0.47	0.48	0.49	0.50	0.51	0.52
SAIFI (CDN)	0.48	0.40	0.43	0.40	0.41	0.43	0.41	0.47	0.46	0.44

The same metrics for see

Figure 3 and

Figure 4 as discussed for Figure 1 and

Figure 2 are presented in Table 2 for convenience, as well as changes between datasets.

Table 2: Summary of Plotted Metrics; 2022 Data Omitted

Metric	Average	Delta from Table 1	Trendline Slope	Delta from Table 1
SAIDI (Manitoba Hydro)	**52 minutes**	**2 minutes**	**1.9 minutes per year**	**0.7 minutes per year**
SAIDI (Canada)	**60 minutes**	**1 minute**	**1.6 minutes per year**	**0.3 minutes per year**

Metric	Average	Delta from Table 1	Trendline Slope	Delta from Table 1
SAIFI (Manitoba Hydro)	0.5 interruptions	0 interruptions	0.01 interruptions per year	0 interruptions per year
SAIFI (Canada)	0.4 interruptions	0 interruptions	0.002 interruptions per year	0 interruptions per year

By omitting one year of data (2022), the rate of change of SAIDI, both in Manitoba and nationwide, change materially:

- Manitoba Hydro SAIDI performance trend changes by 37%; and
- Canada SAIDI performance trend changes by 14%.

At a cursory level, comparing Manitoba Hydro and Canada performance metrics over the past decade indicates that Manitoba Hydro performs favorably compared with its nationwide peers, but the advantage is narrowing. However, the value of the peer comparison is limited unless the data set endpoint selection is considered. Omitting a single year (2022) reveals significant inter-annual volatility in the underlying datasets, and any year-over-year changes or effects must be considered in this context.

Furthermore, Manitoba Hydro's equipment driven SAIDI and SAIFI performance must be evaluated in the context of its overall SAIDI and SAIFI performance from all causes, since that is the performance that customers actually experience. Evaluated from this perspective, even significantly increased equipment replacement investments would provide only modest performance value to Manitoba Hydro's customers.

c) Midgard does not recommend selecting individual years as the basis upon which to perform SAIDI and SAIFI comparisons over time because the significant inter-annual performance volatility makes any evaluation very sensitive to the selected comparison years, and customer perception of trend change can easily be lost in the noise of this inter-annual volatility.

To demonstrate this effect, Table 3 summarizes the averages and standard deviations of Manitoba Hydro's SAIDI and SAIFI metrics over the past 11 calendar years (2012 to 2022) based on all causes of outages, not just equipment failure causes. While the causes of individual outages may vary (i.e., equipment, vegetation, lightning, third-party contacts, etc.), what customers experience is the loss of service – regardless of the root cause of an outage, customers are left without the energy services they desire.

Table 3: SAIDI & SAIFI Calculated Standard Deviation[7]

Description	Average	Standard Deviation
SAIDI	126	18
SAIFI	1.46	0.12

Standard deviation indicates how much individual data points vary from the average value of the data set. Assuming a Normal (Gaussian) outage data distribution, approximately 68% of the data points fall within one standard deviation of the average value. Table 3 indicates that customers would experience outage durations within +/- 18 minutes of the average two (2) out of every three (3) years, and in one (1) out of every (3) years they would experience outages beyond +/-18 minutes of the 11-year average.

A 20-minute change in experienced outage duration over an 11-year period would likely not be noticeable to a typical customer, given that the same customer

[7] Calculated based on the past 10-year impact data, as presented in the attached xlsx file: PUB/COALITION I-2 Attachment 1 (P0649-D022-MDL-R00-EXT - SAIDI-SAIFI Analysis).xlsx.

experiences outage durations that vary more than 18 minutes from the 11-year average in one (1) out every 3 years.

Furthermore, outage durations trend are very sensitive to endpoint selection in such a volatile data set, as discussed in the response to question a). For example, equipment-caused SAIDI changed from 61.08 minutes in 2013 to 52.8 minutes in 2018. Focusing on the outage duration change due to a single root cause would have indicated in 2018 that equipment performance had improved by more than 7 minutes over the previous eight years, which is not a useful assessment.

In Midgard's opinion, the evidence on record demonstrates that:

a. Manitoba Hydro's overall reliability performance (as experienced by its customers) is excellent compared with its Canadian peers;
b. Most customers are more concerned with rate increases than with performance improvement;
c. Outages caused by equipment failures merit ongoing trend evaluation and selective economic mitigation; and
d. There are a range of outage root causes that should be evaluated to determine the most economical approaches to maintaining Manitoba Hydro's excellent reliability performance.

PUB/COALITION I-3 Reference: Midgard Evidence p.30
O&A Increases

Preamble:

On page 30 of its evidence, Midgard states:

> Midgard suggests that increasing operational staff resources to allow them to continue to address equipment failures in a timely manner remains the best near-term strategy for MH rather than replacing low cost (i.e., fully or mostly depreciated) assets with new un-depreciated assets.

Request:

a) Please confirm whether Midgard has reviewed MH's proposed increases in O&A expense and increases in full time equivalent employees with respect to operational staff resources.

b) If confirmed, please explain whether MH's proposed increases to operational staff resources are sufficient to address equipment failures in a timely manner, whether the proposed increased resources are in excess of what is needed, or whether the proposed increased resources are insufficient.

Response:

a) Midgard has not performed a detailed review of Manitoba Hydro's proposed increases in O&A expenses and increases in full time equivalent employees with respect to operational staff resources.

b) Based on Midgard's review of the O&M-related evidence, Midgard is unable to determine if Manitoba Hydro's proposed operational staff increases are sufficient to address equipment failures in a timely manner. Midgard has not found evidence demonstrating that Manitoba Hydro's proposed operational staffing increases are intended largely or materially to address perceived deficiencies in its ability to respond to equipment failures in a timely manner.

PUB/COALITION I-4 Reference: Midgard Evidence p.34; PUB/MH I-101(b)
Trajectory to Mature Asset Management

Preamble:

On page 34 of its evidence, Midgard states:

> Although Midgard may not entirely agree with AMCL that MH is making "good" progress (MH is certainly not making rapid progress, considering that the Manitoba PUB has been issuing decisions and orders requiring MH to improve its asset management competence to better justify its capital investment plans and decisions since 2008), Midgard acknowledges that overall progress is being made. Considering MH's score of 1.81 in context, a score of three (3.00) would indicate broad conformance with the ISO 55001 standard that would be used to assess asset management maturity. [footnotes deleted, emphasis in original]

In the response to PUB/MH I-101(b), AMCL states:

> The time taken for a utility to move from a maturity level of 1.5 to a 2 or 3 is dependent on the resources committed to delivering the business changes. A typical 'trajectory' for asset management capability improvement is between 2 and 3 years to move from a level 1.5 to level 2, and between 4 and 5 years to move from level 1.5 to level 3

Request:

Does Midgard agree with AMCL's assessment of typical trajectories for utilities to mature their asset management capabilities? If not, please explain.

Response:

AMCL's assessment of typical trajectories is consistent with the range of trajectories that Midgard has seen in other Canadian jurisdictions.

PUB/COALITION I-5 Reference: Midgard Evidence p.38; PUB/MH I-87(d) Relating Capital Expenditures to Reliability and Performance

Preamble:

On page 38 of its evidence, Midgard states:

> Based on these conclusions, Midgard understands that risk-based decision making requires better quality data inputs and decision-making processes that address multiple scenarios and alternatives. Decision making frameworks need to support the decision being made (e.g., Strategy 2040 and the delineation between domestic and export-driven investments). The existing tools and frameworks do not currently determine the investments and expenditures required to maintain system performance levels and evaluate the impact that changing investment levels would have on system performance and risks.

On page 41 of its evidence, Midgard states:

> As a result, 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.

In the response to PUB/MH I-87(d), MH states:

> Manitoba Hydro's asset management maturity is not sufficient to be able to adjust business operations capital investment to achieve target levels of performance.

Request:

a) Does Midgard agree that more advanced asset management maturity than MH currently possesses is required in order to relate capital expenditures to reliability and performance, as explained in PUB/MH I-87 and (d)? If not, please explain.

b) In Midgard's view, is MH able to adjust its capital expenditures in order to target the Canadian average SAIDI and SAIFI?

c) Please explain the most significant impediments to MH to be able to relate capital expenditures to targeted levels of system performance and reliability.

Response:

a) Midgard agrees with the statement at a high level. However, general increases in asset management maturity will not necessarily allow Manitoba Hydro to relate its capital expenditures to changes in reliability and performance. The improvements in asset management maturity must occur in key areas that support this type of analysis. Specifically, more advanced asset management maturity in the key areas identified by AMCL are foundational improvements required to relate capital expenditures to reliability and performance:

> *"Three specific areas that AMCL has highlighted as being interdependent in terms of maturity are asset information, risk and review, and asset management decision making. Effective asset management decision making is founded on a clear understanding of current asset performance and future operating risk, coupled with a consensus understanding of operating costs, failure costs, and the cost of asset repairs and renewals. A complete understanding of asset-related costs, risk and performance relies on adequate asset data."* [8]

As stated in evidence:

> *"Midgard agrees with AMCL that these are the three key areas most impairing MH's ability to further advance its asset management maturity."* [9]I

Without good decision making and analysis inputs, Manitoba Hydro is not able to quantitatively relate capital expenditures to reliability and performance outcomes.

[8] Application, Appendix 7.4, p. 7 of 184.
[9] Exhibit CC-8, Section 7.1, p. 37.

Manitoba Hydro acknowledges this when discussing how reliability is considered in its current capital expenditure plan:

> *"Manitoba Hydro's current capital expenditure plan is designed to provide the most value within the spending targets. Reliability is included as a part of the value calculation; however, it is not specifically designed to achieve a certain performance target (5 year average) as Manitoba Hydro's current asset management maturity does not allow for precise mapping of capital expenditures to performance at this time."* [10]

And:

> *"While it would be intuitive to assume that lowering performance targets will result in lower required business operations capital investment, Manitoba Hydro is unable to confirm this. Manitoba Hydro's asset management maturity is not sufficient to be able to adjust business operations capital investment to achieve target levels of performance. i.e., it is unknown how a change in business operations capital investment will impact performance levels.*
>
> *Manitoba Hydro is targeting to maintain the reliability that our customers are accustomed to and that they have indicated are important to them. Please refer to COALITION/MH-I-129."* [11]

In conclusion, if the key areas where Manitoba Hydro's asset management maturity is lagging were improved, then Manitoba Hydro could start relating capital expenditures to reliability and performance outcomes.

b) Despite the claims by Manitoba Hydro that it is not able to adjust its capital expenditures in order to target specific SAIDI and SAIFI outcomes (see response to (a) above), Manitoba Hydro could adjust its capital expenditures to begin targeting Canadian average SAIDI and SAIFI. Manitoba Hydro could adopt a

[10] Manitoba Hydro Response to IR No. 1, PUB/MH I-87a, p. 2 of 3.
[11] Manitoba Hydro Response to IR No. 1, PUB/MH I-87d, p. 3 of 3.

strategy of constraining its capital expenditures so that over time system performance closes the gap with Canadian average SAIDI and SAIFI. This change would not occur overnight – it would take time to close the gap as Manitoba Hydro determines which sustained levels of capital investments and O&M expenditures lead to efficient cost reductions that least negatively impact SAIDI/SAIFI. Hence why Midgard recommended a 10% reduction to begin this process:

> *"At least a 10% reduction in BOC capital budgets is warranted until such time as MH provides evidence that its asset decision-making is supported by quality asset management data, tools and decision-making frameworks."* [12]

c) The most significant impediments to Manitoba Hydro being able to relate capital expenditures to targeted levels of system performance are:

1. Asset Information;
2. Risk and Review; and
3. Asset Management Decision-Making.

These are critical because they are foundational to analysis and quantitative decision making:

> *"To be direct, without good information (i.e., Asset Information) and tools to evaluate that information (i.e., Risk & Review, and Asset Management Decision Making), the quality of MH's investment decisions and tradeoffs is seriously impaired because MH is still firmly in the "Awareness" stages in these key areas."* [13]

[12] Exhibit CC-8, Section 10, p. 85.
[13] Exhibit CC-8, Section 7.1, p. 35.

PUB/COALITION I-6 Reference: Midgard Evidence pp.42 & 57; Appendix 7.7; MFR 43, MIPUG/MH I-82d (Attachment 1); Appendix 5.6

Preamble:

On page 41 of its evidence, Midgard states:

> As discussed in other sections of this evidence, MH's Asset Management and Risk Management processes and data are presently not sufficiently mature to meaningfully support consistent risk assessments across diverse business groups, <u>adequately prioritize dissimilar investments</u>, or enable quantified value-based decision-making. [emphasis added]

On page 10 of Appendix 7.7, MH describes the Bipole I and II HVDC refurbishment investments:

> A comprehensive condition assessment on Bipole I and II valves and controls was completed in 2019 and shows that Bipole II valves have passed their expected lifespan, are in poor condition, and should be replaced as soon as possible.
>
> Bipole component reliability, spare availability, and engineering/technician expertise are all significant risks towards a prolonged outage or outages, resulting in significant financial loss and a degraded ability to provide power to Manitobans.
>
> Estimated costs: $1,000 million - $1,800 million
>
> Estimated schedule: 2022 to 2034

On page 5 of Appendix 7.7, MH describes the Pointe du Bois Renewable Energy Project:

> The Pointe du Bois Unit Replacement Project will install eight new hydroelectric generating units to replace original units that are at the end of their economic life. The new units will increase capacity on the Manitoba Hydro system by 52 Megawatts (MW) and increase the annual amount of clean, low cost, renewable energy, generated at the Pointe du Bois Generating Station. This project will also include construction of a new 115kV transmission line (PW75) from Pointe du Bois

> Station to Whiteshell Station which is required to accommodate the increased generation output from the generating station.
>
> ISD: March 2027

In MIPUG/MH I-82d Attachment 1 p.12 of 225, MH states:

> The Pointe du Bois Unit Replacement Project provides Manitoba Hydro an opportunity to increase system capacity by 52 megawatts (MW) and increase the annual amount of clean, renewable energy generated at the Pointe du Bois Generating Station. The Project would install 8 new generating units that would produce 380 gigawatt hours (GWh) per year, on average, between 2024 and 2055.

In MFR 43, MH shows the need date for new capacity resources as 2030/31 and the need date for new energy resources (assuming no other resources are added) as 2033/34. Absent the additional generation from the Pointe du Bois Renewable Energy Project, it appears that the need date for new resources based on capacity is 2027/28, with continued capacity shortfalls beginning in 2029/30.

In Appendix 5.6, MH shows the need date for new capacity and energy resources as 2033/34 (new wind), assuming continuation of the Curtailable Rate Program and the introduction of a demand response program.

On page 57 of its evidence, Midgard states:

> 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 MH 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 in an impact to domestic ratepayers.

Request:

a) Based on MH's current asset management maturity, how should MH proceed with the evaluations of the investments in Bipoles I and II (sustainment investments) compared with the Pointe du Bois Renewable Energy Project investment (economic benefit in the short term, capacity and energy supply in the medium to long term)?

b) Please explain how the inability of MH to serve firm export commitments resulting from unavailability of an asset such as Bipole II, the requirement to import power, or system impacts other than interruption of domestic customers should factor into MH's capital investment decisions.

Response:

a) Given Manitoba Hydro's current level of asset management (and risk management) maturity, Manitoba Hydro cannot currently employ comprehensive quantified asset and risk management methodologies to evaluate and prioritize sustainment investments such as those cited in the reference. As a result of this circumstance, a dual path evaluation methodology similar to the following should be considered:

   1. <u>System Focus:</u> Identify assets that are critical to reliable system operation using historical deterministic planning methods, e.g., individual assets for which an outage during system peak demand would cause unacceptable operating conditions (e.g., N-1). For individual assets identified as system critical, determine the expected probability of an outage during system peak and trigger a sustainment investment (replacement or rehabilitation) when the outage probability due to asset condition exceeds an established threshold. Note that there is always some probability that any asset may fail, even those whose assessed condition is good or fair, but assets in good or fair condition are not typically replaced because the probability of failure is sufficiently low. Because Manitoba Hydro's asset condition and asset health index database are incomplete or not fit for purpose for many asset classes, in those cases the equipment failure probability will be a qualitative estimate based upon professional judgment using whatever asset or demographic information is available.
   2. <u>Asset Focus:</u> For deteriorated equipment that is not system critical, but that poses a material risk of damaging other equipment or facilities in

the event of a catastrophic failure, the probability of catastrophic failure should be assessed, and an economical sustainment investment (replacement or rehabilitation) should be prioritized for assets with an unacceptably high probability of catastrophic failure. Deteriorated equipment that does not pose a material risk of causing such a catastrophic failure should be assigned a lower priority and investments not executed until there is surplus capital available to spend on lower-priority investments.

Any sustainment investment not justified using either the System Focus or Asset Focus approaches described above would be considered surplus to both system and individual asset needs. In cases where a deteriorated non-critical (surplus) asset cannot continue operation and surplus sustainment funds are not presently available, the asset may be kept out of service or mothballed until surplus funds become available or the investment becomes justified using either the System Focus or Asset Focus approaches.

Because the loss of individual Bipoles does not impact reliable service to customers in almost all circumstances (as discussed in Midgard's response to PUB/COALITION I-8(a)), evaluation and prioritization of Bipole II sustainment investments would utilize the Asset Focus methodology described above.

Similarly, the Pointe du Bois Renewable Energy Project is not presently required to reliably serve loads, so evaluation and prioritization of Point du Bois sustainment investments would utilize the Asset Focus methodology.

In circumstances where a short-term economic opportunity can be exploited by making a premature sustaining investment, the investment evaluation should be supported with a full life cycle NPV economic analysis that accounts for the term of the economic opportunity (e.g., the revenue benefits are short term, but the costs must be evaluated on a full life-cycle basis). If the short-term economic benefits do not justify the increased full life-cycle costs of the investment, the investment should be deferred until the medium- or long-term domestic energy and/or capacity requirements necessitate the investment.

b) This response provides Midgard's opinion on how each of the three considerations embedded in the question should be factored into Manitoba Hydro's capital investment decisions.

Inability to serve firm export commitments resulting from the unavailability of key assets:

Manitoba Hydro's evidence indicates that it does not presently distinguish between domestic customers and firm export customers for the purpose of evaluating its ability to provide reliable service. Similarly, Manitoba Hydro doesn't distinguish in the application between planned asset investments needed to continue reliably serving domestic customers vs. investments needed to continue reliably serving firm export commitments. Manitoba Hydro was unable in IR responses to identify which of its existing system assets are intended to reliably serve domestic loads, which are intended to reliably serve firm exports, and which are presently surplus to either of these needs.

> *"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."* [14]

If there are customized service reliability parameters associated with Manitoba Hydro's firm export commitments, they are presumably set out in the terms and conditions of the respective contracts – Midgard does not have visibility of those

[14] Manitoba Hydro Response to IR No. 2, COALITION/MH II-109d.

terms and conditions and cannot determine if satisfying those reliability parameters has required and/or continues to require Manitoba Hydro to make incremental capital investments beyond what would be needed to reliably serve domestic customers.

However, Manitoba Hydro indicates in IR responses that in almost all circumstances its ability to reliably serve both domestic customers and firm export commitments is not presently jeopardized by unavailability of individual facilities such as Bipole II[15] or MMTP,[16] so the circumstances described in the question are presently hypothetical.

Midgard observes that in any case the cost responsibility for any investments to support firm exports will be entirely borne by domestic customers upon termination of the associated contracts.

<u>The requirement to import power:</u>

Manitoba Hydro states that it presently has import capacity surplus to its requirements.[17] Manitoba Hydro also indicates that this surplus import capacity is a secondary benefit of facilities primarily developed to support exports, e.g., MMTP.

> *"With the completion of the MMTP, the Manitoba to US interface now consists of two 500-kV interconnections plus three 230-kV interconnections. The firm scheduling limit is approximately 2,850 MW for export and 1,400 MW for import."* [18]

Manitoba Hydro's import requirements (from a service reliability perspective) are primarily driven by three factors:

i. Annual energy needed to serve firm loads during low water years;

[15] Please refer to Midgard's response to PUB/COALITION I-8(a) below.
[16] Manitoba Hydro Response to IR No. 2, COALITION/MH I-114b(iii).
[17] Manitoba Hydro Response to IR No. 2, COALITION/MH I-114b(iii).
[18] Application, Tab 5, Section 5.7, p. 36, l. 8-10.

ii. System generation and transmission capacity required to serve peak firm demand under plausible generation and/or transmission contingencies; and

iii. The firm export commitments that MH combines with its domestic customer load forecast when establishing the “firm” energy and demand parameters used in factors i) and ii).

The GRA does not distinguish between Manitoba Hydro’s domestic and firm export commitments when discussing import requirements.

<u>System impacts other than interruption of domestic customers:</u>

The inability to presently distinguish between the reliability requirements of domestic customers and firm export commitments is discussed above, therefore domestic and firm export customer reliability considerations are considered to be identical for the purposes of discussion.

System impacts that involve interruption of opportunistic exports would not typically justify any incremental capital investments, since they are, by definition, opportunistic. For example, in real time Manitoba Hydro may opportunistically choose to use assets that are planned to satisfy its planning reserve margin requirements when these assets would otherwise be idle or underutilized in real time.

Other potential system impacts are more hypothetical, such as for example, internal Manitoba system disturbance events that propagate to external jurisdictions but do not cause loss of internal or firm export loads. Assuming that Manitoba Hydro satisfies its basic mandatory reliability system obligations, such events are very low probability.

PUB/COALITION I-7 Reference: Midgard Evidence p.49

Preamble:

On page 49 of its evidence, Midgard states:

> With the important statements being that as redundancy is added, the criticality of, ratepayer risks posed by, the now redundant assets is reduced because the "failure of a redundant component will not affect the system".

Request:

Please clarify the sentence in the preamble and elaborate on what it is trying to convey.

Response:

Before an asset has redundancy, the failure of that asset causes an outage to the portion of the system being served by that asset (e.g., the consequence is non-zero). After an asset has redundancy, the failure of that asset does not typically cause an outage to the portion of the system being served by that asset because the redundant assets take over and serve that portion of the system (e.g., the consequence is zero or near zero). For example, in CopperLeaf C55:

> *"Secondary Failure is the likelihood of a secondary failure in a redundant system. This calculation is complex and varies from situation to situation; therefore, 5% has been chosen as a reasonable average expectation. This figure represents the probability of the secondary failure as well as the probability that maintenance work will have to be delayed due to the loss of redundancy. The 5% value has been used by Copperleaf at other utilities."*[19]

[19] **Source:** Manitoba Hydro 2017/18 & 2018/19 General Rate Application, Minimum Filing Requirements 107, Copperleaf VFID, Section 5.3.15, p. 15.
https://www.hydro.mb.ca/docs/regulatory_affairs/pdf/electric/general_rate_application_2017/mfrs/pub_mfrs.pdf

While Midgard may not necessarily agree that the selected 5% value is optimal for utility assets with very low probability of simultaneous independent failure, the basic premise is correct. Specifically, the addition of redundancy reduces the risk because an asset failure has zero or near-zero (i.e., 5%) impact on the system because the redundant asset takes over and serves the system.

PUB/COALITION I-8 Reference: Midgard Evidence pp.50,55

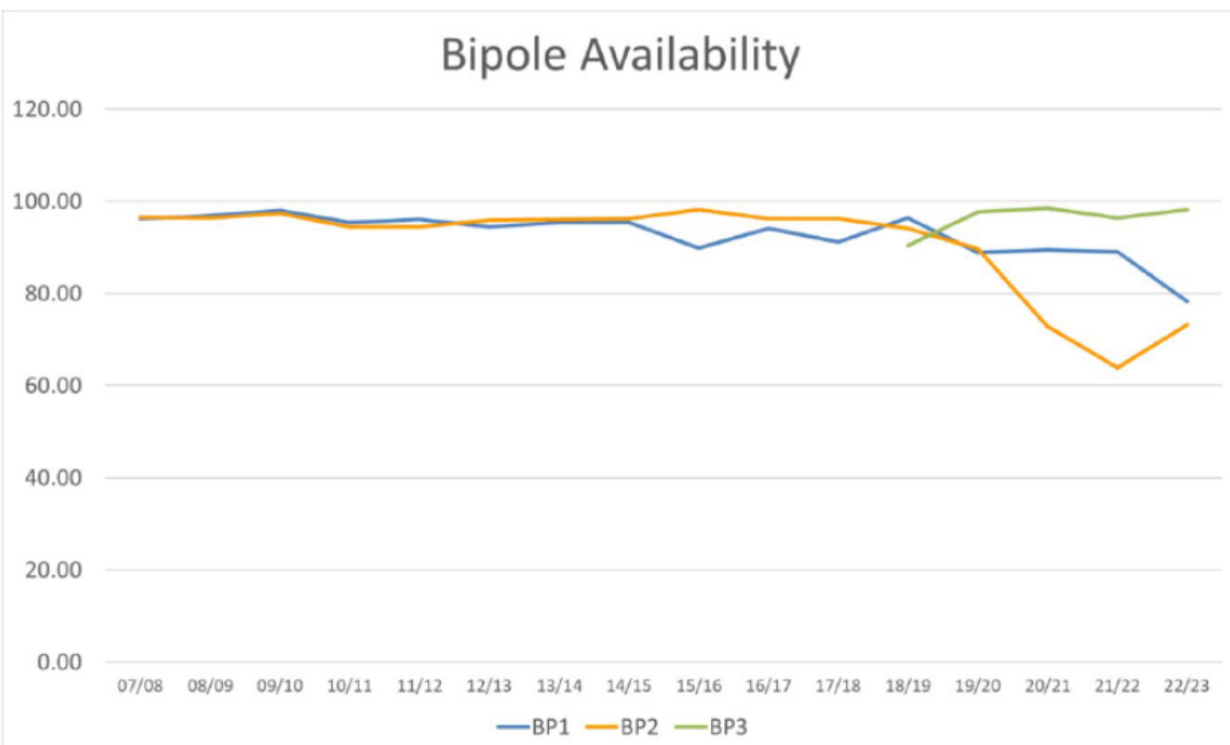
Preamble:

On page 50 of its evidence, Midgard states:

> But despite this understanding MH then provides evidence to argue assets must be replaced because of their condition, not their effect on the system. This inconsistency in approach is shown in the discussion around generation equipment failures and Hydraulic Generation Weighted Availability and Forced Outage Factors.

On page 55 of its evidence, Midgard reproduces Figure 7.6 from MH's Application:

Figure 7.6 Reliability of HVDC System



Request:

Based on MH's current asset management maturity, please explain how MH should evaluate investments in Bipoles I and II, considering the extended periods of unavailability.

Response:

In evidence, Midgard discusses the ratepayer impact of a single Bipole failing:

> *"As shown in the figure above, Midgard acknowledges that Bipole II (and to a lesser extent Bipole I) have seen reductions in availability over the past few years, and Midgard does not dispute MH's assessment that its Bipole assets are aging. Similar to previous however, the operative question becomes determining whether Bipole availability reductions are actually causing system and ratepayer impacts that warrant the proposed investments. Based on a review of the available evidence consideration of this tradeoff is absent.*
>
> *When queried about the Bipole transfer capacities, MH stated:*
>
> > *"Bipole full capacities are as follows:*
> >
> > - *BPI – 1854MW at the rectifier for temperatures above 30°C, the capacity is limited to 1669MW due to limitations of some converter transformers.*
> > - *BPII – 2000MW at the rectifier*
> > - *BPIII – 2000MW at the rectifier*
> >
> > *Collectively the total transmission capacity is approximately 4461MW for temp >28°C and 4818MW for temp <28°C, due to other ac system restrictions."*[20]

[20] Manitoba Hydro response to COALITION/MH I-99a

And when queried about the customer load that was shed historically due to a Bipole failure the answer was none, but caveats were provided regarding the absence of Keeyask:

> *"MH has not shed customer load outside of curtailable load in the past 5 operating years due to an HVDC outage. Therefore, the answer to this question is none."*[21]

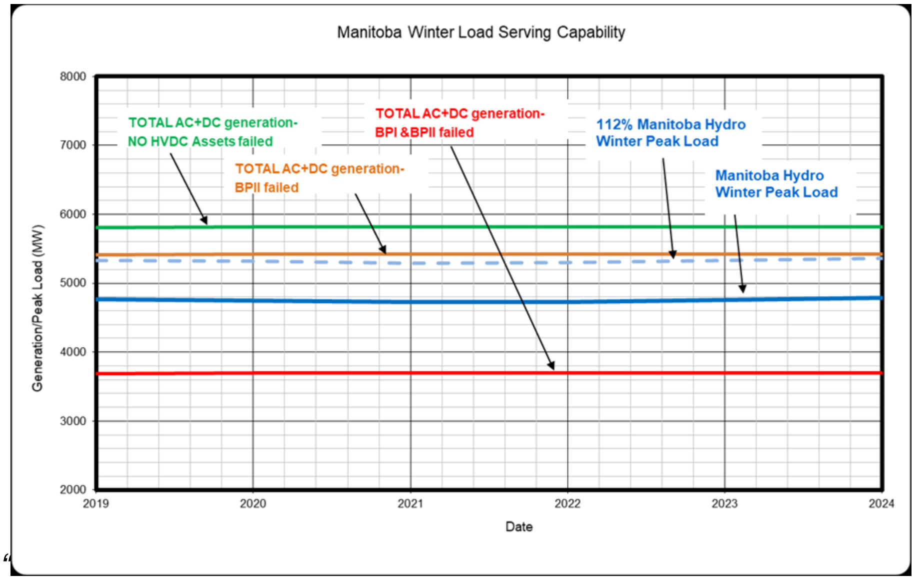
> *"The 5-year timeframe between 2018 and 2023 reflects a unique situation with Bipole III in service with Keeyask Generating Station not fully in commercial service. Future HVDC outage impacts are likely to differ significantly from the past five years as Keeyask Generating Station is coming into full service adding 630 MW of generation capability and thus more power is likely to be delivered through the HVDC system."* [22]

But in any case, MH correctly identifies the crux of the issue:

> *"Loss of domestic load serving ability depends on the load, the availability of the remaining ac generation and the availability of power for import in the MISO market."*[23]

And provides figure and explanatory text that shows with one Bipole failed (in this case Bipole II) all domestic load could be served, and <u>even with two Bipoles failed</u>, MH could still supply domestic load in most cases:

[21] Manitoba Hydro response to COALITION/MH I-99g
[22] Manitoba Hydro response to COALITION/MH I-99h
[23] Manitoba Hydro response to IR No. 1, COALITION/MH I-99e.

“

When more HVDC assets fail (ie. BPI&BPII failed) the total AC and DC generation curve could fall below the 112% Manitoba Winter Peak load. This shortfall would not necessarily result in load shedding in Manitoba, if the short fall is not excessive. However, in such conditions, Manitoba will not be assured of being self-sufficient in meeting its load and would have an Manitoba Hydro 2023/24 & 2024/25 General Rate Application increased dependence on imports from the MISO market to serve Manitoba load. Import contracts of 950 MW and an import capability up to 1400 MW can be a source of supply to meet this shortfall. However, it is not a guaranteed supply from the MISO market for extended periods. In the event that the MISO market is unable to supply the energy required, the Manitoba load may not be adequately supplied.”[24] [25]

Midgard acknowledges that Bipole II and, to a lesser extent, Bipole I have seen reductions in availability over the past few years. However, Midgard challenges the claim that these availability reductions are causing domestic system and ratepayer reliability impacts that urgently justify the proposed investments.

[24] Manitoba Hydro response to IR No. 1, COALITION/MH I-99e.
[25] Exhibit CC-8, Section 7.2.5 (DC Transmission), p. 55-57.

Additionally, in response to IRs, Manitoba Hydro identified a minimal impact in loss of domestic Manitoba load served over the past five years due to bipole failures:

> *"MH has not shed customer load outside of curtailable load in the past 5 operating years due to an HVDC outage. Therefore, the answer to this question is none."* [26]

Midgard concludes in its evidence that a single Bipole failing has a minimal impact on ratepayers because the DC and AC transmission systems have enough redundancy to meet non-curtailable domestic loads, even during peak times. Consequently, when considering failures from a system impact rather than individual asset perspective, the increased failure rates of Bipole I and Bipole II are less system-critical than Manitoba Hydro has indicated:

> *"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 MH 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 in an impact to domestic ratepayers."* [27]

As a result, a simplified analysis approach could be employed wherein investment evaluations for Bipoles I and II could therefore be calculated on a basis of zero or near zero system impact due to transient or duration limited failures (e.g., not a catastrophic failure or a long-term failure).

[26] Manitoba Hydro Response to IR No. 1, COALITION/MH I-99g, p. 9 of 13.
[27] Exhibit CC-8, Section 7.2.5 (DC Transmission), p. 57.

PUB/COALITION I-9 Reference: Midgard Evidence pp.51, 52
Reliability vs. Export Economics vs. Avoiding Additional Damage

Preamble:

On page 51 of its evidence, Midgard states:

> What Midgard questions is whether normal asset aging and associated performance degradation is having any meaningful impact upon the system and ratepayers as evidenced by stable overall SAIDI/SAIFI metrics (see Section 5) and the above confirmation that generation outages do not cause system outages. 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.

On page 52 of its evidence, Midgard states:

> In summary, 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 as generation asset condition naturally degrades.

Request:

a) Please confirm whether there are other factors than domestic reliability that factor into asset investment decisions.

b) Please explain how the unavailability of generation that is surplus to domestic needs but is used to make export sales should be factored into MH's decision making as to whether to invest in generation asset refurbishment.

c) Please explain how the risk of catastrophic failure – where failure of the asset or component results in collateral damage to other systems or components, and where the cost to repair the component and collateral damage far exceeds the cost of proactively replacing the asset or component – factors into any decision to extend the life of an asset because there is redundancy and the system impact will be minimal.

Response:

a) Yes, there are other factors than domestic reliability that factor into investment decisions. Some examples of other factors include (but are not limited to):

1) <u>Worst Feeder:</u> Invest because abnormally bad service exists on a specific feeder even though the overall impact to SAIDI and/or SAIFI is not necessarily material. Many Canadian utilities have a "worst feeder" program to address these types of investments. Note that this evaluation concept can also be applied to radial transmission lines feeding individual industrial customers.

2) <u>Power Quality:</u> Manitoba Hydro presumably applies power quality standards and inability to adhere to those standards would potentially justify investments (Please refer to Midgard's response to MIPUG IR MIPUG/COALITION I-5(e)).

3) <u>Investments to Avoid Catastrophic Failure:</u> Manitoba Hydro should perform the capital investments and O&M expenditures necessary to avoid catastrophic asset failure. For example, Manitoba Hydro should continue to change oil as required to maintain asset health and avoid premature degradation even if the asset is not expected to require future capital investments (please refer to Midgard's response to PUB/COALITION I-9(c) below).

4) <u>Mandatory Legislation:</u> Manitoba Hydro must comply with legislated or regulatory requirements, e.g., PCB replacement in transformers by December 31, 2025, per the PCB Regulations.[28,29]

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[28] **Source:** PCB Regulations (SOR/2008-273), End-of-use dates and Extension, 16 (1). https://laws-lois.justice.gc.ca/eng/regulations/SOR-2008-273/page-1.html#h-746978

[29] **Source:** BCUC Proceeding #949, *BC Hydro Certificate of Public Convenience and Necessity for the Mainwaring Substation Upgrade Project*, Exhibit B-1, Section 2.3.3, p. 2-31, l. 18-20. *"Section 7-17 of the PCB Regulations obligates BC Hydro to remove, by December 31, 2025, all equipment containing PCBs with a concentration of 50 ppm or more."*

5) Obligation to Serve: Manitoba Hydro has a duty to serve and must connect new customers.

6) Pre-existing Contracts: Manitoba Hydro should honour its pre-existing contracts (e.g., firm export contracts).

    a. NOTE: This does not mean that Manitoba Hydro should necessarily extend these contracts, just that Manitoba Hydro should honour its current obligations.

7) Environmental Obligations: Manitoba Hydro may make agreements with provincial, federal or Indigenous governments or other parties that it is obligated to honour.

b) The unavailability of generation that is surplus to domestic need but is used to make opportunistic export sales should be evaluated economically on a full lifecycle NPV basis. The benefits from opportunistic export sales should economically justify the investment, otherwise the investment should not be made until the asset is required to serve domestic loads.

In cases where the generation surplus may eventually be used by domestic loads, the economic analysis should assess the benefits of deferral until such time as sufficient domestic need is present and/or economic risk are adequately managed. Investment deferral has material potential economic benefits to ratepayers and avoids the risks of domestic ratepayers subsidizing otherwise unprofitable exports and bearing the cost risk should export markets materialize differently than forecast.

c) Midgard is not suggesting that Manitoba Hydro expose its assets to the type of catastrophic failure posited in the question. Manitoba Hydro should make the capital investments and O&M expenditures necessary to avoid the failure of components that would cause cascading catastrophic failures. For example, Manitoba Hydro states its strategy for valves in its HVDC system wherein it maintains valve group components (i.e., smaller components within the larger system) to avoid larger failures:

> *"The generation, interconnection and HVDC transmission systems are designed with spare capacity to handle the most frequent failure mode on the HVDC system which is a Valve Group failure. A temporary valve group failure that is repaired causes minimal impact to the ability to serve demand if the failure is limited to a single valve group capacity.*
>
> *If the failure of a valve group is long term where repairs require months to years to complete (i.e., permanent failure) and additional failures happen concurrently to reduce the HVDC capacity further, or a larger failure occurs such as a pole or Bipole, then the impact on load serving capability could affect firm load and financial impacts could be substantial as detailed in COALITION/MH I-99e."* [30]

[30] Manitoba Hydro Response to IR No. 2, COALITON/MH II-86a.

PUB/COALITION I-10 Reference: Midgard Evidence pp.51, 52; Tab 7 p.11

Preamble:

On page 11 of Tab 7, MH states:

> Over the last decade, T-SAIDI [with major events] is showing a negative trend which indicates line outages are taking longer to restore than in previous years. This trend is influenced heavily by the significance of several major weather events that have occurred in recent years. Excluding these major events, such as significant wildfires and the October 2019 storm, results in T-SAIDI values for fiscal years 2019, 2020 and 2022 of 78.68, 42.75, and 100.48, respectively, which is more aligned with historic values. <u>Due to such significant influence from uncontrollable weather events, arriving at conclusions regarding the impacts of asset degradation on this metric is difficult.</u> [emphasis added]

Request:

In Midgard's view, with the major events excluded, what conclusions can be drawn about asset degradation from T-SAIDI values that are more aligned with historic values. Please also characterize Midgard's confidence in these conclusions.

Response:

Based on Manitoba Hydro's filed evidence, Midgard concludes that T-SAIDI values are generally aligned with historic values and are stable. However, absent specific quantified forecasts of asset degradation, Midgard is unable to draw firm conclusions about transmission asset degradation, as it is possible for the overall T-SAIDI values to be stable and aligned with historic values while still experiencing offsetting effects from asset degradation, system surplus, system automation enhancements (e.g., remote switching), and increasing system redundancy.

PUB/COALITION I-11 Reference: Midgard Evidence p.71
Turnover Rate

Preamble:

On page 71 of its evidence, Midgard states:

> Based on a simplified demographic analysis it is clearly apparently that the current asset replacement rate of 5000 poles per year is too low over the long run because a 0.5% turnover rate implies a 200-year distribution wood pole life which is almost triple the 70-year life at which wood poles are expected fail due to condition-related reasons. Therefore, although it is likely that the appropriate long-term wood pole replacement rate is materially higher than 5000 poles/year, MH is unable to determine how much higher. [footnotes deleted]

On page 73 of its evidence, Midgard states:

> 4) The currently planned replacement rates for some asset types (e.g., 5000 distribution wood poles/year, 37 km/year of underground cables) are expected to be inadequate over the longer term as these assets age.

Request:

a) Please explain whether replacing wood poles - or any assets - at a turnover rate sufficient to replace all units within the predicted service life is an appropriate strategy. For example, this would lead to approximately 14,000 wood pole replacements per year.

b) Please explain whether MH should begin ramping up replacements of assets like wood poles and underground cables now in order to avoid a situation where the number of required replacements exceeds MH's capacity to replace them, or does MH have sufficient time to finish maturing its asset management and asset health indicators in order to apply optimal replacement rates for these assets?

Response:

a) Midgard is not asserting that replacing wood poles at a turnover rate sufficient to replace all units within their predicted service lives is the optimal strategy at this time. Midgard draws attention to two issues:

   1) Predicted Service Life: The actual expected service lives of specific asset classes may be materially different (e.g., longer) than Manitoba Hydro's current predicted service life estimates.

   2) Current and Future Pace of Replacement: Since assets do not have infinite service lives, all assets will need to be replaced or refurbished at some time in the future. Manitoba Hydro has transitioned from being a rapidly growing new utility with demographically young assets to being a middle-aged utility with aging assets. At some future time, replacement rates for specific asset classes may need to increase to keep pace with increasing rates of assets reaching end-of-life condition. However, Manitoba Hydro's evidence does not demonstrate that the time for significantly increased paces of replacement for most asset classes has been reached.

b) The time value of money matters to ratepayers. Therefore, ratepayers want Manitoba Hydro to replace assets when their replacement is optimal, not before. Replacing an asset before it should be replaced reduces the value that asset delivers to ratepayers over its lifespan. An asset should not be replaced while it is still reliably providing service, until replacing it will save money on a full lifecycle NPV basis considering all associated operating and capital costs.

   Based on Manitoba Hydro's overall SAIDI and SAIFI performance it appears that Manitoba Hydro has not reached the point where assets are being replaced later than they should be replaced. Manitoba Hydro may be replacing assets earlier than necessary in some cases, but it does not appear it is generally replacing assets later than necessary.

   However, Manitoba Hydro does not have time to delay maturing its asset management and asset health indicators, as the immaturity of its processes costs ratepayers money each day that maturation is delayed, because Manitoba Hydro is making sub-optimal asset investment decisions and will continue to do so until these processes are more mature.

PUB/COALITION I-12 Reference: Midgard Evidence p.82

Preamble:

On page 82 of its evidence, Midgard states:

> There would be limited value to evaluate the proportion of MH's existing facilities that represent Minimum System for the purpose of retroactively determine the prudence of historical investments since these are now sunk costs that domestic ratepayers bear responsible to underwrite. However, understanding the appropriate Minimum System starting point from which to evaluate future incremental investments would enable customers to determine the intended primary purpose of those incremental investments (i.e., to serve domestic customer loads or to support export market transactions), and that would be immensely valuable to ratepayers and presumably the Manitoba PUB.

Request:

a) Please elaborate on why such an analysis would be valuable to ratepayers and PUB.

b) Is the proposed analysis the kind of analysis that would help determine whether the Pointe du Bois Renewable Energy Project or the Bipole I and II HVDC investments should proceed at the present time?

c) In Midgard's view, is this analysis more appropriate in the current GRA or is it more appropriate for this analysis to be considered in an integrated resource planning review proceeding?

Response:

a) The responses in this series all assume the "Minimum System" is the system needed to reliably serve domestic loads, but the concepts are still applicable if firm export commitments are treated as inextricable from domestic load serving obligations.

Such an analysis would be valuable to ratepayers and PUB because it would establish the basis for assessing the need for and urgency of planned capital investments. Until such time as the existing system surplus capacity has been fully consumed and the existing system becomes equivalent the Minimum System, to achieve the goal of lowest cost service any capacity expansion investments should be justified solely on their economic/revenue generation merits, since such expansions, by definition, would not be needed to satisfy service reliability requirements.

Understanding the Minimum System would also enable the ratepayers and PUB to know if proposed sustaining investments to replace or refurbish deteriorated assets that do not pose a risk of causing damage to other assets upon failure are required urgently, or if they can be deferred (see the discussion in PUB/COALITION I-6-a for further information on this approach) . Deteriorated Minimum System assets at risk of imminent failure should be prioritized for replacement, while mitigating surplus asset condition issues should be given a lower priority.

b) Yes, the proposed analysis is the kind of analysis that would help determine whether some or all of the Pointe du Bois Renewable Energy Project or the Bipole I and II HVDC investments should proceed at the present time. The proposed analysis would determine the existing surplus system capacity, and consequently any incremental surplus capacity that would be created by adding new capacity resources (or refurbishing existing capacity resources).

c) This analysis is useful in either type of proceeding.

In the context of an IRP, knowing the minimum required supply resource portfolio in each year of a load forecast is necessary to understand if incremental supply resources are required over the planning period to serve domestic loads. In addition, IRPs typically indicate when new transmission capacity is required to interconnect or transmit power from the incremental supply resources identified in the IRP to loads, so it is useful to know when evaluating the proposed transmission additions if the existing system already has surplus capacity above the Minimum System requirements.

In the context of a GRA, knowing the Minimum System indicates if planned investments will be creating an unnecessary incremental capacity surplus or just maintaining an adequate system to reliably serve domestic loads. This information is useful when evaluating the need for any such investments.

The Consumer Coalition member organizations note further: Caution should be used in assuming that the process currently being undertaken by Manitoba Hydro under the banner of "Integrated Resource Plan" or IRP will lead to a work product consistent with the intent of the PUB in the context of the NFAT proceeding or the intent of the Manitoba Legislature under *The Manitoba Hydro Act*. This observation is based in part upon participation in the process being undertaken under the banner of "Integrated Resource Plan" as well as documents in the public domain associated with the process. Moreover, caution should be exercised in assuming that planning assumptions being conducted under the banner of the "Integrated Resource Plan" are consistent with documents underlying the current General Rate Application such as the 2021 Load Forecast.

PUB/COALITION I-13 Reference: Midgard Evidence pp.84, 85

Preamble:

On pages 84 and 85 of its evidence, Midgard provides a section titled "Conclusions and Recommendations". There do not appear to be any recommendations included in this section.

Request:

Please provide an itemized list of Midgard's recommendations, if any, clearly identifying whether the recommendations are intended for MH or for the PUB.

Response:

Midgard provided the following recommendation, intended for the Manitoba Public Utilities Board to consider upon its final deliberations for the proceeding:

> *"At least a 10% reduction in [Business Operations Capital] budgets is warranted until such time as MH provides evidence that its asset decision-making is supported by quality asset management data, tools and decision-making frameworks."* [31]

[31] Exhibit CC-8, Section 10, p. 85.

PUB/COALITION I-14 Reference: Derksen Evidence pp.15, 16

Preamble:

In her evidence on pages 15 and 16, Ms. Derksen states:

Table 2:

BC Hydro RCCs (%)	2008	2009	2010	2011	2012	2013	2014	2016
Residential	91.8	90.2	92.1	90.6	89.9	89.6	92.9	93.6
GS<35kW	123.8	123.3	124.3	123.5	126.2	126.4	123.5	111.6
MGS	106.2	110.8	109.1	110.4	120.5	120.9	119.5	120.5
LGS	106.2	110.8	109.1	110.4	105.2	102.2	101.5	100.8
Irrigation	83.4	80.9	84.6	78.3	88.3	85.0	90.3	84.5
Streetlighting	125	117.7	117.7	110.1	110.7	112.0	129.4	133.7
Transmission	100.1	99.7	96.4	99	102.5	105.3	97.3	101.4

Table 3:

Hydro Quebec	
Residential	84%
GSS ND < 65 kW	125%
GS Medium (demand) > 50 kW	125%
GS large (demand) > 5000 kW	125%
Large Industrials	116%

Accordingly, a ZOR is typically used by utilities to reflect the fact that there is uncertainty about the results of a COS study. Therefore, a cost-of-service study is used as a guide or benchmark when setting rates.

Request:

a) Does Ms. Derksen support rate differentiation in principle, whereby customer classes with RCC ratios outside of the zone of reasonableness should have their rates adjusted to (eventually) move these classes into the zone of reasonableness? If not, please explain why not.

b) If MH had the same RCC ratios as BC Hydro or Hydro Quebec, in Ms. Derksen's view would these be sufficiently outside the zone of reasonableness to justify rate differentiation to move these classes into the zone?

Response:

a) and b):

The goal of moving RCC ratios outside the ZOR into the ZOR to the exclusion of other considerations should not be viewed as appropriate in the establishment of just and reasonable rates.

For further reference please see AMC/CC I-3.

The RCC's for BC Hydro, Hydro Quebec and Manitoba Hydro are as follows:

- BC Hydro – RCC range of 84% to 133% - range of 49%
- Hydro Quebec – RCC range of 84% to 125% - range of 41%
- Manitoba Hydro – RCC range of 94% to 113% - range of 19%

The RCC results of BC Hydro and Hydro Quebec, which are two hydraulic, vertically integrated electric utilities comparable to Manitoba Hydro are not sufficient to have warranted rate differentiation to move these classes into their ZOR in those jurisdictions. The legislatures in both these justifications found it appropriate to limit or freeze rate differentiation between customer classes presumably for reasons of public policy.

This begs the question of whether and if so, why, MH is sufficiently different from these two similar utilities to justify MH's rigid adherence to 95% - 105%. Further, and importantly, the RCC ranges of these three comparable utilities is also suggestive that the results of MH's PCOSS24 is to be viewed favourably, in the absence of any rate differentiation.

PUB/COALITION I-15 Reference: Derksen Evidence p.28

Preamble:

In her evidence on page 28, Ms. Derksen provides Chart 2 and Chart 3:

Chart 2:

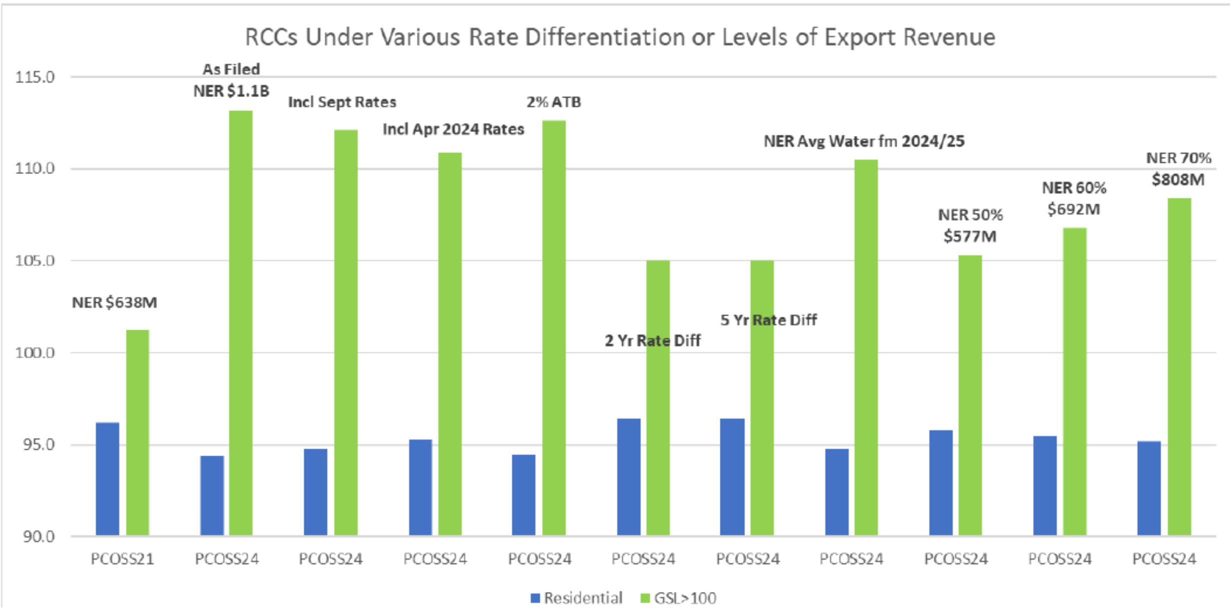
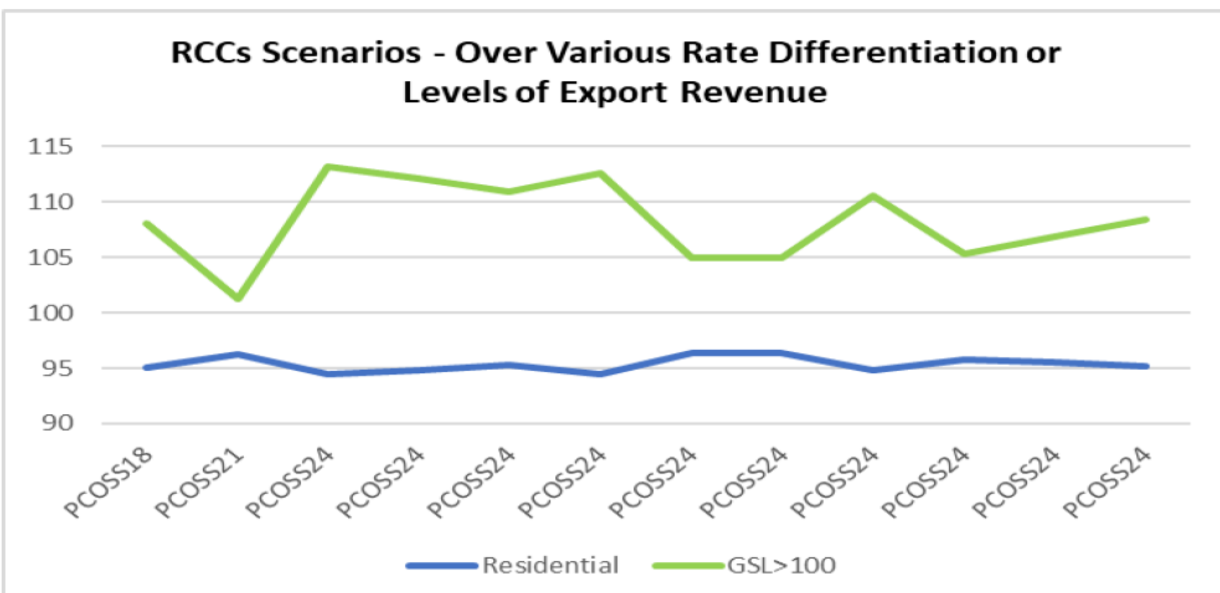


Chart 3:



Request:

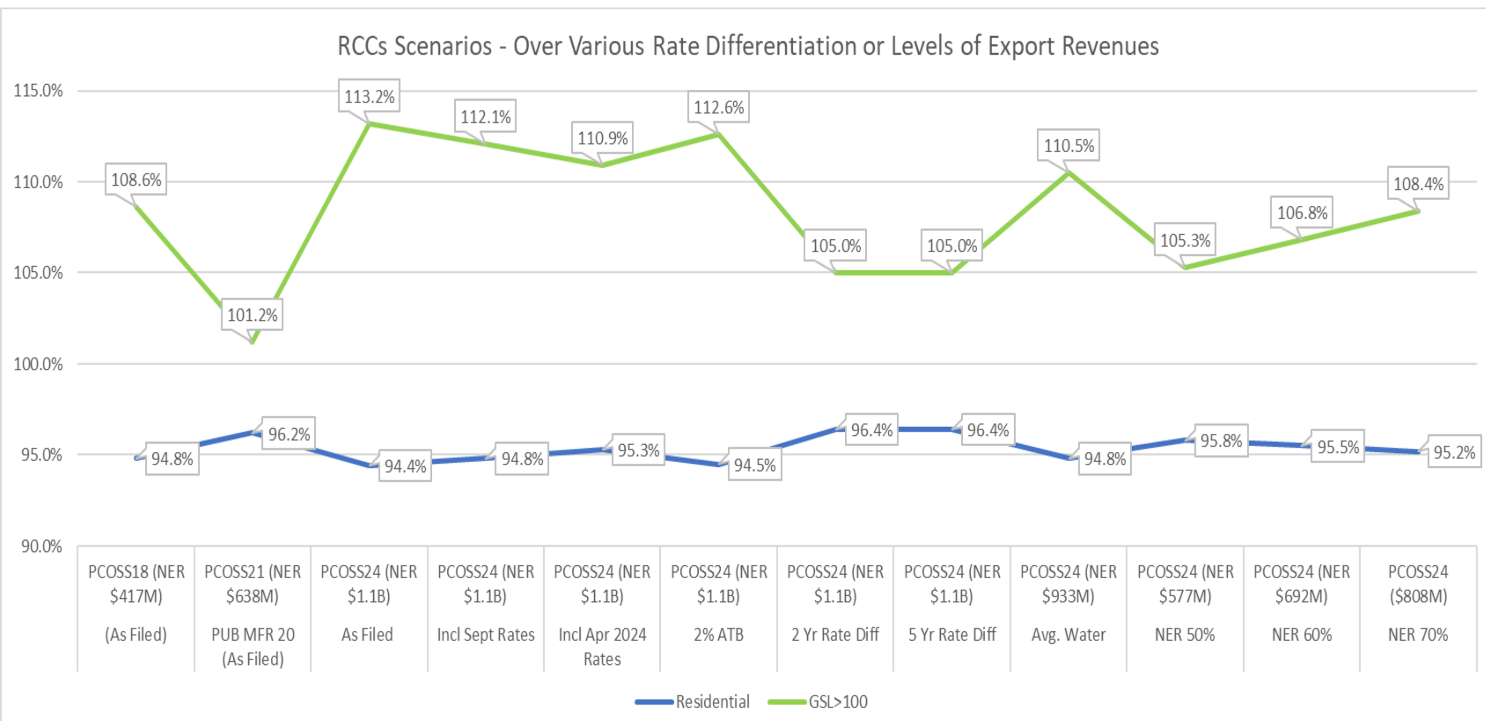
a) Please provide Ms. Derksen's view as to the most appropriate RCC with which to evaluate MH's test year rate increase proposal and explain why.

b) Please re-file Chart 3 fully showing the x-axis labels, or label the data points similar to Chart 2.

Response

a) Please refer to the response to AMC/Coalition IR I-3.

b) Please see Chart 3 below:



The data in the above chart results in an average RCC for Residentials of 95.3% and 108.3% for the GSL>100kV class.

PUB/COALITION I-16 Reference: Derksen Evidence pp.41-43
Revenue-to-Marginal Cost Ratios

Preamble:

In her evidence on page 41, Ms. Derksen states:

> The following table that provides a directional indication of marginal cost by class as well as marginal cost to revenue coverage by class as provided by MH: [footnote deleted]

Table 12:

	Marginal Cost @ Class LF (cents/kWh)	Avg Rev (cents/kWh)	Rev/MC (%)	Marginal Cost @ Class LF (cents/kWh)	Avg Rev (cents/kWh)	Rev/MC (%)
	2017/18 GRA			2023/24 GRA		
	Total MC			Total		
Residential	9.13	8	87.6	6.61	10.27	155.4
GSS ND	8.63	8.6	99.6	6.36	10.32	162.2
GSS D	8.48	6.85	80.7	6.30	8.81	139.8
GSM	8.3	5.98	72.1	6.10	7.97	130.5
GSL 0-30	8.07	5.14	63.7	6.00	6.66	111.1
GSL 30-100	6.68	4.43	66.3	5.27	5.54	105.2
GSL>100	6.67	4.01	60.1	5.26	5.13	97.5
ARL						

In her evidence on page 42, Ms. Derksen states:

> The key observations regarding this marginal cost by class are as follows:
> …
> 2. The theoretical ideal of rates based on marginal cost suggests that rates based on embedded costs should not fall below marginal cost.
> …
> 3. It is unclear whether the substantial changes in the revenue to marginal cost by class may have also been impacted by the move to assign NER as an offset of cost rather than as an addition to revenue by class.
> 4. The relative relationship of RCC difference is significant between the Residential class and the largest GSL class, of 155.4% and 97.5%.

In her evidence on page 43, Ms. Derksen states:

While the circumstances have changed from the perspective that marginal cost by class is now generally higher than embedded cost and thus does not offend the necessity that rates not fall below marginal cost, there is still one class whose revenues are below marginal cost.

Request:

a) Please provide the source of the 2017/18 GRA marginal cost and average revenue information.

b) Please explain whether it was appropriate for MH to propose rates in the 2017/18 & 2018/19 GRA where the revenue-to-marginal cost ratio was less than 100% for each of the classes, as shown in Table 12 of Ms. Derksen's evidence.

c) Please identify any jurisdictions that Ms. Derksen is aware of that calculate marginal cost-based RCC ratios, and explain the purpose for which these jurisdictions calculate these marginal cost-based RCC ratios.

d) If rates should not fall below marginal costs, please explain whether the revenue to marginal cost ratios for PCOSS24 are superior to those from the 2017/18 GRA, since with PCOSS24 only one class has its revenue less than its marginal costs.

e) Please confirm whether the marginal cost information in Table 12 is aligned with the updated marginal costs provided in 2017/18 & 2018/19 GRA PUB/MH II-57R and Exhibit MH-101. If not, please explain whether it would be more appropriate to consider the updated marginal costs from that proceeding and, if so, please refile the table using the information from Exhibit MH-101.

f) Please explain whether any of the analysis or conclusions change if updated marginal cost information from the prior GRA is used.

g) Please explain whether the variability in the marginal cost and revenue-to-marginal cost ratios from those originally filed in the 2017/18 & 2018/19 GRA, the updated marginal cost and ratios from the 2017/18 & 2018/19 GRA, and the current marginal cost and ratios affect the utility or appropriateness of using these values in setting rates, recognizing that MH's marginal costs are partially based on export revenues which are inherently variable.

h) Please explain whether and how the method of allocation of net export revenues affects the calculations of revenue or marginal cost in Table 12.

i) Please confirm whether the rates for the Residential class include costs not captured by the marginal cost derivation, and whether any of these costs (distribution, customer service) are not paid by, or not paid to the same extent as, GSL classes. If not confirmed, please explain.

j) Please explain how these additional costs (distribution, customer service) not related to marginal cost should be reflected in rates, if at all.

Response:

a) Please see Exhibit CC-20 from the 2017/18 GRA, the Econalysis Evidence, dated October 31, 2017, page 86.

b) The question posed is not clear. If the question is asking whether it was appropriate for MH to propose a rate increase in the 2017/18 & 2018/19 GRA, given that the revenue-to-marginal cost ratios are less than 100% and thus, embedded cost is below short run marginal cost, the following is response is provided:

If economic efficiency was MH's only ratemaking goal, it is likely it is likely that MH would have had to propose even larger rate increases at the time in order to bring all classes revenues/rates to at least short run marginal cost and for some classes, would likely have resulted in rate increases that would have constituted rate shock levels. However, economic efficiency is one factor, among many, to be considered in proposing overall revenue increases.

To be clear, Ms. Derksen did not propose in her Evidence that Manitoba Hydro prepare a marginal cost of service study methodology, nor is she suggesting or proposing that rates be set at marginal cost. What Ms. Derksen is saying is that consistent with the PUB's findings flowing from Order 164/16, in which the PUB found that marginal cost was not to be reflected in cost of service, but to be considered as part of the rate design phase in the establishment of rate differentiation and rates, a policy perspective that necessarily considers marginal cost in the assessment of the mechanical output of PCOSS24 is one tool appropriately considered by the PUB.

As a general rule, from a theoretical economic perspective, it is inappropriate to price below short run marginal costs. As experienced by Manitoba Hydro in the past, its embedded costs not only fell below short run marginal cost for all classes, but also resulted in extreme variability by class as shown in the directional indication in Table 12 above. The extreme variability among classes in the degree to which prices under-recovered relative to marginal cost, was one reason for rate changes implemented on an across-the-board basis almost exclusively during the 20-year period beginning in the mid-1990's.

The outcome whereby embedded rates fell below short run marginal cost was one reason MH concluded that its long-standing method of allocating net export revenue to domestic classes based on their use of generation and transmission functions had not provided appropriate and realistic cost recognition for domestic classes. As a result, MH proposed a number of COS methodologies to address the inequity and the unsound economic consequences.

As part of the 2005 COS methodology review, Manitoba Hydro proposed, and the PUB approved the incorporation of short-run marginal cost information in its embedded COSS methodology through a Weighted Energy allocator, in order to assign greater cost responsibility to classes that consume more energy during peak periods. The weighted energy allocator incorporated both equity and efficiency ratemaking goals within the context of embedded cost to service methodology. MH asserted that the marginal value of energy reflected how it plans and operates its predominantly hydraulic generation fleet, which is operated in order to take advantage of varying prices at different times, thus impacting its revenue requirement.

In 2012, MH's consultant Christensen Associates (CA) reaffirmed the use of the weighted energy allocator to incorporate both equity and efficiency ratemaking goals within the context fully distributed cost allocation.[32] CA concluded the importance of recognizing the value of energy during different seasons and times of the day because of decisions customers make on when to consume impact costs incurred by Manitoba Hydro (and thus on MH's revenue requirement) either through reduced market sales or increased use of imports or internal resources.

CA asserted that marginal costs are valuable additions to the COS and rate design process but did not recommend the replacement of traditional embedded cost-based methods with marginal cost-based methods. Marginal cost-based allocation studies will provide a useful guide to pricing, while still under the constraints of overall revenue recovery as defined by financial costs. CA also asserted that marginal cost-based cost allocation may provide guidance in determining target class RCCs and the acceptable range for RCCs. For instance, a particular rate class with marginal cost distinctly different from other rate classes' marginal cost and from its embedded cost might warrant variance from the traditional RCC target.

CA also asserted that one potential application of marginal cost-based cost allocation is in developing an alternative set of RCCs, for comparison with existing embedded cost-based RCCs. A broader use of marginal cost might include the use of MC-based RCCs to influence the range of embedded cost-based RCCs.

No intervenor questioned the importance of the role of marginal cost in the context of MH's operations as part of the 2016 COS methodology review, other than

[32] Please see Christensen Associates Energy Consulting, "Review of Cost-of-Service Methods of Manitoba Hydro" (8 June 2012), filed as Appendix 5 to Manitoba Hydro's 2015 Cost of Service Methodology Review Application to the Public Utilities Board, available online: https://www.hydro.mb.ca/docs/regulatory_affairs/pdf/electric/cost_of_service_study_submission/appendix_5_mh_cos_methodology_report_final_060812.pdf

MIPUG. MIPUG also had previously asserted that the price distorting impacts caused by NER could be addressed through rate design.

Between 1995 and 2016 MH, along with its consultants NERA and CA, studied a number of alternatives to addressing the allocation of NER, which was giving rise to distorted RCCs and embedded cost below short run marginal cost.

In Order 164/16[33], the Board found that the COSS performed by Manitoba Hydro is to be an embedded COSS, stating that there was insufficient evidence on the record to support the development of a marginal COSS. In addition, the Board notes that marginal COSSs are rare in other jurisdictions.

The Board found that allocating on Winter Coincident Peak and unweighted energy, as it directed, means the COSS methodology no longer includes marginal cost considerations in the allocation of Generation costs.

Further, the Board went on to find that marginal cost considerations are more appropriately addressed in the rate design stage of ratemaking and not the COSS stage. The Board found that equity and efficiency are ratemaking goals that should be addressed in a rate-setting process such as a GRA.

While the PUB has directed that marginal cost concepts are not to be reflected in COS methodology, the PUB clearly found that marginal cost is an appropriate ratemaking objective to be considered in rate design.

It is important to note that many of the issues that led to MH's conclusion that its COSS had not provided appropriate and realistic cost recognition for domestic classes in prior years, continue to exist today. The substantial export revenue to which Manitoba Hydro is earning today, and its incorporation into a cost-of-service study that is allocated on a traditional basis of the assets that give rise to the revenue, results in the mixing of marginal and embedded cost. This occurs

[33] Order 164/16, page 53

because of the receipt of export revenue based on marginal costs that arise from an external competitive wholesale market to which MH participates, is incorporated in MH's embedded COSS. In other words, the cost standard used in MH's COS is not purely based on embedded costs, but one that also must deal with marginal costs by virtue of export revenue.

Table 12 above directionally indicates that while most classes embedded revenues/rates are above their marginal cost, except for the GSL>100kv class, which is suggestive that most classes' embedded rates are no longer economically unsound, what continues to exist is the extreme variability between customer classes.

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.

PCOSS24 includes Net Export Revenue of approximately $1.1 billion. There are several important points to raise regarding this level of NER. First, NER of $1.1 billion is offsetting nearly 40% of total revenue requirement of approximately $3.0 billion[34].

Secondly, NER is offsetting 94% of total generation and transmission investment, almost offsetting <u>the entire</u> annualized generation and transmission investment cost in PCOSS24, of approximately $1.2 billion[35], 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%

[34] PCOSS24, Schedule A1
[35]PCOSS24, Schedule A3, Functional Breakdown, $1.09 billion + $152 million

of total generation and transmission investment. The magnitude of this issue has doubled compared to past cost of service results on this basis.

Secondly, as shown in the Table below, NER is sufficient enough to offset nearly 50% of the GSL>100kV class's total cost. On the other hand, the Residential class's offset of cost is still sizable at approximately 35%, but significantly lesser than that of the GSL>100kV class. This is, by order of magnitude, equivalent to the circumstances of the cost-of-service results to which MH expressed significant concern about their reliability in past years.

	Total Allocated Cost	NER	Total Offset PCOSS24
Residential	1352.4	471.2	35%
GSS ND	298.7	106.9	36%
GSS D	234.9	86.9	37%
GSM	378.9	144.0	38%
GSL 0-30	214.8	87.2	41%
GSL 30-100	177.5	82.3	46%
GSL>100	282.0	134.8	48%
ARL	27.6	3.0	11%

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[36]. Class RCCs before NER range from 59% - 97% and with NER range from 94% - 113%.

[36] Evidence of Kelly Derksen, Table 13, page 45

	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.

MH has not considered either the extreme variability in marginal cost by class in it rate differentiation proposals, and the distorted RCCs resulting from very high levels of NER. The mechanistic adherence to the results of PCOSS24 ignores these concerns of fairness and efficiency to the detriment of the Residential class and conflicts with the Board's direction flowing from Order 164/16. In fact, despite the distortions to RCCs, MH proposes rate differentiation of nearly 1% greater for the Residential class than the GSL>100kV class.

These are the outcomes that sole reliance on the output of a COSS fails to address. In her evidence, Ms. Derksen identified the mechanistic reliance that MH placed on the results of PCOSS24 for purposes of both its rate differentiation proposals as inconsistent with past PUB direction and disadvantageous to residential customers.

Ms. Derksen is not suggesting the use of Table 12 mechanically in establishing rates. To do that would require a much larger overall revenue increase and is not necessary to meet the reasonable and prudent costs of MH. Ms. Derksen suggests that one tool available to the PUB to assess the output of PCOSS24 is the use of marginal cost by class that directionally supports no class rate differentiation, and perhaps even a greater than average rate increase for the GSL>100kV class to correct for the fact that their embedded cost continues to be below marginal cost. The use of this marginal cost by class as an indicator certainly would not suggest lower than average rate increases for the GSL>100kV class.

While regulators generally begin any determination of fairness through embedded cost of service studies which aims at assigning costs to the parties that have caused them to be incurred, fairness and economic efficiency appropriately considers more than just embedded cost to serve and in particular in Manitoba Hydro's circumstances, marginal cost has a significant impact to COS and rates. It is inappropriate to ignore these considerations in favour of blind adherence to the results of the COSS, particularly when considerations other than traditional embedded cost causation have been stripped from COS methodology. The results of MH's COSS should be seen as a tool used in the setting of fair, just and reasonable rates. They are not, in and of themselves, fair, just or reasonable, as the Board found in Order 164/16.

c) Without time consuming investigation, it is not possible to respond robustly to the question. Ms. Derksen is aware that Elenchus proposed the use of a M:C ratio as a reasonable alternative to the R:C ratio as a basis for determining justifying rate rebalancing as part of the FEI 2018 Rate Design Application.

Further, marginal cost-based allocation of embedded costs and variants of this approach have been in use for many years in a number of regulatory jurisdictions in West coast U.S. utilities. Marginal cost of service as the direct basis of rate determination occurs at Nova Scotia Power, a vertically integrated electric utility, as part of its Annually Adjusted Rates. The use of marginal costs for purposes of rate determinations is also used by Manitoba Hydro as part of establishing SEP rates.

Newfoundland Labrador Hydro has also prepared a marginal cost of service for explicit rate determination given the addition of the Muskrat Falls Generating Station, although based on stakeholder agreement, its explicit use has been deferred pending further analysis.

As a matter of principle, it is generally accepted that it is economically appropriate to use a marginal COS study to either directly set rates based upon study results (with a reconciliation to ensure that rates are sufficient to recover embedded costs) or to use as a component within the embedded COS study, like the weighted energy allocator used by MH for purposes of allocating generating cost. This is because rates based upon marginal costs provide good economic price signals for consumers and producers to encourage the efficient use of scarce resources. In addition to the findings of the Board in Order 164/16, there are challenges with marginal cost of service, particularly as it relates to the agreement of appropriate methodology suitable for the electric utility.

That said, concepts of marginal cost, like the consideration of marginal cost based RCC's can be a useful tool in assessing the output of an embedded COS, particularly where there is a significant influence of marginal cost, through the allocation of NER, on class RCCs.

Marginal cost is a permanent feature of MH's COSS, by virtue of NER which brings in marginally based revenue into an embedded cost-based COSS. Based on this fact alone, marginal cost and its influence on the results of COS, rate differentiation and rates cannot and should not be ignored.

d) From a theoretical economic perspective, the fact that embedded cost for most classes is no longer below short-run marginal cost as directionally indicated in Table 12, current rates, but for GSL>100kV, are no longer violating the basic economic tenet of pricing too low.

Ms. Derksen is not proposing marginal cost-based rates or a marginal cost of service study. As discussed in the above responses, while the GSL>100kV class is currently the only class that continues to be below marginal cost and may support an above average rate increase, the most important conclusion in the table to observe is the extreme variability in marginal cost by class, as well as the significant volatility resulting from the recent addition of large-scale generation and transmission investment. Further, significant NER revenue (revenue based on marginal cost generated in the export market) continues to distort class RCCs. As discussed above, marginal costs have a permanent significant influence on MH's COS, class RCCs and rate design and cannot be ignored in the setting of class revenue requirements or rates.

e) Table 12, as it pertains to the MH 2017/18 GRA is not aligned with MH Exhibit 101 from that proceeding. As Mr. Harper asserted in his Evidence filed as part of MH's 2017/18 GRA[37], Manitoba Hydro filed information comparing the marginal costs to serve each customer class with the class' average revenue. However, during the interrogatory process parties identified a number of issues with marginal costs values used including: i) the way losses were incorporated and ii) the assumption of a 100% load factor for each class which ignores the differences in annual load profiles across customer classes (e.g. peak vs. off-peak, seasonality and load factor). Mr. Harper went on to attempt to address some of these issues by varying the loss factor applied to each customer class.

Mr. Harper's marginal cost by class and marginal cost RCC attempts to correct for some of the shortcomings of MH Exhibit 101 from the 2017/18 GRA.

Ms. Derksen does not have access to the marginal cost information and other data relied upon to update the marginal cost information filed in MH Exhibit 101, which is only available from Manitoba Hydro. However, Ms. Derksen is not relying on nor is she proposing the PUB rely on the numeric output of the marginal cost analysis precisely but identifies it as one directional indicator that the GSL>100kV class may require an above average rate increase as opposed to the below average rate increase as proposed by MH. In isolation of other factors proposed by Ms. Derksen, the marginal cost by class output comports with an across-the-board rate increase, but for GSL>100kV, as she recommends.

f) The marginal cost information reflected in MH Exhibit 101 would directionally suggest that above average rate increases are required for the GSL classes (and conversely lower than average rate increases for the remaining classes, including the Residential class). With the addition of Keeyask, MMTP, GLTL, and Bipole III, it is unlikely that MH Exhibit 101 is reliable.

g) Please see the responses to parts b), c) and d) above.

[37] MH 2017/18 GRA, Coalition Exhibit CC-20

h) Revenue per Table 12 is impacted by the method of allocation of NER in numerous ways as revenue is a result of COS, its methodology, rate differentiation and historical rate and COS changes. The table below demonstrates how RCC's can oscillate and can be highly volatile. Many, not all, of these RCC's have influenced, either explicitly, or implicitly, MH's revenue request increases by class and are a factor in arriving at current rates.

	PCOSS99	PCOSS01	PCOSS02	PCOSS03	PCOSS04	PCOSS06	PCOSS06	PCOSS08	PCOSS10	PCOSS11	PCOSS13	PCOSS14	PCOSS14	PCOSS14	PCOSS18	PCOSS18	PCOSS18 Order 59/18	PCOSS21	PCOSS24	PCOSS24	PCOSS24	PCOSS24	PCOSS24	PCOSS24	PCOSS24
					Jan 2004	Recommend	117/06	116/08	Nov 2009		meth changes July 2012	June 2013	June 2013 & Bipole III	Order 164/16	As Filed (excl rate inc)	Incl 7.9%	(NER offset cost)	PUB MFR 20 (As filed)	As Filed Dec 2022	As Filed w. Proposed	As Filed w. Proposed Rate Change	2023/24 w. Avg Water fm	70% of 2023/24 NER	60% of 2023/24 NER	50% of 2023/24 NER
	2017/18 GRA Tab 8 App 8.1	2017/18 GRA Tab 8 App 8.1	2017/18 GRA Tab 8 App 8.1	2017/18 GRA Tab 8 App 8.1	COS Review PUB I-15	COS Review PUB I-15	COS Review PUB I-15	COS Review PUB I-15	COS Review PUB I-15	2017/18 GRA Tab 8 App	COS Review PUB I-15	COS Review PUB I-15	COS PPT Oct 30 pg.46	PUB 132 c (2017/18 GRA)	PUB 132 c (2017/18 GRA)	PUB 132 a (2017/18	Order 59/18 Page 197	RCC	RCC	RCC	2024/25 RCC	PUB 141	CC 155	CC 155	CC 155
Residential	92.1	90.7	96.5	92.4	90.6	97.0	94.1	96.2	96.4	95.9	99.2	98.6	101.5	95.5	94.8	95.1	93.5	96.2	94.4	94.8	95.3	94.8	95.2	95.5	95.8
GSS ND	106.9	104.4	109.4	107.3	104.9	107.4	107.4	101.4	105.7	104.8	107.6	107.7	110.9	108.5	112.5	112.7	115.7	113.8	109.7	108.7	107.8	110	110.3	110.5	110.7
GSS D	107.7	105.4	104.7	108.4	109.7	105.4	106.9	107.8	102.8	103.8	103.7	104.9	104.7	103.4	101	100.9	101.3	104	101.8	102.0	102.1	102.1	102.2	102.4	102.5
GSM	105.5	109.4	104.4	102.9	104.8	100.6	101.4	100.2	101.3	101.1	100	100	98.3	100.3	98.3	98	97.8	99.3	100.3	100.3	100.4	100.3	100.3	100.3	100.4
GSL 0-30	101.4	102.6	96.8	93.4	99.9	90.1	91.3	89.9	92.3	91.9	93.3	91.9	89	96.1	99.1	98.7	98.7	95.6	97.9	97.9	97.8	97.4	97.0	96.7	96.4
GSL 30-100	110.3	118.8	109.4	108.8	109.5	101.5	104.7	108.4	106.8	104.2	96.6	101.7	96.2	108	109.3	109.0	113	103.7	112.4	111.3	110.3	110.2	108.4	107.1	105.9
GSL>100	109.5	115.9	99.8	113.5	114.2	103.2	110	112	109.2	112.6	100.5	101	93.6	107.1	108.6	108.1	112.3	101.2	113.2	112.1	110.9	110.5	108.4	106.8	105.3
ARL	93.4	92.0	101.9	109.9	108.9	107.1	107.7	102.4	100.0	105.2	101.8	99.7	120.0	99.5	100.3	101.2	100.3	123.3	108.2	108.2	108.1	112.0	115.3	117.9	120.6

i) and j) If the purpose of the marginal cost derivation as reflected in Table 12 were to be the basis of specific rate determinations for billing purposes, it is not likely these calculations would be viewed as robust enough for that purpose. However, for the stated purpose, which is to provide an additional lens by which to evaluate the RCCs based on the output of PCOSS24, these marginal cost calculations, are not greatly inaccurate, and provide a reasonable directional indication for the intended purpose.

PUB/COALITION I-17 Reference: Derksen Evidence p.47
A&RL RCC Ratios

Preamble:

In her evidence on page 47, Ms. Derksen provides a synopsis of MH's evidence:

- PCOSS18 was prepared consistent with the DSM methodology as directed in Order 164/16. However, during the 2019/20 GRA, the PUB elected to not apply a differentiated rate increase to the A&RL class, noting concerns raised by the Consumer Coalition about possible distortion of the class RCC ratio due to the directed treatment of DSM costs.

In her evidence on page 48, Ms. Derksen states:

> Based upon an historical review of the ARL RCCs, it does not appear that the cost to serve this class was concerningly impacted by the change in COS methodology flowing from Order 164/16. The ARL RCCs certainly do not support this conclusion. It is plausible that the impact of the change in COS methodology to the ARL may have been more discernable in the absence of the significant addition of generation and transmission investment and high levels of export revenue. <u>Thus, the overall issue that MH is proposing to address, does not appear to be an issue.</u> [emphasis added]

In her evidence on page 49, Ms. Derksen states:

> 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.
>
> As a result of the ongoing concerns regarding the adequacy of the allocation of generation and transmission to the ARL class, it is reasonable that an across-the-board rate increase be applied to the ARL class.

Request:

a) Please provide a summary of Ms. Derksen's concerns with respect to possible distortion of RCC ratios due to the treatment of DSM costs.

b) Please explain whether Ms. Derksen has the same concerns with PCOSS24 and its RCC ratios as identified in (a).

c) Please clarify what Ms. Derksen sees as the overall issue that MH is proposing to address, as identified in the underlined portion of the quote from page 48 of her evidence.

d) Does Ms. Derksen disagree with MH's proposed direct assignment of DSM costs for LED roadway project to the Area & Roadway Lighting class? If so, please explain the basis for the disagreement.

e) Does Ms. Derksen consider MH's approach to directly assigning costs proportional to the operating and maintenance cost savings from the LED Roadway Lighting Upgrade to be cost causal? If not, please explain.

f) Please identify the parties that have expressed "ongoing concerns regarding the adequacy of the allocation of generation and transmission to the ARL class" and where and when those concerns have been expressed.

Response:

a) As part of MH's 2019 Rate Application, Ms. Derksen expressed concern regarding the RCCs of the ARL class and recommended that any rate increase granted to MH flowing from that Application be applied on an across-the-board basis including to the ARL Class. Ms. Derksen concluded that there had been a sizable imperceptible benefit distorting the ARL RCC because of the change in the cost-of-service methodology related to DSM which was previously allocated on the basis on class participation (the class that benefits from the program spending is charged with the costs of the program). Order 164/16 directed that DSM be viewed as a system resource and functionalized 100% to generation. While Ms. Derksen viewed this as a reasonable methodology change, one of the many judgments inherent in cost-of-service methodology, there was expectation that the impact of this COS methodology change was likely to benefit the ARL Class to a large degree based on a prior similar occurrence in the mid-1990's given that MH was in the process of incurring a large investment to convert streetlighting to LED that began around 2014.

During the mid-1990s, most of MH's DSM investment was in the HPS lighting program.

The ARL class was obtaining the majority of the benefits but would have paid a minuscule portion of the cost as part of the then allocation methodology of allocating DSM costs on the basis of generation, transmission and distribution ("G,T,D"). Eventually MH elected to allocate DSM costs based on participation for reasons of fairness as a result of the conversion to HPS and because those who benefited from the DSM programs could be reasonably identified.

However, upon further review of the RCCs of the ARL class in this Application, as a result of the rate differentiation proposals by MH coupled with MH's proposed target RCC for the ARL class of 108%, there are some surprising and unexplained results as shown in the table below:

	PCOSS01	PCOSS04	PCOSS06	PCOSS08	PCOSS13	PCOSS14	PCOSS14	PCOSS14	PCOSS18	PCOSS18	PCOSS18	PCOSS18 2019/20 GRA	PCOSS21	PCOSS24	PCOSS24	PCOSS24	PCOSS24	PCOSS24
		Jan 2004	117/06	116/08	meth changes July 2012	June 2013	incl. Bipole III	Order 164/16	Incl 7.9%	Order 59/18	Incl 7.9% & Bipole III	Incl. Bipole	As Filed	As Filed	As Filed w. Proposed Rate Change	2023/24 w. Avg Water fm 2024/25	70% of 2023/24 NER	50% of 2023/24 NER
	2017/18 GRA App 8.1	COS Review PUB I-15	COS Review PUB I-15	COS Review PUB I-15	COS Review PUB I-15	COS Review PUB I-15	COS Review PUB I-55	PUB 132 c & Tab 8	PUB 132 c & Tab 8	PUB 61 a	PUB II-88 (2017/18 GRA)	PUB 61 a	MFR 20		2024/25 RCC	PUB 141	CC 155	CC 155
ARL	92.0	108.9	107.7	102.4	101.8	99.7	114.1	99.5	101.2	100.1	118.2	118.7	123.3	108.2	108.1	112.0	115.3	120.6

The observations are as follows:

1. Between PCOSS01 and PCOSS04, there is a significant shift in the ARL RCC of nearly 17%, from 92% to 109%. It is possible that some of this RCC change may be explained by the incorporation of Winnipeg Hydro into MH COS. It may also result from the sizable distortion occurring from export revenue at the time;

2. Between PCOSS14 and PCOSS18, the ARL RCC moves only slightly from 99.7% to 101.1%, which presumably included the impacts associated with the change in DSM methodology as well as the incorporation of LED streetlighting costs;

3. PCOSS14 includes a scenario to assess the impacts to RCC resulting from the addition of Bipole III. The ARL RCC impact is significant increasing nearly 15% from 99% - 114%;

4. Order 59/18 resulted in an RCC of approximately 100% for the ARL. Once again, a PCOSS18 scenario including the addition of Bipole III resulted in an over 18% increase in RCC to the ARL Class;

5. PCOSS21 results in increase in RCC of over 23% compared to PCOSS18. PCOSS21 would have included the addition of Bipole III, all or part of MMTP and GLTL and part of Keeyask; and

6. PCOSS24 under different NER scenarios appears to have a significant impact on ARL RCC of over 12%, from 108% to 121%.

On this basis, it does not appear that the COS methodology change associated with DSM, and the investment in LED streetlighting was particularly impactful on the RCC of the ARL class, contrary to that expected and experienced by MH in the mid-1990’s.

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.

MH provides no analysis of this circumstance. MH’s response is to continue to view that the DSM methodology change is the driver of the ARL RCC changes and propose a treatment to assign more maintenance cost to the class and targeting an RCC of 108%.

Ms. Derksen is not convinced of the wisdom of targeting an RCC of 108% for this class or targeting a revenue to cost ratio for any class. MH’s proposal to target 108% for the ARL class imputes an absolute standard of correctness regarding revenue to cost ratios which is misplaced for several reasons:

1. Cost, especially regarding joint use facilities, is not a precise concept. The notion of "true cost" is misleading. The extensive generation and transmission assets, as well as export revenue results in even less precision.

2. Even for a given allocation methodology, there can be considerable variation in determining costs due to judgment and the various other refinements that can be used.

Further, MH's proposal to target 108% assumes that the issue is really driven by the change in DSM methodology coupled with the investment in LED streetlights. Based on the above RCC review of the ARL class, it is unlikely this is an issue, at least not one materially concerning, contrary to Ms. Derksen's evidence filed as part of the 2019 Rate Application.

What really appears to be the issue is the avoidance of generation and transmission cost responsibility for the ARL class, perhaps because of the load research/forecasting methodology of this 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.

On this basis, Ms. Derksen concludes that MH's lower than average rate differentiation proposal should not be adopted by the PUB. These outcomes require exploration by MH before any rate differentiation lower than average is justifiable.

b) Please see the response to a).

c) Please see the response to part a) above.

Ms. Derksen's evidence states that the overall issue that MH is proposing to address, does not appear to be a material issue. The issue that MH is proposing to address is the unfairness associated with the change in DSM COS methodology that does not result in an appropriate allocation of the DSM LED streetlighting investment to the ARL class. Based on a review of the RCCs of the ARL class, this does not appear to be a material issue of concern. The material issue of concern is that the significant addition of generation and transmission investment that has doubled the MH's rate base results in a dramatic increase in the RCC (PCOSS21 RCC of over 123%) to the ARL class, and significantly lower than average rate differential. Further, the reduction in NER anticipated by MH is expected to further increase the class's RCCs. This result is both perverse and unreasonable.

d) Yes. Please see the response to part a) above.

e) Principally speaking, this does not appear to be unreasonable. However, as discussed in part a) above, this does not address the material issue of concern, and a temporary fix as with forecasted reductions in NER over the next several years, the RCC of the ARL will once again increase to over 115%.

f) Please see the response to part a) above.

PUB/COALITION I-18 Reference: Derksen Evidence p.50
Allocations to GSL and A&RL Classes

Preamble:

In her evidence on page 50, Ms. Derksen states:

> There have been further fundament shifts in Manitoba Hydro's operations impacting class cost to serve including:
>
> i. The significant addition of generation and transmission investment flowing from the additions of Bipole III, GNGT, MMTP, and Keeyask;
>
> ii. Record levels of NER underpinning PCOSS24 which have an asymmetric benefit to some customer classes, notably the largest GSL classes and ARL; and
>
> iii. A significant reduction in Water Rental Fees and the PGF payments to the Manitoba Government, which have an asymmetric benefit to some customer classes, notably the largest GSL classes and ARL;
>
> These changes profoundly impact cost of service, not only because of the sheer magnitude of the changes, but as a result of all changes impacting generation and transmission. While the result is overall significant increases in the class cost to serve. At the same time, <u>the large increase in Net Income, NER, and the reduction in fees to government disproportionately benefit the largest GSL classes and ARL class</u>. [emphasis added]

Request:

a) Please confirm whether GSL classes benefiting disproportionally from the reduction in government fees means that those classes were and are disproportionally paying those fees. If not confirmed, please explain why not.

b) Considering net income is allocated on the basis of total costs, please explain why the large increase in net income disproportionally benefits the GSL and A&RL classes.

Response:

a) 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 words, despite a nearly <u>$180 million reduction</u> in Water Rental and PGF costs, the Residential class' RCC declines and their rates would have to <u>increase,</u> all else equal. Surely, the sizable reduction in payments to government shouldn't result in Residential customers having to pay more.

Similarly, with the significant addition of generation and transmission investment resulting from Bipole III, MMTP, GTGL and Keeyask, that has doubled the balance sheet of MH, one would expect to see a sizable decline in the RCCs of the largest GSL classes and a corresponding increase in the RCC of the Residential class. This has not occurred, and there has been no explanation provided. In fact, there has been a shift of G&T cost away from the largest GSL classes.

There are numerous counter-intuitive, perhaps perverse outcomes flowing from PCOSS24, similar to these that make it very difficult to accept the results of PCOSS24 at face value.

b) Net Income is considered a cost in cost of service and is allocated on the basis of MH's rate base (total investment) to each class. The impact of an increase in net income to each class will depend on what is driving the increased net income.

In the case where an increase in net income is driven by a corresponding decrease in generation cost (in order to produce the same overall revenue), a decrease in generation cost will result in a reduction in generation cost allocation to certain classes more greatly, like the GSL classes, and disbenefit other classes, like the Residential class. At the same time, all else equal, the lower generation cost will change the mix of functional costs such that those who are allocated all functional costs (G,T & D) will be increased an greater portion of net income.

PUB/COALITION I-19 Reference: Derksen Evidence p.51
Allocations to GSL and A&RL Classes

Preamble:

In her evidence on page 51, Ms. Derksen states:

> MH has also failed to address the spirit of Order 164/16, which moves all ratemaking objectives to the Rate Design phase as part of a GRA, whereby consideration is given to costs and factors other than the purely mechanistic output of the PCOSS. The result is that MH's rate differentiation proposals are based purely on the mechanistic output of PCOSS24, with consideration given to length of time (i.e. gradualism) by which to reflect the output, which conflicts with the intent of the Board's Order 164/16.

Request:

Please elaborate why MH's rate differentiation proposals, which propose to move classes into the zone of reasonableness within a period of five years, conflict with the intent of Order 164/16.

Response:

As discussed in the evidence of Ms. Derksen, the PUB has repeatedly expressed, and reaffirmed as recent as in Order 109/22, flowing from the Centra Cost of Service Methodology Review that:

> "The Board finds that the principle of cost causation remains paramount in establishing a cost-of-service methodology. Rate design matters should not be considered at the cost-of-service stage. They are matters for a general rate application. The Board's approach in this order is consistent with the approach outlined in Order 164/16.

> A cost-of-service study is just one factor the Board may consider in a rate hearing. It is informative, but it is not determinative. Equity and fairness considerations, as well as the public interest, are important considerations in a rate hearing and the Board also takes them into account in setting just and reasonable rates." (Emphasis Added) (**Order 109/22, page 33)**

Based upon a review of Orders 164/16, 59/18, and 69/18, there are numerous findings of the Board that cost causation is of paramount concern in the establishment of cost allocation methodologies. The Board has found in these Orders that cost causation as established through cost allocation methodology and the results of a cost-of-service study are but one factor in arriving at rates that are in the public interest.

The result of these Board findings is that the mechanistic output of a cost-of-service study that only considers embedded cost causation and not other considerations of fairness and equity, economic efficiency, rate stability, and public acceptability, is not reliable as the only basis of setting rates deemed to be in the public interest. A few of the excerpts of the Board are as follows:

- The Board accepts and applies the principle of cost causation in establishing the appropriate method of allocating financial cost…other ratemaking principles for setting just and reasonable rates should be considered in a GRA, and not a cost-of-service process. A COSS neither determines nor changes rates, but may assist in rate setting and in evaluating whether customer classes pay their appropriate share of costs through rates. A COSS together with the proposed revenue requirement, rate design, and other pertinent information, forms the background supporting rate setting. (Order 164/16, page 6)

- The Board finds that ratemaking principles of rate stability and gradualism, fairness and equity, efficiency, simplicity, and competitiveness of rates should be considered in a GRA and not in the cost-of-service methodology. While ratemaking principles are important in the overall process of setting rates, these concepts are issues for rate design. (Order 164/16, page 27)

- The Board's view is that the Uniform Rates Adjustment is a matter of policy and that the costs of the URA are caused by policy…any impacts of the Board's COSS treatment of uniform rates on RCC ratios are a matter for consideration in rate design, not cost of service. (Order 164/16, page 41)

- The Board finds that marginal cost considerations are more appropriately addressed in the rate design and not COSS….Equity and efficiency are ratemaking goals that should be addressed in a rate-setting process such as a GRA. (Order 164/16, page 53)

- There is no basis in the legislation to support the argument that the Board is required to focus on pure cost causation in approving a fair rate, or that a particular tool or methodology, notably the COSS, must be used in order to fairly allocate costs amongst customer classes….there is no requirement for the PUB to rely on a COSS to fix a just and reasonable rate, and that such a study is but one of the elements that the PUB could or could not rely upon in arriving at its order. (Order 164/16, page 16)

- The objective in designing a COSS is to select a cost allocation method for sharing costs. A COSS neither determines nor changes rates but may assist in rate setting by evaluating whether customer classes pay their appropriate share of costs through rates." (Order 164/16, page 18)

- The Board determines that the creation of the Export class was based on ratemaking goals and not cost of service principles….the 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. (Order 164/16, page 33)

- The Board finds that there is no cost of service reason to credit export revenue including Subtransmission, Distribution, and Customer Service….crediting export revenue on total costs is based on Manitoba Hydro's approach of integrating ratemaking goals into the COSS….ss the Board has stated above, <u>those goals are to be considered at the final ratemaking stage</u>. (Order 164/16, page 37)

- The Board finds that the assets in the Diesel zone are not causally linked to the realization of export revenues. Therefore, there is no cost causation basis for the crediting any export revenues to the Diesel class. As previously noted, <u>any resulting need to make adjustments to rates should be raised in a rate-setting process</u>. (Order 164/16, page 41)

- The Board rejects the equivalent peaker methodology as too complex…and directs the use of the system load factor because it is straight-forward and generally accepted in the industry. (Order 164/16, page 48)

- Manitoba Hydro's COS methodology was extensively reviewed that led to Order 164/16. The Cost-of-Service Study and the resultant <u>Revenue to Cost</u> Coverage ratios are <u>tools available to be used by the Board</u>. (Order 59/18, page 24)

- While <u>rate-making principles may justify accepting</u> Revenue to Cost Coverage ratios that are <u>outside of the zone</u>, those principles do not support broadening the zone itself. (Order 59/18, page 197)

- While the <u>cost of service should not</u> necessarily be the <u>overriding factor</u> in designing rates, it is consistent with the ratemaking principle of fairness to consider the output of the Cost-of-Service Study. (Order 59/18, page 198)

These are a few of many of the Board's findings flowing from Order 164/16 and since the issuance of that Order, that make it abundantly clear that the Board's intention was to consider the results of the COS as only one factor in determining revenue by class and rates. Stated differently, the reliance on the mechanical output of the COS, as Manitoba Hydro's rate differentiation proposal does, neglects other considerations of fairness and equity such as the treatment of the disproportional benefit of export revenue to some classes (GSL, ARL), the Uniform Rates Adjustment, and marginal cost considerations that the Board found would be considered in the rate design phase as part of a GRA.

PUB/COALITION I-20 Reference: Derksen Evidence pp. 53, 54; Order 137/21
Normalized Net Export Revenues

Preamble:

In her evidence on pages 53 and 54, Ms. Derksen provides Tables 16 and 17:

Table 16[39]:

	PCOSS24	Test Year 2024/25	In 5 Years - 2028/29
	($ millions)	($ millions)	
Export Revenue	1154.1	963.6	740.0
Less: Water Rentals	31.1	25.5	19.6
Less: Variable O&M	6.8	5.7	4.4
Less: Affordable Energy Fund	0	0	0
Net Export Revenue	**1,116.2**	**932.4**	**716.0**

Table 17:

		Avg. Water	NER 60%
	PCOSS24	PCOSS24	PCOSS24
	As Filed (NER $1.1B)	Avg Water in 2024/25 (NER $933M)	RCC (NER $692M)
	PUB 141	PUB 141	CC 155
Residential	94.4%	94.8%	95.5%
GSS ND	109.7%	110.0%	110.5%
GSS D	101.8%	102.1%	102.4%
GSM	100.3%	100.3%	100.3%
GSL 0-30	97.9%	97.4%	96.7%
GSL 30-100	112.4%	110.2%	107.1%
GSL>100	113.2%	110.5%	106.8%
ARL	108.2%	112.0%	117.9%

Order 137/21 page 13 states:

> Manitoba Hydro is to continue to move customer classes whose revenue to cost coverage ratios are above the Zone of Reasonableness, previously determined by the Board to be between 95% and 105% of the cost of providing service, into the Zone. Accordingly, the general revenue increase is to be recovered through rate increases which are differentiated by customer class, with customer classes within or below the Zone of Reasonableness receiving higher rate increases.

Request:

a) Considering 2024/25 and 2028/29 are both based on average water flows, please confirm whether the water rentals and variable O&M for these years should be approximately the same. If confirmed, please explain whether this affects Ms. Derksen's analysis and conclusions.

b) Based on the PUB's previously stated intentions in Orders 59/18, 69/19, and 137/21 to move classes into the zone of reasonableness, please explain whether differentiated rates are still required to address the four classes that will remain outside the zone of reasonableness in 2028/29.

Response:

a) The question is unclear. In terms of whether O&M and water rentals will be approximately the same assuming the same average water flow conditions, it is not likely because, O&M, for example, has been 1) increasing sizably and 2) it is the nature of the cost changes in addition to the overall magnitude of the cost changes, that is impactful in COS. Given the hypothetical nature of the question, it is difficult to conclude on the potential materiality. Further, in the current circumstances with strict adherence to the output of the COSS, what was once not considered material may now be.

b) As Ms. Derksen's evidence states, and as discussed in response to PUB/Coalition IR I-6 above, the PUB's previously stated intentions in Order 59/18, 69/19 and 137/21 to move classes toward the zone of reasonableness was not unilateral or mechanistic without regard and consideration of other ratemaking objectives. The PUB found these additional objectives to be important considerations in the ultimate rate differentiation by class and rates, having removed such ratemaking objectives from the cost allocation methodology.

Relying solely on the results of PCOSS24, and implementing those results over a period of time other than one year (i.e. gradually) does not at all deal with other important ratemaking objectives such as economic efficiency (marginal cost considerations), the disproportionate benefits to some class' of allocating NER on the basis of generation and transmission investment (economic efficiency and fairness and equity) public acceptability, fairness in the apportionment of total costs and avoidance of undue discrimination.

Had the Board intended to only rely on the results of the COSS, it would have explicitly stated so. It did not. Establishing rates that are in the public interest must necessarily consider a multitude of objectives. The results of an embedded cost of service study that divorces all other ratemaking considerations other than fairness as defined by embedded cost, particularly given the nature of Manitoba Hydro's operations with significant joint generation and transmission investment, and net export revenue is placing a degree of reliance on a study that is inappropriate and conflicts with the intent of the Board through numerous including and subsequent to Order 164/16.

As Ms. Derksen proposes in her Evidence, rate differentiation by class, as proposed by MH is not advisable, perhaps with the exception of the GSS-ND class.

Please also see the response to AMC/Coalition I-3.

PUB/COALITION I-21 Reference: Derksen Evidence pp. 13, 57, 58

Preamble:

In her evidence on pages 57 and 58, Ms. Derksen states:

> The real issue is that the largest GSL class's RCC's have increased as a result of this anomalous record level of NER assumed in PCOSS24.
>
> …
>
> 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.
>
> While the issue is really a GSL class issue, not a Residential cost to serve issue, it appears both perverse and not fair or equitable that as a result of these issues, the Residential class is having to fund this situation.

In her evidence on page 13, Ms. Derksen states:

> It should also be noted that Cost Allocation is a "zero-sum game". This means that to the extent that costs are shifted away from one customer class resulting in lower rates for that class, those costs are picked up by other customer classes resulting in higher rates for those classes such that the utility's established revenue requirement is intact.

Request:

a) Please explain why GSL classes have "lower allocated net income". What is this allocated net income lower than?

b) Considering cost allocation is a “zero-sum game”, please explain how MH and the PUB can solve the “GSL class issue” without differentiated rate increases.

Response:

a) Lower allocated net income is intended to mean as a result of net income being allocated on total investment of generation, transmission and distribution rather than only on generation and transmission investment.

b) Ms. Derksen’s evidence is that once factors other than the mechanical output of the COSS are considered, there is no need in this Application for differentiated rate increases sizably lesser for these classes and given that the circumstance regarding NER is expected to largely self correct. In fact, there is a reasonable argument to be made that the GSL>100kv class requires a greater than average increase in order to ensure their rates are not below short run marginal cost, as discussed in response to PUB/Coalition IR I-3.

PUB/COALITION I-22 Reference: Derksen Evidence p.49 ; Appendix 8.3

Preamble:

At page 49 of her evidence, Ms. Derksen states:

> 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.
>
> 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.
>
> As a result of the ongoing concerns regarding the adequacy of the allocation of generation and transmission to the ARL class, it is reasonable that an across-the-board rate increase be applied to the ARL class.

Request:

Please explain whether Ms. Derksen's proposed across-the-board rate increase for the Area & Roadway (A&RL) class also extends to MH's sub-differentiation proposed to A&RL rates based on LCOSS24.

Response:

Ms. Derksen has not sufficiently studied MH's LCOSS24. Given Ms. Derksen's expressed concerns over the level of cost attribution to the ARL and resulting class RCC as discussed in her evidence and also in response to PUB/Coalition IR I-4, so long as there are no direct or unintended consequences of MH's sub-differentiation proposal to other class RCCs or rate differentiation, in particular, to the Residential class, Ms. Derksen's across-the-board increase proposal for the ARL class applies to the class as a whole.

PUB/COALITION I-23 Reference: MPA Evidence

Request:

Please file the engagement/retainer letter for the scope of services provided.

Response:

The retainer letter has been attached as Attachment 1 to this IR Response.

PUBLIC INTEREST LAW CENTRE | CENTRE JURIDIQUE D'INTÉRÊT PUBLIC

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January 30, 2023

Mr. Pelino Colaiacovo
Morrison Park Advisors
9 Temperance Street, Suite 300
Toronto, ON M5H 1Y6

Sent via email: pcolaiacovo@morrisonpark.com

Dear Mr. Colaiacovo:

Re: Manitoba Hydro 2023/24 & 2024/25 General Rate Application

I am writing on behalf of the Manitoba Branch of the Consumers' Association of Canada (CAC Manitoba), the Aboriginal Council of Winnipeg, and Harvest Manitoba to retain you for services in support of their joint intervention as the "Consumers Coalition" in the Manitoba Hydro 2023/24 & 2024/25 General Rate Application (GRA) before the Manitoba Public Utilities Board (PUB).

Background

Manitoba Hydro filed a GRA on November 15, 2022 seeking confirmation of the January 1, 2022 3.6% interim rate increase and 3.5% rate increases effective September 1, 2023 and April 1, 2024. Following the government of Manitoba's announcement of reductions to Manitoba Hydro's water rental and debt guarantee fees, the corporation reduced its requested rate increases for 2023 and 2024 to 2.0%.

Our clients have long represented the interests of Manitoba Hydro's residential customer class in regulatory proceedings before the PUB. Their application to intervene in this proceeding was approved in the Board's December 8, 2022 Procedural Order.

The Consumers Coalition intends to vigorously test all evidence put forward by Manitoba Hydro in support of its rate application.

Scope of Work

By this letter, we retain you on behalf of the Consumers Coalition for support of its Intervention in the Manitoba Hydro 2023/24 and 2024/25 GRA. Based on your experience and expertise, your work will involve a critical analysis of Manitoba Hydro's justification for its proposed rate changes, including on the basis of the corporation's assertions of financial strength, anticipated investment in capital assets, and financial risk mitigation. In particular, we anticipate your participation will focus on the following:

- Manitoba Hydro's financial targets, including the appropriateness of its selected metrics of financial health and the relevance of these matters to the corporation's access to and cost of capital; and
- The implications of legislated Debt-to-Equity ratios on Manitoba Hydro's customers, its proposed rate trajectory and its capacity to respond to future electrification including of transportation and heating.

We note that other consultants retained by the Consumers Coalition will also be assessing aspects of Manitoba Hydro's application relating to its financial circumstances and forecasting, which may overlap with your areas of focus identified above. To maximize use of complementary skill sets while minimizing duplication of efforts, we ask that you please maintain close contact with us as legal counsel as well as with other consultants throughout your work. This will become particularly important later in the process after the completion of first round information requests.

Your Tasks

In relation to the topics identified above, you will provide the following:

- Draft First Round Information Requests;
- Draft Second Round Information Requests following review of Manitoba Hydro's responses to First Round Information Requests;
- Preparation of a case theory memo identifying and explaining your views on priority issues within your areas of focus for the Consumers Coalition;
- Preparation of independent expert evidence and appearance at the hearing as an independent expert witness; and
- Support for legal counsel and our clients in preparing for and participating in the hearing, including through participation in briefing meetings and preparation of briefing notes upon request.

Any amendments to the tasks or scope of work described above must be agreed to in writing.

Please also note that deadlines for the above tasks will be determined by agreement on an ongoing basis. However, for your information, we direct your attention to the approved hearing timetable found at Appendix A to PUB Order 130/22 for detailed information about the PUB's deadlines.

Duty to the Public Utilities Board

Is it your duty to provide evidence that:

- is fair, objective and non-partisan;
- is related only to matters that are within your area of expertise; and
- to provide such additional assistance as the Public Utilities Board may reasonably require to determine an issue.

Financial Terms

We estimate that the work described above will require no more than 15 days of your time at a rate of $6000 per day for a total of $90,000.00. This amount cannot be exceeded without written authorization. In the event you anticipate being unable to complete the work described above within this time estimate, we ask that you please bring this to our attention with as much notice as possible.

We propose to pay 25% of the total estimated value of this agreement on receipt of a signed copy of this retainer agreement. We propose to pay an additional 25% following the filing of independent expert evidence. Following the conclusion of the hearing, we propose to pay the difference between all amounts paid to date and 75% of the total value of this agreement. All remaining amounts will then be payable contingent on a successful application for final costs by the Consumers Coalition.

Invoices and Reporting

We will require invoices accompanied by detailed time sheets itemizing the date, a brief description of the task, and the number of hours spent (rounded to one decimal place) for each task undertaken. As you may know, PILC is GST exempt (#R107863847).

Conclusion

If you find the terms of this retainer acceptable, please sign and return to my attention one copy of this letter. We recommend that you also retain a copy for your own records.

Thank you,

Byron Williams
Director

I accept the terms of this retainer this 1st day of February, 2023.

Pelino Colaiacovo*
*I am authorized to bind Morrison Park Advisors Inc.

100-287 Broadway, Winnipeg, Manitoba, R3C 0R9
tel 204.985.8540 fax 204.985.8544
e-mail centre@pilc.mb.ca

PUB/COALITION I-24 Reference: MPA Evidence p.7
Cost of Debt Versus Equity

Preamble:

At p. 7 of its evidence, MPA states:

> Manitoba Hydro has provided revised financial forecasts for the 2023/24 and 2024/25 fiscal years, and has estimated that the change in provincial policy will result in combined savings for the utility of approximately $380 million based on the "average" hydro-electric production scenario used in the preparation of the forecast). Based on the same forecast, the combined savings to ratepayers that results from the reduction of the requested rate increases from 3.5% to 2% amounts to approximately $75 million.
>
> In other words, only about 20% ($75 / $380 = 19.7%) of the benefit from the government's change in policy is being passed on to ratepayers, while the rest is going to the utility's bottom line as Net Income.

Request:

What share of the reduction in payments to the government does MPA propose to be provided to ratepayers for the two test years in the form of rates for the 2023/24 and 2024/25 years and indicate the impact on the indicated rate.

Response:

MPA supports a "rate pause" over this GRA period, instead of the approval of the requested 2% rate increases (note that MPA believes the 3.6% interim increase should be confirmed). This would result in an additional $100 million of savings to ratepayers as compared to Manitoba Hydro's proposal.

The result with respect to the impact of the Government of Manitoba change in policy would therefore be approximately 46% of the benefit to ratepayers, with the balance accruing to Manitoba Hydro Net Income ($175 / $380 = 46.05%).

For reasons that are more fully explained in response to PUB/COALITION I-25, below, MPA does not find support in regulatory principles for the proposed rate increases, does not perceive that a "rate pause" would threaten the finances of Manitoba Hydro, and as noted in the MPA Report, does not find arguments about the future rate path that will be imposed due to Bill 36 to be compelling.

**PUB/COALITION I-25 Reference: MPA Evidence p.28
Regulatory Principles**

Preamble:

In its evidence on page 28, MPA states:

> The application includes no compelling arguments, absent the legislation, that support aggressive reduction in the Debt-to-Capitalization Ratio. Nor is the desire to achieve 100% “self-financing” cash flows supported by appeal to any regulatory principles or practice.

MPA does not identify regulatory principles in its evidence.

Request:

Please list the regulatory principles that MPA would typically use or expect to be used to support appropriate levels of cash flows and briefly explain whether these principles apply to MH.

Response:

The PUB identifies a number of regulatory principles that are applicable to assessing a rate application (they appear on the PUB’s website and were included in the MPA Report as Appendix A). These include:

i. Cost of Service Standard
ii. Intergenerational Equity
iii. Matching Principle
iv. Rate Stability and Predictability
v. Used or Required to be Used
vi. Prudence Standard

An alternative set of principles are enunciated in the “Bonbright Criteria” (which were included in the MPA Report as Appendix B). These include:

a) Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety
b) Revenue stability and predictability, with a minimum of unexpected changes that are seriously adverse to utility companies
c) Stability and predictability of the rates themselves, with a minimum of unexpected changes that are seriously adverse to utility customers and that are intended to provide historical continuity
d) Static efficiency, i.e., discouraging wasteful use of electricity in the aggregate as well as by time of use
e) Reflect all present and future private and social costs in the provision of electricity (i.e., the internalization of all externalities)
f) Fairness in the allocation of costs among customers so that equals are treated equally
g) Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (free of subsidies)
h) Dynamic efficiency in promoting innovation and responding to changing demand-supply patterns
i) Simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application
j) Freedom from controversies as to proper interpretation

In the MPA Report filed with the PUB during the 2017/18 & 2018/19 Manitoba Hydro GRA, MPA generalized and described generic regulatory principles as follows[38]:

> *Monopoly Utility Customer Service*: Regulated rates should be set for services which can only be efficiently provided by a monopoly. If a service is amenable to market competition, then it should not be regulated, but rather should be opened to competition, to the benefit of customers. Assuming a territorial monopoly is the only reasonable arrangement for a service, then ensuring the actual delivery of high quality service to customers should be a priority of regulation.
>
> *Economic Efficiency, both Static and Dynamic*: A monopoly utility should be regulated in such a way that its services are delivered as efficiently as possible, making best possible use of available resources, both at any given time and over time. Given that the potential for efficiency changes over time depending on labour markets, available technology and economic conditions, regulators should ensure that utilities are

[38] Please see Intervenor Evidence of Morrison Park Advisors on behalf of the Consumers Coalition and MIPUG, 2017/18 & 2018/19 GRA, page 17. Available online: < http://www.pubmanitoba.ca/v1/proceedings-decisions/appl-current/pubs/2017%20mh%20gra/intervener%20evidence/mpa%20report%20on%20manitoba%20hydro%202017-18%20and%202018-19%20gra_to%20file.pdf>

> not only delivering services using the most efficient tools and practices available at any given time, but are also appropriately planning and investing to perform their functions more efficiently in the future.
>
> *Cost Causality, both Between Customers and Over Time*: Customers should pay the costs associated with the services they use, and rates should reflect that. This is a critical concept in allocating current costs between customer classes, but also with respect to allocating the cost of long-lived assets over time. This principle rests on the recognition that all customers are equally important, so fairness demands that no customers be forced to pay for costs caused by others.
>
> *Stability and Predictability*: Customers' ability to properly plan their usage of the utility's products and services depends on knowledge about how much those services will cost or are likely to cost, and when and in what form they will be available. By the same token, the utility itself can only operate efficiently if it has appropriate foreknowledge of the standards and business practices that are going to be required of it.
>
> *Prudence*: Utilities should operate in a manner which reasonably reflects the common understanding of risks applicable in their industry, and seek to appropriately manage those risks. This principle is both a standard for utility behaviour, and a defense for utilities against after-the-fact criticism of their decisions and behaviour in challenging circumstances.
>
> *Public Interest*: Utilities should be required to operate in a manner that is cognizant of the externalities associated with their products and services, and as much as possible supports the economic and social development of their communities. As a matter of course, utilities should meet all public requirements and standards with respect to labour, environmental, health and safety practices.
>
> *Access to the Capital Markets*: Utilities are capital intensive businesses, and as such should be regulated, organized and operated in a way which will be attractive to the capital markets as an investment opportunity. This will both facilitate ongoing investment, and ensure that the cost of capital applicable to the investment is as low as possible.

The first two principles, "Monopoly Utility Customer Service" and "Economic Efficiency", are not particularly relevant to the current discussion, and will not be discussed further.

Cost Causality

The application of this principle to customers over time (i.e., "intergenerational equity") is very relevant to issues of Revenue Requirement for Manitoba Hydro, while the application of cost causality as between customer classes is more applicable to rate design issues.

In his evidence in this GRA[39], Darren Rankie notes that between 2011/12 and 2021/22, Manitoba Hydro ratepayers have faced a cumulative increase in Revenue Requirement of approximately 42%, while the Manitoba Consumer Price Index has increased by slightly less than 25% over the same period. Moreover, this increase in Manitoba Hydro's Revenue Requirement was in large part driven by the massive capital expenditures on the Bipole III and Keeyask projects, neither of which were in service during the bulk of the time period. This is an obvious failure of the principle of "cost causality".

Today, both projects are in-service, but Keeyask's output is not necessary to adequately serve domestic load within the Province of Manitoba (and will not be for a number of years). Unfortunately, owing to the overruns in both budget and schedule, the facility is projected to be unprofitable for years to come based on the export revenues that it is expected to earn. Domestic ratepayers are in effect subsidizing the Keeyask facility without receiving any benefit in return, at least until some of its output is actually required in order to serve domestic load.[40] Again, this is a clear failure of the cost causality principle.

Despite these apparent burdens on ratepayers, Manitoba Hydro proposes further 2% increases in rates on September 1, 2023, and April 1, 2024. These increases will deliver approximately $25 million of incremental revenue in fiscal year 2023/24, and $75 million in 2024/25. Manitoba Hydro currently forecasts net income in these two years to be a total of $664 million *<u>before</u>* inclusion of the impact of the rate increases. In other words, the $100 million of incremental ratepayer revenue is not required to pay for any cost attributable to ratepayers today, but instead it represents a further contribution to Manitoba Hydro's Equity, which may or may not be important to future ratepayers.

Manitoba Hydro goes even further in its application and argues that "self-financing" of its capital expenditures is desirable (i.e., financing capital expenditures without recourse to Debt). This is not so much a violation of the cost causality principle, but rather it appears

[39] Please see Revenue Requirement Evidence Prepared By Darren Rainkie On Behalf of The Consumers Coalition, page 127.
[40] Moreover, at its current cost per MWh, it is not clear that Keeyask represents the lowest cost means of satisfying domestic customer requirements, when domestic load grows to the point that additional supply is required.

to be a case of simply ignoring its applicability. The principle of cost causality is served by requiring Depreciation to be part of the Revenue Requirement formula: each cohort of ratepayers must pay a fair portion for the use of capital assets, which Depreciation captures. Net Income, which in the context of Manitoba Hydro is a ratepayer contribution to Equity, should ideally be smoothed over time so all ratepayers make a reasonable (and reasonably necessary) contribution. Whether “Depreciation + Net Income” is equal to, greater than or less than Capital Expenditure in any given year is an accidental outcome of the utility’s asset management plan. Instead, Manitoba Hydro is suggesting a principle that the two should be forcibly aligned (i.e., that Depreciation + Net Income = Capital Expenditures), even though that may mean that ratepayers at different times are forced to make very different contributions to Equity. MPA identifies no support for this logic.

Stability and Predictability

As noted, rates have risen approximately 42% over the past decade, which amounts to an average clip of approximately 3% per year. Continuing this trend with the proposed increases of 2% would be consistent, which may be the sole principled reason to support the rate increases. However, “predictability” does not necessarily require absolute consistency over time. For example, a decision to pause rate increases (i.e., 0% instead of 2% increases at the proposed dates), with the understanding that rate increases would likely return to their upward march afterwards, would not be “unpredictable”. A planned, deliberate, modest and widely communicated temporary pause in rate increases would hardly be termed “unpredictable”.

While it is true that many of the rate increases over the past decade have been granted in the interests of “rate smoothing”, there should be limits to the application of this principle to override all other concerns.

Prudence

Manitoba Hydro has argued that its proposed rate increases are required to help manage future risks, such as for interest rate increases, unexpected capital expenditures, or the future restrictiveness of provincial legislation. None of these reasons are consistent with standards of prudence generally applicable to regulated utilities. As the PUB has noted, rate decisions should reflect actual interest rates, not potential future interest rates. A similar argument can be made about potential future capital expenditures: they should be addressed when they actually form part of a documented capital plan, not when they are risks on the horizon. Finally, no objective regulated utility observer would suggest that regulatory decisions on Revenue Requirement are an appropriate forum in which to address potential future issues with legislation.

Public Interest

A critical concern in Manitoba Hydro's conception of its capital structure is the implicit assumption that Debt has a cost, while Equity is free. In the financial accounts of Manitoba Hydro, this is true: no cost to equity is recognized. However, to ratepayers higher rates most definitely have a cost, and this is a fundamental public interest issue that Manitoba Hydro ignores.

In redefining its primary financial target as "Debt to Capitalization" (rather than "Debt to Equity"), Manitoba Hydro has now effectively even erased the concept of "Equity" from its consideration, further reducing the attention paid to the true costs of its Revenue Requirement.

Manitoba Hydro's "Net Income" is nothing other than an Equity contribution by its ratepayers. Managing that contribution so that it is as low as reasonably possible (consistent with the utility's risk profile and financial needs), and as fairly distributed over time as possible, should be a key priority for the utility. Instead, the stated emphasis is on achieving an arbitrarily high target for Equity, not supported by any other regulatory principle.

The current opportunity to pause rate increases – after years of faster-than-inflation increases, increases without the justification of cost causality, and while water levels are higher than usual – is one which the PUB may wish to take advantage of in order to address, however temporarily, the unfairness to ratepayers of being required to contribute excessive Equity to Manitoba Hydro.

Access to Capital Markets

Owing to its structure as a Government Business Enterprise, Manitoba Hydro's access to capital markets is not restricted now, nor is it expected to be in future. An ongoing and legitimate concern for the utility is the potential impact of drought, and what that might do to the finances of the utility, and hence its standing in the capital markets. However, Manitoba Hydro's own analysis of a potential near-term 5-year drought suggests that it is not in danger of financial failure in any meaningful sense (other than missing its artificial Debt-to-Capitalization targets), even with limited 2% rate increases during such a significant event (and noting that the PUB recently approved a 3.6% increase during a single-year drought). There is no reason to believe that the proposed 2% rate increases are required to maintain the financial health of the utility, or the sufficiency of its reserves to manage drought risk.

PUB/COALITION I-26 Reference: Rainkie Evidence pp.10, 117, 131
Interim Rate Increase

Preamble:

In his evidence on page 10, Mr. Rainkie states:

> Providing some weight to each of the three analytical perspectives, but the most weight to the PUB's policy of rate smoothing and requirements of active and prudent cost control, results in a recommendation of a single 1.3% overall rate increase on April 1, 2024 and final confirmation of the 3.6% interim rate increase that was effective January 1, 2022.

In his evidence on page 117, Mr. Rainkie states:

> CC10 and CC11 also assumed that the 3.6% interim rate increase that was approved by the PUB for 2021/22 is confirmed as final. Hindsight with respect to the record profit levels in 2022/23 would indicate that when looking at the combined financial results of 2021/22 and 2022/23, that the 3.6% increase was not required to mitigate the deleterious impacts of drought in 2021/22. However, for the purposes of a rate smoothing evaluation, it appeared counter intuitive to roll-back the 3.6% interim rate increase – only to then to reimpose higher rate smoothing increases in future years.

In his evidence on page 131, Mr. Rainkie states:

> Based upon similar considerations, it is recommended that the PUB provide final approval to MH with respect to the 3.6% interim rate increase that was approved by the PUB effective January 1, 2022. Rolling back the 3.6% rate increase, only to impose larger rate increases in future test years appears counter productive to the objective of rate smoothing. If the PUB determines that further rate relief is due to ratepayers, then this is recommended to be implemented on a prospective basis through a rate pause or lower annual rate increases.

Request:

a) Please confirm whether the quoted passages in the preamble encompass Mr. Rainkie's position and support for the interim 3.6% rate increased approved January 1, 2022. If not confirmed, please indicate where in his evidence additional support may be found, or provide it in response.

b) Please explain whether and how the record levels of net income in 2022/23 factor into Mr. Rainkie's position to support the interim 3.6% rate increase.

Response:

a) Additional support for the recommendation to confirm the 3.6% interim rate increase is provided in the following paragraph from page 131 of Mr. Rainkie's evidence:

> "The cumulative rate increase that results from these recommendations is 4.94% (1.036 * 1.013), which when considered over the four test years that are the subject of this Application is about 1.24% per year – which is consistent with the recommended indicative rate increases for rate smoothing purposes."

In Mr. Rainkie's view, the PUB should consider the four test years that are the subject of this Application (2021/22, 2022/23, 2023/24 and 2024/25) on a holistic basis.

In the 2018/19 GRA and prior regulatory proceedings, MH had calculated a 3.5% indicative rate path based on its 20-year financial forecasts. MH has held back updated long-term financial forecasts since the 2018/19 GRA and had to be directed by the PUB in Order 9/22 (Directive #4), to provide an updated long-term financial forecast in the current GRA.

Mr. Rainkie's evaluation concluded that from a rate smoothing perspective, rate increases towards the lower end of the indicative range of 1.2% to 1.5%, when combined with active cost control over O&A and BOC spending and a less risk adverse debt management strategy, represents a better balancing of the interests of customers and the financial health of MH.

Mr. Rainkie is also of the view that customers should not be disadvantaged as a result of MH withholding a long-term financial forecast for a number of years. The updated financial forecast provides indicative rate increases in the order of 1.2% as recommended by Mr. Rainkie. This updated rate path of 1.2% should be applied to each of the four test years in the current application.

Applying the indicative rate increases of 1.2% per year across the four test years of this Application (2021/22, 2022/23, 2023/24 and 2024/25) would yield a total rate increase of about 4.8%. The 3.6% interim rate increase previously approved by the PUB is sufficient to yield the appropriate revenues for MH for the 2021/22, 2022/23 and 2023/24 Test Years (3 * 1.2% = 3.6%), respectively. Mr. Rainkie's ultimate recommendations to the PUB to confirm the 3.6% interim rate increase and approve a single 1.3% rate increase on April 1, 2024, which total 4.9%, is consistent with the 4.8% indicative rate increases across the four test years, on a holistic basis.

b) As further outlined in the response to part a of this information request, Mr. Rainkie's recommendation to the PUB to approve the 3.6% interim rate increase as final, considers the four test years under review in this Application on a holistic basis and in the context of updated long term financial forecast that demonstrate a significant improvement in MH's financial outlook and a much lower indicative rate path of 1.2%.

The record levels of net income in 2022/23, projected to be in the order of $751 million, are an important contributor to the significant improvement in MH's financial outlook. The prior long-term forecast from the 2018/19 GRA (MH16), projected losses in 2022/23 and the next five years of $418 million.

PUB/COALITION I-27 Reference: Rainkie Evidence p.36

Preamble:

In his evidence on page 36, Mr. Rainkie provides Figure 4 comparing export revenues between MH16 and the current FFS:

Figure 4: Export Revenues - MH22 vs MH16 - $Millions

1	2	3	4 (2 - 3)	5
Year	MH22	MH16	Export Revenue Inc (Dec)	Export Revenue Cumulative Inc (Dec)
2023	1283	779	504	**504**
2024	1153	788	365	**869**
2025	964	805	159	**1028**
2026	780	667	113	**1141**
2027	778	671	107	**1248**
2028	754	662	92	**1340**
2029	740	677	63	**1403**
2030	748	697	51	**1454**
2031	768	709	59	**1513**
2032	766	705	61	**1574**
2033	754	701	53	**1627**
2034	762	696	66	**1693**
2035	783	694	89	**1782**
2036	707	602	105	**1887**

Request:

a) Please provide a version of Figure 4 using net export revenues.

b) Please provide a version of Figure 4 using net export revenues but excluding the years 2023 and 2024 in order to remove the effect of high water flows.

c) Please provide any comments and explain whether any of Mr. Rainkie's analysis changes.

Response:

a) Please see an alternate version of Figure 4, comparing net export revenues between MH 22 and MH16, from 2023 to 2036:

PUB/Coalition I-27a : Figure 4: Net Export Revenues - MH22 vs MH16 - $Millions

1	2	3	4 (2 - 3)	5
Year	MH22	MH16	Net Export Revenue Inc (Dec)	Net Export Revenue Cumulative Inc (Dec)
2023	1063	512	551	551
2024	907	525	382	933
2025	729	536	193	1126
2026	522	409	113	1239
2027	528	411	117	1356
2028	503	399	104	1460
2029	486	411	75	1535
2030	493	427	66	1601
2031	492	429	63	1664
2032	502	443	59	1723
2033	485	440	45	1768
2034	469	428	41	1809
2035	471	417	54	1863
2036	357	335	22	1885

b) Please see an alternate version of Figure 4, comparing net export revenues between MH22 and MH16, from 2025 to 2036.

PUB/Coalition I-27b : Figure 4: Net Export Revenues - MH22 vs MH16 - $Millions

1	2	3	4 (2 - 3)	5
Year	MH22	MH16	Net Export Revenue Inc (Dec)	Net Export Revenue Cumulative Inc (Dec)
2025	729	536	193	193
2026	522	409	113	306
2027	528	411	117	423
2028	503	399	104	527
2029	486	411	75	602
2030	493	427	66	668
2031	492	429	63	731
2032	502	443	59	790
2033	485	440	45	835
2034	469	428	41	876
2035	471	417	54	930
2036	357	335	22	952

c) The purpose of Figures 2, 3 and 4 and from pages 34 and 36 of Mr. Rainkie's evidence was to demonstrate the significant improvement in MH's financial outlook and lower levels of financial risk relative to the last MH GRA, through a number of financial metrics and ratios that have been traditionally used for rate-setting purposes. The export revenues and net export revenues comparisons (provided in the response to parts a & b) both demonstrate significant improvement between MH22 and MH16, for both the 2023 to 2036 and 2025 to 2036 periods of time. In addition, the components of net export revenues (export revenues, water rentals & assessments and fuel & power purchases) contribute to the financial metrics and ratios analyzed in Figures 2 and 3. As such, the analysis and conclusion in Section 4.4 of Mr. Rainkie's evidence that a relative assessment of risks compared to the 2018/19 GRA does not support MH's assessment that its risks are elevated for rate setting purposes, does not change.

PUB/COALITION I-28 Reference: Rainkie Evidence pp.24-33; Coalition/MH I-1(b) Risks

Preamble:

In his evidence on page 24, Mr. Rainkie states:

> The sixth concern with respect to Strategy 2040 for rate-setting purposes, is that Strategy 2040 is contributing to upward pressures in rates as a result of increased levels of spending and resulting in self-imposed risks in terms of MH's future financial outlook and cash flows.

In his evidence on page 25, Mr. Rainkie states:

> While MH is concerned with respect to its future financial health, its levels of debt and levels of cash flow – the increased spending forecasts in the order of $2.3 billion may be seen as constituting self-imposed risks by MH.

In his evidence on page 29, Mr. Rainkie states:

> In the Application, MH provided the following summary of its Top Enterprise Risks, and in the information request process asserted that all of these risks were increasing and that some of the risks were new risks compared to prior risk assessments provided to the PUB[16]: [footnote 16: Coalition/MH I-1b and 7 h]

In his evidence on pages 31 to 33, Mr. Rainkie identifies two risks that appear to have reduced: completion of major projects risk and interest rate risk.

Request:

a) Please elaborate on the self-imposed risks flagged on pages 24 and 25 of Mr. Rainkie's evidence.

b) Please provide Mr. Rainkie's comments with respect to each of the risks in the table in the response to Coalition/MH I-1(b), including Mr. Rainkie's assessment of whether the risks are increasing, decreasing, or remain steady with brief reasoning supporting the assessments.

c) Please identify any additional risks, other than interest rate risk and MNGT completion risk, that are decreasing or have decreased since the 2017/18 & 2018/19 GRA and provide supporting reasoning.

Response:

a) Throughout MH's Application and supporting materials, it outlines its concerns about ensuring its financial health in the future, and the projected levels of debt maturities and cash flow, primarily as a result of the investment in major capital projects. It also asserts that the majority of its risks are imposed.

At the same time MH articulates its concerns about financial health, debt and cash flow levels and imposed risks – it plans a $2.3 billion increase in O&A and BOC spending (in the 14-year comparable period between MH22 and MH16) which increases each of the risks (pressure on financial health, higher levels of debt and lower levels of cash flow) that it indicates it is concerned about.

In Mr. Rainkie's assessment the best means for MH to manage these risks is to exercise financial discipline over the expenditures on which it has the most control (O&A and BOC). As a result, Mr. Rainkie concludes that the forecast MH $2.3 billion increase in spending on O&A and BOC is really a "self-imposed" risk by MH, through its own spending priorities.

In addition to MH spending priorities, Mr. Rainkie notes in Section 4.5, pages 37 and 38 of his evidence that MH enterprise planning priorities are inconsistent with its high-level risk assessment – such as multi-year journeys to complete its ERM Program and implementation of a modern asset management framework and not having a MHEB approved IT Strategy and associated business cases - despite the concerns expressed by MH about elevated risks, aging asset risks and technology risk. In Mr. Rainkie's assessment, the above noted facts are inconsistent with MH's high-level risk assessment and represent further elements of risks that are "self-imposed" by MH, through its own enterprise planning decisions.

b) and c):

As outlined in Section 4.3, pages 29 to 31 and Section 4.4, pages 31 of Mr. Rainkie's evidence, the MH high-level risk assessment is incomplete and not balanced and the MH ERM Program is in the early stages of development. As a result, MH's high-level risk assessment of its top risks noted in the preamble to the information request do not represent a comprehensive risk assessment that can be relied on for rate-setting purposes. MH's high-level risk assessment is consistent with a one-page summary table that would be included in an annual report.

Typically, assessments of utility's risks for rate-setting purposes consider the combined business and financial risks, compared to assessments that were made at prior rate proceedings. These risk assessments for rate-setting purposes are typically very detailed and in a comprehensive report format and often involve the use of consultants that are experts in risk assessments. At the very least, risk information consistent with Corporate Risk Management Reports that have been provided by MH at prior regulatory proceedings (that include detailed risk profiles, ratings on probability, consequence, tolerance, current status, actions required and assessment of residual risk), are useful in the MH rate-setting process. MH's high-level risk assessment contains none of this detailed information and analysis.

In the absence of a detailed risk assessment by the applicant, it is impossible for intervenor experts to bridge these deficiencies and provide a full and complete risk assessment of their own. This is particularly the case in the absence of the Manitoba Energy Policy and the fact that the IRP is still in process and not part of the scope of this GRA proceeding.

In Section 4.4, pages 31 to 37, Mr. Rainkie identified elements of a more comprehensive and balanced risk assessment for rate-setting purposes, based on the more limited risk assessment information on the record of the current proceeding than in the past and the limitations with respect to the Manitoba energy policy and MH IRP. This assessment covers many of the elements of the MH top enterprise risks and can be summarized as follows:

- Drought risk: drought risk is reasonably consistent with the past two MH GRA's;
- Interest rate risk: MH conceded that its average interest rate risks remains at the lower end of its interest rate guidelines and MH provided high interest rate sensitivities indicating that interest rate risk is down 38% relative to the 2018/19 GRA and 56% relative to the 2015/16 GRA;
- Disruptive technology, self-generation & stranded assets, technical innovation and cyber security risks: MH acknowledged in its 2022/23 Enterprise Plan that there are both opportunities and challenges associated with energy industry

transition issues related to decarbonization, decentralization and digitization. MH also acknowledged that its hydro-electric system will become even more valuable in the future as the world responds to climate change, given its system is a dispatchable resource and not exposed to carbon pricing or future GHG management policies. MH indicated it had no ability to assess the portion of its business risks related to evolving industry trends;

- Loss of market access to export power markets risks: MH acknowledged this risk has improved as a result of a push to more variable renewable resources, increasing the need and industry wide support to maximize interconnections and market access;

- Overall financial risk: lower relative to past MH GRA's and NFAT proceeding given the substantial improvement in MH's near-term and long-term financial outlook. MH did not acknowledge this significant risk reduction in its high-level risk assessment; and

- Completion of major capital projects risks: a material and substantial reduction to MH's financial and business risks (reputational and contractual). MH did not acknowledge this significant risk reduction in its high-level risk assessment.

In addition to the above noted elements of risk assessment contained in Section 4.4 of his evidence, Mr. Rainkie also notes the following:

- Export revenues & export price risks: Daymark Energy Advisors concluded in its independent evaluation that MH's export revenue forecasts are conservative (pages 57, 58 and 63), "there is potential for incremental revenue if MH can monetize its excess summer capacity" and "…the potential for additional revenues for MH's clean, dispatchable products" and "it is likely that there will be opportunities for premium pricing or additional revenues for MH's exports as the MISO market continues to evolve". It would be an element of "double-counting" to have an export revenue forecast that is independently assessed as conservative on the one hand – and then also build in residual risk into the rate increases requested for the forward Test Years in order to build up financial reserves for such risks; and

- Aging assets risk: Midguard Consulting concluded in its independent evaluation that "Despite MH's claims that its aging assets are degrading substantially and threaten system reliability, its SAIDI and SAIFI metrics show

> that MH's system performance continues to be stable and superior to MH's Canadian utility peers" (page 6).

While the collective assessments of the independent consultants to this regulatory proceeding cannot correct for an incomplete and unbalanced high-level risk assessment by MH, the independent assessments do support Mr. Rainkie's conclusion in Section 4.8, page 40 of his evidence, that a relative assessment of risks since the last MH GRA does not support the MH assessment of elevated business and financial risks for rate-setting purposes.

PUB/COALITION I-29 Reference: Rainkie Evidence p.39
Regulatory Action to Address Long-Term Risks

Preamble:

In his evidence on page 39, Mr. Rainkie states:

> The PUB policy from Order 59/18 is that rates should not be set to increase financial reserves (retained earnings) for all identifiable risks and that the PUB is prepared to consider regulatory action (rate increases) when, and if, emerging risks actually materialize.
>
> …
>
> The key aspects of this rate-setting policy guidance, can be summarized as follows: [footnote deleted]
>
> 1. The PUB is prepared to take regulatory action (rate increase) as required when emergent situations face MH;

Request:

Please explain whether the Manitoba Hydro Amendment Act (Bill 36) rate cap and debt-to-capitalization targets constrain the PUB's ability to take regulatory action (rate increases) to address emergent risks.

Response:

The PUB found in Order 70/22 that the amended legislative framework does not apply to its consideration of the present Application and will not apply to rate-setting for Manitoba Hydro until April 1, 2025. However speculating on the rate-setting process after April 1, 2025, Mr. Rainkie offers the following observations:

- As outlined in Section 5.3, page 44 of Mr. Rainkie's evidence, the statute's debt ratio targets are prescribed with a certain degree of flexibility created by the rate cap provisions which will determine the actual rate increase. As such, it appears the Province has prioritized customer rate impacts over attainment of MH debt ratio targets, and as a result these targets are not a constraint to the extent emphasized by MH in this proceeding;

- Section 39.6 of the new legislative framework provides for the government to make regulations respecting the framework for setting or varying rates in a number of circumstances, including sub-section (d) which specifies that the government may modify a debt to equity ratio target or the target date for achieving the target, in response to unforeseen or extenuating circumstances. As such, it appears that the Province has built safeguards into the new legislative framework to facilitate a response to a potential negative financial event impacting MH or a significant emergent risk requiring regulatory action;

- As it relates to the rap cap provisions of the new legislative framework, Mr. Rainkie agrees with the assessment of Morrison Park Advisors (MPA) on page 21 of its report that “if there is a problem with legislation, then the utility should bring it to the attention of the government and request a change in legislation. The PUB should not be asked to mitigate a future problem with a legislative restriction though an action that does not have regulatory merit today. If interest rates or some other cost increase to the point that regulated electricity rates should increase more than inflation, then the government of the day should respond and loosen the restriction to the level required.”;

- Mr. Rainkie would add to the MPA assessment - that the Province of Manitoba owns MH, consolidates MH’s financial results into its own financial results and provides a provincial debt guarantee to the vast majority of MH’s outstanding debt. In the event of a significantly negative financial event requiring PUB regulatory action, it would be in the interest of the government of the day to loosen the rate cap provision to the level required, to manage its own financial and credit rating implications. Just as is the case in the situation where regulatory commissions assume rational behavior by financial markets in approving capital structures and rates of return for regulated enterprises, it is appropriate to assume rational behavior by the Province of Manitoba for rate-setting purposes in the current regulatory proceeding, in the event of a significantly negative financial event for MH, while under the rate cap provisions;

- PUB regulatory action can occur over a period of years and does not need to happen all in one test year. MH is projecting to have financial reserves (retained earnings) of $4.2 billion (please see Mr. Rainkie's evidence, Section 9.3, Figure 25, page 113) by the end of the 2024/25 Test Year, even without any rate increases in the forward Test Years. MH's financial reserves are forecast to steadily grow to $8.6 billion under the 2% rate path (MH22) and to between $6.4 billion and $8.1 billion in the CC10 and CC11 financial scenarios with 1.2% to 1.5% rate increases and active cost control/appropriate debt management strategies by MH (please see Mr. Rainkie's evidence, Section 9.4, Figure 28, page 121). MH is well positioned to withstand large negative financial events such as drought ($1.7 billion estimated reduction to retained earnings), combined with PUB regulatory action over an appropriate period of time (not constrained to a single test year or three-year test period);

- If there is concern with respect to the rate cap provisions – this points to the necessity for MH to exercise fiscal discipline/active cost control and ensure that it is not following an overly risk adverse and more costly debt management strategy – not to the pre-approval of additional rate increases by the PUB in the forward Test Years, just in case they are needed in the future. In Mr. Rainkie's view, management action (prudent cost control and debt management strategies) should precede regulatory action (rate increases). Assuming a return to long-term inflationary targets in the order of 2%, the recommended 1.2% to 1.5% indicative rate increases than embedded prudent cost control by MH, leave flexibility for PUB regulatory action over multiple years, when required; and

- Pre-approval of additional rate increases in the forward Test Years as a result of concerns with respect to the rate cap provisions would be inconsistent with the PUB's prior rate-setting policy guidance from Order 59/18 that rates should not be set to increase financial reserves for all identifiable risks, but only when risks actually materialize (please see Mr. Rainkie's evidence, Section 4.7, page 39, for a summary).

PUB/COALITION I-30 Reference: Rainkie Evidence p.42

Preamble:

In his evidence on page 42, Mr. Rainkie states

> The use of a number of traditional financial metrics and financial ratios elevates rate-setting to that of policy judgement of an appropriate and balanced rate path and not the false precision of mechanistic goal seeking of one financial ratio (debt to equity ratio).

Request:

Please explain which financial ratios and targets are referenced in the above statement.

Response:

The conclusion from the evaluation of MH's financial targets for the purposes of this proceeding (Section 5.7 of Mr. Rainkie's evidence), is the recommendation that the PUB use its policy determinations from Orders 59/18 and 69/19 and place primary weight on the traditional financial targets for rate-setting purposes in this GRA.

This conclusion is fundamental to Mr. Rainkie's recommendation to the PUB to balance the interests of customers with the financial health of MH, through the application of judgement with respect to traditional financial metrics and targets and past PUB policy pronouncements with respect to appropriate financial metrics and targets to be used for rate-setting.

As outlined in Section 5.1, pages 42 to 43 of Mr. Rainkie's evidence, the six traditional financial metrics and targets that the PUB has used to make judgements on MH rate proposals are the financial metrics of net income, net debt and financial reserves (retained earnings) levels, and the three long-standing MH financial targets, debt to equity ratio of 75%:25%, EBITDA interest coverage of 1.80 and capital coverage of 1.20.

In addition, as further outlined in Section 5.6, pages 48 to 49 of Mr. Rainkie's evidence, the PUB set out important policy guidance in Orders 59/18 and 69/19, with respect to the appropriate financial targets to use for rate-setting purposes. This policy guidance includes:

- the PUB's focus on five of the traditional rate setting metrics/ratios of levels of financial reserves (net income and retained earnings) and debt and interest coverage and capital coverage ratios;

- The PUB placed the debt to equity ratio in its appropriate context as not being the sole determinate of the pacing of rate increases to balance the interests of customers with the financial health of MH. In fact, the PUB questioned the appropriateness of the debt to equity ratio for a vertically integrated monopoly crown utility with a debt guarantee from a provincial government, like MH; and

- The PUB also expressed interest in rule-based regulation through consideration of the appropriate levels of financial reserves to manage risks.

Mr. Rainkie's rate smoothing analysis in Section 9.4, pages 121 to 124, provide his evaluation of the six traditional financial metrics in order to make a recommendation to the PUB with respect to an indicative rate path towards the lower end of a 1.2% to 1.5% range - as a more appropriate balancing of the interests of customers with the financial health of MH.

Mr. Rainkie's recommended approach to the PUB of the use of judgement and past regulatory policy to guide rate setting contrasts with the proposed MH 2% rate path that is based on a goal-seek to attain a single financial target - the 30% debt ratio target in the new legislative framework that will not become operative until April 1, 2025.

PUB/COALITION I-31 Reference: Rainkie Evidence pp.42-43 (section 5.1)

Request:

a) Please comment on the whether the KPMG recommended targets should be considered in light of the recommendations made in the report.

b) Please indicate whether or not MH should apply any further financial metrics for rate setting.

Response:

a) Yes, the KPMG overall finding was that the long-standing financial targets that were used by MH were appropriate. The KPMG recommended financial targets are consistent with MH's prior three financial targets to maintain a minimum equity ratio of 25%, a minimum EBITDA interest coverage target of 1.80 and a minimum capital coverage of 1.20, as outlined in Section 5.1, pages 42 and 43 of Mr. Rainkie, evidence.

Mr. Rainkie has considered these three financial targets and the PUB policy guidance on appropriate financial targets for rate-setting purposes (please see the response to PUB/Coalition I-30), as part of the rate smoothing analysis in Section 9.4, pages 121 to 124 of his report. His evaluation includes the PUB policy guidance with respect to the questionable appropriateness of debt to equity ratio target for MH and this target not being the sole determinate of the pacing of rate increases to balance the interests of customers with the financial health of MH.

b) Mr. Rainkie is not recommending any further financial metrics or targets be used for rate-setting in this proceeding, other than the six traditional financial metrics/targets discussed in the response to PUB/Coalition I-30.

Mr. Rainkie agrees with the MH assessment outlined in Section 5.2, page 44 of his evidence that the three traditional financial targets, represent all three financial statements, allow for consistent presentation over time and demonstrate similar trends to the additional financial metrics that MH is monitoring.

In addition, as outlined in Section 5.6, pages 52 and 53 of Mr. Rainkie's evidence, he indicates that the conclusions and recommendations from the 2019/20 MH Rate Application with respect to the use of the Uncertainty Analysis to consider rule-based regulation and appropriate levels of financial reserves for rate-setting purposes, are as applicable now as the were in the prior MH rate proceeding. The Uncertainty Analysis can be used as a rate-setting tool that is a customized internal analysis that directly focuses on the unique risks and capital requirements of MH as a crown owned monopoly utility with a provincial debt guarantee. This is contrasted with the MH use of the debt to equity ratio as the driver of its 2% proposed rate path, which is an externally focused benchmark, which the PUB recognized in Order 59/18 as having limitations for rate-setting for MH. As outlined on page 54 of his evidence, Mr. Rainkie views the increase in financial reserves over the next 20 years that flow from the MH proposed 2% rate path as a "$5 billion issue". The Uncertainty Analysis could be adapted as a primary rate-setting methodology that is specific/internal to MH to directly set rule-based electricity rates. Alternately, the Uncertainty Analysis could be used as a secondary rate-setting methodology to test if the $5 billion increase in financial reserves through the goal seeking towards the externally focused debt to equity targets is reasonable and balances the interests of customers with the financial health of MH.

PUB/COALITION I-32 Reference: Rainkie Evidence p.55 (section 6.0)

Request:

Please provide the analysis that supports the extrapolated increase in O&A expenses.

Response:

The passage that is referenced from Mr. Rainkie's evidence in Section 6.0, page 55, reads as follows "Extrapolating these near term O&A increases into the forecast period results in a projected cumulative increase in O&A costs of $1.5 billion compared to the last GRA".

The analysis that supports this evaluation is provided in Figure 13, page 77 of Mr. Rainkie's evidence, which is reproduced below for ease of reference. Figure 13 demonstrates that there has been a $1.5 billion cumulative increase in O&A forecasts between 2022/23 and 2035/36, between MH22 and MH16, since the last MH GRA.

Figure 13: Operating & Administrative Expenses - MH22 vs MH16 - Millions

1	2	3	4	5
			(2 - 3)	
Year	**MH22**	**MH16**	**MH22 vs. MH16**	**Cumulative Inc (Dec)**
2023	589	536	53	**53**
2024	657	548	109	**162**
2025	687	559	128	**290**
2026	683	571	112	**402**
2027	697	583	114	**516**
2028	711	595	116	**632**
2029	724	607	117	**749**
2030	736	620	116	**865**
2031	739	633	106	**971**
2032	754	646	108	**1079**
2033	769	660	109	**1188**
2034	785	674	111	**1299**
2035	800	688	112	**1411**
2036	816	702	114	**1525**

PUB/COALITION I-33 Reference: Rainkie Evidence p.97 (section 8.3)

Preamble:

At p. 97 of his evidence, Mr. Rainkie states:

> In recognition of the possibility that a definitive decision is not reached, a number of pragmatic alternative scenarios were canvassed in the information request process to provide options and comparisons for the PUB for rate-setting purposes. The options include:[112] [Footnote 112: Coalition/MH I-41 c d e f]
>
> > 1. A status quo option, where MH would be directed by the PUB to continue to defer amounts into the Change in Depreciation Method and Losses on Disposal of Assets RDA's, without any amortization (as was directed in Order 59/18);
> >
> > 2. An option with the continued deferral of amounts but with amortization over the amortization periods proposed by MH (MH, WPLP and KHLP) as noted above;
> >
> > 3. An option with the continued deferral of amounts but with amortization over the average remaining service life of MH's assets of 49 years; and
> >
> > 4. An option assuming approval of all MH depreciation proposals, as noted above and contained in MH22.

Request:

Please comment on the status of the account based on the first option, under IFRS-14 exposure draft and discuss the implications from a financial reporting and rate setting purposes consistent with the proposed standard.

Response:

Mr. Rainkie concurs with the evaluation of MH (Appendix 4.3 Amended, Section 1.4.4, Pages 16 to 18) and Mr. Madsen who has provided evidence on behalf of GSS/GSM in this proceeding (Section 3.2.9, pages 34 to 41), that the PUB should approve a recovery (or refund) period for all RDA's, including the Depreciation related RDA's.

There has been discussion in past PUB proceedings and the current proceeding that the RDA capturing the difference between depreciation methodologies (ELG IFRS compared to ASL CGAPP) may naturally unwind over time as all depreciation methods are designed to provide a systematic recovery of the same balances of property, plant and equipment. However, it is unclear to Mr. Rainkie that given the forecasts of a growing asset base for MH into the future, that the cross-over point between methods and reversal/unwinding of these differences will be reached within any reasonable forecast period of time.

On balance, for both financial reporting and rate-setting purposes (RDA's are recognized in the financial statements of MH), it is important that the PUB specify a recovery period for the depreciation RDA's. This would ensure that the RDA balances continue to meet the criterial for deferral under both the interim and final IASB standards (assuming the exposure draft is finalized) that allow for continuation of rate-regulated accounting practices. In addition, it is appropriate from a regulatory perspective that MH be able to recover or refund all deferred costs or revenues in RDA's over an appropriate period of time that has been approved by the PUB.

As such, it appears that the status quo option (with no amortization of depreciation related RDA's) is not sustainable in the future and the PUB may either have to make a final determination of the appropriate depreciation method and related issues for rate-setting purposes or direct an alternate option (including approval of amortization periods) in the event that the final determinations on these issues cannot be reached in the current regulatory proceeding.

PUB/COALITION I-34 Reference: Rainkie Evidence pp.99-100 (section 8.3, Figures 20 and 21)

Request:

a) Please provide an alternative figure 20 providing a comparison of Option # 2 and Option #3 (49 year amortization period) shown on p. 97 of Mr. Rainkie's evidence.

b) Please provide an updated figure 21 adding option #3 (49 – year amortization period) shown on p. 97 of Mr. Rainkie's evidence.

c) Please indicate which is more appropriate period of amortization, that proposed by MH or the average remaining life of the assets and provide the merits of each approach.

Response:

a) Please see an alternative Figure 20 below, which provides a comparison of Depreciation RDA Option #2 (MH proposed amortization periods) with Option #3 (amortization over MH's average remaining service life of assets of 49 years or ARSL).

PUB/Coalition I-34a : Figure 20: Net Income Depreciation Options - $Millions

1	2	3	4	5
			(2 - 3)	
Year	Net Income MH Amortization Periods	Net Income ARSL	Net Income Difference	Cumulative Net Income Difference
2023	751	751	0	0
2024	462	466	-4	-4
2025	289	295	-6	-10
2026	151	157	-6	-16
2027	173	181	-8	-24
2028	111	119	-8	-32
2029	112	121	-9	-41
2030	137	146	-9	-50
2031	137	147	-10	-60
2032	207	218	-11	-71
2033	235	245	-10	-81
2034	268	280	-12	-93
2035	331	344	-13	-106
2036	309	323	-14	-120
2037	346	361	-15	-135
2038	376	391	-15	-150
2039	426	442	-16	-166
2040	506	523	-17	-183
2041	574	591	-17	-200
2042	634	652	-18	-218
Averages:				
1 - 10 Years	253	260	-7	-31
11-20 Years	401	415	-15	-145
1-20 Years	327	338	-11	-88

b) Please see an updated Figure 21 below, which adds Option #3 (amortization over MH's average remaining service life of assets of 49 years or ARSL) to the comparisons.

PUB/Coalition I-32b: Figure 21: Regulatory Deferral Account (RDA) Balances - $Millions & % of Total Assets - 2032 & 2042

	1	2	3	4	5	6	7	8
	MH22 2032 Forecast	MH Amortization Periods 2032 Forecast	MH ARSL 2032 Forecast	Status Quo 2032 Forecast	MH22 2042 Forecast	MH Amortization Periods 2042 Forecast	MH ARSL 2042 Forecast	Status Quo 2042 Forecast
DSM Programs RDA	396	396	396	396	550	550	396	550
Conawapa & Keeyask RDAs	298	298	298	298	162	162	298	162
Ineligible Overhead RDA	270	270	270	270	335	335	270	335
Other RDAs	169	169	169	169	18	18	169	18
Sub-Total	1133	1133	1133	1133	1065	1065	1133	1065
Depreciation Related RDAs	665	793	865	988	434	1194	1463	1830
Total RDAs	1798	1926	1998	2121	1499	2259	2596	2895
Total Assets	31419	31419	31419	31419	35422	35422	35422	35422
% of Total Assets:								
Depreciation Related RDAs	2.1%	2.5%	2.8%	3.1%	1.2%	3.4%	4.1%	5.2%
Total RDAs	5.7%	6.1%	6.4%	6.8%	4.2%	6.4%	7.3%	8.2%

c) As Mr. Rainkie noted in observation #4 on page 99 of his evidence – Option #3 (amortization over ARSL) has net income impacts that are reasonably similar to Option #2 (MH proposed amortization periods). While Option #3 (amortization over ARSL) has the slight benefit of administrative simplicity, if consideration is provided to the forecast RDA balances in 2041/42 which are $269 million or 0.7% lower (column 6 less column 7 in part b of this response), then on-balance, Option #2 (MH proposed amortization periods) is preferable.

PUB/COALITION I-35 Reference: Rainkie Evidence pp.107-108 (section 8.7)

Request:

a) Please indicate the merits of directing a portion of the excess profits in 2022/23 to the MCP in addition to the proposed reduction in payments to Government fees.

b) If merited, please file an updated analysis reflecting this scenario.

Response:

a) and b):

Mr. Rainkie observes that (1) the reductions to the payments to government fees form a significant portion of the MH profit in the 2022/23 fiscal year projected at $751 million and (2) regulatory deferral accounts most often are based on expense or revenue deferrals and not net income which encompasses all elements of expense and revenues (including those judged to be normal or excess).

If the PUB decides that it wants to defer a portion of the excess profits in 2022/23 in order to aid in rate smoothing over the subsequent years past the forward test years in this Application (2023/24 and 2024/25), then the windfall reduction to payments to government fees or the abnormally high levels of projected export revenues would be the logical candidates for an expense and/or revenue based addition to the MCP RDA.

The 50% and 100% deferral options summarized in Mr. Rainkie's evidence in Section 8.7 (pages 107 and 108), provide a significantly large range of additional deferral into the MCP RDA of between $272 million (36% of projected 2022/23 net income) and $543 million (72% of projected 2022/23 net income) to judge the merits of such a deferral of the contributors to the projected excess MH's profits in 2022/23.

Please also see the response to PUB/Coalition I-36, for further discussion with respect to the merits of deferring projected excess MH profits into the MCP RDA.

PUB/COALITION I-36 Reference: Rainkie Evidence p. 108 (section 8.7)

Request:

Please provide a similar analysis in Figure 24 comparing the impact of the two options, 50% and 100% deferral of the reduced payments to government and amortize the balance over the 20-year forecast, and discuss the merits of the longer time frame versus that proposed.

Response:

In the original Figure 24 from page 108 of Mr. Rainkie's evidence, the amortization of the 50% and 100% deferral can be summarized as follows:

- In the 50% deferral option the $370 million of the MCP RDA is amortized over 10 years = amortization of $37 million from 2025/26 to 2034/35; and
- In the 100% deferral option the $641 million of the MCP RDA is amortized over 10 years = amortization of $64 million from 2025/26 to 2034/35.

Mr. Rainkie has made a slight revision to Figure 24 to aid in the comparison requested in the question, such that the calculation of columns 5 and 6 now show the impact of the 50% and 100% deferral as compared to MH22 (the original Figure 24 had the difference columns being MH22 compared to the 50% and 100% deferral options).

Figure 24 Revised: Major Capital Deferral - Additional Options - $Millions

1	2	3	4	5	6
				(3 - 2)	(4 - 2)
Year	Net Income MH22	Net Income 50% Deferral	Net Income 100% Deferral	Net Income 50% vs MH22 Difference	Net Income 100% vs MH22 Difference
2023	751	659	567	-92	-184
2024	469	380	291	-89	-178
2025	295	207	119	-88	-176
2026	149	139	167	-10	18
2027	166	155	183	-11	17
2028	97	135	164	38	67
2029	92	130	158	38	66
2030	111	149	177	38	66
2031	105	143	170	38	65
2032	169	209	236	40	67
2033	190	229	256	39	66
2034	219	257	285	38	66
2035	277	314	341	37	64
2036	250	250	251	0	1
2037	282	283	283	1	1
2038	309	310	310	1	1
2039	358	359	360	1	2
2040	439	440	441	1	2
2041	507	508	508	1	1
2042	569	572	572	3	3
Averages:					
1 - 10 Years	240	231	223	-10	-17
11-20 Years	340	352	361	12	21
1-20 Years	290	291	292	1	2

In the alternate version of Figure 24 requested in the information request, the amortization of the 50% and 100% deferral can be summarized as follows:

- In the 50% deferral option the $370 million of the MCP RDA is amortized over 17 years = amortization of $22 million from 2025/26 to 2041/42; and
- In the 100% deferral option the $641 million of the MCP RDA is amortized over 17 years = amortization of $38 million from 2025/26 to 2041/42.

The alternate version of Figure 24 is provided below, including the revision to the difference columns:

PUB/Coalition I-36: Figure 24: Major Capital Deferral - Additional Options - $Millions

1	2	3	4	5	6
				(3 - 2)	(4 - 2)
Year	Net Income MH22	Net Income 50% Deferral	Net Income 100% Deferral	Net Income 50% vs MH22 Difference	Net Income 100% vs MH22 Difference
2023	751	659	567	-92	-184
2024	469	380	291	-89	-178
2025	295	207	119	-88	-176
2026	149	124	141	-25	-8
2027	166	140	157	-26	-9
2028	97	120	138	23	41
2029	92	115	132	23	40
2030	111	134	151	23	40
2031	105	128	144	23	39
2032	169	194	210	25	41
2033	190	214	230	24	40
2034	219	242	259	23	40
2035	277	299	315	22	38
2036	250	272	289	22	39
2037	282	305	321	23	39
2038	309	332	348	23	39
2039	358	381	398	23	40
2040	439	462	479	23	40
2041	507	530	546	23	39
2042	569	594	610	25	41
Averages:					
1 - 10 Years	240	220	205	-20	-35
11-20 Years	340	363	380	23	40
1-20 Years	290	292	292	1	2

In terms of the relative merits of the 10-year and 17-year amortization period, Mr. Rainkie notes the following observations:

- Rate smoothing through goal seeking the attainment of debt to equity ratios at the end of the forecast period (such as the 2% rate path in MH22) generally results in cumulative rate increases that “over-shoot” reasonable financial ratios by the end of the forecast period. The resulting rate paths from these goal seeking exercises are not balanced between the impacts on customers and the financial health of MH;

- In MH’s long-term financial forecasts, net income tends to be lower in the 10 or more years following the test years and then ramps up in the second decade of the forecast as a result of the impacts of cumulative rate increases over time;

- The specification of the 50% and 100% deferral options and a 10-year amortization period after the Test Years by Mr. Rainkie (Coalition/MH I-42 fg) was designed to defer the historically high financial results in the bridge year (2022/23) and forward Test Years (2023/24 and 2024/25) into the MCP RDA – creating a larger balance in the MCP RDA. The objective is to increase net income in the first decade of the forecast, without the need to ramp up rate increases to levels in the first decade of the forecast - that will eventually overshoot reasonable financial targets in the second decade;

- Stated differently, the rate smoothing occurs from deferring the favorable financial results from the first three years of the financial forecast to the next 10 years of the forecast – rather than requiring higher than necessary rate increases to “prop up” financial results in the first decade of the forecast – only to “over-shoot” financial results in the second decade of the forecast;

- The alternative of a 17-year amortization (as compared to a 10-year amortization period) would defeat the purpose of the larger MCP RDA to a certain extent – given that a 17-year amortization period would produce lower net income in the first decade of the forecast (when higher net income is desirable for rate smoothing) and higher net income in the second decade of the forecast (when it is generally not needed); and

- The 10-year amortization of a larger MCP RDA is a more balanced option of rate smoothing for customers than a 20-year goal seeking exercise or a 17-year amortization period.

For the above noted reasons, Mr. Rainkie’s view is that the 10-year amortization period for a 50% to 100% MCP RDA deferral option is superior to the 17-year amortization period and a 2% rate path based on a goal seek of a debt to equity ratio target in 2039/40.

PUB/COALITION I-37 Reference: Rainkie Evidence p. 111 (section 9.0)

Preamble:

At p. 111 of his evidence, Mr. Rainkie states:

> The MH rate increase proposals of a 2% rate increase on September 1, 2023 and a 2% rate increase represent a cumulative rate increase of 4.04% or approximately $74 million on an annualized basis. The net present value (NPV) of these two rate increases to customers in perpetuity is approximately $1.5 billion, assuming a social discount rate of 5%. [Footnotes deleted]
>
> The rate increases that are proposed to be confirmed or awarded for the four test years under review in this Application (2021/22, 2022/23, 2023/24 and 2024/25) represent a cumulative rate increase of 7.79% or approximately $139 million on an annualized basis. The NPV of these three rate increases to customers in perpetuity is approximately $2.8 billion, assuming a social discount rate of 5%. [Footnotes deleted]

Request:

Please provide the definition of the social discount rate and its determination at 5%.

Response:

The use of a social discount rate estimates the NPV of the proposed rate increases using a ratepayer cost of capital, as it is the ratepayers that bear the cost of the rate increases in perpetuity.

The source of the social discount rate of 5% was the Morrison Park Advisors (MPA) October 2017 Report (Consumers Association Exhibit #17) to the PUB as part of the 2018/19 MH GRA. On page 48 of the MPA report, lines 11 to 17, MPA indicated that the ratepayer cost of capital is estimated at 5%, made up of a 3% real discount rate and an assumed rate of inflation of 2%.

The social discount rate of 5% compares to the MH weighted average cost of capital (WACC) of 5.75% that was used in calculating NPV's of the rate increases (to 2041/42) in the response to PUB/MH I-17 abcd.

For comparison purposes, using the MH WACC of 5.75% would produce an NPV of the 4.04% rate increases in the forward test years of $1.3 billion ($74 million/.0575) and of the 7.79% rate increases in the four test years that are the subject of this Application of $2.4 billion ($139 million/.0575), in perpetuity.