## GSS-GSM/Coalition-1

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| **Part and Chapter:** | The Deepening Gap: Energy Poverty in Manitoba and the Way Forward, by Dr. Das | **Page #:** | 31 |
| **Topic:** | Rate Design | | |
| **Subtopic:** | Economic Efficiency | | |

**Preamble (if any):**

Page 31 of Dr. Das' report states the following:

> **Rate design tools** are increasingly part of the equity debate. Conventional rate structures distribute costs uniformly across customer classes, but there is research that highlights their potential to either deepen or mitigate inequities. For instance, time-of-use rates or fixed charges can disproportionately affect low-income households with limited flexibility to shift demand. A recent working paper on designing electricity rates for an equitable energy transition argues for explicitly embedding equity into rate-setting, including affordability thresholds and protections for vulnerable households (Borenstein et al., 2021). This aligns with the *Advisory Council*'s call for shifting some costs from ratepayers to taxpayers to balance overall affordability while safeguarding investments needed for decarbonization.

The reference for the Borenstein et al. report is provided on page 44 of Dr. Das' report, and available online https://www.next10.org/publications/electricity-rates

The referenced Borenstein report discusses economic efficiency in rate design, including for example on page 34:

> The core objective of this analysis is to propose a tariff that is more economically efficient. Roughly, this means a tariff with volumetric prices that are as close to social marginal cost as possible.
>
> …
>
> In addition, the volumetric rate should be time varying, as marginal costs vary across hours and days.

**Question:**

a) Is it the opinion of Dr. Das that rate structures designed for economic efficiency should be avoided to protect vulnerable households and those that have limited flexibility to shift demand?

   i) If yes, please explain how in an environment such as Manitoba Hydro's with increasing electricity demand and prices for capacity, price signals should be considered to help slow these increases.

b) If economically efficient rate structures are considered for residential and commercial ratepayers (such as those discussed in the Borenstein report), what specifically does Dr. Das recommend to shift 'costs from ratepayers to taxpayers to balance overall affordability while safeguarding investments needed for decarbonization'.

**Rationale for Question:**

**Response:**

a) It is not my opinion that economically efficient rate structures should be avoided. Rather, they should be implemented with equity safeguards. While marginal-cost pricing improves efficiency, it can disproportionately affect low-income and electrically heated households with limited flexibility to shift demand.

   Borenstein et al. (2021) also propose income-based rates as one way to reconcile efficiency and equity. Under this approach, volumetric prices still reflect the true cost of electricity (preserving efficient price signals), while charges or vary by income, protecting affordability for vulnerable customers.

   In Manitoba's context—where winter heating loads and building inefficiencies limit responsiveness—price signals should be introduced gradually and paired with targeted bill credits, income-qualified rebates, or efficiency upgrades to maintain affordability while moderating peak demand growth.

b) Borenstein et al. (2021) suggest balancing efficiency and equity by funding some fixed or policy-related costs through taxation rather than electricity rates. In Manitoba, this could mean shifting low-income supports or decarbonization incentives from Hydro's rate base to provincial or federal funding, recognizing the public-good. This approach preserves Hydro's cost-recovery integrity while enhancing affordability through progressive, taxpayer-funded mechanisms.

## GSS-GSM/Coalition-2

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| **Part and Chapter:** | Midgard Report | **Page #:** | 22 |
| **Topic:** | Vegetation Management | | |
| **Subtopic:** | Willingness to pay & social permission for capital expenditures | | |

**Preamble (if any):**

Page 22 of the Midgard states that:

> MH's customer consultation shows that customers consistently prioritize price over other factors, and although ratepayers are willing to accept higher prices to maintain system reliability, support is limited, with residential customers preferring rate increases at or below inflation. Rate increases materially above inflation are not supported by the majority of ratepayers, and the successive 3.5% increases proposed by MH exceed the range tested in MH's consultation surveys.

Section 8 of the Midgard evidence proposes adjustment to the Vegetation Management O&A spending in the test years.

**Question:**

a) In Midgard's opinion, are customer consultation results regarding system reliability and affordability acceptance a valid consideration in preparing Vegetation Management plans, including in pacing increased activity and spend? Please explain.

   i. If yes, does the proposed forecast spending for Vegetation Management reflect spending levels at or below inflation, reflecting customer preferences? Please explain.

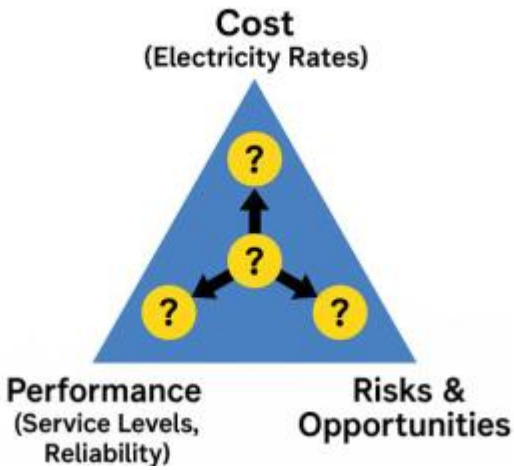
b) Please provide recommendations for Key Performance Indicators (KPIs) and/or benchmarks that should be used to assess and measure effectiveness of Vegetation Management activities.

**Rationale for Question:**

**Response:**

a) Yes, customer consultation results regarding system reliability and affordability are a valid consideration in preparing vegetation management plans, including in pacing increased activity and spending. Asset management, which includes

vegetation management, always involves balancing cost, risk, and performance (reliability). As stated in Midgard's evidence:

> *"…the revenue requirement and consequently the rates paid by ratepayers, regulatory boards must make trade-offs between ratepayer costs (the proposed … investments which will affect rates), system performance (the expected service quality and reliability impact of the investments) and risks (the system, safety, environment and economic hazards and opportunities the investments are intended to address). This trade-off concept is illustrated in Figure 11.*
>
> **Figure 11: Regulatory Trade-off Between Cost, Performance and Risk**
>
> 
> 
>
> " [1]

Without customer consultation results, the trade-off between vegetation management costs and customer preferences regarding performance and risk cannot be adequately assessed.

For clarity, trade-offs should not be viewed in isolation. MH should assess vegetation management budgets in the broader organizational context to ensure that spending delivers equivalent or greater benefits per dollar than other investments. For example, MH should not spend an additional $1 on vegetation management if an equivalent ratepayer outcome could be achieved for less than $1 elsewhere in the organization, and vice versa. As stated in Midgard's evidence:

> *"Moreover, and for clarity, from an organizational cost-effectiveness standpoint, vegetation management budgets should be set to achieve an appropriate level of risk mitigation per dollar spent, consistent with the level of risk reduction achieved by alternative capital investments from across the entire organization. Underspending on vegetation management while allocating funds to capital projects is imprudent if the marginal SAIDI and SAIFI benefits from increased vegetation control exceed those from additional capital spending elsewhere in the organization (and vice versa).*

[1] Exhibit CC-13, Section 6, p. 36, l. 19 to p. 37, l. 2.

*Midgard has not found evidence that MH evaluates vegetation management budgets against capital investment alternatives on an organizational marginal risk-mitigation basis, and therefore cannot support proposed spending levels in this context."* [2]

i. MH's proposed vegetation management spending is increasing by 20.6%[3] per year over the test period, which is far higher than the forecast 2.1-2.2% rate of inflation[4] over the same period. In recognition of historic resource constraints faced by MH, the recommendation proposed by Midgard also increases faster than the forecast rate of inflation, but at a far lower rate than the rate proposed by MH. Midgard proposes a substantial 9% per year increase in comparison to the 20.6% per year increase proposed by MH.

Midgard believes that its proposal better reflects the trade-off between cost, risk and performance desired by residential ratepayers. Midgard's proposed rate of increase is closer to stated customer desires for rate increases closer to the rate of inflation, reflects MH's historic resource constraints, and reflects spending trends that have contributed to MH's reliability metrics that are both better than MH's Canadian peers and acceptable to residential ratepayers as per MH's customer survey.

b) Midgard recommends the following Key Performance Indicators (KPIs) and benchmarks to assess and measure the effectiveness of Vegetation Management activities:

1) Distribution: Annual Vegetation Management Budget per Right-of-Way-km (ROW-km)

2) Transmission: Annual Vegetation Management Budget per ROW-km

3) Annual Vegetation Management Budget per GWh delivered (Domestic)

4) Annual Vegetation Management Budget per GWh delivered (Domestic + Extra-Provincial)

5) Percentage of Distribution Outages by Primary Cause (see Manitoba Hydro Response to COALITION/MH I-47(a)(i–xii), p. 3 of 4)

6) Percentage of Transmission Outages by Primary Cause

7) NERC vegetation management non-compliances (by count)[5]

[2] Exhibit CC-13, Section 8, p. 94, l. 13-20.
[3] Increasing from $23.5M at the end of 2024/25 (start of 2025/26) to $41.2M at the end of 2027/28 is equivalent to a compounding 20.6% annual increase over that period.
[4] Exhibit MH-1, Tab 9, MFR 58, Figure 1, p. 2 of 9.
[5] This metric may be confidential between the Manitoba PUB and MH.

Midgard's proposed KPIs are focused on ratepayer outcomes rather than isolated vegetation removal efficiency metrics such as "$/Hectare Cleared." Midgard does not recommend such isolated metrics because they can incentivize undesirable behaviors, such as clearing larger ROW areas to reduce unit costs without improving ratepayer outcomes (i.e., targeted reliability at lowest cost). MH is not a forestry company aiming to clear trees more efficiently. It is a utility that should focus on mitigating risks more cost effectively.

From the utility perspective, a tree is not a tree, it is a potential risk, and a utility vegetation management program should be evaluated against its risk reduction cost effectiveness. In the future, MH may consider adding additional risk-related KPIs to measure the total risk posed by vegetation on and around the ROW and the risk mitigation achieved per dollar spent. Based on the evidence reviewed by Midgard, however, MH is not yet ready to implement such KPIs.

Finally, Midgard recommends that MH always benchmark its vegetation management KPIs against its own historical performance. Self-benchmarking allows MH to track and quantify internal process improvements, efficiency gains, and risk mitigation effectiveness over time. Such self-benchmarking highlights whether a utility's productivity and effectiveness are improving or declining over time.

**GSS-GSM/Coalition-3**

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|---|---|---|---|
| **Part and Chapter:** | Midgard Report | **Page #:** | 68, 79 |
| **Topic:** | HVDC Reliability Capital Expenditures | | |
| **Subtopic:** | | | |

**Preamble (if any):**

HVDC reliability spending in the test years as shown at page 68 of the Midgard report:

| | FT26 | FY27 | FY28 | FY29 | FY30 | FY31 | FY32 | FY33 | FY34 | FY35 |
|---|---|---|---|---|---|---|---|---|---|---|
| HVDC Reliability | 26.2 | 341.4 | 551.7 | 768.9 | 1003.1 | 1122.9 | 690 | 492.6 | 522.2 | 553.3 |

Page 79 states:

Midgard recommends that the proposed Test Period spending of $920M for the HVDC Reliability Project be largely deferred beyond the Test Period, with Bipole II converter replacement deferred three years and Bipole I replacement deferred six years.

**Question:**

a) Can Midgard explain how it came up with the specific deferral periods of six and three years for Bipole I and II HVDC Reliability spending respectively?

b) Are there any resulting impacts on revenue requirement (i.e. is any of the HVDC reliability spending in the test years expected to be put in-service within the same test period from 2025/26 to 2027/28)? If so, please provide estimated impacts.

c) In Midgard's opinion, is capital expenditures, such as HVDC reliability spending, appropriately included within an Integrated Resource Plan when the timing of expenditures may be flexible, and are not necessarily being justified for reasons other than near-term domestic need? Please explain.

**Rationale for Question:**

**Response:**

a) Several factors contributed to the deferral recommendations. The most important factor is that the evidence did not support MH's proposed project initiation timings in terms of existing risk and risk mitigated by the projects. The evidence provided

by MH does not support completing both Bipole I and Bipole II (collectively, the "HVDC Reliability Project") on the initial schedule proposed by MH.[6]

Regarding the specific selection of three years for Bipole II, it was deferred so that the project need and scope could be reconsidered in the next GRA after MH improves its project definition, scoping, and cost estimation. A Class 10 estimate is highly preliminary for long range planning and has no set accuracy range[7], and as a result is so preliminary and conceptual that it has little merit.[8] As stated by MH:

> *"Class 10 estimates are early, high-level estimates based on conceptual assumptions, used for budgeting future needs when scope and methods remain to be developed. AACE defines Class 10 estimates as cost estimates prepared for longer term planning needs, where specific project definition is primarily supported by the description of an identified future, but not a specific project scope."*[9]

For an investment of this size, a more reasonable estimate would be a Class 3 (or 4) estimate, similar to what BC Hydro is required to file in its Revenue Requirements Application ("RRA") and Certificate of Public Convenience and Necessity ("CPCN") applications:

1. BC Hydro CPCN filings use Association for the Advancement of Cost Engineering International ("AACEI") cost estimate classes. For example, the Lower Mainland Reactive Power Reinforcement Project CPCN cites a Class 3 estimate based on preliminary design.[10]

2. For Revenue Requirements Applications, estimates reflect more advanced phases. For example, BC Hydro's Fiscal 2024 Annual Report distinguishes that for capital projects, the total forecast cost used for Implementation phase (and in-service projects) is the "Authorized Amount," and for pre-Implementation, the "Pre-Implementation Cost Estimate" is cited.[11]

Advancing from Class 10 to Class 3 (or 4) will take time, and three (3) years is a reasonable estimate for the additional work required to refine the estimate class to be undertaken, while also coinciding with the next GRA timeframe. Moreover, MH acknowledges its expectation that the project scope and estimate will change after the Front-end Engineering Design ("FEED") is completed:

> *"Manitoba Hydro … will collaborate with the OEM for the Front-end Engineering Design ("FEED") phase of the project to develop the scope and*

[6] Exhibit CC-13, Section 7.4, p. 68, l. 17-19
[7] Manitoba Hydro response to PUB-MH II-32 (b)
[8] Exhibit CC-13, Section 7.4.2, p. 78, l. 3 to p. 79, l. 23.
[9] Manitoba Hydro response to PUB-MH II-32 (d)
[10] BCUC Project No. 1599385, Exhibit B-1, Section 1.2.3, p. 1-7, l. 15-17. Link.
[11] BC Hydro, Fiscal 2024 Annual Report to the British Columbia Utilities Commission. Link.

*estimate for the project. It is expected that the scope and estimate will change after the FEED phase has been completed."* [12]

Regarding the six-year deferral of Bipole I, MH estimated that the Bipole II upgrade would require a six-year lead time[13] and provided only a Class 10 estimate. Based on MH's proposed schedule, the Bipole II and Bipole I would proceed, in part, concurrently. Midgard proposes separating the upgrade projects so they do not overlap and to enable the Bipole I upgrade to benefit from the learnings of the Bipole II upgrade. Midgard also included one year of schedule slack between the two projects to account for possible delays in completing the Bipole II upgrade. Schedule slack is reasonable and necessary given the recent delivery performance of major utility projects in Manitoba and across Canada, and in consideration of the preliminary nature of the existing Class 10 estimate and project scope. As a result, the initiation date for the Bipole I upgrade was deferred six years.

b) The Manitoba-specific rules and precedent for determining when early-stage project activities such as project scoping, initial design, consultation, permitting, and limited long-lead procurement are included in MH's revenue requirement are outside Midgard's direct experience. However, MH has identified the "HVDC Reliability Scope Development" capital spending separately from the remainder of the "HVDC Reliability" capital spending. Since these activities have been identified separately, Midgard anticipates that the "HVDC Reliability Scope Development" spending will be included in the test period revenue requirement. Accordingly, please refer to Morrison Park Advisor's filed evidence for its assessment of the revenue requirement implications of Midgard's proposed capital schedule.[14]

c) Investments the size of the HVDC Reliability Project could be included within the transmission portion of an Integrated Resource Plan on that basis that a planned retirement date is known for the existing HVDC assets (i.e. Bipole II and I). Filing an Integrated Resource Plan creates a forum where major transmission constraints can be identified and mitigation options assessed for need, timing, and the resulting impacts on resource alternatives.[15] The drivers of transmission need typically include forecast transmission capacity constraints (considering already committed additions and planned retirements), forecast domestic load, and firm export obligations. The inclusion of major transmission capital such as the HVDC

[12] Manitoba Hydro response to PUB-MH II-32 (d)
[13] Manitoba Hydro response to PUB/MH II-32(a-d), Attachment 1, Section 4.1, p. 44 of 57. *"The 6-year lead time considers the feasibility/planning study, RFP preparation, RFP process, design, manufacturing, factory tests, construction and commissioning based on the experience of Bipole III project and other similar HVDC refurbishment projects. If the feasibility/planning study and RFP preparation can be done at an early stage, the lead time is expected to be reduced by about 1.5 to 2 years."*
[14] Exhibit CC-15, Section 4, p. 22, l. 7-27.
[15] There can be other standalone processes to assess forecast need and options to address that need (e.g., Certificate for Public Convenience and Necessity in BC), but an integrated resource plan is a common place to evaluate these issues and establish the timing of larger projects. However, regardless of where need and preferred options are selected, a better estimate than Class 10 is required to approve the capital investment.

Reliability Project would not be tied only to near-term domestic need but to the expected constraints and resource options available to MH, whether domestic or non-domestic.

**GSS-GSM/Coalition-4**

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|---|---|---|---|
| **Part and Chapter:** | Midgard Report | **Page #:** | 78 - 79 |
| **Topic:** | HVDC Reliability Project | | |
| **Subtopic:** | Cost Estimate Uncertainty | | |

**Preamble (if any):**

The Midgard report summarizes Manitoba Hydro's capital expenditure as a "high-level Class 10 estimate, prepared for budgeting purposes with scope and methods to be developed at a future date."

The Midgard report summarizes the AACE guidance on Class 10 estimates, as:

> *"This type of estimate is highly conceptual, with limited scope definition, and often based on parametric or analogous assumptions. Specific engineering information and project development details are typically lacking, even more so than for a Class 5 estimate."*

**Question:**

a) Is the spending forecast for the HVDC Reliability Project based on a Class 10 estimate in each year (i.e. including test year periods)? If not, please differentiate the types of budget estimate for each year of spending.

b) In Midgard's experience with past Manitoba Hydro capital expenditure plans and in other jurisdictions, is a level 'Class 10' estimate normal course in justification for capital spending being undertaken in the test years? Is it acceptable for longer-term forecasts in which rate increases are being set?

    a. Please provide examples of other jurisdictions, especially if there are any for similar types of works as Manitoba Hydro is proposing with its HVDC Reliability project.

c) At a high level, please explain the different class levels for capital expenditure budgets, and highlight what range of levels is most appropriate to submit in support of a general rate application. In your response please specify if the appropriate 'Class' level differentiates between the near-, medium- and long-term forecast.

d) Based on the response for part (c) above, how does a Class 10 budget differentiate from an acceptable Class level budget for supporting a rate

application (i.e. what further information and steps would be required for the acceptability of Manitoba Hydro's HVDC reliability capital budget for rate setting purposes)?

**Rationale for Question:**

**Response:**

a) Based on the available evidence, the HVDC Reliability Project spending for each year should be treated as a Class 10 estimate.

b) Based on Midgard's experience in other jurisdictions, a Class 10 estimate is not typical for major capital investments similar in magnitude to the HVDC Reliability Project (i.e. an order of magnitude similar to Keeyask). When seeking approval for a project of this magnitude that ratepayers are being asked to underwrite, a more detailed cost estimate is typical, appropriate, and in some jurisdictions, mandatory. For example, in British Columbia a typical utility capital project follows these development stages:[16]

1. Identification Phase: Projects begin with an assessment of needs, risks, and alternatives. Budget targets are high-level (Class 5 estimates) and no financial approval is granted. Board review is required for high-value projects.

2. Definition Phase: Detailed engineering, risk analysis, and business case development refine budget targets (Class 3 or 4 estimates). Financial approval and board endorsement are required for large projects.

3. Implementation Phase: Construction and execution occur within fixed, authorized budgets that include reserves for variances. Significant budget or scope changes require board or committee approval.

4. In-Service Phase: The project transitions to operation. Post-implementation review compares actual costs to forecasts for lessons learned.

This is the first proceeding in which Midgard has seen a declared Class 10 estimate used to support budgeted costs within a test period. Midgard does not have a firm opinion on the acceptability of a Class 10 estimate for projecting rate trajectories beyond the test period, as the actual trajectory is often determined by a combination of well understood cost components and less certain cost risk factors. However, Midgard has not seen regulatory budget approval for a capital project the size of the HVDC Reliability Project based on a Class 10 estimate, even in cases where some spending extends well into the future.

[16] BC Hydro, Board Governance Manual, Terms of Reference: Capital Projects Committee, p. 2 of 3. Link.

a. Please refer to Midgard's response to part b).

c) As MH states:

> *"Class 10 estimates are early, high-level estimates based on conceptual assumptions, used for budgeting future needs when scope and methods remain to be developed. AACE defines Class 10 estimates as cost estimates prepared for longer term planning needs, where specific project definition is primarily supported by the description of an identified future, but not a specific project scope."* [17]

Based on the BC Hydro example from Midgard's response to GSS-GSM/CC-3, a Class 3 is an appropriate level to submit for approval. However, in Midgard's experience, utilities sometimes inadvertently overstate the actual quality of the cost estimate provided, so it is not unreasonable to expect that the actual quality could be one estimate class worse than declared, hence the "Class 3 (or 4)" text in the response to GSS-GSM/CC-3. For clarity, Midgard is not suggesting that BC Hydro actively acts in this manner, Midgard believes utilities intend to provide Class 3 estimates when declared as such. Midgard is providing a broader observation beyond the specific BC Hydro example referenced herein.

Class levels are not differentiated by near-, medium-, or long-term timeframes because they are cost estimates associated with a specific project, not forecasts of an input (e.g., inflation) or a market factor (e.g., the price of diesel, steel, or labor in the future).

d) A Class 10 estimate is not adequate to justify a project of the magnitude of the HVDC Reliability Project or the resulting impact on rates. Midgard cannot define the appropriate Class estimate for rate-setting purposes, as setting rates does not constrain which projects MH will choose to execute. A Class 10 estimate provides limited evidentiary value for supporting the rate trajectory impacts that will ultimately be driven by such a significant capital expenditure. Notwithstanding this observation, Midgard recommends that a Class 3 (or 4) estimate is more appropriate, given the size of the investment and its implications for MH's fiscal health and ratepayer cost risk.

[17] Manitoba Hydro Response to PUB/MH II-32(d), p. 9 of 9.

## GSS-GSM/Coalition-5

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|---|---|---|---|
| **Part and Chapter:** | Midgard Report | **Page #:** | 24 - 27 |
| **Topic:** | Customer Connection | | |
| **Subtopic:** | Customer Consultation | | |

**Preamble (if any):**

In section 4.2 of the Midgard Evidence, Midgard assesses the usefulness of Manitoba Hydro's customer value survey.

In GSS-GSM/MH I-16a, Manitoba Hydro details the steps it takes in its customer connection process.

When asked in GSS-GSM/MH I-16b, Manitoba Hydro states it does not quantitatively benchmark or monitor its customer connection process steps including cost, communication, process delays, time to completion.

In response to GSS-GSM/MH II-15a & GSS-GSM/MH II-16e, Manitoba Hydro describes its sole service extension improvement target, aiming for five days on average, to energize residential customers within pre-serviced subdivisions (Winnipeg, Selkirk & Steinbach) once inspections are passed and all requirements are met and only specifically for pre-serviced subdivisions.

**Question:**

a) In Midgard's experience in other jurisdictions, what do other utilities do to track, benchmark and improve the process of customer connections (especially in relation to standards, costs, and timelines)?

   a. Please specify between residential, commercial and industrial level connections if possible.

   b. Please provide examples of other jurisdiction improvement initiatives that have been undertaken to improve timelines, transparency or cost in relation to customer connection activities.

b) In Midgard's view, is Manitoba Hydro's lack of quantitative tracking for customer connection activities including for costs, communication, process delays and completion timelines normal course for utilities? Please explain.

c) Please provide any benchmarks and/or KPIs that may be worthwhile for Manitoba Hydro to adopt if it aims to improve its customer connection process, communications, timelines and cost efficiencies.

**Rationale for Question:**

GSS-GSM is trying to understand best practice for customer service connections for new residential, mass market commercial, and industrial customers. Midgard is the expert in this proceeding with scope related to distribution capital expenditures.

**Response:**

a) In Midgard's experience, utilities generally track two types of metrics for customer connections. The first type relates to unit costs per connection, separated by customer type (e.g., residential, general service of various sizes, and industrial of various sizes and/or connection voltages). Unlike the vegetation management example discussed in Midgard's response to GSS-GSM/CC-2(b), unit cost metrics are appropriate here because utilities have a duty to serve, and the customer determines the capacity of the required connection, not the utility. Therefore, showing improving productivity, as demonstrated by reducing unit costs, is appropriate.

   The second type of metric pertains to the time required to complete customer connections. Determining which steps to include in the measure of time metric is critical and often subject to debate. A key feature from both customer and utility perspectives is defining the start trigger and the end condition for each step in the connection process. For example, for the interconnection study step of a multi-step interconnection process, the clock starts when the customer deposit is received for an interconnection study and stops when the study is delivered to the customer. The utility should not be penalized for the time it takes a customer to secure funds and make the deposit, while the customer expects the utility to act promptly once the deposit payment is made. The process repeats for each step of the connection process when there are multiple steps (e.g., interconnection request, study, permitting and connection construction).

   For simple connections (e.g. residential connections), a similar process defining the start trigger and the end condition occurs, but once the process is started the activities effectively all the utility's responsibility. For example, once the residential or general service customer has requested an interconnection and provided the deposit, the clock starts and does not stop until the connection is complete because all the intermediate steps are within the utility's responsibility and control.

   As interconnections range from simple (e.g., a residential house connection comprising a single low voltage span) to complex (e.g., large industrial loads or distributed generation interconnections), the number of steps increases. The key is to define the steps governing the overall process (e.g., interconnection study, permitting and construction times) and exclude uncontrollable factors (e.g., the time it takes a customer to commit and pay deposits).

   Metrics must also be defined to account for the customer type or selected service voltage (which will typically be different for residential, commercial and industrial customers).

i) Please refer to Midgard's response to part a).

ii) One key initiative Midgard has seen implemented successfully is the development of written interconnection standards, providing both the utility and the applicable customer (e.g., industrial or distributed generation customer) with a consistent benchmark for assessing technical decisions. Standardization reduces surprises by making customer requirements explicit, and it reduces utility workloads and timelines because once customers provide the stated inputs, the utility has what they need to complete the work (otherwise the utility standard is deficient and must be upgraded). Another complementary initiative is providing standard study and construction cost estimates to the customer, along with clear indications of the factors that could increase costs.

b) A lack of quantitative tracking for customer connection activities, including costs, communication, process delays, and completion timelines, is not uncommon for Canadian utilities. However, it is not best practice. Some utilities have improved transparency and performance by tracking costs, expected communications, sources of process delay, and expected completion timelines. Midgard cannot accurately assess where MH falls on the spectrum between poor and best practice, but best practices do exist, and Midgard is confident that peer utilities would be willing to share knowledge in areas where MH seeks improvement.

c) Midgard recommends that MH review its current interconnection processes and apply KPIs as outlined in part (a) above. Based on the available evidence, there is insufficient detail on the record to make specific KPI recommendations, but the general guidance in part (a) provides a reasonable starting point.

## GSS-GSM/Coalition-6

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| **Part and Chapter:** | Morrison Park Advisors Report | **Page #:** | 11 |
| **Topic:** | Rate Impacts | | |
| **Subtopic:** | | | |

**Preamble (if any):**

Morrison Park Advisors Report, page 11 states:

> The Keeyask Generating Station is a case in point: the facility was constructed not because it was immediately necessary to serve domestic load (it was forecast to be *eventually* necessary to serve domestic load, but not for the first number of years after its planned in-service), but because it was believed that the energy produced could be sold at a profit in export markets, therefore delivering benefits to Manitobans. Instead, the project was late, over-budget, and has not been profitable. The result was significant upward pressure on domestic rates, as compared to what would have been the case had the project not been undertaken.
>
> …
>
> A saving grace for domestic ratepayers has been that the Province, over the past three years, has chosen to reduce these taxes and fees, and has therefore shifted some of the burden of the project away from domestic ratepayers and onto taxpayers.

This question may be best answered by a combination of Coalition experts, specifically Morrison Park Advisors and Darren Rainkie, as it covers both areas of expertise and approved scope in this proceeding.

**Question:**

a) Please quantify the statement that Keeyask "has not been profitable", as it relates to revenue requirement and domestic rates in the years since Keeyask was in-service and in the forecast period.

b) Please quantify, to the extent possible, the amount of the Keeyask project cost burden that has been shifted from domestic ratepayers onto taxpayers in the years since Keeyask was in-service and in the forecast period.

**Rationale for Question:**

**Response:**

a) Keeyask and domestic rates

In the NFAT process in 2013/14, the PUB publicly examined a number of development plans proposed by Manitoba Hydro at the time, in order to advise the government of the day on the approval of major capital expenditures proposed by Manitoba Hydro. A critical choice at that time was whether to pursue the development of the Keeyask hydroelectric generation station and a supporting transmission line to the United States, or instead cancel that project and prepare to build natural gas-fired electricity generators to serve only domestic load, rather than exports.

MPA was an expert witness in the NFAT process, and undertook substantial analysis of the alternatives, including testing multiple future scenarios to understand the strengths and weaknesses of each option (and a number of other options considered at the time).

At the time of construction commencement in July 2014, the proposed budget for the Keeyask GS was $6.5 Billion (which had already been increased from earlier, lower estimates), and the target in-service date was 2019/20. Notably, the export transmission line was an integral part of the capital spending plan option, so the "real" cost of saying yes to Keeyask was even higher (in the gas-based alternative, no export transmission line was required). Moreover, saying no to Keeyask at that time would not have meant the immediate construction of gas-fired plants, since Manitoba load was not expected to require new supply until some time in the 2020s: the exact date and nature of construction could therefore be left to future decision-making.

Based on all of the available information and budgets supplied by Manitoba Hydro, MPA's analysis at the time concluded that the construction of the Keeyask GS and its associated export transmission line was at least as good an option for Manitoba ratepayers as the gas-based alternative.[18] However, we noted that a cost overrun of $1 B would mean that the Keeyask option would deteriorate and be inferior to the gas alternative by at least some measures. By extension, though this was not stated at the time, an even larger cost overrun would make the plan clearly inferior.

In the event, the Keeyask GS cost $8.7 Billion, and began producing electricity in February 2021 rather than November 2019, an overrun of $2.2 Billion and 15 months. This level of cost overrun means that Keeyask clearly turned out to be inferior to the alternative.

- While interest rates over the construction period were lower than forecast at the time of the construction approval, export prices have also been lower than forecast, so these two factors at least partially cancel each other out.

[18] Please see Exhibit MPA-3-1, at Morrison Park Advisors (MPA) Exhibits

- Building Keeyask and signing the associated export contracts has made Manitoba Hydro more financially sensitive to droughts than it otherwise would have been. The fact that several years of drought has coincided with the completion of Keeyask is an additional stroke of ill fortune, at the worst possible time when Manitoba Hydro debt levels are at their highest point, at least partially as a result of Keeyask.[19]

- The size of the cost overrun is such that it overwhelms any possible counter-argument about the long-term value of Keeyask and the transmission line.

- Manitoba domestic load has grown more slowly than was predicted at the time of the Keeyask decision, and hence had Keeyask not gone ahead, it is likely that construction of other electricity generation supplies would have been delayed further, beyond what was contemplated and analyzed in 2013/14.

With this context in mind, it is nearly impossible to calculate the "net cost" of Keeyask to ratepayers, save to say that the alternative – i.e., not constructing it and its associated transmission line – would have left Manitoba ratepayers better off.

- The commercial details of the export contracts associated with the Keeyask GS and transmission line project are not public.
- The timing of alternative generating station construction, had it been necessary to build it, is not clear, because of the change in load forecast that has occurred.
- The nature of what would have been planned as an alternative (i.e., combined or single-cycle gas turbines, wind power, batteries, etc.) is not clear (since the costs of each of these technologies has changed so much over the past 12 years).
- The timing of drought years cannot be foreseen or controlled, and so would it be fair to include the impact of drought on Keeyask's performance in terms of calculating its costs against a notional alternative plan?

As a final point on this issue, it is notable that the First Nations partners on the Keeyask GS project exercised their option to convert their common equity to preferred equity after the project was completed. Ostensibly, this was because they believed that the minimum annual payments associated with preferred equity would result in higher dividends than common equity payments that depend on the profitability of the Keeyask Partnership over time.

b) Shifting of cost burden to taxpayers

[19] Note that Manitoba Hydro was also approximately $2 Billion over budget on the Bipole III project nearly concurrently with Keeyask, contributing to Manitoba Hydro's predicament.

In 2022, the Government of Manitoba cut the Debt Guarantee Fee from 1% per annum (calculated based on outstanding Manitoba Hydro debt borrowed from the government) to 0.5% per annum. As of April 1, 2025, that rate was reduced to 0.4%, in 2026 to 0.3%, and in 2027 to 0.15%. This change is very substantial. As of March 31, 2025, Manitoba Hydro's outstanding long-term debt was approximately $25 Billion. At a rate of 1%, this would be an annual payment to government of $250 Million, however at a rate of 0.15% it would only be $37.5 Million, a reduction of $212.5 Million per year.

In 2022, the Government of Manitoba cut the Water Rental Fee in half. In the year ended March 31, 2025, the water rental fee recorded by Manitoba Hydro was $69 Million. Had the rate not been reduced, the fee would have been double, at $138 Million.

In 2025, the Government of Manitoba announced the cancellation of the Crown Corporations Capital Tax. In the year just ended, that tax amounted to $131 M (the same as in the year previous), but it will no longer be paid.

Summing up these various changes, the Government of Manitoba has voluntarily reduced its revenues by over $400 Million per year, apparently indefinitely (though any of these decisions could be reversed by any future government at any time).

By way of comparison, the Keeyask Hydropower Limited Partnership recorded revenues of approximately $364 Million in the year ended March 31, 2023, and $280 Million in the year ended March 31, 2024.[20] In effect, the government has reduced its fees, charges and taxes on Manitoba Hydro by more than the additional annual costs associated with the Keeyask GS. The reductions may not, however, be sufficient to also cover the additional costs associated with the export transmission line built at the time of Keeyask, and for the cost overruns associated with Bipole III. Nevertheless, a significant burden has been removed from ratepayers, resulting in a net loss of expected revenue for the government (and hence a burden transferred to taxpayers).

[20] Please see the Application, Tab 9, Attachment to MFR 9, page 105.

## GSS-GSM/Coalition-7

| | | | |
|---|---|---|---|
| **Part and Chapter:** | Morrison Park Advisors Report | **Page #:** | 13 |
| **Topic:** | Capital Plans & Approach to rate setting | | |
| **Subtopic:** | | | |

**Preamble (if any):**

Morrison Park Advisors Report, page 13 states:

> Issues related to longer-term "demand side management" and capital expenditures are often the subject of long-term planning processes outside of rate hearings (such as the Integrated Resource Plan exercise currently underway). In addition, long-term capital plans of any kind are not valid, in the case of Manitoba Hydro, unless they are explicitly approved by the government, and hence assumptions about future capital spending are merely placeholders for future decision processes. As a result, to the extent that these longer-term load expectations and capital plans are addressed as part of short-term rate-setting, the linkage appears to be through their potential impact on financial risk management needs and presumed rate stability impacts.

This question may be best answered by a combination of Coalition experts, specifically Morrison Park Advisors, Midgard Consulting and Darren Rainkie, as it covers multiple areas of expertise and approved scope in this proceeding.

**Question:**

a) To the extent possible, please estimate how much of the long-term rate trajectory is being driven by placeholder values for i) long-term future capital spending, and ii) other issues (DSM, etc.) related to longer-term planning processes outside of rate hearings.

**Rationale for Question:**

**Response:**

Detailed analysis of the sub-components of capital spending forecasted by Manitoba Hydro was not within the scope of work of MPA, and therefore we cannot venture to provide an answer to this question. However, the reports of Mr. Rainkie and Midgard Consulting may provide insight into this issue.

## GSS-GSM/Coalition-8

| | | | |
|---|---|---|---|
| **Part and Chapter:** | Morrison Park Advisors Report | **Page #:** | 16 & 23-24 |
| **Topic:** | Financial Risk Management | | |
| **Subtopic:** | Short-term liquidity | | |

**Preamble (if any):**

Morrison Park Advisors Report, page 16 states:

> In order to ensure liquidity in the face of uncertain cashflows during any 12-month period, the corporation maintains cash or cash equivalents equal to six months of expected cash requirements. In addition, the corporation has authority to issue up to $500 million in short-term promissory notes in its own name, and has access to another $500 million of short-term notes through the Province of Manitoba. Maintaining these liquidity resources is important, and it should be non-controversial that rate-setting should be supportive.

This question may be best answered by a combination of Coalition experts, specifically Morrison Park Advisors and Darren Rainkie, as it covers both areas of expertise and approved scope in this proceeding.

**Question:**

a) Please provide your best estimate of the amount of revenue required in each of the test years to maintain a six-month cash requirement target as explained by MPA above.

    a. Does Manitoba Hydro have this level of revenue/cashflow over the test years at existing rates? If not, what level of rate increase is needed in each year?

b) Please update the estimate provided in response to part (a) above for the following scenario adjustments to the test years:

    a. It is reduced in each test year such that Operating & Administrative expense is only increased by an inflationary 2% (not including SAP = this would effectively reduce forecast O&A by $22 million in 2025/26, by $57 million in 2026/27, and $46 million in 2027/28)

    b. It is reduced in each test year for HVDC reliability expenditures ($26.2 million in 2025/26, $341.4 million in 2026/27, and $551.7 million in 2027/28);

    c. It is reduced for the SAP S/4HANA operating expenditure ($19 million in 2025/26 and $137 million in 2026/27); and

d. It is reduced for all three of the above scenarios at the same time in the test years.

**Rationale for Question:**

**Response:**

Cash-on-hand and short-term credit lines are liquidity resources that are fundamental to operating a business efficiently, safely and well. As discussed in MPA's Report, Manitoba Hydro maintains, by policy, a minimum of six months worth of cash on hand, and has access to at least two specific sources of short-term credit.

A company's cash-on-hand is the result of its starting cash position and cash flow in any given period, which in turn depends on three classes of company activities: operations (i.e., revenues and expenditures, which can result in either positive or negative cash flows), investing in capital goods (which generally consumes cash), and raising capital (which for Manitoba Hydro means issuing debt or retiring debt outstanding, the result of which can be either positive or negative cash flows). It is important to note that even if a company's operations are generating less cash at a given time (because of drought conditions, for example), the company can still maintain a satisfactory amount of cash on hand if it reduces its expenditure on capital goods, or it issues more debt. Cash becomes a problem if lenders are unwilling to provide new debt to the utility, and the company is "bleeding cash" at the same time (because of either or both of poor operations or high capital expenditures).

The questions asked relate to potential changes in Manitoba Hydro revenues and spending. Each of the scenarios described would change the "cash flow from operations" that would result at Manitoba Hydro (by assuming 0% rate increases for three years), while also considering different amounts of expenditure cuts to specific line items of the Manitoba Hydro operating or capital spending plan. However, any estimate of cash availability must consider not only cash flows from operations and cash flows required for capital spending, but also financing activities.

For example, the question asks what would happen if no rate increases were granted over three years. According to the reference financial forecast provided by Manitoba Hydro in its application, this decision would reduce revenues, and hence cash flows by $282 Million in total over the three years 2026 to 2028. *Other things being equal*, cash on hand resources would decline by this amount. But would other things actually be equal? If no rate increases were granted, would Manitoba Hydro not find any operational savings that could be achieved, or consider delaying or curtailing some capital expenditures? Would Manitoba Hydro not consider borrowing more cash to make up for its operational shortfall?

On the other hand, if the PUB simply ordered 0% rate increases without satisfying itself that Manitoba Hydro could appropriately manage its cash requirements, would there be a heightened risk that the capital markets would react badly and increase the cost of

Manitoba Hydro's debt (and the cost of debt of the Province of Manitoba!)? How would higher interest costs affect Manitoba Hydro over time? Unfortunately, there is no simple or automatic response to these issues.

The options presented in part b) of the question represent different ways expenditures for operating and capital spending line items could be reduced by Manitoba Hydro. Simplistically, each of these could be compared to the revenue foregone by ordering 0% rate increases to determine the net impact on cash flows. For example, the three years of cost reductions in scenario a. amount to total savings of $125 M, which could partially offset the revenue forgone by the 0% rate increase proposition. Scenario c. suggests an additional $156 M in expenditure reductions. Together, these two expenditure reductions would fully offset the revenue foregone, and in theory should mean that Manitoba Hydro continues to have satisfactory levels of cash on hand (noting that in its recently released Annual Report, Manitoba Hydro's Statement of Cash Flows reported closing cash as of March 31, 2025 of $1,073 M, and this is assumed to be satisfactory for liquidity purposes). Scenario b. posits reductions in capital expenditures which are substantially larger than $282 M, and therefore which would have a net positive impact on near term cash resources, even if rate increases were 0%. However, would these reductions in capital spending be permanent, or would these be temporary delays in capital expenditures, such that cash resources would be required in the future?

For each of the expenditure reduction scenarios in the question, the critical issue is not whether they would offset the need for specific rate increases, but whether the expenditure reductions are appropriate on their own merits. It is not within MPA's scope to answer these questions, which are better addressed by other experts participating in the GRA process. However, the determination of approved rate increases normally ***follows*** the investigation of planned spending by a utility to ensure it is all prudent, rather than trying to find expenditure reductions to justify zero rate increases.

## GSS-GSM/Coalition-9

| | | | |
|---|---|---|---|
| **Part and Chapter:** | Evidence of Kelly Derksen, Section 4.1 | **Page #:** | 11 - 22 |
| **Topic:** | PCOSS Treatment of Government Payment Relief | | |
| **Subtopic:** | | | |

**Preamble (if any):**

In these sections, Ms. Derksen analyzes the RCC and cost impact of government payment relief, based on 'directional 20 year' scenarios.

**Question:**

a) For the charts provided in these sections calculating the impacts on RCCs due to the government payment relief (water rental fees, provincial debt guarantee, capital tax), please confirm, that the scenarios consolidate the overall impact from these payment reductions over the entire 20 year IFF and apply to the PCOSS26 results (i.e. the RCC and cost results shown will be hypothetically implemented over a 20 year period).

   i. If not confirmed please explain what the 'directional 20 year period' represents for these scenarios, including impacts to costs and RCCs.

**Rationale for Question:**

**Response:**

a) The analysis is difficult to interpret. However, it is Ms. Derksen's understanding that Chart 5 (pg. 21) extracted from Coalition/MH II-55 (pgs. 13 & 14) reflects the following:

   - The combined impact by class of all payment reductions, on an annual basis for each of the next 20 years of the IFF period; and

   - An increase in government payments in PCOSS26 to levels prior to the announced reductions (including those in the 2023/24 GRA). Instead of reducing PCOSS26 Net Income to balance to MH's overall revenue requirement as it typically does, MH proportionately adjusted each revenue requirement cost to hypothetically account for anticipated cost changes over the next 20 years (IFF period).

   Therefore, Charts 3, 4 & 5 (pages 18, 21) are understood to reflect the potential annual impacts by class in each of the next 20 years.

Charts 1 & 2 (pages 15, 16) which were extracted from Coalition/MH II-55 (pgs. 6 & 7) reflects only the current Test Year impact associated with total Water Rental Fee reductions to date (assuming Net Income was adjusted to balance to MH's total revenue requirement in the 2025/26 Test Year).

It is noted, however, as discussed in Ms. Derksen's evidence, it is likely that the consolidated overall impacts underestimate the true impact because of the underlying assumption that rate base (and revenue requirement) will continue to reflect the current functional proportions over the entire 20-year period given MH's plans for generation and transmission investment.

**GSS-GSM/Coalition-10**

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|---|---|---|---|
| **Part and Chapter:** | Evidence of Kelly Derksen, Section 4.2 | **Page #:** | 24-25 |
| **Topic:** | PCOSS Treatment of Net Income | | |
| **Subtopic:** | | | |

**Preamble (if any):**

Ms. Derksen states,

> Typically, a cost-of-service study allocates revenue requirement on the basis of current investment (by way of financing costs and depreciation), with a forecast of capital expenditures for the test year. In other words, for purposes of PCOSS, revenue requirement, including Net Income is allocated based on current used and useful capital investment and not before the capital goes in service – which is conceptually similar to a rate base rate of return methodology

**Question:**

a) Please provide examples of how other utilities functionalize, classify, and amortize revenue requirement return and/or net income within cost of service methodology.

b) Is Manitoba Hydro's approach to functionalize net income through a test year rate base rate of return methodology in line with other Canadian jurisdictions? Please explain.

**Rationale for Question:**

**Response:**

Responding to both Questions a) & b):

While Ms. Derksen has not undertaken a specific jurisdictional review given its time intensive nature, she expects that most, if not all, utilities will "allocate" Net Income on a similar basis as Manitoba Hydro and Centra Gas, proportionately based on Rate Base. This is because Net Income is the derivative in the Test Year of all the costs incurred in the provision of utility service after reducing from total revenue. There really is no better allocation methodology for Net Income, generally speaking.

However, what sets MH and Centra apart from other utilities is its cost-of-service methodology for establishing revenue requirement rather than Rate Base/Rate of Return (RB/ROR). Compared to RB/ROR which looks solely at the current Test Year for the

derivation of Net Income (equity return), MH and Centra look beyond the current Test Year, by as much as 20 years out. In a steady-state environment (i.e. without significant capital expenditure plans), allocating Net Income based on MH's current asset base is reasonable. In an environment whereby the utility is seeking increased levels of Net Income in anticipation of future significant investment in generation and transmission, it is at least unclear whether MH's current PCOSS methodology remains appropriate.

Please also see the response to PUB/Coalition 31.

## GSS-GSM/Coalition-11

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|---|---|---|---|
| **Part and Chapter:** | Evidence of Kelly Derksen, Section 5.4 | **Page #:** | 34-36 |
| **Topic:** | PCOSS Impacts due to Load Research | | |
| **Subtopic:** | | | |

**Preamble (if any):**

On pages 35-36, Ms. Derksen states that,

> … load shifts benefitting GSL classes (through lower cost allocation) suggests the critical need for increased energy and demand management/reduction programs (including rate design) aimed at Residential, GSS and GSM classes, that have been absent despite numerous programs made available to the largest industrial customers. This is of particular concern and necessary as those who are able to afford to transition to electricity, is driving, in part, the apparent earlier need for new generation resources, such as commercial and industrial customers who are riskier customers to the utility, while smaller demand-intensive customers (such as Residential and GSS classes), who are largely price takers and fairly price inelastic, will be left funding ever increasing levels of this investment, simply because current cost allocation methodologies and rate design are unable of moderating these circumstances, or potentially even compounding the issue.
>
> This also suggests that MH's proposal to increase the BMC for smaller volume classes may not be appropriate as it reduces the incentive of customers to conserve energy.

Coalition expert, Dr. Das, references a report on California rate design by Borenstein et al. available online https://www.next10.org/publications/electricity-rates

The referenced Borenstein report discusses economic efficiency in rate design, including for example on page 34:

> The core objective of this analysis is to propose a tariff that is more economically efficient. Roughly, this means a tariff with volumetric prices that are as close to social marginal cost as possible.
>
> …
>
> In addition, the volumetric rate should be time varying, as marginal costs vary across hours and days.

**Question:**

a) Please provide the reference and/or supporting data for Chart 10.

b) Regarding necessary rate design options, for Residential, GSS and GSM rate classes specifically, please explain whether or not increasing the fixed charge and reducing volumetric prices to align with marginal costs (including time varying options), as reviewed in the Borenstein report, would help to rectify the issues Ms. Derksen identifies as a result of the review on load research.

c) Please provide recommendations on how rate design options can be designed and implemented that address Ms. Derksen's concerns related to demand management/reduction programs, especially in the near-term without Advanced Metering Infrastructure.

**Rationale for Question:**

**Response:**

a) The data underpinning Chart 10 was provided by response to MH/GSS I-6f, consolidated in the table below:

| Potential Variance in RCCs<br>Source: GSS I-6f | PCOSS26<br>As Filed | PCOSS26<br>Low | PCOSS26<br>High | Range |
|---|---|---|---|---|
| Residential | 96.9% | 94.2% | 99.5% | 5.3% |
| GSS ND | 108.0% | 101.9% | 113.6% | 11.7% |
| GSS D | 96.0% | 91.0% | 100.6% | 9.6% |
| GSM | 97.8% | 95.2% | 100.7% | 5.5% |
| GSL 0-30 | 100.9% | 97.1% | 104.3% | 7.2% |
| GSL 30-100 | 110.4% | 108.8% | 112.3% | 3.5% |
| GSL >100 | 110.6% | 109.2% | 112.3% | 3.1% |

b) It is expected that any increase in the fixed monthly charge would hamper, rather than rectify, increasing peak consumption and declining load factor customers/classes. This is because the fixed monthly charge, despite some benefit to both the utility and customers by providing revenue/bill stability, really says to the customer that whatever they do, does not matter at all. Any fixed monthly charge disincentivizes a customer to reduce consumption which is likely to increase as the level of the charge increases.

Even the equal payment plan, while a popular payment option for customers, disincentivizes customers consumption choices by de-linking the payment from the underlying cost.

Further, the evidence is unclear whether the majority of low-income households are low users or high users. For these reasons, for purposes of rate design, Ms. Derksen is generally not a proponent of increasing the fixed monthly charge.

In terms establishing rates based on "social marginal cost" discussed in the Borenstein Report, it is unclear what is really meant by "social". Of course, it is understood rates based on marginal cost are theoretically superior from an economic efficiency perspective. However, the incorporation of externalities is highly subjective in terms of what constitutes an externality and its related quantification. Apart from the fact that externalities, arguably, are already implicit in MH's overall cost to serve to some degree and despite that externality costs are likely to implicitly form a larger component of MH's cost to serve in the future as a result of the energy transition, it is unclear how social marginal costs would be defined and derived for purposes of ratemaking.

The inclusion of externalities, however defined, must also be balanced against the cost consequences not only between customers within the class but also in the context of the higher costs MH is projecting, and the impact, in particular, on low-income households.

For these reasons, Ms. Derksen generally views that externality costs should not be combined with marginal costs for purposes of a perceived efficient rate design.

That said, Manitoba Hydro's role and objectives with respect to environmental leadership will inevitably form part of the upcoming IRP review which will have fundamental implications that should be understood before ratemaking decisions are made.

c) While automated meters are normally a prerequisite for "true" time-of-use (TOU) or real-time pricing, utilities, including MH, can still design simpler demand-response-type rates for residential customers without them. This includes seasonal, tiered (inverted) and critical peak rates – each have advantages and disadvantages and are presumably part of the current demand response review being undertaken by MH.

## GSS-GSM/Coalition-12

| | | | |
|---|---|---|---|
| **Part and Chapter:** | Evidence of Kelly Derksen, Section 6.1 | **Page #:** | 39 - 42 |
| **Topic:** | Rate Comparison to Other Jurisdictions | | |
| **Subtopic:** | | | |

**Preamble (if any):**

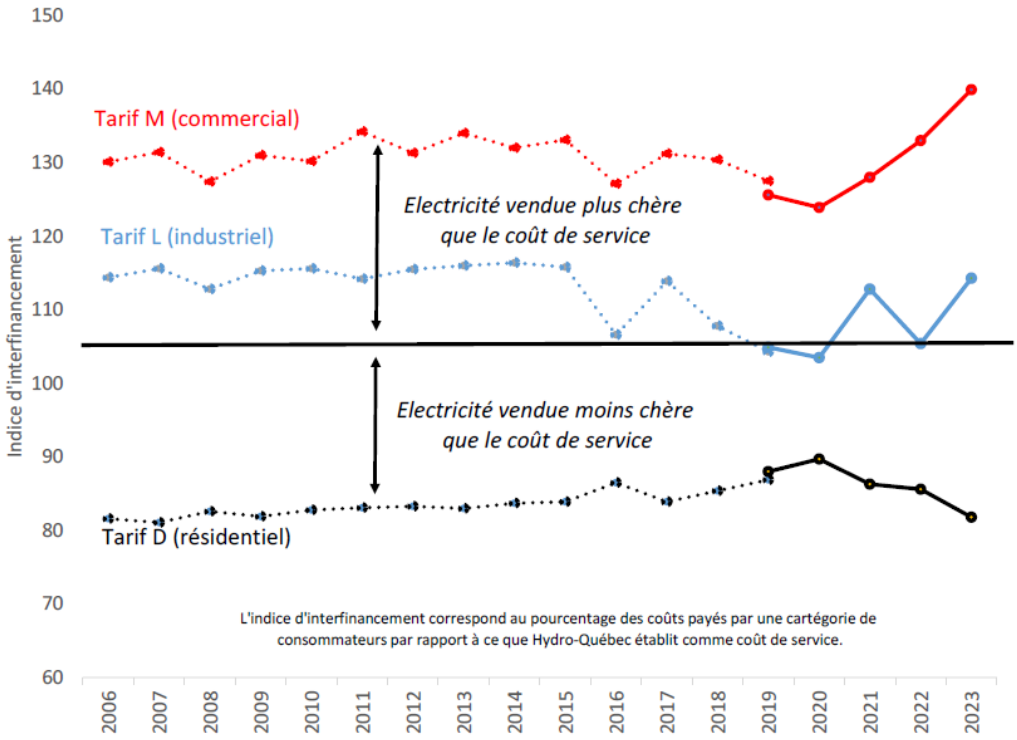
This section of Ms. Derksen's evidence provides recommendations on rate increases and RCC rebalancing based on Manitoba Hydro rate class comparisons to lowest cost jurisdictions. Specifically on page 42:

> On this basis, while a stringent reliance on the RCCs of some rate classes might suggest a lesser than average rate increase if taken at face value (that is, cost causation only) relative to MH's Range of Reasonableness of 95% to 105%, the competitiveness of rates objective and priority of MH suggests at a minimum, that any differentiation of rates resulting in a higher-than-average rate increase for the Residential class is not supportable. Similarly, an above average differentiated rate increase would be appropriate with consideration given to the competitiveness of rate objective for MH's equivalent to Small Power classes in order to decrease the rate disparity between MH classes compared to the lowest rates in Canada.

Hydro-Quebec, the lowest jurisdictional comparator for almost all rate classes in Chart 11 (and for the pinpointed Residential and Small Power bars), has a long history of commercial and industrial customers cross-subsidizing residential customers, as depicted in the chart below (which shows the 'cross-subsidization index' in the y-axis corresponding to the percentage of costs paid by a category of consumers compared to what Hydro-Québec establishes as the cost of service):[21]

[21] Graph as per La tarification de l'électricité au Québec Enjeux, préoccupations & options, by Pierre-Olivier Pineau, page 16, available online: https://energie.hec.ca/wp-content/uploads/2025/04/TarificationElectriciteQC_DocumentReference_24fev2025.pdf

**Graphique 9. Évolution de l'interfinancement de 2006 à 2023 (Whitmore et Pineau, 2025)**




Most recently, Hydro Quebec provided its interfinancing indices (i.e. RCCs) for 2023, where residential customers were 81.8% compared to Commercial between 130 – 139% and industrial at 114%.[22] [Unfortunately Hydro-Quebec does not provide these types of documents in English, so French references have been provided]

This is partially due to domestic rate caps for residential customers limited to 3% as of 2023 (where as commercial are fully index and industrial rates are adjusted annually by the Energy Board).[23]

**Question:**

a) Please confirm that Chart 11, and the resulting observations from the analysis done in Chart 11, compare Manitoba Hydro proposed rates in 2028 against other jurisdictions (namely in Montreal and Vancouver) rates as of April 1, 2024.

[22] Hydro-Quebec, RENSEIGNEMENTS GÉNÉRAUX (General Information), last Revised 2024-09-23, as shown in Tableau 8, page 11 of 15, available online: https://www.regie-energie.qc.ca/fr/participants/dossiers/R-9001-2023/doc/R-9001-2023-B-0015-RapAnnuel-PiecesRev-2024_09_24.pdf

[23] As explained in the following Province of Quebec news release, available online: https://www.quebec.ca/nouvelles/actualites/details/adoption-du-projet-de-loi-no-2-hausse-des-tarifs-dhydro-quebec-limitee-a-3-pour-les-quebecois-45784

b) In comparison of Manitoba Hydro rates against low-cost jurisdictions, particularly Quebec, does Ms. Derksen agree there may be contextual considerations of relevance to review when considering differentiated rate changes on the basis of jurisdictional competitiveness?

c) From the preamble, Hydro-Quebec residential (Tarif d) rates have been heavily cross-subsidized for decades, with RCCs in the low 80% range, by commercial customers with RCCs in the 130% to 140%. Is Ms. Derksen, in her recommendation to consider potential differentiated rate increases (at a maximum of across-the-board for residentials but potentially higher for small power) on the basis of comparing to Hydro-Quebec rates, implying that these levels of RCCs are reasonable benchmarks of comparison for Manitoba? Please explain.

**Rationale for Question:**

**Response:**

a) Confirmed.

b) Yes, for sure. Please see the response to PUB/Coalition I-40.

c) Ms. Derksen is uncomfortable with the characterization that “residential rates have been heavily subsidized for decades by commercial customers”. To the extent that rates have been reviewed and approved by the Regie, such rates are thus deemed to be fair and equitable.

Please see the response to PUB/Coalition I-40

## GSS-GSM/Coalition-13

| | | | |
|---|---|---|---|
| **Part and Chapter:** | Evidence of Kelly Derksen | **Page #:** | |
| **Topic:** | COSS Distribution Classification | | |
| **Subtopic:** | Distribution Plant Assets | | |

**Preamble (if any):**

Evidence filed on behalf of the GSS-GSM, by Ms. Davies, in Section 6 recommends that distribution plant asset costs, especially Wires & Poles and potentially Transformer costs, should be changed in this proceeding and classified on the basis of both energy and demand. This is based on a Canadian jurisdictional comparison, past precedent of Manitoba Hydro, current experience in Manitoba with Centra Gas, and cost causation.

Currently, Manitoba Hydro classifies Poles & Wires and Transformer costs 100% to demand (allocated using class Non-Coincident Peak demand).

**Question:**

a) Please provide Ms. Derksen's perspective on Manitoba Hydro's current approach to classifying distribution plant assets and whether or not she supports a change to the current methodology.

**Rationale for Question:**

GSS-GSM would like to understand the perspectives of the other Cost of Service experts in this proceeding on this matter.

**Response:**

Ms. Derksen is supportive of such a review. However, it is unclear what might be the appropriate timing for such a review. It appears that a thoughtful approach to reviewing cost of service methodology, including the classification of distribution investment as suggested, government payment relief and others, and rate design, is necessary and generally preferrable to one-off reviews. The Corporation is in the midst of energy transition, with its roles and objectives with respect to environmental leadership inevitably part of the upcoming IRP review. The outcome of the IRP review will likely have fundamental implications that should be understood before ratemaking strategy decisions are made, which includes cost allocation methodology.

## GSS-GSM/Coalition-14

| | | | |
|---|---|---|---|
| **Part and Chapter:** | Evidence of Darren Rainkie | **Page #:** | 6 & 75 - 77 |
| **Topic:** | Approach to rate setting | | |
| **Subtopic:** | | | |

**Preamble (if any):**

Mr. Rainkie's evidence recommends the following approach to rate setting in this proceeding:

> The 2.25% rate recommendation emphasizes the medium term to 2035 in recognition of the inherent uncertainty in MH's operations and the limited reliability of the 3.5% MH long-term rate path to 2045.

**Question:**

a) In Mr. Rainkie's experience has MH taken a near- to medium-term approach to rate setting in past proceedings (i.e. not using a 20 year rate trajectory)?

b) If yes, does the prior rationale for this rate setting approach have any application to the current circumstances.

**Rationale for Question:**

**Response:**

a) In Mr. Rainkie's 35 years experience with PUB rate-setting, MH electricity rates have been set by the PUB in the vast majority of the Test Years on a basis other than using a 20-year long-term even annual indicative rate path.

Mr. Rainkie's experience with PUB rate-setting dates back 35 years to 1990. Up to and including the 2012 Test Year, MH had generally presented a 10-year financial forecast in support of its rate applications, with specific rate proposals for the test years that were not tied to a long-term even annual indicative rate path. As such, the PUB approved rate increases in those test years on a basis other than using a 20-year long-term even annual indicative rate path.

MH began presenting 20-year financial forecasts for the 2013 and 2014 Test Years which continued until the 2019 Test Year (7 test years in total). During that timeframe, the PUB approved electricity rates based on a 20-year long-term even annual indicative rate path for the 2016, 2017, 2018 and 2019 Test Years (4 test years in total).

Since that time, MH's 2020 Test Year application was based on a 1-year financial forecast, the 2022 Test Year application was based on a 2-year financial forecast and the 2024 and 2025 Test Years application was based on a 20-year financial forecast. The electricity rate increases approved by the PUB in the 2020 to 2025 timeframe have not been based on a 20-year long-term even annual indicative rate path.

In summary, MH electricity rates have been set by the PUB in the last 35 years on a basis other than using a 20-year long-term even annual indicative rate path. There are only 4 Test Years between 2016 and 2019 where the PUB approved rate increases using a 20-year long-term indicative rate path.

b) Yes, the prior rationale for a rate-setting approach that does not involve adopting a long-term 20-year even annual indicative rate path as the basis of approving rate increases in the Test Period is appropriate for the circumstances of the current GRA.

The PUB's rate determinations in the last MH GRA placed more emphasis on the Test Years than the long-term rate path projections due to MH's state of uncertainty and concerns with respect to the reliability of MH's forecasts and cost estimates.

In Mr. Rainkie's view, for the current GRA, the level of uncertainty and concerns with respect to the reliability of substantial placeholder spending ($11.7 billion) and prudency of cost forecasts are such that these concerns have increased since the last GRA. These concerns are such that the MH 3.5% long-term rate path continues to be of limited reliability for rate-setting purposes in the current GRA.

Mr. Rainkie has concluded that in these circumstances it is appropriate to place more emphasis on the Test Years and medium term to 2035 to set rates for the 2026 to 2028 Test Period and that 2.25% rate increases in the Test Years are balanced and reasonable.

## GSS-GSM/Coalition-15

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| **Part and Chapter:** | Evidence of Darren Rainkie | **Page #:** | 8 & 37 |
| **Topic:** | O&A Cost control | | |
| **Subtopic:** | Priority Based budgeting | | |

**Preamble (if any):**

Mr. Rainkie on page 8, states that:

> Additionally, it is concluded that MH's largely bottom-up and incremental focused O&A budget approach is ineffective at controlling O&A cost increases. MH would benefit from adopting a priority-based budgeting approach.

**Question:**

a) What would a priority-based budgeting approach look like in the context of Manitoba Hydro's 20-year operating forecast? Would it focus more on the test years, the medium-term, or implemented over the entire 20 year period?

b) How is cost controls prioritized in a priority-based budgeting approach.

c) Please provide examples of utilities in other jurisdictions that budget in this manner and set rates accordingly.

d) Would a priority-based budgeting approach address the concerns raised on day-to-day spending for O&A and BOC? Please explain and provide examples if possible.

**Rationale for Question:**

**Response:**

a) In Mr. Rainkie's view, a priority-based budgeting approach would focus on the 3-year Test Period to set stretch O&A budget targets for those years. O&A projections for years 4 and thereafter would be based on a long-term planning assumption, such as 2% escalation.

An O&A budget approach that focuses on a rolling 3-year period would allow departmental management to take a longer-term view towards MH's organizational aspirations and develop outcome/results oriented plans and efficiency initiatives to achieve established O&A targets. The 3-year period would provide sufficient certainty to departmental management on the available O&A funding for departmental initiatives, while at the same time signaling the commitment of the organization to meet the O&A targets over that period. Under this approach,

departmental management would be expected to adhere to the 3-year targets and there would be no automatic re-budgeting of the year 2 and year 3 O&A targets during the next budgeting cycle.

Mr. Rainkie notes that MH had success with this 3-year approach for the period from 2015 to 2017, when MH adopted a top-down target of managing O&A growth within a 1% increase, excluding the impacts of accounting changes.

b) Please see the response to PUB/Coalition 1-28 e to h, where Mr. Rainkie outlines how a priority-based budgeting approach could be used by MH to control O&A costs and facilitate (i) a shift in the mindset from costs being beyond its control to being able to influence the O&A cost trajectory, and (ii) the shift in focus from inputs, expenditure line-items and departments to programs and services, and achieving results and outcomes that are aligned with its strategy and providing value to ratepayers.

c) Please see the response to PUB/Coalition I-28 d.

d) Yes, a priority-based budgeting approach is a tool that MH could utilize to address the concerns with respect to day to day spending for O&A and to set stretch O&A targets within the context of its overall financial outlook. Please see the response to PUB/Coalition I-28 e to h, where Mr. Rainkie outlines the high-level steps to implement a priority-based budgeting approach for O&A and the response to PUB/Coalition I-24 b, where Mr. Rainkie outlines examples of areas of O&A to target for cost reductions.

With respect to BOC, Mr. Rainkie observes that a priority-based budgeting approach can also be used to manage and control day to day capital spending. The principles of priority-based budgeting are applicable regardless of the accounting treatment of an expenditure (i.e., expense vs. capitalize).

However, Mr. Rainkie would expect that MH achieving maturity related to asset management would serve the same purpose in terms of controlling day to day BOC spending. Mr. Rainkie is supportive of MH accelerating its achievement of maturity in asset management and focusing on that initiative in order to prioritize and control BOC spending.

## GSS-GSM/Coalition-16

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|---|---|---|---|
| **Part and Chapter:** | Evidence of Darren Rainkie | **Page #:** | 106 - 108 |
| **Topic:** | Cloud Computing & SAP | | |
| **Subtopic:** | | | |

**Preamble (if any):**

Mr. Rainkie recommends that:

> Interim Approval of the SAP RDA is Recommended Together with an Upper Limit
>
> In consideration of the quandary and the concerns noted above, the following recommendations are made:
>
> 1. Approve an SAP Core RDA on an interim basis in this GRA out of necessity or expedience as significant expenditures are likely near and it is desirable to smooth these expenditures into rates over time;
>
> 2. Set an upper limit on the amount that MH is able to defer into the SAP Core RDA and the requirement for MH to come back to the PUB with a review and vary application if it wants to defer more than the upper limit initially approved by the PUB. This upper limit could be the $156 million placeholder included in MH25 or some other figure from the fall 2025 CIJ as appropriate; and
>
> 3. Set the requirement that final approval of the interim SAP Core RDA is conditional upon the receipt of adequate project justification and a separate regulatory proceeding with appropriate timing and process, including intervenor participation. An appropriate amortization period would be considered in this separate regulatory proceeding based on more information about the SAP Core Project than that which presently exists on the record of the current GRA.

For the Cloud Computing (CCA) spending and RDA, Mr Rainkie recommends:

> There is no evidence on the record of this proceeding with respect to the specifics of the small-scale CCA spending and similar concerns with respect to the diminished scrutiny of CCAs with blanket deferral treatment exist as was outlined in Section 7.7 of this Evidence related to the proposed SAP Core RDA.
>
> On balance, it is recommended that the PUB not approve the proposed Small-Scale CCA RDA. The lower materially of the net deferral amount and the benefits of special treatment of these costs through an RDA do not outweigh the concerns related to less regulatory scrutiny.

**Question:**

a) Does Mr. Rainkie recommend that Cloud Computer Arrangements (CCA) spending should be treated in the same manner as SAP Core spending moving forward, i.e. subject to future scrutiny prior to full implementation. If not, please provide Mr. Rainkie's recommendation on approval of CCA spending in the test years and beyond.

b) Is it Mr. Rainkie's understanding that the SAP Core project and CCA spending are linked and/or related for operational and decision-making (justification) purposes? Please explain.

**Rationale for Question:**

**Response:**

a) Yes, Mr. Rainkie is of the view that there is a paucity of information related to the nature and justification of the MH small-scale CCA program and associated expenditures and that additional regulatory scrutiny of these expenditures for rate-setting purposes is required, similar to the situation with respect to SAP Core project spending. MH has confirmed in the information request process that the small-scale CCA program expenditures in this rate application are placeholders and that to date, the small-scale CCA expenditures have not required a capital investment justification (CIJ).

   For these reasons and the lack of material rate-setting benefits associated with the deferral of these expenditures, Mr. Rainkie is not comfortable with blanket deferral account treatment for these small-scale CCA program expenditures as proposed by MH and recommends that the PUB not approve this proposal.

b) Mr. Rainkie is not aware of any assertions by MH that the SAP Core project and small-scale CCA program are significantly linked or related for operational and decision making/justification purposes.