

**Order No. 43/26**

**MANITOBA HYDRO**  
**FINAL ORDER**  
**FISCAL 2026-2028 GENERAL RATE APPLICATION**

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**March 19, 2026**

**BEFORE:** Robert Gabor, K.C., Chair  
Marilyn Kapitany, B.Sc.(Hon), M.Sc., Vice-Chair  
Jim Hrichishen, B.A. (Hon.), M.A, Member  
Tannis Mindell, Assoc. Ed., Member  
Kurt Simonsen, BSc., M.N.R.M., Member

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## 1.0 EXECUTIVE SUMMARY

### 1.1 What is this Order About?

This is an order of the Public Utilities Board (“Board”) in Manitoba Hydro’s Fiscal 2026 – 2028 General Rate Application. The Order finalizes an existing 4.0% interim general rate increase that came into effect on January 1, 2026 and approves two general revenue increases — an increase of 3.5% effective January 1, 2027 and another increase of 3.0% effective January 1, 2028.

A general revenue increase is not the same as a general rate increase. A general rate increase means that all customer classes will pay the same increase. The 4.0% interim increase that came into effect on January 1, 2026 was a general rate increase. It applied to all customers except those in the four northern communities served through diesel generation, also known as the Diesel Zone. In contrast, the two increases for January 1, 2027 and January 1, 2028 are general revenue increases. These increases will be differentiated, such that some customer classes will be paying a higher increase than the 3.5% and 3.0% approved and other customer classes will be paying a lower increase. The exact percentages will be determined through a subsequent compliance filing by Manitoba Hydro. However, the Board anticipates that the maximum additional increase will be approximately 0.3% in each of the two years. This means that certain customer classes, including residential ratepayers, will be paying increases of approximately 3.8% and 3.3%, beginning January 1, 2027 and January 1, 2028, respectively. The rate differentiation relates to a need to ensure that each customer class pays its fair share of Manitoba Hydro’s costs that are properly attributable to each class, as explained in section 1.5 below.

In this Order, the Board also:

- denies, for rate-setting purposes, 1.0% of Manitoba Hydro’s proposed operating & administrative expenses, excluding those related to the SAP S/4HANA project, in each of 2026/27 and 2027/28;

- directs Manitoba Hydro to file quarterly reports and other information regarding its major capital projects, the SAP S/4HANA Project, water flow conditions, any changes to large electric loads of its customers, and modifications to existing operating & administrative expenditure reports;
- directs Manitoba Hydro to utilize the most recent 2024 Depreciation Study to determine depreciation and amortization expense for 2026/27 and 2027/28;
- denies Manitoba Hydro's renewed request to amortize the Change in Depreciation Method Deferral Account for which the Board denied amortization in Order 101/23;
- approves as final the Joint Keeyask Development Agreement (JKDA) Preferred Distributions Deferral Account previously approved on an interim basis;
- approves a deferral account for costs related to the replacement of Manitoba Hydro's SAP enterprise management software, with the approval limited to a cap of \$167 million for Manitoba Hydro;
- approves a small-systems cloud computing deferral account similar to the one recently approved for Centra Gas;
- directs Manitoba Hydro to make revisions to its uncertainty analysis for the next general rate application;
- denies Manitoba Hydro's request to change its load research methodology for cost of service purposes;
- requires Manitoba Hydro to reduce the number of hours used to calculate peak demand from 50 hours to 10 hours;
- approves rate differentiation for various types of light fixture in the Area & Roadway Lighting customer class;
- approves rate increases equal to the corresponding residential and general service rate increases for Diesel Zone customers in 2026/27 and 2027/28;
- directs Manitoba Hydro to rebalance the demand and energy rate components for the industrial customer classes;

- approves a change to the definition of billing demand for industrial customers; and
- finalizes existing interim orders regarding Manitoba Hydro's Curtailable Rate Program (CRP) and Surplus Energy Program (SEP).

## 1.2 The Board's Rate Approval Mandate

The Board is required to approve Manitoba Hydro's electricity rates under *The Manitoba Hydro Act*. Rate approvals must be granted for a three-year rate period and are subject to seven rules set out in subsection 39(5) of the statute. This includes a requirement to base the Board's decision on the revenue requirement during the rate period, as well as a requirement to be guided by the government's declared policies set out in subsection 39.1(1) of the statute. One of those policies states that the rates for specific customer classes are to be based on the revenue requirements, or costs, properly allocated to that class. This policy factored into the Board's decision to approve differentiated rate increases in this Application despite the utility asking for an across-the-board increase.

In approving overall rates, the Board considers both Manitoba Hydro's short-term revenue needs and its long-term projections in an effort to achieve rate stability and avoid rate shock for consumers. This is consistent with the government's policy set out in subsection 39.1(1) of *The Manitoba Hydro Act* that, to the extent practicable, rates or changes in rates should be stable and predictable from year to year.

## 1.3 Manitoba Hydro's General Rate Application

Manitoba Hydro filed its Application on March 28, 2025. In the Application, the utility sought an across-the-board general rate increase of 3.5% on January 1, 2026, 3.5% on January 1, 2027, and 3.5% on January 1, 2028. By the time Manitoba Hydro filed its Application, the utility was already experiencing a drought that got progressively worse throughout the proceeding.

The Board conducted an extensive hearing process, consisting of two rounds of written information requests, the participation of six approved interveners, four weeks of oral evidence and cross-examination, and detailed written submissions. The Board's decisions in this Order are based on the sworn evidence provided at the hearing by means of written exhibits and oral testimony.

### 1.4 Why is the Board Approving Rate Increases?

#### 1.4.1 Manitoba Hydro is Experiencing an Extreme Drought

In the short term, Manitoba Hydro is suffering from a severe drought, with water flows in 2025 approaching the second-lowest levels since record-keeping began 112 years ago, as indicated in Figure 1.1.

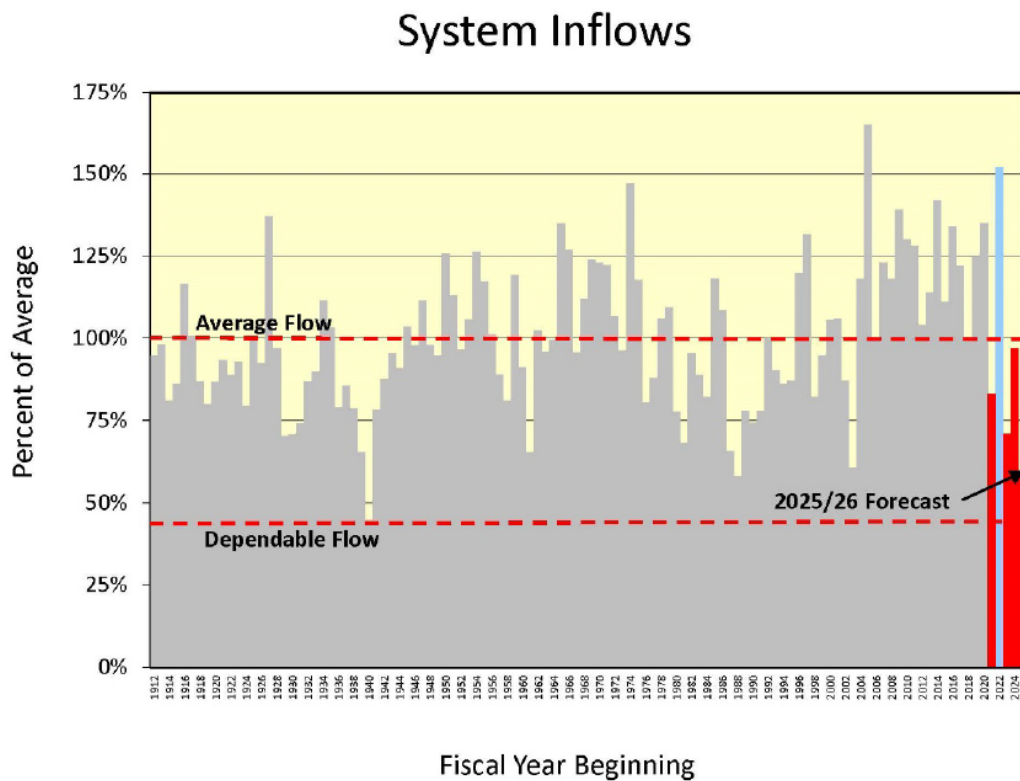


Figure 1.1 — Total System Inflows into Manitoba Hydro’s River Systems and Reservoirs.

Between the filing of Manitoba Hydro's Application in March 2025 and the beginning of the oral hearing in November 2025, Manitoba Hydro's financial projections for 2025/26 deteriorated by over \$600 million. When Manitoba Hydro filed its Application, it was projecting a net income of \$218 million for 2025/26. By November, the utility was projecting a \$409 million loss, an adverse turnaround of \$627 million.

As indicated in Figure 1.2, four of the past five years have been drought years. The figure, which compares Manitoba Hydro's actual and currently projected results to the forecasts presented in previous general rate applications, shows that, over five years, Manitoba Hydro's net income is expected to be \$1.75 billion less than projected.

Net Income \$ in millions	2021/22 Actual	2022/23	2023/24	2024/25	2025/26 Forecast	Cumulative
		Actuals / Forecasts				
2021 to 2023/24 Actuals & 2025/26 Forecast	(\$249)	\$573	(\$135)	(\$49)	(\$409)	(\$269)
2021/22 Actual; 2022/23 to 2024/25 Amended Financial Forecast Scenario; 2025/26 GRA Forecast	(\$249)	\$751	\$469	\$295	\$218	\$1484
<b>Change in Net Income</b>	<b>\$0</b>	<b>(\$178)</b>	<b>(\$604)</b>	<b>(\$344)</b>	<b>(\$627)</b>	<b>(\$1,753)</b>

Figure 1.2 — Actual Net Income Compared to Previous Forecasts

In response to the ongoing drought, including its impact on Manitoba Hydro's cash flow-based financial targets, the Board approved a 4.0% interim general rate increase on January 1, 2026 in Order 161/25. That increase applied to all customer classes except those in the Diesel Zone, since Diesel Zone customers are not served by hydroelectric generation and, therefore, their electricity costs are not affected by the drought.

The Board has not approved further rate increases of 4.0% for 2027 or 2028 as it is still possible that water flows will revert to normal levels in the second and third years of the rate period. However, if the drought conditions persist in these years, this may be a material difference to justify the Board's reconsideration of the rates it is approving in this Order under subsection 39.4(1) of *The Manitoba Hydro Act*.

#### **1.4.2 Capital Expenditures**

In the previous general rate application, Manitoba Hydro projected capital expenditures of \$18.2 billion over 20 years. In the current Application, this amount has increased to almost \$31.2 billion. The majority of the increase relates to a new HVDC Reliability Project intended to conduct extensive refurbishments and replacements of the Bipole I and II converter stations. While the last general rate application contained a \$1.8 billion placeholder for this project, the estimate ballooned to \$6.8 billion in the current hearing.

The Board is concerned about the accuracy of the current \$6.8 billion estimate. Manitoba Hydro projects it as a Class 10 estimate, which means that it is a highly preliminary estimate used for planning purposes with no set accuracy range and that it has a possible variance of 100% or greater. Given the proposed contract structure as a cost-reimbursable contract and the early stage of the estimate, there is substantial risk that the cost may be fundamentally different than the projected amount.

The Board notes Manitoba Hydro's evidence that the HVDC Reliability Project is needed and accepts that the project is critical to the utility and its customers. However, the Board observes that, in the 2017/18 & 2018/19 General Rate Application, the utility presented contradictory information that showed that, with the loss of both the Bipole I and Bipole II transmission lines, the utility would have sufficient capacity through the remaining Bipole III line and other generation and transmission assets to meet peak winter demand. The Board is concerned with this change in information.

Manitoba Hydro also projects to spend \$2 billion in the short term on three new natural gas combustion turbines to be used as a capacity resource that can be dispatched during periods of peak demand. The need for these turbines will be considered in the review of Manitoba Hydro's Integrated Resource Plan filed in January 2026.

Under subsection 39(5) of *The Manitoba Hydro Act*, the Board cannot disallow amounts to support Manitoba Hydro's capital program if the expenditures have been approved by the provincial Treasury Board. During the hearing, Manitoba Hydro stated that Treasury Board has approved Manitoba Hydro's capital expenditures for 2025/26, but not yet for 2026/27 and 2027/28. The Board notes the disconnect between the Board's review and decisions with respect to the capital expenditures in the three-year rate period, which are based on the Board's extensive review and testing of the proposed expenditures, and Treasury Board's process of approving Manitoba Hydro's capital expenditures one year at a time. This disconnect has made it difficult for the Board to carry out its role, as it does not know what Treasury Board will approve for the second and third years of the rate period.

Neither the HVDC Reliability Project nor the combustion turbines will affect Manitoba Hydro's revenue requirement during the rate period, as neither project will be in service by 2028. However, these projects, if they proceed, will significantly affect Manitoba Hydro's cash flow requirements in the short term, as illustrated in Figure 1.3. For the next decade, the expenditures required for the HVDC Reliability Project and the new capacity resource will exceed Manitoba Hydro's cash flow from operations. Given the anticipated revenue requirement for these projects once they come into operation, the projects could also lead to rate shock in subsequent rate periods if the Board were to ignore them entirely. As such, the Board considered the projects, and the risk they create, in fixing rates in the current Application. However, the Board did not specifically approve a rate increase for revenue requirement created by those projects.

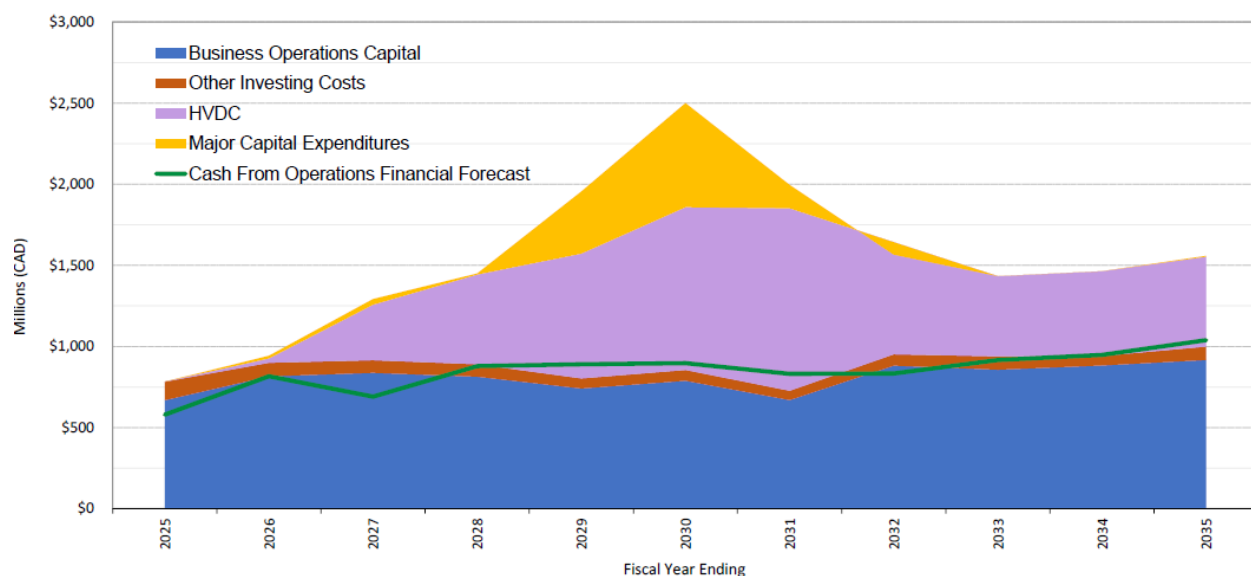


Figure 1.3 — Cash Flow Cost Coverage

The Board accepts Manitoba Hydro’s proposed business operations capital expenditures, which relate in part to the refurbishment or replacement of existing assets. However, the Board notes that, despite the utility experiencing one of the most severe droughts on record, it did not attempt to reduce or re-pace such spending in the short term. The failure to do so remains a concern to the Board.

### 1.4.3 Increasing Debt and Finance Expense

In the last general rate application, Manitoba Hydro presented a debt reduction strategy and planned to reduce its debt by almost \$2.5 billion over 20 years. With the new major capital projects now planned by the utility, Manitoba Hydro expects to increase its debt by \$8.6 billion over the same timeframe. In addition, the utility currently refinances approximately \$1 billion annually. While in the short term, Manitoba Hydro’s annual finance expense is actually decreasing, this is because most of the new debt is being capitalized to construction projects. As such, the primary impact in the short term is a need for additional cash flow and an erosion of Manitoba Hydro’s cash flow-based financial metrics.

### 1.4.4 Increased Operating & Administrative Expenses

Operating & administrative expenses (“O&A”) are Manitoba Hydro’s second-highest expense category after finance expense. For the three-year rate period, Manitoba Hydro’s O&A projection has increased by \$528 million, or 25%, since the last general rate application, as illustrated in Figure 1.4.

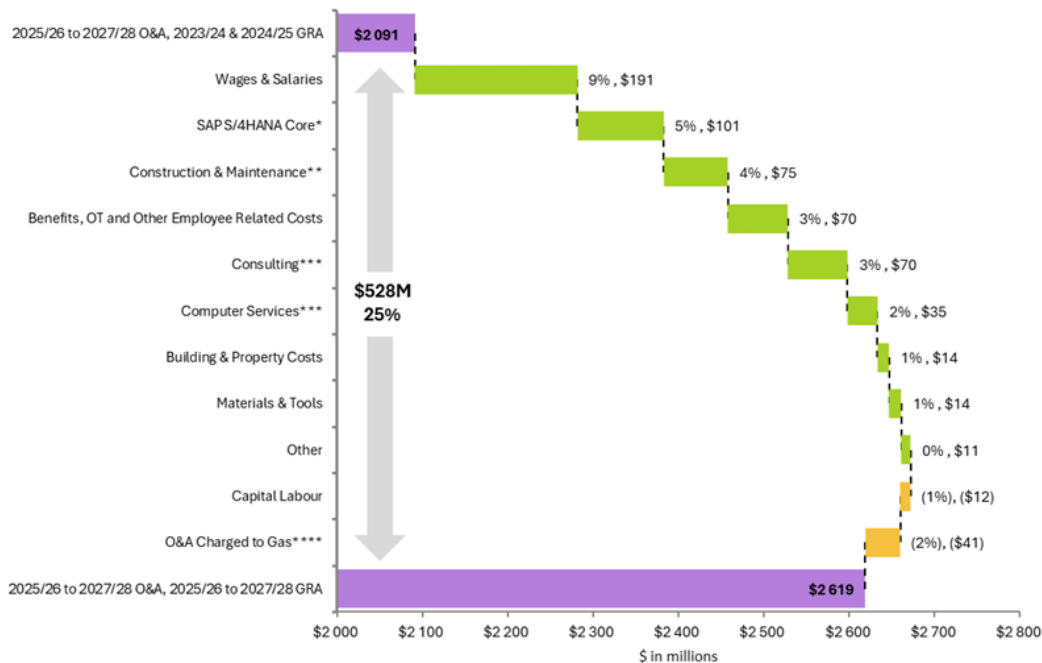


Figure 1.4 — 3-Year Comparison with Last General Rate Application

The largest portion of the increase relates to wages and salaries for Manitoba Hydro’s largely unionized workforce. However, a significant portion also relates to a project by Manitoba Hydro to replace its aging SAP enterprise management software with SAP S/4HANA, a cloud-based software program. While Manitoba Hydro currently projects a cost of \$193 million for the project (for Manitoba Hydro and Centra Gas), that cost relates only to the first of three phases, and does not include the replacement of Manitoba Hydro’s billing software or future enhancements to the new software suite. Manitoba Hydro is also planning to spend an increasing amount of money on construction and maintenance work, including increased vegetation management.

Both interveners and the Board are concerned about the ongoing escalation of Manitoba Hydro's O&A expenditures, including Manitoba Hydro's decision not to reduce expenditure growth during the drought. In this Order, the Board is disallowing 1.0% of Manitoba Hydro's planned O&A expenditures, excluding the costs of SAP S/4HANA, as set out in Figure 1.5.

Fiscal Year	2025/26	2026/27	2027/28
Projected O&A Expenditures	800	968	851
Original Projected SAP S/4HANA Expenditures*	19	137	-
Projected O&A Expenditures Excluding SAP S/4HANA (\$ millions)	781	831	851
Required 1.0% Reduction for 2026/27 & 2027/28 (\$ millions, rounded)	n/a	(8)	(16)
Approved O&A Expenditures for Rate-Setting (\$ millions)	781	960	835

\* As described in section 14.2, the projected expenditures for the SAP S/4HANA project were revised by Manitoba Hydro during the hearing. However, the original expenditures for this project are used in this table as Manitoba Hydro did not update its total O&A budget for the rate period.

Figure 1.5 — Disallowed O&A Expenditures for 2026/27 & 2027/28

While the Board approves the establishment of a deferral account for the SAP S/4HANA Project, it is placing a cap of \$167 million on the amounts that Manitoba Hydro's electric operations are authorized to defer. Previously, the Board ordered that no deferral would be granted until Manitoba Hydro provided its business justification to the Board. This has not yet been done, but the Board understands the need for this project now, because support for Manitoba Hydro's current SAP system is expected to end in 2027.

Nonetheless, the Board is concerned about the potential for cost escalation and so will not approve any further deferral beyond the \$167 million for Phase 1, or any amounts for Phases 2 or 3, until Manitoba Hydro provides its business justification to the Board as previously ordered and unless Manitoba Hydro advises the Board that it has exceeded or anticipates exceeding its current estimated deferral for Phase 1. The Board will also take steps to ensure that the \$17 million of the Phase 1 deferral account allocated to Centra Gas is dealt with in a similar manner.

**1.4.5 Reductions in Payments to Government do not Offset the Cost Increases**

Manitoba Hydro’s debt is guaranteed by the provincial government. In return, Manitoba Hydro pays a debt guarantee fee to the Province of Manitoba. Before the current rate period, that fee was 0.5%. Effective April 1, 2025 (the beginning of the rate period), the provincial government reduced the fee to 0.4%, with a commitment for further reductions to 0.3% on April 1, 2027 and 0.15% on April 1, 2028. This reduces Manitoba Hydro’s revenue requirement during the rate period by \$395 million.

Effective April 1, 2025, the Province of Manitoba has also eliminated the Corporation Capital Tax for Crown corporations, including Manitoba Hydro. The elimination will save Manitoba Hydro \$395 million during the rate period.

As set out in Figure 1.6, the reduction in payments to government will save Manitoba Hydro \$5.3 billion over 20 years. However, in light of the increased capital expenditures and O&A expenses, Manitoba Hydro’s financial metrics will remain weaker than the utility sees as ideal under the new financial forecast despite these reductions. This is true even with the higher rate increases now projected by the utility, compared to the rate increases projected at the last general rate application.

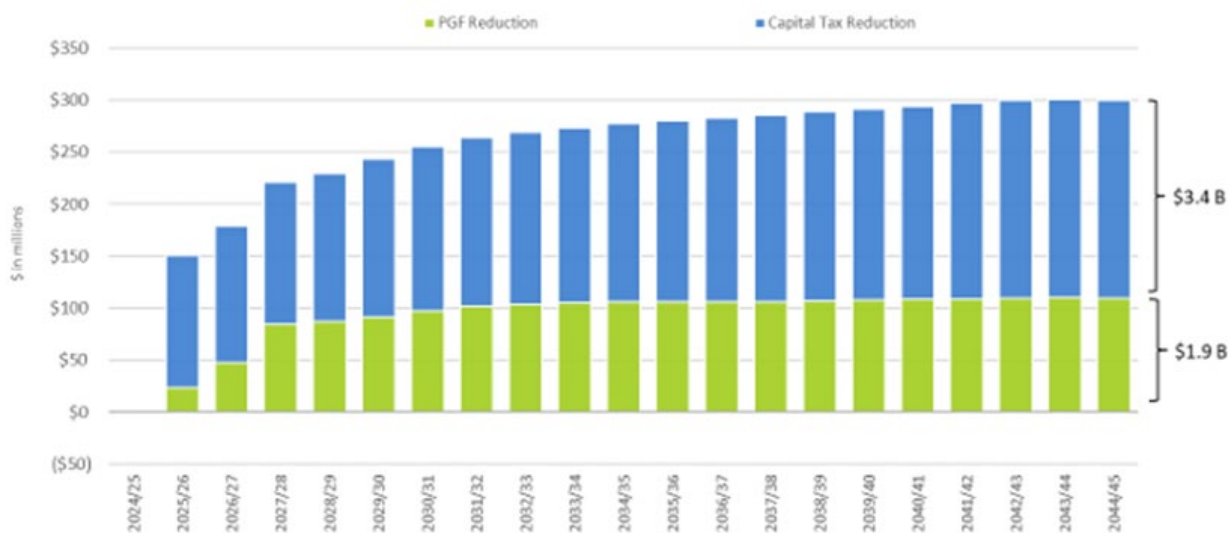


Figure 1.6 — Savings from Government Fee Reductions

### 1.5 Why Aren't All Customers Receiving the Same Rate Increase?

One of the principles of utility ratemaking, which is also written into *The Manitoba Hydro Act* as a provincial policy objective, is that different classes of customers should pay the costs properly attributable to each class. This is known as cost causation. Different customer classes cause a utility to incur different costs. For example, residential customers tend to have a significant variation in their use of electricity, such as by using more electricity in winter when heating is required. This causes a utility to incur costs to meet short-term peak demands. In contrast, industrial processes tend to use electricity more consistently, and so do not have large variations in their demand. Also, large customers who are served directly off the transmission system do not require a utility to incur distribution system costs.

The various load and service characteristics of Manitoba Hydro's customer classes are considered in the utility's cost of service study. In this Order, the Board requires Manitoba Hydro to make two changes that affect the cost of service methodology. Firstly, the Board denies Manitoba Hydro's request to use a new load research methodology to determine the contribution of each customer class to peak demand. Secondly, the Board requires the utility to use the top 10 hours instead of the top 50 hours to determine peak demand.

Based on the cost of service study, Manitoba Hydro determines the revenue-to-cost coverage ("RCC") ratio for each customer class. An RCC ratio of more than 100% indicates that a customer class pays more than the costs allocated to it under the cost of service study. An RCC ratio of less than 100% means that a customer class does not pay all of the costs allocated to that class.

Cost allocation involves judgment and is not an exact science. To account for variability, the Board has, for many years, applied a "zone of reasonableness" where the Board found that RCC ratios between 95% and 105% indicated that the revenues from a customer class adequately recovered the allocated costs. In the 2017/18 & 2018/19 General Rate Application, the Board required Manitoba Hydro to bring all customer classes into the zone of reasonableness within ten years by applying differentiated rate increases.

In the current Application, Manitoba Hydro proposed to apply rate increases on an across-the-board basis, despite not all classes currently being in the zone of reasonableness. The RCC ratios of each customer class under the last prospective cost of service study (PCOSS) and under the newest study are illustrated in Figure 1.7.

[1] Customer Class	[2] PCOSS24		[4] PCOSS26		[6] Proposed Rate Increases
	RCC	[3] ZOR	RCC	[5] ZOR	
Residential	94.4%	Below	96.9%	In	3.5%
General Service Small Non-Demand	109.7%	Above	108.0%	Above	3.5%
General Service Small Demand	101.8%	In	96.0%	In	3.5%
General Service Medium	100.3%	In	97.8%	In	3.5%
General Service Large 750V-30kV	97.9%	In	100.9%	In	3.5%
General Service Large 30-100kV	112.4%	Above	110.4%	Above	3.5%
General Service Large >100kV	113.2%	Above	110.6%	Above	3.5%
Area & Roadway Lighting	108.2%	Above	104.2%	In	3.5%

Figure 1.7 — PCOSS26 RCC Results Compared to the PCOSS24 RCC Results, with Manitoba Hydro's Proposal for Equal Rate Increases for all Classes

The Board finds that it continues to be in the public interest to move all customer classes into the zone of reasonableness. Accordingly, it directs Manitoba Hydro to apply differentiated rate increases to take effect January 1, 2027 and January 1, 2028 based on bringing all classes into the zone of reasonableness within five years. However, the Board is not requiring changes to the previously approved 4.0% rate increase that took effect January 1, 2026.

The exact amount of rate differentiation required will be determined through a compliance filing by Manitoba Hydro. Because of the two changes to Manitoba Hydro's cost of service methodology as discussed above, the exact percentages are not currently on the record of this proceeding. However, the Board anticipates that some customer classes, including residential ratepayers, will pay approximately 0.3% more, while the largest industrial classes, which are currently significantly above the zone of reasonableness, will pay approximately 1.0% less than the approved rate increases of 3.5% and 3.0% in 2027 and

2028. The Board requires Manitoba Hydro to provide its compliance filing within 60 days of the issuance of this Order to confirm the exact percentages for each customer class.

### **1.6 Bill Affordability and Energy Poverty**

The Board continues to be concerned about energy affordability and energy poverty in Manitoba. However, there is now an express legislative limitation in *The Manitoba Hydro Act* that states that the Board cannot approve differential rates based on affordability or other socio-economic factors. The Board remains of the view that if the government chooses to exclude these matters from the Board's jurisdiction, then the government has a responsibility to meaningfully address those issues. The cuts to payments to government described above do not meaningfully address energy poverty if the rate increases projected by Manitoba Hydro are now consistently above inflation and almost double what the utility projected three years ago.

The Board notes that the government has not acted on the Board's recommendations, made in the 2014 review of Manitoba Hydro's preferred development plan and in multiple rate orders since that time, to introduce targeted energy bill initiatives to mitigate the impact of Manitoba Hydro's rate increases on lower income customers. Targeted programs are needed as energy is an essential service and programs of general application do not help those most in need.

While Manitoba's electricity rates are low compared to other jurisdictions, Manitoba's cold climate and the prevalence of electric heating in areas without natural gas can lead to significant bills for customers. The Board recommends that the Province of Manitoba undertake an Energy Poverty Reduction Review, including initiatives being taken in other jurisdictions, and provide an energy poverty reduction strategy. The Board further recommends that the Province of Manitoba implement refundable income tax credits that specifically target low-income ratepayers in Manitoba to alleviate the annual energy burden of those customers. The provincial government already has access to income data and the necessary infrastructure in place to administer such credits, allowing them to be implemented at a lower administrative cost than equivalent bill credit programs offered through Manitoba Hydro or non-government organizations.

## 1.7 Reliability of Manitoba Hydro's Evidence

It became clear in this hearing that there has been a fundamental change in Manitoba Hydro's evidence on several issues between previous general rate applications and the current Application. Such changes, without sufficient explanation, make it challenging for the Board to fulfill the provincial policy objective of ensuring stable and predictable rate increases.

One fundamental change relates to the HVDC Reliability Project. As described above, in the 2017/18 & 2018/19 General Rate Application, Manitoba Hydro provided evidence that the Bipole III transmission line would be able to meet peak demand if both Bipole I and Bipole II failed. In the current hearing, Manitoba Hydro's evidence on this issue changed. It is problematic when the protection expected of a multibillion-dollar capital project fails to materialize and, as a result, requires another multibillion-dollar capital project on an urgent basis.

Similarly, it is problematic when, between rate applications two years apart, Manitoba Hydro's projected O&A expenses increase by 38%. Increases of this magnitude require the Board to take a short-term view, without being able to rely on the utility's medium- to long-term projections.

Lastly, in both the recent Centra Gas general rate application and the current Manitoba Hydro general rate application, there was a similar theme: despite a deteriorating financial condition, the utility neither adjusted its short-term rate ask nor did it make difficult short-term cost-cutting decisions. In both instances, this effectively forced the Board to make decisions that should have been made by the utility, as well as to approve a higher rate increase than requested in the first year of the rate period.

While the Board has always considered rate stability as an important aspect of rate setting, the 2022 amendments to *The Manitoba Hydro Act* make it clear that the provincial government shares this policy objective. Both Manitoba Hydro and the Province of Manitoba should be aware that, for the Board to be able to discharge this mandate, the

Board requires and expects to receive complete and up to date information available in future applications.

### 1.8 Timing of Manitoba Hydro's Application

As Manitoba Hydro's Integrated Resource Plan has yet to be reviewed or approved, Manitoba Hydro submitted a Proxy Development Plan as part of its Application to demonstrate the resource options that could meet its upcoming supply needs. While the Board finds that the Proxy Development Plan is acceptable for the purposes of this Application, it notes that the need for a proxy plan highlights the problem of hearing the Application and the Integrated Resource Plan out of sequence. The Integrated Resource Plan should have been reviewed first, with the resulting approved development plan informing the financial forecast upon which rates are approved.

Efficiency Manitoba's Efficiency Plans have not been referred to the Board for review since the original Plan was referred in 2019. As a result, the Board has not had an opportunity to explore the reasons that Efficiency Manitoba has been unable to meet the legislated efficiency targets to date, nor the steps taken to improve its processes and likelihood of achieving the targets.

While the Board would prefer to make the rate increases issued in this Order effective April 1 of each year to align with Manitoba Hydro's fiscal year, the timing of Manitoba Hydro's filing of this Application made it difficult for the Board to do so without issuing two rate increases within one calendar year. The Board finds that there would be a significant benefit for Manitoba Hydro to file its next general rate application in time for April 1, 2028 rates, as it is clear to the Board that the intent of the revisions to *The Manitoba Hydro Act* was to align rate increases with the beginning of the fiscal year. However, the Board notes that the legislation does not currently enable the Board to require Manitoba Hydro to file its application by a specified date. As such, the Board recommends that the Province of Manitoba amend *The Manitoba Hydro Act* to give the Board the power to compel Manitoba Hydro to file its applications on a timely basis.

## 2.0 BACKGROUND

### 2.1 What is a General Rate Application?

Manitoba Hydro is an electric utility owned by the provincial government. It is a Crown corporation and, under *The Manitoba Hydro Act*, has been granted a monopoly on the retail sale of electrical power in Manitoba. The utility's customers, which are grouped into customer classes based on the type of service they receive, are Manitoba's electric ratepayers.

Manitoba Hydro is vertically integrated, which means that it is responsible for the generation, transmission, and distribution of electricity. Manitoba Hydro generates electricity at its sixteen hydroelectric generating stations in Northern and Eastern Manitoba, as well as a natural gas-fired generation station in Brandon. Manitoba Hydro also procures electricity from the St. Leon and St. Joseph wind farms and imports and exports electricity outside of Manitoba. Transmission is the long-distance transportation of electricity over high-voltage lines. Distribution involves the provision of electricity to individual neighbourhoods and, eventually, the end user. In many other jurisdictions, the generation, transmission, and distribution functions are divided among different companies.

The Public Utilities Board ("Board") is an independent, quasi-judicial tribunal created by the provincial government to regulate utilities and approve rates charged to consumers, including Manitoba Hydro's rates. It does so through a public process called a "general rate application". In a general rate application, Manitoba Hydro provides evidence under oath as to why it should be awarded a rate increase, as well as whether and how that rate increase is to be apportioned among different customer classes. Representatives of different ratepayer groups that have been granted intervener status by the Board also provide evidence and present the perspective of their respective ratepayer group to assist the Board in gaining a better understanding of the issues.

## 2.2 The Board's Jurisdiction to Approve Rates

As of April 1, 2025, the Board's jurisdiction to approve Manitoba Hydro's rates is now under *The Manitoba Hydro Act*, rather than *The Crown Corporations Governance and Accountability Act*. Under the new legislation, rates must be set for a three-year "rate period" that begins on April 1, 2025. The legislation also places a 4% general rate increase cap on each of the three fiscal years of the rate period.

This is the first general rate application under *The Manitoba Hydro Act*. Subsection 39(5) of the legislation provides the following rules that apply to the approval or variation of rates by the Board:

1. The regulator must base its order or decision about rates on the revenue requirements for the rate period.
2. When reviewing the revenue requirements, the regulator must take into account and be guided by
  - a) the policies set out in section 39.1;
  - b) any applicable policies established by regulation under section 10.2 of *The Public Utilities Board Act*;
  - c) any directives issued to the corporation under *The Crown Corporations Governance and Accountability Act* or *The Financial Administration Act*; and
  - d) the maximum general rate increase allowed for a fiscal year determined under section 39.2 (4%).
3. The regulator may not reduce for rate-setting purposes the amount required to support the capital expenditure program approved by Treasury Board for the rate period.
4. Subject to the policies set out in section 39.1, the corporation may propose changes to its cost allocation method or rate design, and the regulator may approve or disallow those changes or require the corporation to make other changes to them. However, the regulator may not require a change to the

classification of customers for rate-setting purposes that has not been proposed or agreed to by the corporation.

5. Rates for different customers or classes of customers must not differ based on affordability or other socio-economic factors.
6. Rates within a class may differ based on the type, level or combination of services provided to the customer.
7. If the regulator directs the corporation to defer the recognition of costs or revenue, it must also specify, as part of that direction, when, or the conditions under which, the corporation may recognize those costs or that revenue.

Subsection 39(1) defines “revenue requirement”. Further discussion of what is included in revenue requirement is found in section 3.1.3 of this Order.

Subsection 39.1(1) goes on to establish the following additional policies of the government with respect to electricity and rates:

- The rates charged by the corporation to each class of grid customers in Manitoba are to be based on the revenue requirements properly allocated to that class.
- The rates charged to a class of grid customers in Manitoba are to be the same throughout the province.
- Subject to the other two policy objectives and to the extent practicable, rates or changes in rates should be stable and predictable from year to year.

The Board notes that the new legislation does not invalidate the long-standing Court of Appeal jurisprudence on the Board’s mandate. The Manitoba Court of Appeal considered and summarized the Board’s mandate as follows in *Consumers’ Association of Canada (Man.) Inc. et al. v. Manitoba Hydro, Electric Board*, 2005 MBCA 55 at paragraph 65:

*The PUB has two concerns when dealing with a rate application; the interests of the utility’s ratepayers, and the financial health of the utility. Together, and in the broadest interpretation, these interests represent the general public interest.*

In Order 5/12 at page 27, the Board endorsed the following description of its role in rate-setting:

*The Board's role, according to [the Consumers' Association of Canada and the Manitoba Society of Seniors], must involve ensuring that MH's forecasts are reasonably reliable, ensuring that actual and projected costs incurred are necessary and prudent, assessing the reasonable revenue needs of the Corporation in the context of the overall general health of MH, determining an appropriate allocation of costs between classes, and setting just and reasonable rates in accordance with statutory objectives.*

*The Board endorses these principles and the objectives as set out above that must inform it in the present circumstances when fixing rates for the test years in question.*

### 2.3 **Bonbright Criteria**

Utility regulators across Canada often assess rate proposals against a series of ratemaking principles described in Dr. James Bonbright's text, *Principles of Public Utilities Rates*. The Bonbright principles are not a technically precise set of rules. Rather, they reflect the balancing of interests performed by utility regulators, including the Board.

In Order 101/23, which arose out of Manitoba Hydro's last general rate application, the Board identified a list of ratemaking criteria based on Bonbright's *Principles of Public Utility Rates*, as set out in Figure 2.1.

Bonbright Criteria		Category
1.	Price signals that encourage efficient use and discourage inefficient use	Efficiency
2.	Fair apportionment of costs among customers	Fairness
3.	Avoid undue discrimination	
4.	Customer understanding and acceptance, practical and cost effective to implement	Practicality
5.	Freedom from controversies as to proper implementation	
6.	Recovery of the revenue requirement	Stability
7.	Revenue stability	
8.	Rate stability	

Figure 2.1 — Simplified Bonbright Criteria

## 2.4 Approvals Sought by Manitoba Hydro in this Application

Manitoba Hydro filed the current general rate application for fiscal years 2026 to 2028 on March 28, 2025 (the “Application”). The utility seeks the following approvals:

1. Approval of rate schedules incorporating an overall 3.5% increase in General Consumers Revenue effective January 1, 2026, sufficient to generate additional revenues of \$21 million in 2025/26;
2. Approval of a further overall 3.5% increase in General Consumers Revenue effective January 1, 2027, sufficient to generate additional revenues of \$22 million in 2026/27;
3. Approval of a further overall 3.5% increase in General Consumers Revenue effective January 1, 2028, sufficient to generate additional revenues of \$23 million in 2027/28;
4. The requested general revenue increases are proposed to be applied equally to all rate classes, on an across-the-board basis, and to each component, with the exception of the Area & Roadway Lighting rates for which Manitoba Hydro is seeking differentiated rates among the lighting types and certain rate components for diesel service in off-grid communities;
5. Approval of differentiated rates within the Area & Roadway Lighting rates, as well as changes to some of the light-emitting diode (“LED”) lighting rate descriptions;
6. Approval to apply the 3.5% proposed General Revenue increases to the Diesel Residential class and Diesel General Service class;
7. Endorsement of changes to existing deferral accounts and the establishment and amortization of new regulatory deferral accounts, summarized as follows:
  - a) Final approval of the established Joint Keeyask Development Agreement (“JKDA”) Preferred Distributions Deferral Account, approval to include annual revaluation adjustments related to the preferred distribution obligation in the deferral account and approval of an amortization period;
  - b) Approval to establish and amortize a Cloud Computing Regulatory Deferral account for SAP S/4HANA Core;

- c) Approval to establish and amortize a Cloud Computing Regulatory Deferral account for Small-Scale Software Systems; and
  - d) Approval to modify the recovery mechanism for the change in depreciation method balance for rate setting purposes, by establishing a regulatory deferral account with recovery through net movement based on an amortization period;
8. Final Approval of Interim Orders related to the JKDA, weekly Surplus Energy Program (“SEP”) rates and Curtailable Rate Program (“CRP”) annual reference discounts, and any further interim orders issued subsequent to the filing of the Application and prior to the Board’s final order; and
9. Endorsement of modifications to the Terms and Conditions of the CRP.

## **2.5 The Rate-Setting Process**

Establishing consumer rates for electricity sales is a multi-step process, as illustrated in Figure 2.2 below. As a first step, the Board reviews and approves the costs Manitoba Hydro is allowed to recover each fiscal year in rates (known as the “rate period”). Together with any required contributions to reserves to meet financial targets, this determines the revenue requirement for each year, which is the amount Manitoba Hydro is given the opportunity to recover through rates charged to consumers.

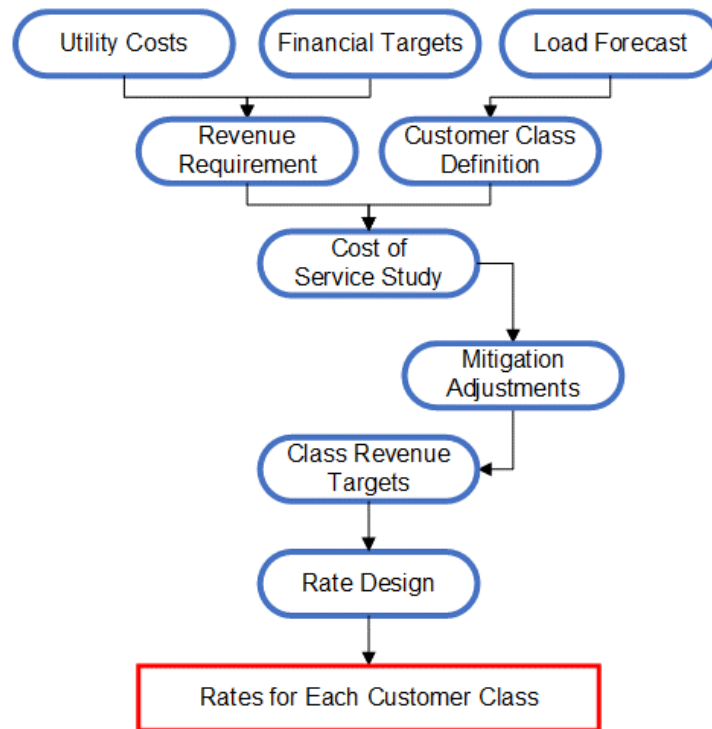


Figure 2.2 — Rate-Setting Process for Manitoba Hydro (Simplified)

To determine how much Manitoba Hydro will recover from domestic sales to Manitoba ratepayers, the utility develops a load forecast to estimate the amount of electricity customers will consume during each year of the rate period, with detailed consumption estimates by customer class. Manitoba Hydro currently has the following major customer classes, which are described further in section 20.5:

- Residential;
- General Service Small Non-Demand;
- General Service Small Demand;
- General Service Medium;
- General Service Large 750 V – 30 kV;
- General Service Large 30 – 100 kV;
- General Service Large > 100 kV; and

- Area & Roadway Lighting.

Manitoba Hydro also estimates the amount of electricity it will export to neighbouring jurisdictions and the resulting revenues from those export sales.

Many of the costs incurred by Manitoba Hydro are shared costs, meaning they are incurred to provide service to more than one customer class. The utility conducts cost of service studies to calculate how different customer classes contribute to overall costs, a regulatory principle known as “cost causation”. The steps and results of a cost of service study are discussed in further detail at section 16.2.

Based on its cost of service study, Manitoba Hydro determines the cost of providing service to each customer class. By comparing those costs against the revenues the utility expects to receive from electricity sales to each class, Manitoba Hydro can assess whether revenues equal costs or whether, under the existing rates, the utility expects to over- or under-recover costs. By making mitigation adjustments through differentiated rate increases or a redesign of the rate structure, revenues from each customer class can be aligned with costs to service that customer class.

Manitoba Hydro’s rates consist of three components, which are invoiced monthly to the appropriate customer class: (1) a basic monthly charge intended to recover the fixed costs of providing electricity service, (2) an energy charge per kilowatt-hour (“kWh”) of consumption, and (3) a demand charge based on a customer’s peak demand during the month. Not all customer classes pay all three rate components. For example, residential consumers do not pay a demand charge and industrial customers do not pay a basic monthly charge. In these customer classes, the fixed costs or demand costs are recovered through other rate components. In addition, Manitoba Hydro’s Area & Roadway Lighting customer class is invoiced a flat monthly fee per luminaire.

## 2.6 Approved Interveners

The Board invited applications for intervener status and adjudicated those applications following a pre-hearing conference held on May 1, 2025. In Order 69/25, the Board approved the following parties as interveners:

- Assembly of Manitoba Chiefs (“AMC”), the political and technical coordination organization for all 63 First Nations in Manitoba that primarily represents the interests of First Nations residential and commercial customers;
- Consumers Coalition, a coalition of the Manitoba Branch of the Consumers’ Association of Canada, Harvest Manitoba, the Aboriginal Council of Winnipeg, and the Manitoba Seniors Equity Action Coalition that primarily represents the interests of residential customers;
- Representative of the General Service Small and General Service Medium Customer Classes (“GSS/GSM Representative”), an association that primarily represents the interests of commercial customers;
- Manitoba Eco-Network and Environmental Defence (“MEED”), an environmental coalition that represents the interests of customers and the public in environmental protection;
- Manitoba Industrial Power Users Group (“MIPUG”), an association of large energy consumers that primarily represents the interests of industrial customers; and
- Manitoba Keewatinowi Okimakanak (“MKO”), a non-profit advocacy organization that represents more than 65,000 Treaty First Nation citizens in Manitoba and that primarily represents the interests of Northern First Nation residential customers.

## 2.7 Scoping and Oral Evidence

Leading up to the oral hearing of this Application, the Board issued several procedural orders that narrowed the scope of the Application as a whole, as well as the issues in scope for oral evidence. In Order 69/25, the Board ruled Manitoba Hydro’s 2025 Integrated Resource Plan (“IRP”) out of scope, except to the extent that assumptions made with respect to that forecast underpinned this Application. In Order 129/25, the Board made a ruling on issues that were in scope for oral evidence and issues that were to be dealt with exclusively in writing.

The Board heard oral evidence from November 17, 2025 to December 11, 2025, with final submissions made on December 16, 18, 19, and 22, 2025.

### **3.0 RATE PATH AND RATE APPROVALS**

#### **3.1 Background**

##### ***3.1.1 Manitoba Hydro's Rate Request***

Manitoba Hydro's Application seeks the following rate increases:

- a 3.5% overall increase in General Consumers Revenue effective January 1, 2026;
- a 3.5% overall increase in General Consumers Revenue effective January 1, 2027;  
and
- a 3.5% overall increase in General Consumers Revenue effective January 1, 2028.

The utility proposes to apply the rate increases equally to all customer classes, without rate differentiation either by customer class or rate component.

Manitoba Hydro's Application is consistent with sections 39 to 39.2 of *The Manitoba Hydro Act*, which require the utility to seek rates for a three-year rate period, with the maximum annual rate increase in any individual fiscal year capped at 4%.

##### ***3.1.2 Change in Rate Path from the Last Application***

In the last general rate application, which approved rates for the 2023/24 and 2024/25 fiscal years, Manitoba Hydro initially sought rate increases of 3.5%, which is identical to the rate path projected in the current Application. However, after the Province of Manitoba reduced the provincial debt guarantee fee and the water rental rate payable by Manitoba Hydro by one-half, the utility reduced its rate request in that application from 3.5% to 2.0% in each fiscal year. At the time, Manitoba Hydro was at the end of a decade of investments in major generation and transmission capital projects, such as the Keeyask Generating Station and the Bipole III transmission line, with the utility planning to shift its capital expenditures towards business operations capital. The Board ultimately approved 1% increases in general consumer revenue effective September 1, 2023 and April 1, 2024 as detailed in Orders 101/23 and 104/23.

The debt guarantee fee is a fee that Manitoba Hydro pays to the provincial government in order for the government to guarantee Manitoba Hydro's debt, which in turn allows the utility to obtain a lower borrowing rate. Before the last general rate application, the fee was 1.0% applied to outstanding debt. In the course of the last application, it was reduced to 0.5%. The water rental rate is a fee levied under *The Water Power Act*. Before the last general rate application, it was \$20.32 per horsepower-year (the unit of energy used in water power regulations). In the course of the last general rate application, it was reduced to \$10.16 per horsepower-year.

For the current rate period, the previously reduced water rental rate remains the same. However, the provincial government has cut the debt guarantee fee further to 0.4% for 2025/26 and has committed to cut it further to 0.3% for 2026/27 and 0.15% for 2027/28. Over the three-year rate period, Manitoba Hydro expects the additional reductions to reduce its revenue requirement by \$155 million.

In addition, the Province of Manitoba has eliminated the capital tax levied under *The Corporation Capital Tax Act* for Crown corporations, effective April 1, 2025. Over the three-year rate period, Manitoba Hydro expects the elimination of the capital tax to reduce its revenue requirement by \$395 million.

As the reduction in the provincial debt guarantee fee and the elimination of the capital tax also affect future years beyond the three-year rate period, those savings will continue to reduce Manitoba Hydro's revenue requirement. As set out in Figure 3.1, over the 20-year forecast period, Manitoba Hydro expects the cumulative savings from the reductions to amount to \$5.3 billion.

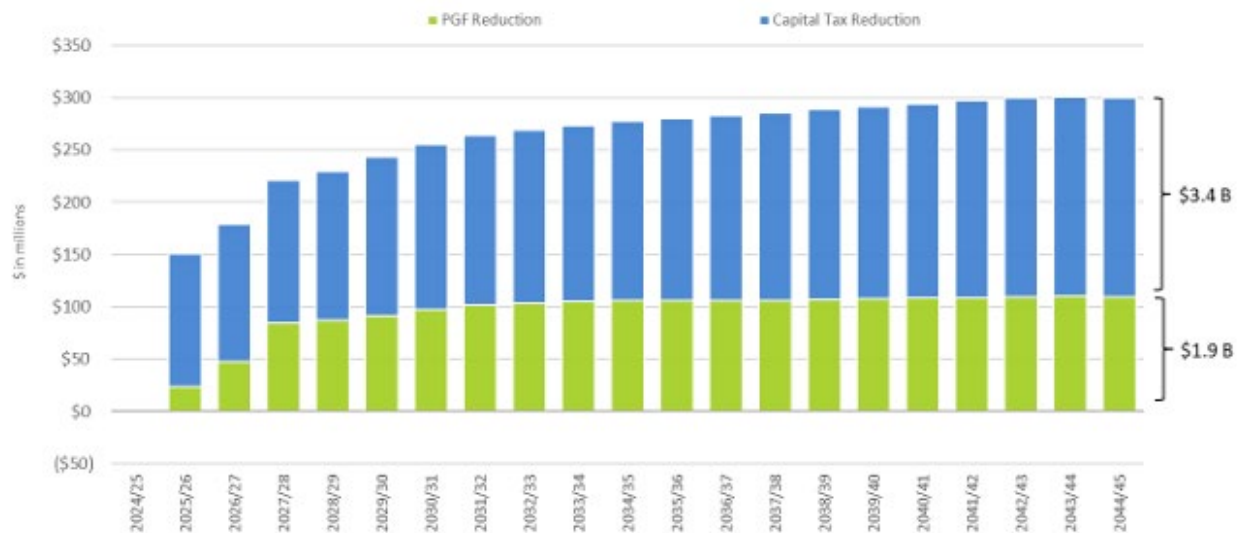


Figure 3.1 — Savings from Government Fee Reductions

Despite these further reductions in transfer payments and Manitoba Hydro having increased its rate path from 2.0% in the last general rate application to 3.5% in the current Application, Manitoba Hydro predicts a weaker financial situation for the utility under its current rate proposal than under the proposal presented in the 2023/24 & 2024/25 General Rate Application. This includes an \$8.6 billion increase in the net debt balance over the next 20 years, and a current plan to maintain a debt-to-capitalization ratio of approximately 85% until the end of the 2030s, eventually achieving 79% in 2044/25. In contrast, in the 2023/24 & 2024/25 General Rate Application, the utility was projecting a pay-down of debt in the latter years of its forecast, achieving a debt-to-capitalization ratio of 70% by 2040.

The change in Manitoba Hydro’s financial forecast between the last and current general rate application, despite \$5.3 billion in savings from reduced payments to government, is caused by several factors. Firstly, as discussed in section 10.0, Manitoba Hydro is embarking on another period of significant investment in its assets. The utility intends to engage in an aggressive program of major capital expenditures that includes the refurbishment of its aging high voltage direct current (“HVDC”) assets and the construction of new dispatchable capacity resources, which are expected to be three combustion gas turbines, at a collective cost of over \$10 billion. Manitoba Hydro projects a further \$20 billion in business operations capital expenditures over the next 20 years,

as discussed in section 10.0, in order to sustain and grow Manitoba Hydro's existing assets to reliably serve Manitoba's growing energy needs into the future.

Secondly, as discussed in section 11.0, Manitoba Hydro is projecting a \$4.2 billion cumulative increase to its operating and administrative expenditures ("O&A") over its 20-year forecast compared to the last general rate application. This includes a replacement of the utility's SAP enterprise resource planning software, Phase 1 of which is currently projected to cost \$193 million in total between Manitoba Hydro and Centra Gas.

Thirdly, the Province of Manitoba, in its provincial energy policy (called the Affordable Energy Plan) has committed Manitoba Hydro to procure up to 600 megawatts ("MW") of Indigenous majority-owned wind power.

### **3.1.3 Allowance for Net Income**

Subsection 39(1) of *The Manitoba Hydro Act* defines "revenue requirement" as:

*"revenue requirement", in relation to a rate period, means the amount of rate revenue required in each fiscal year within the rate period to pay the reasonable costs forecast by the corporation for that fiscal year, including*

- (a) the corporation's operating, maintenance and administrative expenses;*
- (b) amounts in respect of capital expenditures;*
- (c) debt service costs; and*
- (d) power purchases, taxes, fees and other amounts required to be paid out of the corporation's revenue.*

This definition of revenue requirement makes no allowance for a return or contributions to reserves.

When amendments to *The Manitoba Hydro Act* were enacted November 3, 2022, the definition of revenue requirement in subsection 39(1) of the Act included the elements in the currently approved definition, but also:

*(b) to achieve, in accordance with the regulations, the financial targets set out or referred to in subsection 39.1(1) and address material risks that could affect the achievement of those targets.*

The need to achieve the financial targets in subsection 39.1(1) required Manitoba Hydro to earn a positive net income and thus net income was a valid part of the revenue requirement.

When *The Manitoba Hydro Act* was amended in July 2025 to remove the financial targets in subsection 39.1(1), the definition of revenue requirement in subsection 39(1) was also amended to remove item (b). However, no other element was added to specifically include net income as a valid element of revenue requirement. While Manitoba Hydro has not historically earned a return payable to a shareholder, in most years it has earned net income which forms a contribution to its reserves, also known as retained earnings. It was therefore an issue in this hearing whether the Board could set just and reasonable rates that would be expected to result in positive net income.

#### **3.1.4 Drought Impacts**

When Manitoba Hydro filed its Application on March 28, 2025, the utility was expecting a positive net income for 2025/26 of \$218 million. However, since that time, Manitoba has experienced a severe drought, with water flows currently being close to the second-lowest flows on record. As a result of the 2025/26 drought, Manitoba Hydro now projects a \$409 million loss this year, representing a negative turnaround of \$627 million in the first test year. The current year drought follows below-average water flows in three of the previous four years. Cumulatively, over the past five years net income is expected to be negative \$269 million.

In addition to the projected loss, the drought also decreased Manitoba Hydro's earnings before interest and taxes ("EBIT") based interest coverage ratio to 0.6, which is below Manitoba Hydro's 1.2 ratio target. The EBIT interest coverage ratio is a longstanding financial metric used to assess Manitoba Hydro's ability to meet its interest costs. When the EBIT ratio falls below 1.0, the utility cannot fully pay its interest expenses with its operating profits and must rely on cash reserves, or additional borrowing, to meet its

payment obligations. However, Manitoba Hydro confirmed that it continues to be able to make interest payments out of operating cash flow and would not have to borrow to pay interest unless the losses increased to \$570 million.

Despite Manitoba Hydro's deteriorating financial situation in 2025/26, the utility did not amend its 3.5% rate request for the rate period, nor did it seek interim rate relief. However, Manitoba Hydro acknowledged in cross-examination that the utility would need as much of a rate increase as it could get. Manitoba Hydro advised that, in making this decision, it considered affordability as well as the possibility of water flows rebounding relatively quickly.

A more complete discussion of the impacts of the drought and recent below-average water flows is found in section 4.0.

### ***3.1.5 Interim Rate Relief and Order 161/25***

Following the oral hearing in November and December 2025, the Board considered the submissions of the parties summarized below and granted, on its own accord and on an urgent basis, an interim general rate increase of 4.0% effective January 1, 2026. The details of the rate were set out in Order 161/25. In that Order, the Board found that a rate increase at the legislated maximum of 4% was justified because of the 2025/26 drought, and that expecting a \$409 million loss while keeping the rate ask at 3.5% was not prudent. However, the Board also observed that the 4.0% rate increase approved in that order would only take effect at the beginning of the 4<sup>th</sup> quarter of the 2025/26 fiscal year and, as such, would only recover an additional \$24 million in that year.

As Manitoba Hydro did not apply for an interim rate increase and the Board issued the increase on its own accord after the oral hearing had ended, none of the submissions of the parties summarized below, including those of Manitoba Hydro, address the finalization of Order 161/25.

## 3.2 Position of the Parties

### 3.2.1 *Manitoba Hydro*

Manitoba Hydro submits that its proposed 3.5% rate path balances a number of priorities, including allowing the utility to make \$31 billion of system investments over the next 20 years while providing stable and predictable rates for customers. The utility points out that, even with the proposed rate increases, Manitoba Hydro's rates will continue to be the lowest, or among the lowest, in North America. In addition, Manitoba Hydro states that it continues to support customers facing challenges with energy affordability. Manitoba Hydro emphasizes the link between cash flow sufficiency and profitability, and notes that the proposed rate path will allow the utility to keep its debt-to-capitalization ratio steady over the next 10 years while it undertakes significant capital investments. While the utility has a debt-to-capitalization ratio target of 75%, it is forecasted to remain consistently above 80% during the 20-year forecast period, as discussed further in section 5.1.1.

Manitoba Hydro cites declining asset performance and reliability as leading to investment challenges at a time of rising inflation. It also notes growing demand and aging technical systems, including the need to replace its SAP software.

Citing the evidence of its Chief Executive Officer, Manitoba Hydro submits that the legislated 4% rate cap set out in *The Manitoba Hydro Act* requires rates to be set in a manner that recognizes the "lumpiness" of revenue requirements which could occur when large expenses are incurred in a short period, especially those that relate to large capital projects. According to Manitoba Hydro, the legislated rate cap requires rate smoothing over multiple years to lessen the effect of large expenditures by avoiding a rate spike in the year that the expense arose.

Manitoba Hydro cites the testimony of MIPUG's witness Mr. Bowman that likens the utility to a super tanker that needs to be steered with a long-term view. In Manitoba Hydro's view, the approach suggested by the Consumers Coalition's witness Mr. Rainkie and by the GSS/GSM Representative's witness Ms. Davies contradicts this approach, as they

suggest placing an emphasis on the near term to medium term, based on a perceived lack of certainty on the actual level of capital investments that they state the utility will ultimately incur.

Manitoba Hydro points out that it has experienced a drought during four of the last five years, which collectively has reduced retained earnings by up to \$1.9 billion compared to projections from the last general rate application. However, the utility states that, despite this, the performance of its assets is declining and asset refurbishments such as the HVDC Reliability Project cannot be deferred. It also notes the need for new energy and capacity resources is only four to six years away. In Manitoba Hydro's view, the utility must act early to secure resources in the face of global competition for specialized utility equipment that has resulted in long lead times.

In addition, the utility submits that years of fiscal restraint have created a vegetation management backlog, and the SAP software used by Manitoba Hydro is nearing the end of its life. Manitoba Hydro states that taking a short- to medium-term view in setting rates ignores that Manitoba Hydro has no choice but to address these cost pressures, while needing to ensure that rates remain stable, affordable, and predictable for its customers. The utility acknowledges that 3.5% is the minimum required in the rate period, and that the utility is taking a long-term perspective for its rate proposals for the rate period.

Manitoba Hydro states that, in the context of multiple drought years, it has taken measures and made decisions to manage costs, such as proposing a lower level of business operations capital than recommended by the utility's asset management plan. However, the utility states that the prolonged duration of the drought has limited options to defer spending and that continuing to rely on cost deferrals would come at the expense of system reliability and future increased costs. Regarding operational costs, the utility points out that it has not filled all budgeted positions from the 2024/25 fiscal year in order to do more with less, and that wages and salaries were underspent by \$12.4 million. In addition, for every position that becomes vacant, the utility is reviewing whether it needs to fill the role in the same capacity. The utility emphasizes that it has maintained the growth of non-staff O&A expenditures at 2.0%, and that O&A cuts cannot offset drought

losses, since this might mean an amount equal to Manitoba Hydro's entire payroll base would be required to deal with the loss.

As the 2025/26 drought developed, Manitoba Hydro did not seek an interim rate increase earlier than its originally-proposed January 1, 2026 date due to the Government-imposed rate freeze in 2025 and because there remained uncertainty in the water inflows during the spring and summer of 2025. Manitoba Hydro also stated that it did not seek to amend the 3.5% increases for the second and third years of the rate period because Manitoba Hydro is taking a balanced and long-term view regarding rates. Manitoba Hydro's board of directors was kept updated on the financial situation, but senior management did not seek a revised rate request. However, at the oral hearing, Manitoba Hydro's senior management described that 3.5% is the minimum rate increase required by the utility, but that from a purely financial perspective, Manitoba Hydro would need as much of a rate increase as it could get.

Manitoba Hydro argues that rate paths that propose increases below 3.5% will result in cash flow shortfalls and increased debt. While intervener consultants have agreed that Manitoba Hydro should earn a positive net income, they have proposed rate scenarios that do not achieve positive earnings without arbitrary or unrealistic reductions to O&A expenses and capital spending reductions that are not grounded in evidence and don't acknowledge binding commitments in collective bargaining agreements. Manitoba Hydro notes that both intervener witnesses Mr. Colaiacovo and Mr. Bowman have recommended an immediate 4% rate increase in light of the 2025/26 drought. It further states that, as a result of several years of losses, the utility's EBIT interest coverage ratio has been below 1.0 in four out of five years, which signals to debt investors that the utility's operating income has not been sufficient to cover its interest on debt. The utility advises that, under its updated financial forecast as filed in response to undertakings, over the first decade of the forecast, annual earnings will average approximately \$60 million, while the EBIT interest coverage ratio will average 1.05 and the debt-to-capitalization ratio will weaken to 87%. For these reasons, Manitoba Hydro objects to the alternative rate paths proposed by interveners in this hearing.

Manitoba Hydro argues that the amount of revenue earned must be sufficient to pay for reasonable costs forecast by the corporation, including debt service costs and amounts in respect of capital expenditures. In considering these aspects in *The Manitoba Hydro Act* definition of revenue requirement, it is essential to consider how the approved rates permit Manitoba Hydro to earn sufficient cash to meet those requirements to fulfill its mandate. Manitoba Hydro states this is why it is necessary for it to earn a positive net income and have sufficient financial reserves.

### **3.2.2 Interveners**

#### **Assembly of Manitoba Chiefs**

The AMC opposes rate increases that exacerbate affordability challenges for First Nations on-reserve residential customers. This intervener would instead like rates to be kept as low as possible until Manitoba Hydro implements effective affordability measures. The AMC further supports MKO's opposition to any rate increase for Diesel Zone customers.

The AMC notes that a temporary rate freeze does not alter Manitoba Hydro's underlying cost structure and cautions against a drought-related rate increase that will become embedded in future rates. As an example, it cites the last general rate application, in which the Board found that, in retrospect, a 3.6% drought-related rate increase was not required because drought conditions transitioned to record water flows in the subsequent year.

The AMC further argues that, while the legislation restricts rate differentiation based on socio-economic factors, it does not limit the Board's authority to consider affordability, reconciliation, bill impacts, or equity when setting just and reasonable rates. These remain an essential component of the Board's function, particularly where uniform increases impose disproportionate burdens on vulnerable customers. Further, although drought conditions may place upward pressure on rates, the Board must ensure that rate increases intended to address drought impacts do not simply enable continued growth in

operating and capital expenditures, leaving Manitoba Hydro in equivalent or worse financial position at the end of the rate period.

While the AMC recommends rates being kept as low as possible, it has not recommended a specific rate path.

### **Consumers Coalition**

The Consumers Coalition submits that even in the context of ongoing drought conditions, Manitoba Hydro avoids hard choices and seeks comfort in three cumulative rate increases from captive ratepayers as part of a “wishful” 20-year plan to make substantial progress to achieve its target debt-to-capitalization level. In the view of this intervener, the Board has options on how to balance the interests of ratepayers against the financial health of Manitoba Hydro. Referring to Manitoba Hydro’s “doomsday claims”, it argues that there has been an unreasonable escalation of O&A costs and no effort to reduce spending in response to the drought. In addition, the review of Manitoba Hydro’s IRP has not yet been completed, and the utility’s asset management plan and capital planning process include highly uncertain preliminary estimates for very expensive projects.

In the Consumers Coalition’s submission, the need for new capacity resources is now delayed as a result of the 200 MW of new seasonal diversity exchange agreements discussed in section 8.0. In addition, the HVDC Reliability Project currently only has a Class 10 cost estimate attached to it, which makes the cost projections highly uncertain. Regarding the increase in O&A, the Consumers Coalition notes that the 1.5% increase in the rate path – the proposed 3.5% path compared to the 2.0% path presented at the last general rate application – would only address the \$4.2 billion increase in projected O&A costs discussed in section 11.0. The Consumers Coalition also states that, to date, Manitoba Hydro has not faced any challenges regarding new debt issues or the cost of debt, and that there is no obvious relationship between Manitoba Hydro’s credit spread and the utility’s debt level. The Consumers Coalition calls for a strong regulatory signal from the Board and expresses concern that, absent such a signal, the trend of increasing costs is likely to continue and escalate further.

In the Consumers Coalition's view, the Board does not need to be backed into a corner and can appropriately reflect uncertainty and necessary cost controls in its decisions. It recommends looking beyond the three-year rate period to the medium term. Further, this intervener argues that the strongest tool available to the Board to ensure affordability for all Manitobans is the lowest possible overall rate increase that addresses Manitoba Hydro's financial health in the short and medium term. This reflects appropriate caution due to significant long-term uncertainty, sends a strong efficiency signal that drought requires management action alongside other tools, and that prudent fiscal stewardship demands more effective long-term cost controls on behalf of Manitoba ratepayers. While drought is a serious concern, the Consumers Coalition submits it is important for the Board not to overreact given recent precedent of record net income following significant drought years. Even if the Board accepts a higher rate increase in 2025/26 for drought response, the rate increases approved for 2026/27 and 2027/28 should be adjusted to reflect the Board's view of the total three-year revenue requirement.

Overall, the Consumers Coalition recommends that the Board approve rate increases of 2.25% in each year of the rate period. This recommendation is predicated on a curtailment of future O&A spending as recommended by the Consumers Coalition's witness Mr. Rainkie, as well as a 10% reduction to business operations capital spending. The Consumers Coalition specifically asks the Board to reject the premise that no meaningful changes to Manitoba Hydro's forecast will arise as a result of the IRP review. According to the Consumers Coalition, Manitoba Hydro's capital expenditure plan includes \$11.7 billion of placeholders, amounting to 38% of the 20-year long-term capital projection.

The Consumers Coalition also identifies a number of potentially problematic provisions in the existing requirements of *The Manitoba Hydro Act* that give rise to considerable risk in the way that they constrain the Board's exercise of its independent discretion and authority. Specifically, it would like the Board to recommend that government address the following issues in the statute:

- A statutory three-year rate period, coupled with the need to get Cabinet approval for a mid-period adjustment, creates inflexibility and impairs the ability to respond to changes in circumstances.
- There is a need for clarity on the role of retained earnings in rate-setting.
- The role of rate design principles relative to class costs is unclear, as is the Board's authority to recommend changes to the cost of service methodology with the recommendation or consent of Manitoba Hydro.
- The ability to consider the prudence of near-term capital spending appears insufficient.

### **GSS/GSM Representative**

The GSS/GSM Representative recommends a focus on the rate period and a short-term approach to determining rates. It proposes to accomplish this by approving inflationary rate increases for all three years of the rate period, with an additional adder in response to the severe 2025/26 drought. Based on this methodology, it recommends three years of 2.0% rate increases, with an additional 2.0% in one of the years, or spread across multiple years, on account of the 2025/26 drought. The 2.0% drought adder is intended to generate an additional \$72 million during the rate period, which would address the impact of the 2025/26 drought over eight to ten years. In the view of the GSS/GSM Representative, separately addressing the 2025/26 drought sends the message to all parties that the Board acknowledges the severity of the drought, while also signalling to Manitoba Hydro that the utility must make hard choices to adjust to circumstances.

This intervener notes that the most practical way to implement its proposed 2% cumulative drought adder is with an additional 1% in both 2025/26 and 2026/27, which provides greater benefits in the near-term and still allows rate smoothing. For 2027/28, there is no indication that above-inflationary increases are warranted and this gives Manitoba Hydro time to implement meaningful cost decreases, with some of them passed on to ratepayers.

Like the Consumers Coalition, the GSS/GSM Representative emphasized the uncertainty in Manitoba Hydro's forecast. In its view, where rates are being increased in a manner that considers the long term, there should be a specific rationale for those increases. The GSS/GSM Representative urges the Board to protect ratepayers from a continued pattern of Manitoba Hydro spending as it sees fit despite cautions from the Board. This intervener notes that, from the 2021/22 fiscal year to the 2024/25 fiscal year, O&A expenditures have increased cumulatively by \$176 million, or 30%. The GSS/GSM Representative takes issue with Manitoba Hydro's employee-related costs, vegetation management costs, and SAP-related costs, as described in section 11.0. In addition, it relies on the evidence of Midgard Consulting Inc. ("Midgard") on behalf of the Consumers Coalition with respect to business operations capital.

#### **Manitoba Eco-Network and Environmental Defence**

MEED is not taking a position on the overall rate increase, but it submits that Manitoba Hydro's plan to build a three-turbine gas plant should not be used to justify higher rates. The need for new combustion turbines will be determined in the upcoming IRP and Major New Facilities Review proceedings.

Despite the above, MEED does not take a position on the rates to be approved in this hearing.

#### **Manitoba Industrial Power Users Group**

MIPUG submits that on a full reading of *The Manitoba Hydro Act*, the Board has the ability to look beyond the current three-year rate period when setting rates. Further, while the statute's definition of revenue requirement does not indicate inclusion in rates of any amounts for reserves or net income, such factors are inherent to an understanding of the other sections of the statute. According to MIPUG, while the requirement for the Board to set rates on Manitoba Hydro's "revenue requirement" suggests that the Board needs to look at the specific rate period, the provision needs to be read together with the government policies enshrined in subsection 39.1(1) of the statute, including the policy that rates should be stable and predictable from year to year.

Nonetheless, MIPUG cautions that a rate hearing should not turn into an unlimited assessment of every cost Manitoba Hydro may face for the coming decades. In MIPUG's submission, the requirement for rate stability only applies "to the extent practicable" and does not expressly modify the need to set rates based on the revenue requirement during the rate period. MIPUG also points out that subsection 39.4(1) of *The Manitoba Hydro Act* enables Manitoba Hydro to seek a variance from approved rates if there is a material change in circumstances, subject to the 4% rate cap.

Overall, MIPUG does not see Manitoba Hydro's financial forecast, as presented, as a credible or reasonable forecast. In its submission, the forecast includes an inferior mix of near-maximum rate increases combined with weak financial performance for at least the first ten years, leading to insufficient resilience.

To address this concern, MIPUG recommends a rate path of 4.0%, 4.0% and 0% for the rate period. It further recommends that the Board set out its understanding of the conditions that could lead to a reconsideration of rates under subsection 39.4(1) of the Act.

In making this recommendation, MIPUG is guided by the deterioration in Manitoba Hydro's financial forecast between the filing of the Application and the oral hearing. It notes that the updated forecast filed during the oral portion of the hearing leads to a retained earnings increase of only \$400 million over 12 years, most of which are years with normal water flows. MIPUG contrasts this against the forecast filed with the application, which projected a retained earnings increase of \$1.3 billion over the same time period. MIPUG notes that there have similarly been deteriorations to Manitoba Hydro's EBIT interest coverage ratio (projected to average 1.05 over 10 years) and capital coverage ratio (projected to average 1.02 over 10 years), and that Manitoba Hydro has characterized this situation as "treading water".

Under MIPUG's proposed rate path, rates for the first two years of the rate period are set at the legislated maximum, while rates for the third year would provide flexibility for an adjustment on January 1, 2028 if necessary. Since the rate cap applies in each

government fiscal year, which begins in April and ends in March, MIPUG further notes that it would be possible for the third-year rate increase to be granted sometime in 2027 instead of at the beginning of 2028 if the circumstances at the time support a further rate increase.

MIPUG calculates that its proposal is projected to yield \$296 million in added revenue to Manitoba Hydro during the rate period, compared to \$282 million during the same period from Manitoba Hydro's 3.5% path. As such there is no credible argument that MIPUG's rate path fails to yield Manitoba Hydro equal or better revenues. Further, Manitoba Hydro's proposal gives limited flexibility as it will largely preclude a further increase based on reconsideration (only 0.5% from the rate cap). While MIPUG states that drought is an inherent component of Manitoba Hydro's cost structure, it points out that the additional borrowings incurred in 2025/26 because of the drought will result in \$30 million of increased finance expense in all future years, unless that debt is discharged. As such, MIPUG suggests that its proposed rate path more than addresses the additional costs for the first two years of the rate period.

### **Manitoba Keewatinowi Okimakanak**

MKO argues that given the existing limitations in *The Manitoba Hydro Act*, and the need to provide some relief to First Nation residential customers, MKO is forced to formally advocate for a 0% rate increase for all residential customers and diesel community customers. MKO submits that, although Manitoba Hydro talks about reconciliation, the corporation proposed no action with respect to electricity rates for Indigenous customers. Further, this intervener argues that residential customers living on reserves, who get less service than those located in southern Manitoba, should not bear the fault for Manitoba Hydro's failed budgeting.

As further discussed in section 19.0, MKO submits that recommending legislative changes could be considered appropriate or necessary to carry out the Board's broad mandate under the existing legislative requirements, specifically under clause 39(4)(b) of *The Manitoba Hydro Act* to set just and reasonable rates.

### 3.3 Board Findings

#### 3.3.1 *Jurisdiction under The Manitoba Hydro Act*

The Board finds that it has jurisdiction under *The Manitoba Hydro Act* to approve net income as part of the revenue requirement during the rate period.

Statutory interpretation now follows Driedger's Modern Principle, described as follows in the 2<sup>nd</sup> edition of E. Driedger, *Construction of Statutes*:

*Today there is only one principle or approach, namely, the words of an Act are to be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament.*

The Board finds that subsection 39(5) of *The Manitoba Hydro Act* authorizes the Board to approve rates that include a net income for Manitoba Hydro, even though net income is not expressly included in the definition of the revenue requirement in the Act. The Board believes that this was an oversight in the legislation. Reserves are an integral part of utility regulation. Without reserves, as created by a positive net income and the resulting retained earnings, it would be impossible for Manitoba Hydro's rates to be stable, at least not without the extensive use of deferral accounts, on which the Act imposes restrictions. More importantly, such an interpretation would permanently "freeze" Manitoba Hydro's retained earnings at their current level, regardless of any risk assessments, financial targets, or other metrics. Doing so would have the effect of overriding the Manitoba Court of Appeal's jurisprudence that requires the Board to balance the interests of ratepayers against the financial health of the utility. The Board recommends that the Province of Manitoba amend *The Manitoba Hydro Act* to explicitly include net income as a component of revenue requirement, in a similar manner in which reserves (a similar concept) were included in *The Crown Corporations Governance and Accountability Act* in the past.

The Board similarly finds that it has the authority to consider the financial health of Manitoba Hydro beyond the current rate period when determining appropriate levels of net income and rates. Rule 1 of subsection 39(5) of *The Manitoba Hydro Act* requires the Board to base its order or decision about rates on the revenue requirement for the rate

period in the near term. However, rule 2 also specifically requires the Board to take into account the policies set out in section 39.1. Clause 39.1(1)(d) makes it a policy of the government that, to the extent practicable, rates or changes in rates should be stable and predictable from year to year. In the context of a utility undergoing major capital projects, rate stability almost always involves a need for rate-smoothing to prevent rate jumps as projects enter service and are recorded on the operating statement. In the context of a privately owned utility that pays dividends, this may involve the extensive use of rate-smoothing deferral accounts. However, in the context of a government-owned utility like Manitoba Hydro, it may involve managing rates with a degree of foresight, to both the medium-term period of ten years and long-term period of 20 years, using retained earnings as a balancing tool. Such balancing is consistent with the well-established Bonbright principles set out in section 2.3.

### ***3.3.2 Rate Approval for the Rate Period***

The Board confirms the 4.0% interim rate increase approved effective January 1, 2026 and approves two additional increases to Manitoba Hydro's general revenues:

- a 3.5% increase to general consumer revenues effective January 1, 2027; and
- a 3.0% increase to general consumer revenues effective January 1, 2028.

As set out in section 18.0, the increases for 2027 and 2028 are to apply on a differentiated basis, while the confirmed rate increase for 2026 will not be differentiated.

The Board finds that it is in the public interest to finalize the previously awarded 4.0% general revenue increase for January 1, 2026. For the reasons set out in Order 161/25, it is necessary for Manitoba Hydro to receive a rate increase at the 4% legislative maximum. Even with that increase, Manitoba Hydro is expected to experience a loss of approximately \$406 million in 2025/26, which means that any rate increase below the legislative maximum is not prudent, as noted by the Board in Order 161/25.

However, for the remaining two years of the rate period, the Board finds that rate increases at the legislative maximum are not justified at this time. It is still possible that water flows will revert to normal levels in 2026/27, which would alleviate Manitoba Hydro's losses, even if reservoir levels at the start of the next fiscal year remain low.

As explained in Order 161/25:

*The Board remains mindful of its mandate to balance the interests of ratepayers against the financial health of the utility. Manitoba Hydro's residential rates are currently the 2nd-lowest in Canada, but energy poverty continues to be a serious problem in the province. However, while the Board shares the concerns about affordability expressed by several interveners, it must respond to the serious nature of the drought.*

The Board considered the totality of the evidence in determining that a rate increase of 3.5% on January 1, 2027 and a 3.0% increase on January 1, 2028 are in the public interest. That evidence is summarized in the remainder of this Order, but includes the following salient points:

- Manitoba Hydro's assets are aging and require reinvestment to maintain safe and reliable service, including business operations capital expenditures that are in excess of \$700 million per year, an increase of approximately \$200 million compared to the test years from the last general rate application.
- Manitoba Hydro is embarking on two major capital projects, the High Voltage Direct Current ("HVDC") Reliability Project with a capital cost of \$6.8 billion and the development of dispatchable capacity resources, which are expected to be three combustion turbines at a cost of \$2.5 billion.
- Replacement of Manitoba Hydro's existing SAP enterprise management software with SAP S/4HANA is expected to cost \$193 million for Phase 1 of this project.
- Operating & administrative ("O&A") expenses are increasing, primarily due to negotiated wage settlements and increases to vegetation management.

The Board makes findings related to these items later in this Order, including disallowing a portion of Manitoba Hydro's projected O&A expenditures for each of the 2026/27 and 2027/28 fiscal years. However, the Board finds that these capital and operating expenditures will put pressure on Manitoba Hydro's finances and, absent the rate increases approved by the Board, will cause degradation of Manitoba Hydro's financial health that is not in the public interest. As explained in section 5.0, Manitoba Hydro needs to maintain an interest coverage ratio on an earnings before interest and taxes ("EBIT") basis in excess of 1.0 in order to recover the full cost of providing service to ratepayers.

The Board accepts the arguments of the Consumers Coalition and the GSS/GSM Representative that, in this Application, there remains significant uncertainty regarding Manitoba Hydro's capital projects. The uncertainty in capital, operations, and administrative spending as well as future water flows all have an influence on the Board's rate decisions which are explained further in the remainder of this Order. However, the magnitude of the above expenditures, even if they are ultimately reduced or deferred, are such that rate increases above the rate of inflation are required.

A rate path of 4.0%, 3.5% and 3.0% results in cumulative rate increases throughout the rate period that are almost identical to Manitoba Hydro's proposed rate path of 3.5% in each year. However, the effect of the rate path ordered by the Board is to front-load a portion of the incremental revenue, such that Manitoba Hydro will earn a higher amount of additional revenue in the rate period than what the utility sought.

If the current drought should continue into 2026 or beyond, Manitoba Hydro will have three feasible options. Firstly, it can take an aggressive cost management approach, particularly through the re-prioritization of business operations capital and O&A expenditures. Secondly, if necessary, Manitoba Hydro could obtain Cabinet approval to seek a rate variance under subsection 39(4) of *The Manitoba Hydro Act*. With the rate increases during the rate period being front-loaded, the rate path approved by the Board provides more flexibility for adjustments in the third year than Manitoba Hydro's proposal. Thirdly, Manitoba Hydro could seek approval for future rate increases earlier in the fiscal year than January 1. It is clear to the Board that the intent of the revisions to *The Manitoba*

*Hydro Act* was to align rate increases with the beginning of the fiscal year on April 1. However, the timing of Manitoba Hydro's filing of this Application places the Board in the difficult position of either ordering the rate increases to take effect on January 1 or issuing two rate increases within one calendar year. While the Board would prefer to make the rate increases effective at the beginning of Manitoba Hydro's fiscal year, to do so in this Application would require the Board to issue two rate increases within one calendar year, which raises possible affordability concerns. Nonetheless, there would be a significant benefit for Manitoba Hydro to file its next general rate application in time for April 1, 2028 rates.

The Board notes that the legislation does not currently enable the Board to require Manitoba Hydro to file its application by a specified date. While the Board has tried to move Manitoba Hydro to regular applications in the past, it lacks the jurisdiction to force Manitoba Hydro to a hearing. Unlike other jurisdictions in Canada which have this power, the Board is forced to wait for Manitoba Hydro to file its rate application before the Board can respond. As such, the Board recommends that the provincial government amend *The Manitoba Hydro Act* to give the Board the power to compel Manitoba Hydro to file its application on a timely basis.

Awarding rate increases that are in line with Manitoba Hydro's requested rate path is not an explicit endorsement by the Board of Manitoba Hydro's spending on capital expenditures or O&A expenses. As explained in section 11.3, the Board finds that Manitoba Hydro's growth in O&A expenses is too high, and reduces the level of planned O&A expense by 1% in the second and third years of the rate period for rate-setting purposes.

The Board notes Manitoba Hydro suggested numerous times that it has no choice but to incur the proposed expenditures. This is effectively shifting the onus onto the Board to make decisions that Manitoba Hydro should be making.

The Board further notes that at the last general rate application, which was filed only 28 months before the current Application, Manitoba Hydro represented to the Board that it could safely and reliably operate the utility with 2% rate increases into the future. Only 28 months later, and even after the government has further reduced the debt guarantee fee and eliminated the corporate capital tax which reduced the revenue requirement by \$148 million, Manitoba Hydro insists that a rate path of 3.5% is necessary. The \$148 million reduction in revenue requirement is equivalent to a 7% rate decrease, yet Manitoba Hydro requests a 3.5% increase in each year of the rate period before taking into account the current year drought. When asked what has caused the major changes in the forecast since the last general rate application, Manitoba Hydro was unable to provide a sufficient explanation to the Board. Such changes, without sufficient explanation, make it challenging for the Board to fulfill the provincial policy objective of ensuring stable and predictable rate increases. The Board is also concerned that the forecast may dramatically change again at the next general rate application for the next three year rate period.

## 4.0 DROUGHT IMPACTS AND HYDROLOGY

### 4.1 Background

#### 4.1.1 Drought

By the nature of its operations, Manitoba Hydro is susceptible to drought conditions. Manitoba Hydro generates electricity from 16 hydroelectric generating stations on the Winnipeg, Saskatchewan, Burntwood, Laurie, and Nelson Rivers. These generating stations are fed from the waters of the Nelson-Churchill drainage basin, which extends from northwestern Ontario, into the United States, and west to the Rocky Mountains. Precipitation in this large geographic area has been below the long-term average since November 2022. As a result, Manitoba Hydro has experienced below-average inflows into its system for four of the past five years, beginning with the drought in 2021/22. Figure 4.1 shows the water inflows into its system since 1912. The current 2025/26 year is forecasted to approach the second lowest inflows on record.

System Inflows

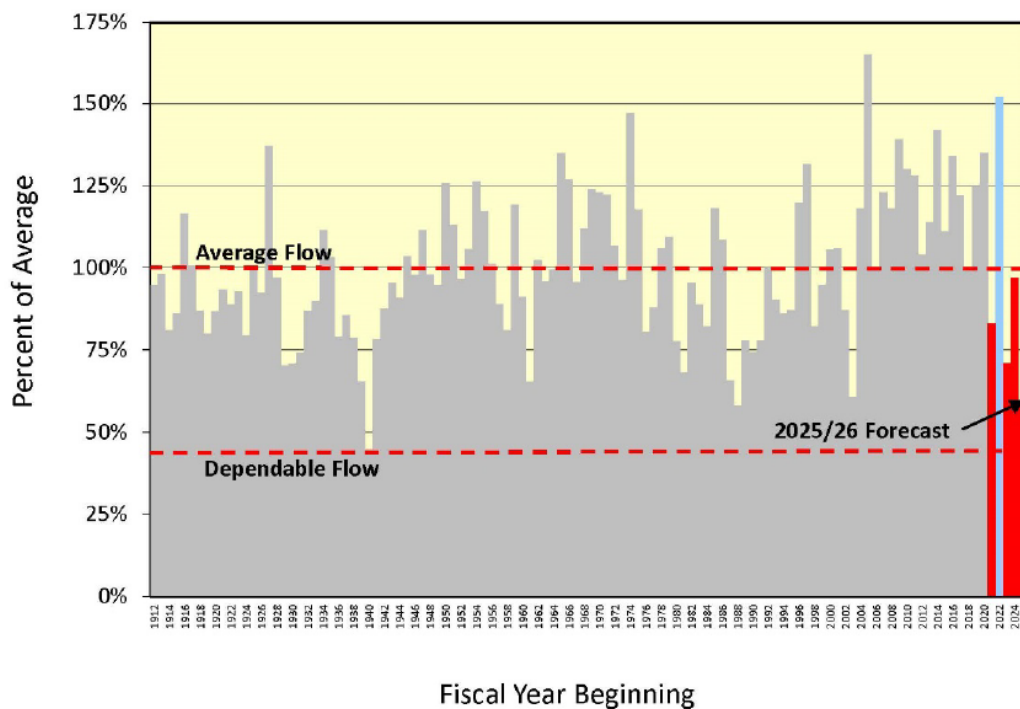


Figure 4.1 — Total System Inflows into Manitoba Hydro’s River Systems and Reservoirs

Figure 4.2 shows the actual hydraulic generation since 1992/93, as well as projections for the 2025/26 to 2027/28 rate period. The red and blue hash marks show the upper and lower generation levels depending on the range of precipitation that could be experienced. This figure shows that hydraulic generation for 2025/26 will reach the lowest level since the 2002/03 drought year. The reduced hydraulic generation means Manitoba Hydro has less surplus electricity to export and must import to meet domestic demand.

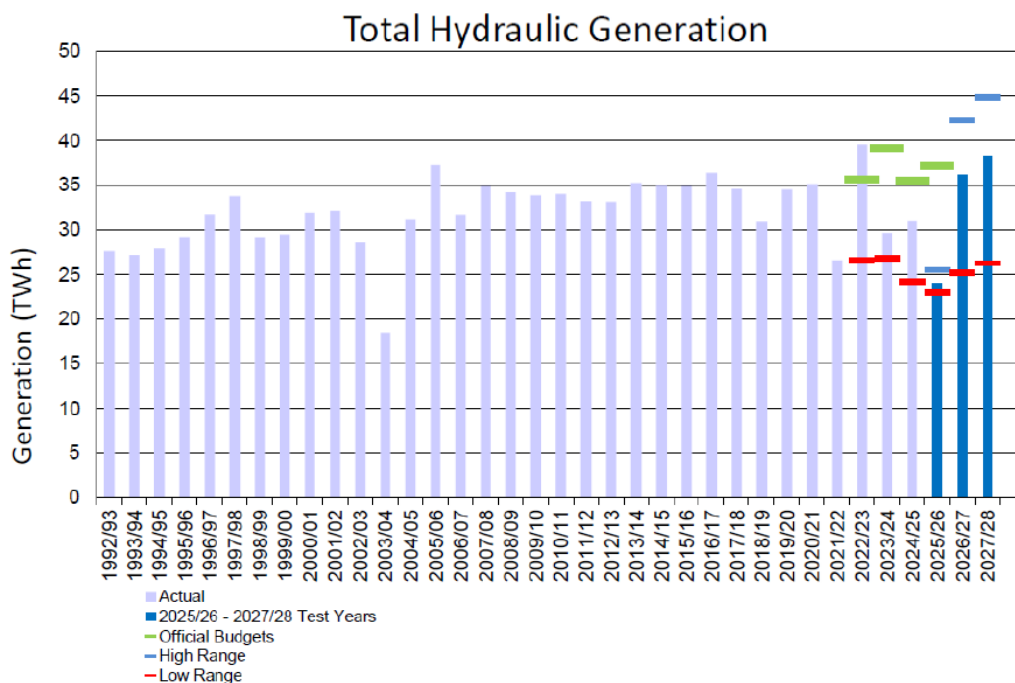


Figure 4.2 — Total Hydraulic Generation with High and Low Ranges

In 2025/26, Manitoba Hydro expects to generate approximately 23,000 gigawatt-hours (“GWh”) from its hydroelectric stations – a decline of 13,100 GWh from the 36,175 GWh forecasted when this Application was filed. This decline is equivalent to half of the Manitoba domestic demand. Projections for the 2026/27 and 2027/28 years of the rate period are based on the inflow conditions described in the following subsection.

**4.1.2 Financial Impacts from Drought**

The below-average water conditions over four of the last five years have significantly changed Manitoba Hydro’s finances compared to the forecast presented at the 2023/24 & 2024/25 General Rate Application and the original forecast filed with the current

Application. Manitoba Hydro compared the actual results from 2021/22 to 2024/25 and the 2025/26 forecast to the Amended Financial Forecast Scenario from the 2023/24 & 2024/25 General Rate Application, as well as to the forecast in the current Application. This showed that the cumulative earnings over the three-year period (2022/23 to 2024/25) fell \$1.13 billion below what was presented at the last general rate application. When one includes the updated 2025/26 forecast, the cumulative earnings are expected to be \$1.75 billion lower, as shown in Figure 4.3.

Net Income (Loss) \$ in millions	2021/22 Actual	2022/23	2023/24	2024/25	2025/26 Forecast	Cumulative
		Actuals / Forecasts				
2021 to 2023/24 Actuals & 2025/26 Forecast	(\$249)	\$573	(\$135)	(\$49)	(\$409)	(\$269)
2021/22 Actual; 2022/23 to 2024/25 Amended Financial Forecast Scenario; 2025/26 GRA Forecast	(\$249)	\$751	\$469	\$295	\$218	\$1,484
<b>Change in Net Income (Loss)</b>	<b>\$0</b>	<b>(\$178)</b>	<b>(\$604)</b>	<b>(\$344)</b>	<b>(\$627)</b>	<b>(\$1,753)</b>

Figure 4.3 — Actual Net Income Versus Forecasts Made at the Last General Rate Application and in the Current Application

While Figure 4.3 shows that Manitoba Hydro's net income is cumulatively \$1.75 billion less than previously forecasted, Manitoba Hydro also provided a worst-case scenario (low inflows) for 2025/26 that shows the cumulative reduction to be \$1.85 billion and an optimistic outcome (high inflows) of \$1.64 billion.

As system inflows are heavily dependent on the amount of precipitation, which is highly uncertain, Manitoba Hydro is unable to forecast whether the current drought conditions will continue in 2026/27. For this second year of the rate period, Manitoba Hydro's financial forecast assumes an average of the financial results as modeled for forty years of water flow cases, based on carrying forward the reservoir storage levels modeled as of the end of 2025/26 for each flow case. This means that Manitoba Hydro's forecast of hydraulic generation in 2026/27 will be lower because the reservoir storage levels are

depressed due to the current drought. All else being equal, the lower storage levels will result in a reduction to hydraulic generation in 2026/27 of 1,700 GWh and a decrease in the forecast net income from \$187 million in the original application filing to \$169 million as of the October 2025 update. However, the range of net income due to the variability in precipitation and water flows in 2026/27 is wide, ranging from a net loss of \$468 million to a positive net income of \$466 million.

#### **4.1.3 Order 101/23 Directive 26 – Drought Management Succession Plan**

At the last general rate application, Manitoba Hydro explained that it was embarking on a succession planning initiative which sought to ensure that its institutional knowledge of reservoir and hydroelectric system operations would be preserved. In Order 101/23, the Board found that there was merit to Manitoba Hydro formalizing and documenting the institutional knowledge and expertise on drought risk into additional policies and procedures. Directive 26 of Order 101/23 states:

*Manitoba Hydro is directed to file, with its next general rate application, an update on its key process documentation and succession planning initiative with respect to drought risk and drought management procedures, including a description of all progress made in formalizing institutional knowledge into written policies and procedures.*

In this hearing, Manitoba Hydro filed an update showing the topics where it had enhanced its documentation as well as new topics that have now been documented. Further, Manitoba Hydro has made steady progress in enhancing and building out its hydrological forecasting tools and reporting capabilities, including its Physical Based Inflow Forecasting system. This includes adding new inflow forecast locations that apply detailed hydrologic modelling technology, expanding the number of hydrological runs using a longer record of historical climate data, adding and updating hydrologic models, investigating the use of machine learning, and evaluating the potential to use longer range precipitation forecasts in its operations.

Manitoba Hydro has also formalized the oversight of its drought operations. Specifically, Manitoba Hydro established a Drought Risk Subcommittee of the Enterprise Risk Management Committee, which is activated when drought conditions develop. Manitoba Hydro activated the subcommittee in the summer of 2023, and it has remained active since then due to ongoing drought conditions. The subcommittee provides strategic-level oversight and decision-making to help mitigate drought risk, receiving frequent, scheduled updates pertaining to water conditions, energy markets, financial performance, and risk-related analyses. The subcommittee is chaired by the Director Enterprise Risk Management, and consists of the Chief Operating Officer, Chief Financial Officer, and directors and senior leaders from Finance, Treasury, Energy Markets, and Energy Planning & Operations.

In regards to succession planning for drought management-related roles, Manitoba Hydro has also identified critical positions and potential successors, completed an analysis of backup and cross-training needs, and implemented organizational changes within the Energy Operations Planning department.

## **4.2 Position of the Parties**

### **4.2.1 *Manitoba Hydro***

Manitoba Hydro submits that it continually evaluates risks and has been proactive and strategic in managing the operational and risk management aspects of the current drought.

Manitoba Hydro describes rate relief, retained earnings, and management action as the “three legs of the stool” that are to underpin the response to a drought. In response to the current drought, Manitoba Hydro submits that it has taken action in all three areas. For example, in this Application, Manitoba Hydro seeks rate increases, relies on a reduction in its retained earnings, and has taken management action. The management action includes reducing Manitoba Hydro’s business operations capital expenditures below the levels recommended by its Asset Management Plan, as well as limiting the growth of full-time equivalent employees.

Manitoba Hydro states that its retained earnings have declined by \$1.9 billion due to low water conditions experienced in four of the last five years. Additionally, the utility submits that the severity of the ongoing drought is such that management action through reductions in capital and operating expenditures cannot come close to fully countering the magnitude of the financial impacts of the drought.

Despite the intensification of the drought conditions in 2025/26 and the deterioration in its financial health, Manitoba Hydro confirmed that its senior management did not approach its board of directors and propose increasing the requested rate increase above the original 3.5% request or advancing the effective date of the increase. Manitoba Hydro explained that this was, in part, because the provincial government had instituted a one-year rate freeze in 2025, and due to the remaining uncertainty regarding the inflows during the spring and summer of 2025, with the potential for precipitation to ameliorate the drought conditions later in the fall. Manitoba Hydro was also taking a long-term view of its finances, as well as the affordability of its rates into consideration. However, Manitoba Hydro indicated that from a purely financial perspective, a higher rate increase than the proposed 3.5% may be warranted.

#### **4.2.2 *Intervenors***

##### **Assembly of Manitoba Chiefs**

In the AMC's view, the required rate response to drought must be balanced and weighed against the affordability of Manitoba Hydro's rates. While drought conditions may place upward pressure on rates, the Board must ensure that the rate increases which are intended to address drought impacts do not simply enable continued growth of operating and capital expenditures, leaving Manitoba Hydro in an equivalent or worse financial position at the end of the rate period.

##### **Consumers Coalition**

The Consumers Coalition criticized Manitoba Hydro's response to the drought, arguing that Manitoba Hydro has made no attempt to reduce its capital and operating expenditures in light of the prolonged drought conditions. As such, Manitoba Hydro is

avoiding the hard choices with respect to capital and operating expenditures that are needed to be made when such severe drought conditions erode its financial health. In the Consumers Coalition's view, Manitoba Hydro is presenting a false choice to the Board between the proposed rate increases and unacceptable degradation in Manitoba Hydro's financial health. Instead, the Consumers Coalition submits that the Board should send a strong signal to Manitoba Hydro that it must control its costs and provide reliable projections to the Board, grounded in an analysis of options. The apparent urgency to address the current drought is of Manitoba Hydro's own making by failing to take action on controllable expenditures over the past five years.

The Consumers Coalition does not find the ongoing drought supports the proposed rate increases, as ratepayers have already paid for this drought in the rates previously paid. These previous revenues have built up Manitoba Hydro's retained earnings, and future revenues will rebuild the retained earnings when the current drought ends. As an example, Manitoba Hydro's retained earnings are at a sufficient level that they exceed the expected impact of a seven-year drought.

### **GSS/GSM Representative**

The GSS/GSM Representative submits that it is important for the Board to not only recognize the impact of drought on rates, but also the obligation of Manitoba Hydro to take action and adjust its approach to expenditures. The GSS/GSM Representative does not accept that Manitoba Hydro does not have control over these expenditures.

### **Manitoba Industrial Power Users Group**

MIPUG claims that Manitoba Hydro should manage drought impacts as per the approach previously articulated by the Board. Specifically, it should rely on retained earnings that have been built up for exactly this purpose, increase rates, and reduce expenditures as it has done in the past under the leadership of its former president, Bob Brennan, or when requested by the Minister responsible for Manitoba Hydro.

## Manitoba Keewatinowi Okimakanak

In MKO's view, Manitoba Hydro has already set aside reserves that will address a five-year drought, and thus the existence of the current drought should not materially affect the rate-setting approach.

### 4.3 Presenter Evidence and Board Comments

As summarized in Appendix B of this Order, the Board heard a presentation from Chief Darryl Wastesicoot and representatives of York Factory First Nation during this hearing. At issue was Manitoba Hydro's water flow management operations, the related impacts to the levels of Split Lake, and access to essential ferry services, especially during drought conditions. The Board acknowledges the concerns raised by York Factory First Nation and thanks the presenters for the opportunity to learn more about this issue. However, given the limitations of section 39 of *The Manitoba Hydro Act*, the Board cannot issue any directive to Manitoba Hydro regarding the management of Split Lake's water levels. The Board encourages improved dialogue between Manitoba Hydro and affected communities to further explore opportunities for improvement and information exchanges.

### 4.4 Board Findings

The Board finds that Manitoba Hydro should have amended its original rate increase of 3.5% for the first year of the rate period to 4.0%, the maximum allowed under *The Manitoba Hydro Act*, in light of the extreme drought conditions experienced in 2025/26 to date.

When Manitoba Hydro filed its Application in March 2025, it had experienced below-average water conditions in three of the last four years. The financial projections underpinning its Application were based on a return to normal water flows in 2025/26 and were projected to yield a net income of \$218 million, predicated on a 3.5% rate increase on January 1, 2026. At that point in time, the assumption of a return to normal water flows in 2025/26 was consistent with Manitoba Hydro's financial forecasting methodologies used for upcoming fiscal years.

However, as this proceeding progressed through the 2025/26 fiscal year, Manitoba Hydro found itself in another year of below-average water conditions, which intensified into the current projection that this year will approach the second worst drought on record. The initially projected net income of \$218 million for 2025/26 is now projected to be a \$409 million net loss, a reversal of \$627 million. Despite this dramatic reversal, Manitoba Hydro did not seek to amend its rate request of 3.5% for any of the years in the rate period.

As explained in Order 161/25, the Board found that Manitoba Hydro required a 4.0% increase on January 1, 2026 in order to protect the financial health of the utility in light of this intense drought. While the Board does not have concerns with how Manitoba Hydro operates its reservoirs in the event of drought, the Board has concerns with how Manitoba Hydro approached this Application and specifically the rate increases that Manitoba Hydro claims are needed to maintain its financial health. The Board heard that the Chief Financial Officer and the Chief Operating Officer are both members of the Drought Risk Subcommittee. The deterioration in the financial health of the corporation was therefore known to Manitoba Hydro's senior executives and stronger management action in response to these rapidly deteriorating conditions should have been undertaken.

As explained in section 3.3, the Board approves additional revenue increases of 3.5% and 3.0% on January 1, 2027 and January 1, 2028, respectively. These revenue increases are predicated on a return to normal or near-normal water flows. As a return to normal or near-normal water flows is uncertain, there is a risk that the revenue increases approved in this Order will be insufficient if drought conditions continue. Conversely, the revenue increases may be excessive if Manitoba Hydro experiences water conditions that are well above average, as occurred in 2022/23. Accordingly, beginning in 2026/27, the Board directs Manitoba Hydro to file a report with the Board 45 days after the end of each fiscal quarter, that contains the following information:

1. Graphs of system energy in storage, system potential hydraulic energy from inflows, total system inflows, and total hydraulic generation (showing the original and updated forecasts as well as the low and high range);

2. The original budget and updated forecast for the current year extra-provincial revenues, water rentals and assessments, fuel and power purchases, net export revenue, and net income for the remaining years of the rate period; and
3. Graphs and tables of the range of net export revenues with respect to the percentile of possible water flow conditions for each of the remaining years of the rate period.

Manitoba Hydro has previously provided the requested information to the Board in general rate application filings, including in the current filing. The Board intends to use this information to assess whether Manitoba Hydro's rates during the rate period are sufficient, or whether the rate reconsideration process described in subsection 39.4(1) of *The Manitoba Hydro Act* should be initiated for the remaining portion of the rate period. Manitoba Hydro should provide these reports until the end of the current three-year rate period.

The Board finds that Manitoba Hydro was inconsistent in how it articulated to the Board the impacts of drought in four of the last five years. Manitoba Hydro claimed that its retained earnings have declined by \$1.9 billion because of the ongoing drought. However, this decline is a decline from the forecast projections made by Manitoba Hydro, and not from absolute numbers, a caveat that Manitoba Hydro did not always clarify. The actual decline in absolute retained earnings over the past five years to the end of 2025/26 is projected to be \$284 million – a decrease from \$3.074 billion to \$2.79 billion. This change has weakened Manitoba Hydro's financial position, but it is a smaller decrease than presented.

The Board finds that Manitoba Hydro has satisfied Directive 26 of Order 101/23, requiring Manitoba Hydro to file an update in this Application on its key process documentation and succession planning initiative with respect to drought risk and drought management procedures, and deems this directive complete.

## 5.0 FINANCIAL TARGETS AND UNCERTAINTY ANALYSIS

### 5.1 Background

#### 5.1.1 *Financial Targets*

Manitoba Hydro has the following long-standing financial targets used for planning purposes:

- a debt-to-capitalization ratio of 75% (alternatively a debt ratio or debt-to-equity ratio of 75:25);
- a capital coverage ratio of 1.2;
- an interest coverage ratio based on earnings before interest and taxes (“EBIT”) of 1.2; and
- an interest coverage ratio based on earnings before interest, taxes, depreciation, and amortization (“EBITDA”) of 1.8.

The debt-to-capitalization ratio measures the ratio of Manitoba Hydro’s debt to its total capitalization. While *The Manitoba Hydro Amendment and Public Utilities Board Amendment Act*, S.M. 2022, c. 42, previously added a legislative requirement of 70%, the legislated target has since been repealed.

The capital coverage ratio measures Manitoba Hydro’s ability to fund ongoing reinvestment in, and replacement of, existing assets (referred to by Manitoba Hydro as “business operations capital”) out of current cash flow. The ratio is calculated by dividing Manitoba Hydro’s cash flow from operations by its capital expenditures, not including capital expenditures on major new generation and transmission assets.

The interest coverage ratio measures Manitoba Hydro’s ability to pay interest on outstanding debt without requiring new debt to make those payments. Traditionally, Manitoba Hydro calculated the interest coverage ratio on an EBIT basis and set a target ratio of 1.2. However, in 2015 KPMG, a major consulting firm, recommended that Manitoba Hydro use an EBITDA-based interest target that is 50% higher than the existing

EBIT target. KPMG accordingly recommended an EBITDA-based ratio of 1.8. Manitoba Hydro's board of directors approved both targets.

At the 2017/18 & 2018/19 General Rate Application, the Board reviewed submissions related to Manitoba Hydro's retained earnings levels and performance relative to financial targets. In Order 59/18, the Board found that Manitoba Hydro's financial targets had to be assessed in the context of a Crown utility that was in the midst of a major capital expansion that would double its asset base. Further, the Board concluded that there was merit to gaining a better understanding of the financial reserves required for Manitoba Hydro under various circumstances.

Manitoba Hydro's financial targets were further reviewed during the 2023/24 & 2024/25 General Rate Application. To resolve issues related to enterprise performance management and financial targets, Directive 27 of Order 101/23 (later modified by Order 103/24) directed Manitoba Hydro to participate in a collaborative workshop focused on enterprise performance management and key performance indicators.

In 2024, pursuant to the Board's direction in Order 101/23, Manitoba Hydro began a review of its financial targets that included consultations with interveners. Following difficulties encountered during the consultation process, the Board set aside Directive 27 of Order 101/23 in March 2025 and requested Elenchus Research Associates, the Board-appointed facilitator, to prepare a report with recommendations on how to improve the process for future consultations.

However, prior to the above development in March 2025, Manitoba Hydro retained Atrium Economics to conduct a financial target review and establish a set of financial metrics for the utility's consideration. Phase I of Atrium's review involved analyzing financial health metrics of comparable utilities and their relevance to Manitoba Hydro's regulatory context, while Phase II focused on testing financial outcomes using Manitoba Hydro's financial models and the identified metrics. While the preliminary results from the Phase I work was presented during the 2024 workshop sessions, Phase II is still ongoing.

Until the Financial Target Review is completed, Manitoba Hydro is not formally adopting any new financial measures or targets. Notwithstanding this, Manitoba Hydro continues to consider a number of financial measures to assess its financial health, including the long-standing financial metrics such as annual earnings, the debt ratio, interest coverage ratios (EBIT and EBITDA), and the capital coverage ratio. The utility is also tracking the trends to the net debt balance, the year-over-year change to the net debt balance, the cash flow surplus/deficit, the self-financing ratio, and the ratio of cash flow to net debt to assess financial health. However, as discussed in section 12.0, under the utility's financial forecast as filed with the Board, Manitoba Hydro's debt ratio will remain consistently above 80% and is not projected to reach the 75% target during the 20-year forecast period. Figure 5.1 shows the results of Manitoba Hydro's key financial metrics, including the impact of the drought on these metrics over the rate period.

\$ in millions	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
<b>Net Income/(Loss)</b>							
Actuals (21/22 - 24/25) & 25/26-27/28 Forecast*	(\$249)	\$573	(\$135)	(\$49)	(\$409)	\$169	\$101
AFFS (22/23 - 24/25) & 2026 to 2028 GRA (25/26-27/28)		\$751	\$469	\$295	\$218	\$187	\$127
<b>Increase/(Decrease)</b>		(\$178)	(\$604)	(\$344)	(\$627)	(\$17)	(\$27)
<b>Cumulative Increase/(Decrease)</b>		(\$178)	(\$782)	(\$1 126)	(\$1 753)	(\$1 770)	(\$1 797)
<b>EBIT Interest Coverage Ratio</b>							
Actuals (21/22 - 24/25) & 25/26-27/28 Forecast*	0.77	1.60	0.86	0.94	0.60	1.16	1.10
AFFS (22/23 - 24/25) & 2026 to 2028 GRA (25/26-27/28)		1.80	1.51	1.32	1.22	1.19	1.13
<b>EBITDA Interest Coverage Ratio</b>							
Actuals (21/22 - 24/25) & 25/26-27/28 Forecast*	1.31	2.25	1.59	1.61	1.29	1.87	1.85
AFFS (22/23 - 24/25) & 2026 to 2028 GRA (25/26-27/28)		2.48	2.21	2.06	1.92	1.91	1.90
<b>Capital Coverage Ratio</b>							
Actuals (21/22 - 24/25) & 25/26-27/28 Forecast*	0.51	2.15	0.77	0.67	0.24	0.89	1.20
AFFS (22/23 - 24/25) & 2026 to 2028 GRA (25/26-27/28)		2.26	2.23	1.61	1.06	0.91	1.24

\* Exhibit MH-42 Undertaking 24 updated with MH Undertaking Accepted on Transcript Page 1440 - October 2025 Update Forecast

Figure 5.1 — Deterioration in Manitoba Hydro's Financial Situation<sup>1</sup>

### 5.1.2 Uncertainty Analysis

To help understand the risks it faces and how those risks can affect its financial conditions, Manitoba Hydro prepares an uncertainty analysis. Manitoba Hydro introduced its uncertainty analysis tool at the 2014 Needs For and Alternatives To ("NFAT") review

<sup>1</sup>The second line in the table refers to the Amended Financial Forecast Scenario filed by Manitoba Hydro in its 2023/24 & 2024/25 General Rate Application. The values for 2022/23, 2023/24, and 2024/25 are based on this forecast. The values for 2025/26, 2026/27, and 2027/28 are based on the forecast included in the current application. The top row, marked "Actuals", is the most recent December 2025 forecast.

into the utility's preferred development plan, where it presented a probabilistic analysis of multiple risks. A similar analysis was undertaken for the 2017/18 & 2018/19 General Rate Application.

For recent general rate applications, Manitoba Hydro moved away from this approach, which attracted criticism from interveners and the Board at the 2023/24 & 2024/25 General Rate Application. Specifically, Manitoba Hydro filed a sensitivity analysis that assessed the financial impacts of a five- or seven-year drought, above- and below-average water conditions, high and low export prices, high and low interest rates, reductions in business operations capital spending, and the impact of different rate increase scenarios. However, this sensitivity analysis only varied a single parameter, unlike the uncertainty analysis which varied multiple parameters.

In Order 101/23, the Board found that an uncertainty analysis could have quantified risks in a better manner than a sensitivity analysis that only considers the individual impacts of each risk. As such, Order 101/23 Directive 28 required Manitoba Hydro to complete, and file with its next general rate application, an uncertainty analysis that assesses the probability and likely impact of the risks faced by the corporation.

Consistent with the Board's directive in Order 101/23, Manitoba Hydro filed an uncertainty analysis in the current Application. The uncertainty analysis combines 1,008 different scenarios arrived at by modelling the following three parameters:

- water flows for each of the 112 years for which Manitoba Hydro has records (112 scenarios);
- export prices (reference price, 20% lower than reference, and 20% higher than reference) (3 scenarios); and
- interest rates (reference rate, 1% lower than reference, and 1% higher than reference) (2 scenarios).

The water flows follow historical sequences. For example, one of the 112 sequences is a repeat of the seven-year drought experienced in the 1930s and 1940s. Manitoba Hydro considers these parameters to be the highest-impact factors, but notes that increases to capital expenditures, O&A expenditures, and the timeliness of rate increases can also have a significant impact on the financial forecast.

Based on the 1,008 scenarios resulting from this analysis (112 x 3 x 3), Manitoba Hydro prepared box-and-whisker charts for multiple parameters, including net income and retained earnings under two different approaches. In Approach #1, Manitoba Hydro used its projected rate path of 3.5% rate increases. In Approach #2, Manitoba Hydro adjusted its rate path based on perfect foresight of the water flow, interest rate, and export price parameters such that net income averages \$150 million per year and retained earnings reach \$4.7 billion in 2034/35.

In Figures 5.2 and 5.3, the boxes represent the probability range from 25% to 75%, while the whiskers represent the probability range from 5% to 95%. The grey dots represent individual modelling results below 5% and above 95% of the cases.

As illustrated in Figure 5.2, under Approach #1, net income is equal to or greater than zero in all forecast years in 28% of the 1,008 financial projections. Approximately 75% of the scenarios would result in the utility’s net income exceeding zero in all but three years: 2031/32, 2032/33, and 2033/34. In approximately 5% of the scenarios, the losses would exceed \$250 million in each year. These results demonstrate acceptable financial results in the majority of cases, assuming the 3.5% rate path.

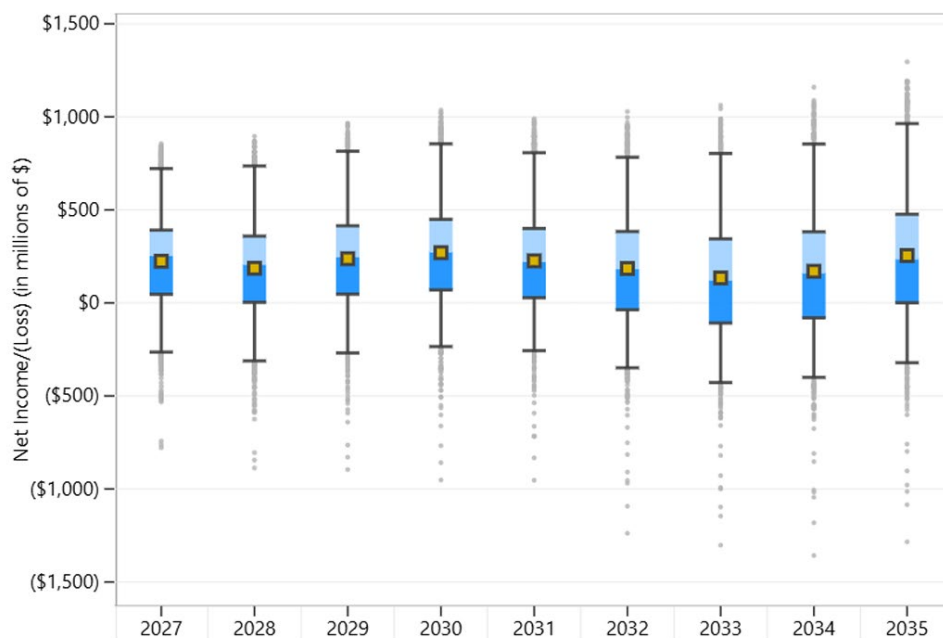


Figure 5.2 — Net Income and Losses under Approach #1

Figure 5.3 shows the effect of different modelling outcomes on Manitoba Hydro's retained earnings. As illustrated in the chart, in 25% of the scenarios Manitoba Hydro's retained earnings balance would largely stagnate, while in 5% of the worst-case scenarios, retained earnings would decrease to \$2.1 billion or less. However, even under a worst-case scenario of 1% higher interest rates, unfavourable export prices, and the worst nine-year sequence of water flows, represented by the lowest of the grey dots, Manitoba Hydro would maintain a positive retained earnings balance assuming continued 3.5% rate increases.

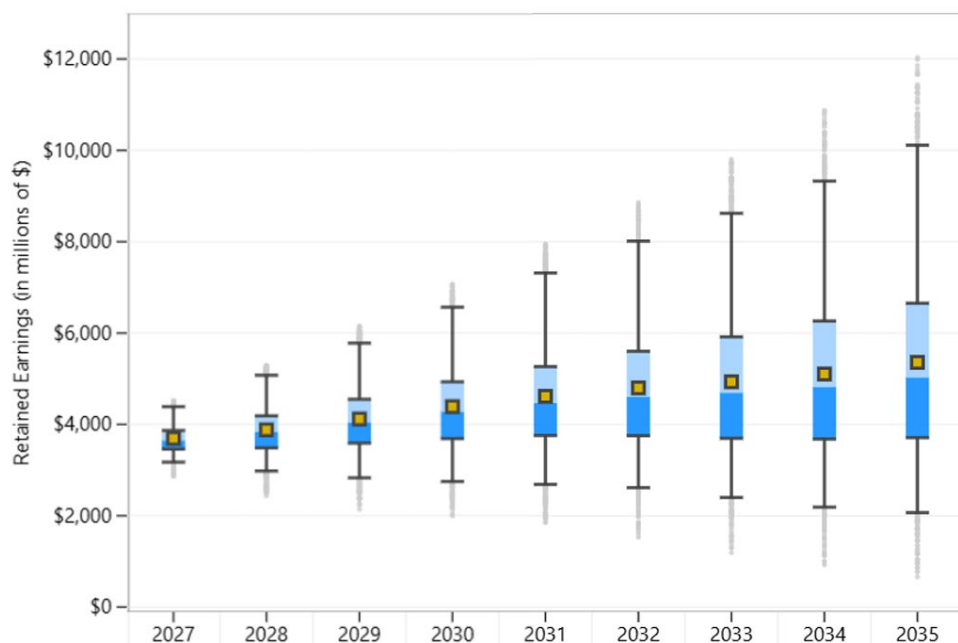


Figure 5.3 — Retained Earnings under Approach #1

Under Approach #2, the utility notes that 331 of the 1,008 scenarios would require a rate increase in excess of the legislated 4% rate cap in order to reach the targeted retained earnings of \$4.7 billion by 2034/35. The utility acknowledges that this includes possible futures for which the rate cap could result in a weakened financial position for the utility.

## 5.2 Positions of the Parties

### 5.2.1 *Manitoba Hydro*

Manitoba Hydro maintains that without the 3.5% test year increases, the utility would experience a cash shortfall in many years, and increased debt would be required to support its capital investments. The proposed 3.5% rate path also allows historical net income levels over the first decade and enables higher net income in the second decade, which allows Manitoba Hydro to move towards its long-term cash flow and debt-to-capitalization ratio targets. The utility submits this ensures that revenues can gradually increase to avoid weakening the utility's financial position during a period of major capital projects and ensures a sound financial footing when these projects are completed.

With respect to its financial targets, Manitoba Hydro argues that it relies on a variety of industry-accepted financial metrics to assess financial health, covering all the major categories, including profitability, interest and capital coverage, cash flow, and leverage. Further, Atrium has been retained to conduct a financial target review. Once completed, the utility maintains that the outcomes of Atrium's report will be considered when developing and presenting a set of financial metrics for the Manitoba Hydro-Electric Board's review and consideration.

Regarding the uncertainty analysis, Manitoba Hydro states that it relies on its uncertainty analysis, as well as its separately filed sensitivity analysis, to assess and quantify the financial impact of the risks it faces. Both methods are complementary and provide valuable insights. In the utility's view, the approach to its 1,008 scenarios in its uncertainty analysis is appropriate, and probabilistic weightings would add a degree of subjectivity and arbitrariness that is not warranted.

### 5.2.2 *Intervenors*

#### **Consumers Coalition**

Relying on the testimony of its witness Mr. Rainkie, the Consumers Coalition believes that there is merit to using a probabilistic approach to the uncertainty analysis. As is, the Consumers Coalition questions what value the uncertainty analysis brings to the regulatory process. It cites the testimony of its witness Morrison Park Advisors that indicated the repeated discussions about financial targets and rate paths in recent proceedings have been a substitute for clear thinking about financial management. However, the Consumers Coalition acknowledges that the existing financial metrics and targets do provide a robust picture of Manitoba Hydro's financial health and revenue needs.

The Consumers Coalition's expert witness Mr. Colaiacovo of Morrison Park Advisors is of the view that for a utility like Manitoba Hydro, which provides power at cost, the EBITDA-based and EBIT-based interest coverage ratios should be the primary financial indicators. In Mr. Colaiacovo's view, it is critical that rates be set such that EBITDA interest coverage ratio will be greater than 1.0 in all but the most exceptional circumstances in order to generate sufficient cash flows to pay both Manitoba Hydro's expenses and its debt interest obligations. If the EBITDA interest coverage ratio is below 1.0, then Manitoba Hydro must borrow to pay operating expenses or interest. Mr. Colaiacovo gives even greater weight to the EBIT interest coverage ratio. If the EBIT interest coverage ratio is persistently below 1.0, then ratepayers are not paying Manitoba Hydro for the full costs incurred to provide them service. He supports a target greater than one, but did not indicate precisely what margin above 1.0 should be used. Through multiple rate applications since the 2017/18 & 2018/19 General Rate Application, Mr. Colaiacovo has questioned the relative usefulness of a debt-to-capitalization target, as previously legislated in *The Manitoba Hydro Act*, as compared to other more useful financial indicators.

The Consumers Coalition therefore recommends that the Board direct a collaborative process regarding Manitoba Hydro's financial targets, financial reserves, scenario analysis and sensitivities, and the role of, and potential enhancements to, the uncertainty analysis. In addition to including probabilities, this intervener sees merit in including management actions and regulatory action into the analysis and using it to assess the residual risk and its impact on Manitoba Hydro's reserves. The Consumers Coalition further recommends that the Board, Manitoba Hydro, and interveners all contribute to a work plan for the collaborative process up front, which is to include establishing a scope, timeline, objectives, and expected outcomes.

### **GSS/GSM Representative**

The GSS/GSM Representative is not taking a position on Manitoba Hydro's uncertainty analysis or financial targets, but is expressing optimism that the results of Manitoba Hydro's ongoing financial target review will include a shorter-term financial metric, other than cash flow, to establish appropriate levels of net income in the short term.

### **Manitoba Industrial Power Users Group**

While MIPUG did not make submissions regarding the approach to Manitoba Hydro's uncertainty analysis or financial targets, its expert witness Mr. Bowman concluded that the uncertainty analysis was most informative in assessing Manitoba Hydro's proposed revenue requirement. For example, Manitoba Hydro's uncertainty analysis indicates that there is a one in four chance that the utility would need to violate the 4% rate cap every year for 10 years, just to keep equity above \$3.8 billion and the 10-year capital coverage ratio at 1. Further, Mr. Bowman maintains the utility's approach to determining the three main input parameters is appropriate, the modelling approach was pragmatic, and the utility's preferred approach is less subjective than an approach that includes probabilities. Mr. Bowman relied on the finding in the 2017/18 & 2018/19 General Rate Application that assigning weights to parameters made little difference to the output. However, Mr. Bowman sees a benefit to adding a responsive rate regime that does not assume perfect foresight to the model.

### 5.3 Board Findings

The Board finds that the rate increases approved in this order are necessary to maintain the financial health of Manitoba Hydro. As explained in previous orders, the Board continues to accept Manitoba Hydro's long-standing financial targets, including the 75% debt-to-capitalization target. The Board also considers other financial metrics prepared by Manitoba Hydro when assessing its financial health.

In Order 59/18, the Board accepted Morrison Park Advisors' evidence that debt-to-capitalization is a questionable metric for a vertically integrated monopoly Crown utility with a debt guarantee from the provincial government. The Board also attempted to find a balance between rate increases and the level of debt to fund capital projects. Part of finding that balance was to place concerns about the amount of debt and retained earnings in a different perspective by also considering cash flow, using two long-standing financial metrics used by Manitoba Hydro: interest coverage ratio and the capital coverage ratio.

In the current Application, the Board similarly finds a balance between rate increases and the appropriate amount of debt by considering the interest coverage ratios. The Board accepts the evidence of Mr. Colaiacovo that the interest coverage ratio is the most critical financial metric. The Board notes his view that the earnings before interest, taxes, depreciation, and amortization ("EBITDA") interest coverage ratio should be greater than 1.0 in all but the most extreme circumstances. This differs from Manitoba Hydro's target of 1.8, although the Board recognizes that Manitoba Hydro's target is based on average water conditions. The Board also accepts Mr. Colaiacovo's view that the earnings before interest and taxes ("EBIT") interest coverage ratio should be above 1.0 in the long run, as this indicates that ratepayers are paying the full cost of power.

Looking beyond the current drought year, Manitoba Hydro's 3.5% rate path shows the EBITDA interest coverage ratio equalling or exceeding the 1.8 target every year of the forecast period, while the EBIT interest coverage ratio is greater than 1.0 in every year of the forecast except one. These projected results support the rate path approved in this order.

Regarding Manitoba Hydro's financial target review, the Board is not directing a formal consultation process at this time. With Manitoba Hydro still awaiting the Atrium report, the Board is not convinced that a parallel consultation process would be sufficiently helpful to justify the associated costs. However, the Board directs Manitoba Hydro to file any evaluation regarding updated financial targets, including memoranda provided to the Manitoba Hydro-Electric Board for the purpose of obtaining approval for new targets, together with its next general rate application.

The Board finds that Manitoba Hydro's uncertainty analysis is a valuable stress-testing tool. In the current hearing, the analysis allowed the Board to assess the worst-case impact on Manitoba Hydro's retained earnings as well as the impact of the 4% rate cap. However, when the uncertainty analysis is considered together with Manitoba Hydro's enterprise strategy, it becomes apparent that capital cost overruns represent an additional major risk factor.

As demonstrated by the Keeyask Generating Station project and the capital project review that followed, capital cost overruns are a major risk factor for large capital projects. With Manitoba Hydro embarking on two major capital projects, as well as its increased business operations capital spending, the Board finds that the uncertainty analysis should be expanded to include capital expenditures as a fourth parameter. The Board accordingly finds Directive 28 of Order 101/23, requiring Manitoba Hydro to complete and file in this Application an uncertainty analysis that assesses the probability and likely impact of risks faced by the corporation, to be completed, but directs Manitoba Hydro to revise its uncertainty analysis for the next general rate application to include capital expenditures. However, the Board is not directing any specific assumption to be made in the analysis and leaves it up to Manitoba Hydro to determine what deviations from the reference case are appropriate.

## **6.0 CORPORATE STRATEGY**

### **6.1 Background**

As a large vertically integrated hydroelectric utility, Manitoba Hydro faces multiple risks that the utility attempts to manage and mitigate. At the last general rate application, Manitoba Hydro explained that it was in the process of establishing an Enterprise Risk Management program to provide an enterprise-wide assessment of risks faced by the utility. This Enterprise Risk Management Program also tied into Manitoba Hydro long-term strategy, called “Strategy 2040”, which was focused on what the utility called the “three D’s” — decentralization, digitalization, and decarbonization. Decentralization was focused on the increased availability of power options beyond Manitoba Hydro, such as solar, wind, or other alternatives which are installed by customers behind the meter. Digitalization was focused on technology growth, such as smart devices and an increase in automation. Decarbonization was focused on the reduction of carbon emissions through the electrification of space heating, transportation (including the potential widespread adoption of electric vehicles), and industry.

In this hearing, Manitoba Hydro explains that it has abandoned Strategy 2040 and replaced it with six enterprise goals. These six goals are meant to focus on the utility’s core mandate over the next three years to meet the energy needs of Manitobans in a safe, reliable, and affordable manner. Manitoba Hydro’s six enterprise goals are illustrated in Figure 6.1.







	What's the goal?	Why it's important?
 <b>Employee Experience</b>	To improve employee engagement by 10% each year until 2028 by focusing on the 3 most impactful drivers of engagement: Leadership Enablement, Total Rewards and Wellness.	Employee experience is vital for engagement, retention, productivity, innovation, fostering a positive culture, aligning team goals, and driving organizational performance and success. Focusing on Employee Experience and Engagement allows for employees to understand how their work connects and contributes to our customers, communities and organizational goals.
 <b>Financial Health</b>	By January 2028 generate \$20 million additional recurring net income via new sources (incremental to rate increases), while achieving our financial targets.	Providing safe and reliable energy requires a solid foundation of financial strength, transparency and stakeholder trust. Net income incremental to required rate increases will improve cash flow and reduce reliance on debt.
 <b>HVDC Reliability Project</b>	By December 2026 complete phase A of bipole 2; by December 2027 complete phase A bipole 1, while continuing to ensure reliability of Manitoba Hydro's system.	Phase A focuses on scope refinement, preliminary design, and engineering, further project planning and manufacturing slot reservation. Valve technology has been decided for bipole 2 but not for bipole 1, so bipole 1 will take longer. We must address HVDC infrastructure now. The HVDC system is the backbone for delivering electrons from northern to southern Manitoba and maintaining reliability. Bipole 1 and 2 are at end of life.
 <b>Modern Customer Solutions</b>	By March 2027 implement the first phase of Modern Customer Solutions including AMI, EV infrastructure, demand response, clean heat and customer energy literacy.	Manitoba is lagging compared with other jurisdictions, in meeting customer needs and expectations. Manitoba Hydro needs to modernize our grid, to provide customers with more efficient services, greater control over their energy use, confidence to own electric vehicles and support the integration of renewable energy sources, while ensuring reliability and affordability.
 <b>New Energy Resources</b>	Start construction of the first wind farm beginning with shovels in the ground by April 2027. Start the required construction of dispatchable generation by April 2028.	To meet the increasing demand for electricity and advance reconciliation, Manitoba Hydro must establish a process for the buildout of new, affordable wind generation that is majority Indigenous owned and build dispatchable resources to meet our capacity need date in 29/30.
 <b>SAP</b>	Implement and deploy SAP S/4HANA Core "Out of the Box" by December 2026.	Support for our 25-year-old SAP system will end in 2027. SAP S/4HANA ensures that core systems are future-proofed and can continue to receive updates and support from SAP.

Figure 6.1 — Manitoba Hydro's Enterprise Goals

The six enterprise goals include enumerated projects that Manitoba Hydro is advancing and planning to fund during the current rate period and subsequent rate periods. These include the HVDC Reliability Project, Advanced Metering Infrastructure (“AMI”), electric vehicle (“EV”) charging infrastructure, and the purchase of up to 600 MW of wind energy as contemplated in Manitoba’s provincial energy policy from 2024 called the Affordable Energy Plan. It also includes the SAP S/4HANA project discussed in section 11.1.3. Neither the HVDC Reliability Project nor the planned procurement of wind resources have a revenue requirement impact in the current rate period. However, as set out in section 10.1.3, Manitoba Hydro will start to expend funds on the HVDC Reliability Project during the upcoming rate period. It will also have to expend funds on new dispatchable capacity resources that will be used, in part, to back up future wind power.

Despite Manitoba Hydro's revised strategy in this hearing, Manitoba Hydro states that it continues to make progress on its Enterprise Risk Management Program to fully establish and mature a proactive, comprehensive, and standardized approach for the management of risk across the enterprise. The next steps and targeted areas of focus now include the implementation of an enterprise-wide risk appetite, tolerance, and quantification process, and continuing work on strengthening the understanding of the interdependencies and interrelationships of Manitoba Hydro's top enterprise risks.

## **6.2 Position of the Parties**

### **6.2.1 *Manitoba Hydro***

Manitoba Hydro emphasizes that it operates based on an updated strategic direction focused on meeting the utility's core mandate. In Manitoba Hydro's view, the utility's six enterprise goals are aligned with the Province of Manitoba's Affordable Energy Plan as well as Manitoba Hydro's December 2023 mandate letter. Manitoba Hydro submits that affordability is only part of Manitoba Hydro's broader mandate – it also needs to focus on the safety and reliability of its service while meeting the future energy needs of Manitobans. In Manitoba Hydro's submission, the enterprise goals target the issues most critical to Manitoba Hydro and provide value to its customers. Fundamentally, Manitoba Hydro needs to make the required investments to sustain its assets, build its workforce, and ensure it can meet the energy needs of its customers now and into the future. The utility also notes that the updated enterprise strategy meets every element of sound strategy design: clear aspirations, deliberate focus, measurable value creation, defined capabilities, and enabling management systems.

### **6.2.2 Interveners**

#### **Consumers Coalition**

The Consumers Coalition was the only intervener to comment on Manitoba Hydro's corporate strategy. The Consumers Coalition argues that Manitoba Hydro should demonstrate it has an integrated strategic management system that prioritizes controlling costs and exercising fiscal stewardship on behalf of ratepayers. Further, it states that Manitoba Hydro lacks a long-term integrated strategic framework that could maintain affordability for ratepayers. This is supported by the Enterprise Risk Management Program remaining under development and the existing enterprise goals being focused on the next three years, with affordability not explicitly listed. As a result, the Consumers Coalition recommends that Manitoba Hydro should be directed to report back in the next general rate application on its long-term corporate strategy, including the elements that are, or will be, aligned to the strategy and how it will address external threats to affordability.

### **6.3 Board Findings**

The Board finds that Manitoba Hydro's corporate strategy is important to assessing the 20-year financial forecasts that underpin the utility's general rate applications.

For several years prior to the last general rate application, the Board anticipated the development of Manitoba Hydro's updated long-term strategy, which ultimately became Strategy 2040 and was reviewed at the 2023/24 & 2024/25 General Rate Application. The Board made no findings about Strategy 2040 in Order 101/23. Since that time, Manitoba Hydro implemented a new vision and mission, along with six enterprise goals, that do not reference Strategy 2040 and are more focused on the utility's shorter-term priorities.

With respect to the new strategy, the Board finds that the six enterprise goals are appropriate, but notes that ratepayer affordability is not one of those goals. The Board recommends that Manitoba Hydro consider making ratepayer affordability of its electricity service the seventh goal.

To assess the utility's progress on the six enterprise goals presented in this hearing, the Board directs Manitoba Hydro to report back at the next general rate application on the progress made toward achieving the targets and outcomes related to each enterprise goal. If new enterprise goals are adopted before the next general rate application, the utility's report must include the targets and measurements associated with these new goals.

The Board will not adopt the Consumers Coalition's recommendation to direct Manitoba Hydro to report back in the next general rate application on its long-term corporate strategy at this time. The Board will consider the progress made toward achieving the shorter-term objectives at the next general rate application and could revisit the Consumers Coalition's recommendation at that time.

## 7.0 LOAD FORECAST

### 7.1 Background

Manitoba Hydro estimates the projected future demand for electricity of each customer class in its load forecast. In this Application, Manitoba Hydro submitted its 2024 Load Forecast as the basis for the expected demand for electricity from its domestic customers. As with previous load forecasts, Manitoba Hydro states that the 2024 Load Forecast reflects a single potential future and that the utility is still evaluating how the changing energy landscape could affect the demand for energy in Manitoba. For example, Manitoba Hydro's IRP has several potential futures and demand forecasts, but these do not underpin the projected domestic revenues in this Application.

The 2024 Load Forecast is similar to previous load forecasts in that Manitoba Hydro develops demand forecasts for three sectors: Residential, General Service Mass Market, and Top Consumers. The 2024 Load Forecast incorporates energy efficiency savings resulting from Efficiency Manitoba's activities which target energy savings of 1.5% of domestic electricity sales each year. The evidence filed in this hearing suggests that as of 2023/24, Efficiency Manitoba has not met its energy savings targets, instead achieving savings ranging between 1.03% and 1.26% since its inception in 2020/21.

Manitoba Hydro introduced improvements to its load forecasting methodology which are reflected in the 2024 Load Forecast. To understand how Manitoba Hydro customers will utilize electricity into the future, the utility developed hourly load profiles for each of the existing customer sectors along with hourly load profiles of key emerging technologies, such as electric vehicles and solar generation, to capture the evolving mix of end uses over time. This improvement provides additional modelling granularity, provides visibility on the impacts of emerging technologies and demand-side management activities, and allows Manitoba Hydro to track changes in energy consumption patterns over time. In turn, this improves the utility's peak demand modeling process. Manitoba Hydro also now subdivides its customers into six geographic zones within Manitoba in order to develop demand forecasts tailored to each zone.

One of the outputs from the 2024 Load Forecast is the estimated gross firm energy, which includes domestic electricity sales, Manitoba Hydro’s own electricity use, and losses throughout the system. Gross firm energy is expected to increase at a rate of 0.9% per year for the first ten years of the forecast and at a rate of 1.3% per year over the twenty-year planning horizon to 2043/44, as shown in Figure 7.1.

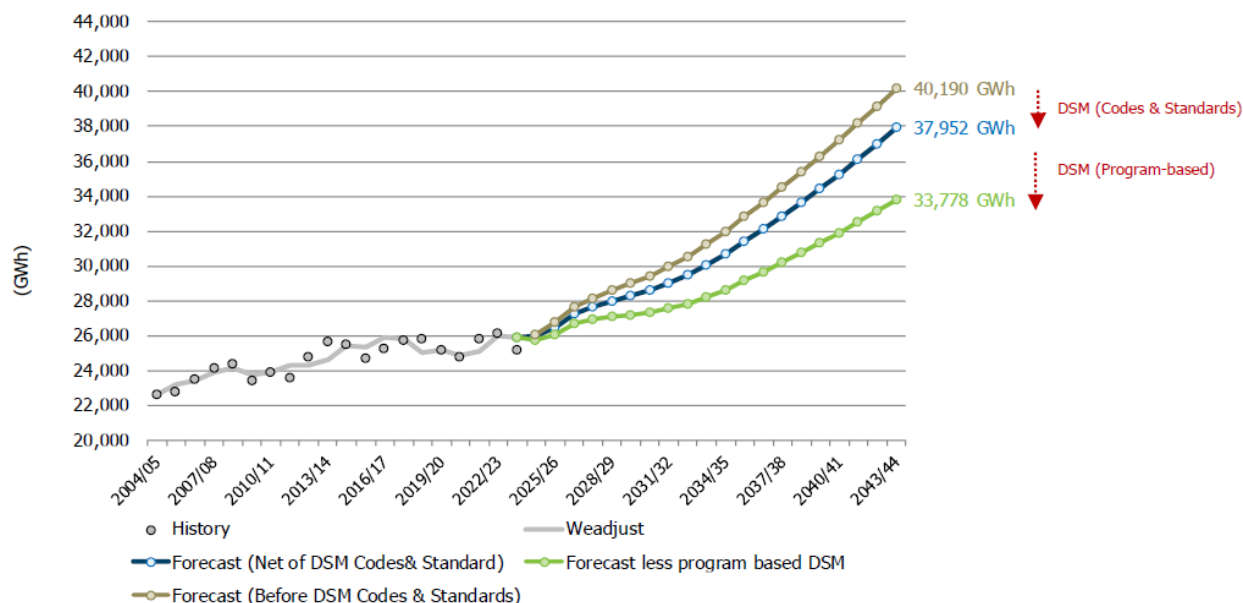


Figure 7.1 — Gross Firm Energy with Demand-Side Management Reductions

Manitoba Hydro attributes the increased growth rate in the second ten-year period of the forecast to an increase in the number of electric vehicles, fewer energy efficiency improvements related to codes and standards, and price elasticity due to lower rate increases compared to the first ten years. Manitoba Hydro no longer assumes that Manitoba will meet the federal zero-emission passenger vehicle mandate of 100% of sales by 2035. While Manitoba Hydro continues to assume that plug-in electric vehicles are anticipated to have a significant impact on the Manitoba load, this load is lower by about one third compared to the 2021 Load Scenario that underpinned Manitoba Hydro’s 2023/24 & 2024/25 General Rate Application.

Behind-the-meter solar photovoltaic generation is not forecasted to have a significant impact on demand, reducing gross firm energy by only 238 GWh, or 0.6%, by 2043/44.

The 2024 Load Forecast predicts increased electricity demand over the first 15 years compared to the 2021 Load Scenario, as shown in Figure 7.2. The increase is due to greater historical growth in the Residential and General Service Mass Market sectors, a new Top Consumer customer commencing in 2026/27 as a result of switching to electric operations, increases in production levels of other Top Consumer customers, and enhanced modeling of the impacts of demand-side management in collaboration with Efficiency Manitoba.

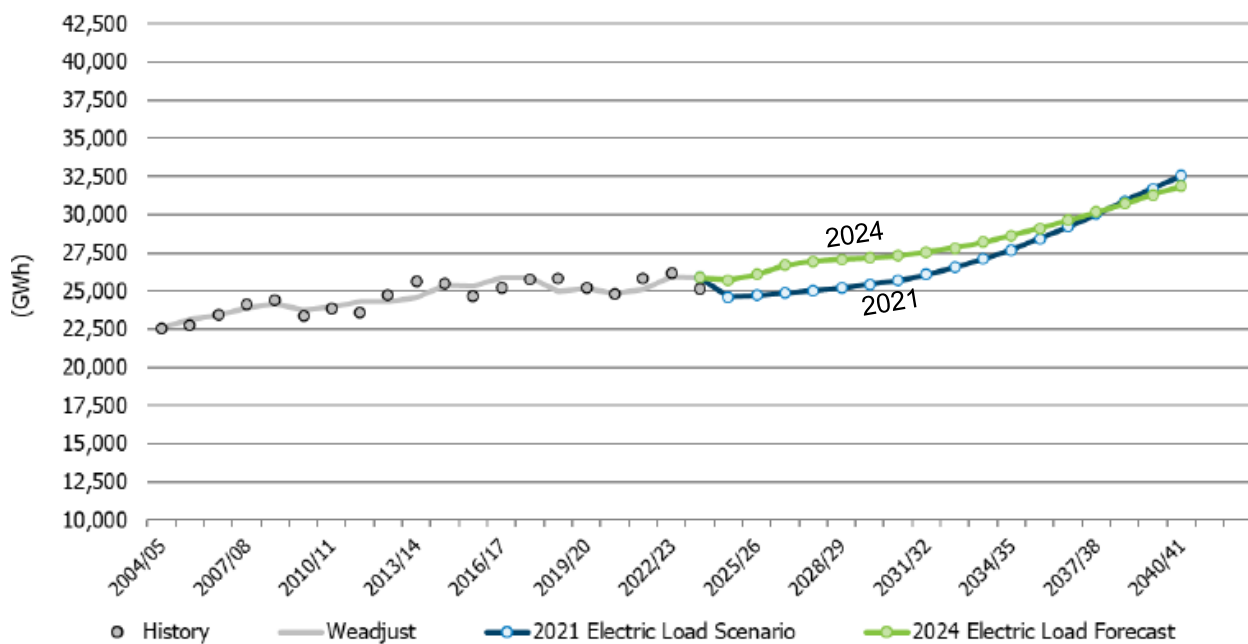


Figure 7.2 — Comparison of Gross Firm Energy for 2021 and 2024 Load Forecasts

In contrast to the gross firm energy forecast, which is the amount of electricity consumed over the course of the entire year, gross total peak refers to the maximum instantaneous demand for electricity, which for Manitoba Hydro occurs in the winter. Manitoba Hydro’s gross total peak is expected to grow at 1.3% per year for the first ten years of the forecast and by 1.5% per year over the twenty-year planning horizon, as shown below in Figure 7.3.

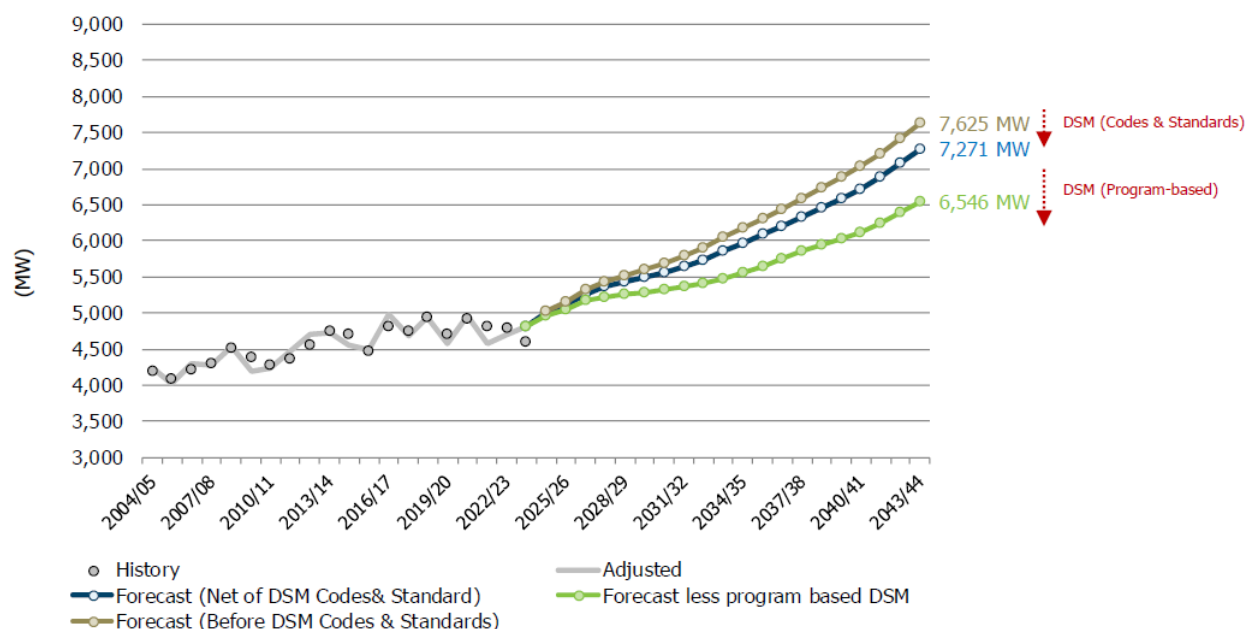


Figure 7.3 — Gross Total Peak with Demand-Side Management Reductions

While the projected growth in energy and demand are increasing domestic revenues for Manitoba Hydro, they are also driving the need for new generation resources, as explained in section 9.0.

According to Manitoba Hydro, there is significant uncertainty in the second decade of the Load Forecast. However, the projected load for the rate period is consistent with the range of possible loads from Manitoba Hydro’s 2023 Integrated Resource Plan.

Subsection 49.2(3) of *The Manitoba Hydro Act* requires Manitoba Hydro to deny a request for new electric service if the load exceeds 5 MW and it is not reasonably feasible for the corporation to supply the requested power considering the corporation’s capacity to supply the power and the impact on the province’s electricity grid. Manitoba Hydro must also deny requests for service if the requirements prescribed in the regulations are not met. The *Requests for Service Regulation* further outlines how Manitoba Hydro is to handle requests for service under subsection 49.2(3) of the Act.

## 7.2 Position of the Parties

### 7.2.1 *Manitoba Hydro*

Manitoba Hydro argues that the 2024 Load Forecast represents an average growth scenario, where there is an equal probability that the actual load will be higher or lower than projected. Further, the utility submits that Manitoba's energy demand is growing and that it expects load growth over the next decade at an annual rate of 1.3%, causing a need for new resources to meet capacity and energy requirements.

Despite not meeting its targets for energy savings for the years 2020/21 to 2023/24, Manitoba Hydro assumes that Efficiency Manitoba will meet its targets in the future. Manitoba Hydro notes that in the first years of operation, Efficiency Manitoba endured the COVID-19 pandemic and faced significant inflationary pressures which limited its ability to deliver on its annual targets. Manitoba Hydro has confidence that the targets will be achieved as Efficiency Manitoba's processes are becoming more mature, Manitobans are more familiar with their program offerings, and Manitoba Hydro continues to work with Efficiency Manitoba through its integrated planning processes to identify and help pursue high-value energy efficiency.

Manitoba Hydro disagrees with the Consumers Coalition's witness Midgard's assessment that the 2024 Load Forecast overstates the growth in demand. The Load Forecast was prepared using the best available information at the time of preparation and remains reliable to evaluate Manitoba's short and mid-term expected energy requirements. Manitoba Hydro also argues that Midgard's suggestion that Manitoba Hydro's recent load forecasts are inflated is not supported by evidence. The need date for energy and capacity resources has consistently been advanced in recent years, as opposed to being deferred or pushed further into the future. Further, Manitoba Hydro's expected load growth over the next decade is lower than North American power industry expectations.

### 7.2.2 *Intervenors*

#### **Consumers Coalition**

While the Consumers Coalition did not make submissions regarding Manitoba Hydro's load forecast, its expert witness Midgard observed that Manitoba Hydro's weather-adjusted load has grown 0.5% per year over the past 10 years. Midgard considers the load growth projected by Manitoba Hydro of 1.3% for the next 10 years to be a substantial step-change compared to historic load growth rates.

#### **Manitoba Eco-Network and Environmental Defence**

MEED criticizes Manitoba Hydro's use of only a single load growth scenario, arguing that one scenario is insufficient for asset management planning. According to MEED, although the IRP will examine more than one load growth scenario, an approach that considers several different scenarios for how decarbonization will be achieved should also be carried forward into the next general rate application.

### 7.3 **Board Findings**

The Board finds that the 2024 Load Forecast is a reasonable forecast upon which to base the projections for revenues during the 2025/26 to 2027/28 rate period. For clarity, this finding applies to the load forecasting methodology improvements incorporated into the 2024 Load Forecast, as well as the results of the 2024 Load Forecast itself.

However, the Board does not have evidence to show that Efficiency Manitoba will meet its legislated energy savings target of 1.5% throughout the rate period, and is concerned of Manitoba Hydro's reliance on this assumption. As Efficiency Manitoba's Efficiency Plans have not been referred to the Board for review since the original Plan was referred in 2019, the Board has not had an opportunity to explore the reasons it has been unable to meet its legislated efficiency targets to date, nor the steps taken to improve its processes and likelihood of achieving the targets. If Efficiency Manitoba does not achieve its target for energy savings, Manitoba Hydro's domestic load and revenues will be higher, while being partially offset by a decrease in export revenues.

With respect to any new large supply of power under section 49.2 of *The Manitoba Hydro Act* and the corresponding *Requests for Service Regulation*, the Board finds that any loads greater than the threshold amount, as set out in subsection 49.2(1) of *The Manitoba Hydro Act*, could affect Manitoba Hydro's load, resulting in more revenue or cost for the utility. The Board views that any such change could qualify as a material difference to justify a reconsideration of the Board's rates under subsection 39.4(1). Accordingly, the Board directs Manitoba Hydro to file a report with the Board, within 45 days after the end of each fiscal quarter, on any loads greater than the threshold amount for a large supply of power as set out in subsection 49.2(1) of *The Manitoba Hydro Act* that were added or removed from Manitoba Hydro's system supply requirements during the last quarter, and how these loads are expected to affect Manitoba Hydro's net income in the remaining years of the rate period.

## 8.0 EXPORT REVENUE

### 8.1 Background

Even under the most severe drought conditions, Manitoba Hydro generates sufficient electricity to sell energy into export markets. Manitoba Hydro sells some of its electricity at fixed prices under contracts with utilities in other jurisdictions, even during drought conditions. The utility's existing export contracts are summarized in Figure 8.1. The remaining energy is sold on the spot market at prevailing market prices.

Contract Name	Capacity (MW)	Type	Term
<b>Basin Electric</b>			
Basin 50 – 80	50 – 80	Capacity Sale	Jun. 1, 2023 – May 31, 2028
<b>Dairyland Power</b>			
DPC 50 Diversity Exchange	50	Diversity Exchange	Jun. 1, 2022 – May 31, 2027
<b>Great River Energy</b>			
GRE 200 Diversity Exchange	200	Diversity Exchange	Nov. 1, 2014 to Apr. 30, 2030
<b>Minnesota Municipal Power</b>			
MMPA 65 – 105	65 – 105	System Power Sale	Jun. 1, 2020 – May 31, 2030
MMPA 100 Diversity Exchange	100	Diversity Exchange	Jun. 1, 2030 – May 31, 2036
<b>Minnesota Power</b>			
MP 250	250	System Power Sale	Jun. 1 2020 – May 31, 2035
MP 250 Energy Exchange	0	Energy Exchange	Jun. 1, 2020 – May 31, 2035
MP 133	0	Surplus Exchange	Jun. 1, 2020 – May 31, 2040
MP 133 Energy Exchange	0	Energy Exchange	Jun. 1, 2020 – May 31, 2040
<b>Northern States Power</b>			
NSP 200	200 (summer)	System Power Sale	May 1, 2025 – Apr. 30, 2030
NSP 350 Diversity Exchange	350 – 200 (declines to 200 May 1, 2028)	Diversity Exchange	May 1, 2025 – Apr. 30, 2030
<b>SaskPower</b>			
SaskPower 100	100	System Power Sale	Jun. 1, 2020 – May 31, 2040
SaskPower 215	215	System Power Sale	Jun. 1, 2022 – May 31, 2052
<b>Wisconsin Public Service</b>			
WPS 100 Product A	100	System Power Sale	Jun. 1, 2021 – May 31, 2027
WPS Product B	0	Surplus Sale	Jun. 1, 2027 – May 31, 2029
<b>WPPI Energy</b>			
WPPI 100 Diversity Exchange (summer-winter)	100	Diversity Exchange	Jun. 1, 2024 – May 31, 2035
WPPI 100 Diversity Exchange (summer-spring)	100	Diversity Exchange	Jun. 1, 2030 – May 31, 2035

Figure 8.1 — Manitoba Hydro's Export Contracts

Manitoba Hydro only commits to export contracts for dependable energy, meaning electricity that the utility expects to be able to generate even during the worst drought on record. Dependable energy is also used to serve Manitoba customers. Manitoba Hydro sells surplus dependable energy that is not under contract, as well as surplus energy generated in excess of dependable energy, on the spot market. These are known as opportunity sales. Manitoba Hydro also sells surplus energy to select Manitoba customers under the Surplus Energy Program, which is described further in section 20.2.

Manitoba Hydro's total exports (dependable sales under contract and opportunity sales at market prices) depend on water conditions and the demand in Manitoba, as only energy not needed to meet Manitoba's demand can be exported. Total exports also depend on the available capacity of the transmission interconnections.

Aside from Manitoba Hydro's contracts with SaskPower (a Saskatchewan Crown corporation), all of Manitoba Hydro's export contracts are with American utilities located within the territory of the Mid-Continent Independent System Operator ("MISO"). While approximately 40% of Manitoba Hydro's current export sales are made under contract in normal water conditions, the utility expects this percentage to decline to 25% by 2029/30.

At the 2023/24 & 2024/25 General Rate Application, the issue of export revenues was extensively canvassed. The Board retained Daymark Energy Advisors ("Daymark") as an independent expert consultant to provide an assessment of Manitoba Hydro's export revenue forecasts and forecasting methodology. The Board found in Order 101/23 that Manitoba Hydro had appropriately projected its export revenues during the test years. However, the Board had difficulty reconciling the trends toward decarbonization and increased electrification with Manitoba Hydro's projections of declining export market prices and its assumption of no new export capacity sales from its surplus summer capacity.

At the 2023/24 & 2024/25 General Rate Application, Manitoba Hydro indicated that while it intended to continue to seek opportunities to sell its remaining excess capacity, it did not anticipate any such sales in its export revenue projections. Further, Manitoba Hydro

advised in this hearing that it was able to enter into, or extend, contracts for both power sales and seasonal diversity exchanges. Specifically, this includes a summer-only 200 MW power sale with Northern States Power, and seasonal diversity exchanges with Northern States Power, Minnesota Municipal Power Agency, and Wisconsin Public Power Inc. (“WPPI”) Energy totalling between 600 and 750 MW. Diversity exchange agreements allow for Manitoba Hydro to access firm capacity from its counterparty in the winter or spring in exchange for providing its own capacity to the counterparty in the summer, although there may not be incremental revenue associated with these contracts. In this way, Manitoba Hydro is able to help meet its winter and spring peak demand requirements, while enabling the counterparty to meet its summer demand requirements.

Manitoba Hydro projects that its net export revenues (gross export revenues less fuel and power purchased and water rentals and assessments) will continue to decline into the future. By 2043/44, Manitoba Hydro expects its net export revenues will be negative on a normal-water basis as domestic load consumes more of the current surplus generation, gross export revenues decrease, and new power purchases from the planned 600 MW of wind generation offset these remaining revenues.

To estimate its opportunity sales revenue, Manitoba Hydro prepares a near-term energy price forecast and a long-term energy price forecast. For this purpose, Manitoba Hydro relies on third-party forecasters who provide forecasts of on-peak energy, off-peak energy, and capacity prices in the MISO market.

When Manitoba Hydro first filed this Application, it assumed its net export revenue would produce a net income of \$218 million in 2025/26. However, as referenced in section 4.0, the significant drought conditions in 2025/26 have reduced hydraulic generation, leaving Manitoba Hydro with less energy to export. By the time of the oral hearing, Manitoba Hydro expected to experience a net loss of \$409 million, primarily because of the deterioration in water conditions. Section 4.1.2 further describes the financial impacts of the 2025/26 drought.

As Manitoba Hydro is still negotiating with counterparties for energy supplies for the current winter period, as well as hedging the prices of energy purchases, Manitoba Hydro requested that certain of its information with respect to exports be held in confidence by the Board as disclosure could negatively affect Manitoba Hydro's negotiating position. As such, Manitoba Hydro has not disclosed the details of its 2025/26 net export revenues on the public record of this proceeding. The issue of Manitoba Hydro's confidential information is further addressed in section 20.5 of this order.

## 8.2 Manitoba Hydro's Position

Manitoba Hydro submits that it continues to optimize its export contract portfolio to provide value for Manitobans, as evidenced by its six new or extended power sale and diversity exchange agreements since the last general rate application.

While seasonal diversity contracts can defer the need for new generating capacity in winter when Manitoba's load is highest, the availability of winter import capacity from the MISO market is uncertain past 2030 due to retirements of coal generation and demand growth. Manitoba Hydro states that the North American Electricity Reliability Corporation ("NERC") identifies that falling planning reserve margins in the MISO market for both winter and summer seasons contribute to an elevated resource adequacy risk starting as early as 2028.<sup>2</sup> As such, Manitoba Hydro will continue to monitor conditions and explore opportunities in neighbouring markets, while ensuring alignment with government direction.

None of the interveners took a position with respect to Manitoba Hydro's export revenue projections.

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<sup>2</sup> NERC 2024 Long-Term Reliability Assessment, December 2024, pp. 6-7  
[https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC\\_Long%20Term%20Reliability%20Assessment\\_2024.pdf](https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf)

### 8.3 Board Findings

The Board reiterates its finding from Order 101/23 that Manitoba Hydro's methodology for forecasting export revenues is appropriate. The Board finds that Manitoba Hydro has appropriately projected its export revenues during the rate period by using its established method of developing a consensus export price forecast based on independent forecasts from third parties.

The Board notes that Manitoba Hydro has secured additional summer power sales and seasonal diversity exchange agreements since the last general rate application. This aligns with the Board's previously articulated view that Manitoba Hydro's surplus summer capacity has considerable value. The value of these agreements to Manitoba Hydro is discussed in section 9.0 on resource planning.

## 9.0 RESOURCE PLANNING

### 9.1 Background

#### 9.1.1 *Integrated Resource Plan*

In the Board's 2014 Needs For and Alternatives To (NFAT) report on Manitoba Hydro's proposed capital development plan, the Board recommended the adoption of integrated resource planning. The recent amendment to *The Manitoba Hydro Act* requires Manitoba Hydro to prepare an integrated resource plan ("IRP") with a minimum 10-year planning horizon. The purpose of an IRP is to analytically determine what resources are in the best interests of consumers by examining a full spectrum of possible supply-side and demand-side options and measuring them against a collective set of objectives and criteria. Integrated resource planning is an improvement from traditional utility resource planning, which focuses only on the supply-side resources and not demand-side resources such as energy efficiency measures.

As set out in section 38.1 of *The Manitoba Hydro Act*, Manitoba Hydro must provide the IRP to the Minister responsible for the utility, and the Lieutenant Governor-in-Council must approve the plan. Cabinet may refer the plan to the Board for review and recommendations before the IRP is approved.

Following the conclusion of the evidentiary portion of the current Application, Manitoba Hydro's 2025 Integrated Resource Plan was referred to the Board for public review. As of the date of this Order, the review of the IRP is proceeding.

In Order 69/25, the Board ruled the IRP out of scope for this Application, except to the extent assumptions made in the IRP also underpin this Application.

#### 9.1.2 *Proxy Development Plan*

While the IRP was out of scope, resource planning was a significant consideration in this Application by Manitoba Hydro. Based on the projections in the 2024 Load Forecast, Manitoba Hydro states that due to the expected growth in the total peak demand, it will not have sufficient generating capacity to supply the winter peak demand as early as

2029/30. To meet this peak demand, Manitoba Hydro plans to construct new generating assets that are expected to enter service as early as 2030/31, as discussed in section 10.0 of this Order.

For the purposes of this Application, Manitoba Hydro developed a “proxy” resource development plan that it describes as consisting of a relatively low-cost set of high-potential resource options that could meet upcoming supply needs (the “Proxy Development Plan”). Manitoba Hydro developed the proxy plan in advance of filing the 2025 Integrated Resource Plan, as Manitoba Hydro needed to put forth a financial forecast that was based on sufficient resources to meet the electricity needs of its customers over the 20 year financial forecast.

Manitoba’s Hydro Proxy Development Plan includes:

- 600 MW (installed capacity) of majority Indigenous-owned wind (200 MW in 2029, 200 MW in 2031, and 200 MW in 2033) to align with Manitoba’s Affordable Energy Plan;
- Increasing the capability of Manitoba Hydro’s existing system through refurbishments and supply side enhancements;
- Demand response programs as potential lower cost options to defer new resources; and
- A dispatchable capacity resource to balance supply and demand starting in 2030/31, consisting of natural gas fuelled combustion turbine electricity generating units added in 2030 and 2039.

While 600 MW of wind generation is expected to be added in tranches, because of the intermittency of wind, Manitoba Hydro only relies upon 20% of the installed wind generation capacity as firm supply that is available to meet the winter peak demand. Beginning in 2030, Manitoba Hydro’s Proxy Development Plan assumes 20% of the first 200 MW tranche, or 40 MW, will contribute to meeting the winter peak demand.

As described in section 8.1 above, Manitoba Hydro secured three new seasonal diversity agreements since the filing of the original Application, two of which contribute a total of 200 MW of capacity to meet the winter peak demand.

## **9.2 Position of the Parties**

### **9.2.1 *Manitoba Hydro***

Manitoba Hydro submits that the Proxy Development Plan represents a set of low-cost resources to meet winter peak demand while aligning with the provincial government's policy and a net-zero grid mandate. At this time, no specific investment or resource decisions have been made as those decisions will be made through the upcoming IRP process. The IRP will result in a road map that includes recommended and alternative development plans, learnings, near-term actions, and signposts.

As Manitoba Hydro expects load growth over the next decade at an annual rate of 1.3%, it submits that new resources are required to meet capacity and energy requirements. Need dates for energy and capacity resources have consistently been advanced in recent years: presently, the anticipated need date for capacity resources is 2029/30 and the need date for dependable energy is 2031/32. As there is uncertainty in the market's ability to provide reliable capacity for Manitoba's winter demand, Manitoba Hydro must be proactive to ensure in-service dates for new resources can be met to ensure a reliable electrical system for Manitoba. Most utilities are having to address accelerated load growth, which is increasing demand on limited equipment suppliers and driving up costs and lead times when procuring the required equipment.

### **9.2.2 *Intervenors***

#### **Consumers Coalition**

The Consumers Coalition submits that given Manitoba Hydro's history regarding the Wuskwatim Generating Station, Bipole 3, and the Keeyask Generating Station, the Board should not have confidence in the utility's approach to resource planning. The Consumers Coalition notes that the seasonal diversity exchanges materially change the case for developing new combustion turbine resources in the rate period. Further, without the updated IRP, and in light of Manitoba Hydro's history with respect to demand-side management, it is unknown if there is untapped demand-side management potential to meet growing electricity needs. A review of Manitoba Hydro's IRP will likely lead to an updated Efficiency Manitoba plan, which may in turn lead to revised energy savings targets. Revised energy savings targets may ultimately have an effect on Manitoba Hydro's need date for other new resources.

#### **GSS/GSM Representative**

The GSS/GSM Representative recommends that optional rates and programs for bill management, such as demand response programs, should be prioritized for commercial customers to maximize the least cost options included in the IRP.

#### **Manitoba Eco-Network and Environmental Defence**

While MEED agrees that this Application is not the appropriate venue to assess the need for and alternatives to the proposed gas-fired generation facilities, Manitoba Hydro cannot rely on a purported need to build such facilities by 2030/2031 to justify increased rates without actually providing evidence in support of that need.

While MEED does not take issue with Manitoba Hydro's base load forecast, it disagrees with Manitoba Hydro's assessment of the need date of 2030/31 for new electricity generating resources. In MEED's view, with the addition of the two new 100 MW winter-summer diversity agreements, Manitoba Hydro's winter peak capacity shortfall is only 30 MW in 2030/31. The forecast 30 MW capacity deficit is only 0.4% of Manitoba Hydro's total winter capacity, and that deficit remains below 30 MW through 2033/34 even without

the new natural gas combustion turbine generating facility. Further, Manitoba Hydro confirmed during the hearing that it could take steps and adjust its operations so that this small 30 MW shortfall did not cause electricity outage problems for its customers. With the new energy efficiency measures announced by the provincial government, and using the 2024 Load Forecast, MEED submits that the need date for the new combustion turbine facility is pushed to at least 2034/35. Accordingly, the \$2 billion investment in the combustion turbine facility is not necessary and cannot be justified as yet another capacity buffer in addition to the existing capacity reserve margin and other protections.

MEED states that there would be significant benefits from deferring construction of new combustion turbine resources beyond 2030/2031. These benefits include reduced rates and additional time to conduct a proper regulatory review of the IRP as envisioned by *The Manitoba Hydro Act*.

MEED also recommends that Manitoba Hydro consider non-wires alternatives in its capital and resource planning. Non-wires alternatives include grid-scale batteries or geographically targeted energy efficiency initiatives. Non-wires alternatives are cost-effective approaches to meeting generation, transmission, and distribution capacity requirements without resorting to traditional infrastructure projects.

### **9.3 Board Findings**

As the integrated resource plan (“IRP”) was not available for consideration by the Board in this Application, the February 2, 2026 filing has not influenced the findings and directives of the Board. At the conclusion of the IRP review, the Board will submit a report to the Minister responsible for Manitoba Hydro with the Board’s recommendations, as required by the legislation.

The Board finds that for the purposes of this Application, Manitoba Hydro's Proxy Development Plan is acceptable for financial planning purposes, as the IRP has yet to be reviewed or approved. However, the need for a proxy resource development plan in this application highlights the problem of hearing the Application and the IRP out of sequence. The IRP should have been reviewed first, with the resulting approved development plan informing the financial forecast upon which rates are approved.

As further described in section 10.0, Manitoba Hydro is expected to make commitments to combustion turbine manufacturers, either doing so already or in the near future, in order to secure production slots and ensure the turbines are available to provide service by 2030/31. However, as shown by MEED, with the stroke of a pen on import and capacity exchange contracts, Manitoba Hydro is able to eliminate its near-term winter peak capacity shortfall.

Over the past two decades, Manitoba Hydro has been principally driven by the need for energy resources, not capacity resources, as its supply of dependable energy was the limiting factor in meeting the needs of Manitobans. With the expiry of the previous Northern States Power capacity exchange diversity agreement in 2025 and the Great River Energy capacity exchange agreement in 2030, Manitoba Hydro finds itself in an impending capacity deficit that prompted the need for the combustion turbine facility. However, with the recent signing of new diversity agreements with Northern States Power and WPPI Energy, that capacity deficit largely appears to be temporarily eliminated.

The Board cannot direct Manitoba Hydro to take any action or refrain from taking action with respect to committing to a combustion turbine facility. However, in accordance with subsection 16(3) of the *Manitoba Hydro Act*, the Board expects to review the needs for and alternatives to the proposed combustion turbine facility. The Board will assess the proposed facility and make its recommendations to government at that time.

## **10.0 ASSET MANAGEMENT AND CAPITAL EXPENDITURES**

### **10.1 Background**

Manitoba Hydro maintains a large number and wide range of assets to generate, transmit, and distribute electricity to its customers. To continue to serve both new and existing customers, Manitoba Hydro must continually make capital investments in its system.

The utility distinguishes between major capital projects and business operations capital. Major capital projects relate to significant new, or refurbishment of, generation and transmission assets and include projects of a substantial cost. All capital expenditures that are not for major capital are for business operations capital. The utility further divides business operations capital into three components: (1) sustainment, (2) capacity and growth, and (3) business operations support. Sustainment spending is intended to maintain or replace existing assets. Capacity and growth spending is intended to accommodate new customers or increase capacity to accommodate higher load requirements. Business operations support spending relates to investments made to support Manitoba Hydro's operations, such as maintaining the utility's fleet of motor vehicles.

#### ***10.1.1 AMCL's Maturity Assessment of Manitoba Hydro's Asset Management Approach***

Since at least 2008, the Board has been recommending that Manitoba Hydro develop asset condition assessments and improve its asset management methodologies. In 2016, Manitoba Hydro retained an external consultant, UMS Group, to assess the maturity of its asset management methodologies compared to industry best practices and international standards for asset management. The consultant found that Manitoba Hydro's asset management methodologies were at the "awareness" stage and were still maturing. Consequently, in Order 59/18, the Board directed Manitoba Hydro to retain an independent consultant to assess Manitoba Hydro's development of its asset management program and its progress in addressing the recommendations made by UMS Group and to report back at the next general rate application. At the 2023/24 &

2024/25 General Rate Application, Manitoba Hydro provided an asset management maturity assessment performed in 2022 by its external consultant Asset Management Consulting Ltd. (“AMCL”).

In the 2022 assessment, AMCL concluded that Manitoba Hydro had made improvements since the 2016 UMS review. On an asset management maturity scale of zero to five developed by the Institute of Asset Management, AMCL concluded that Manitoba Hydro had improved from a maturity score of 1.5 at the 2016 UMS review to a score of 1.81. The Board subsequently found that Manitoba Hydro was making progress in maturing its approach to capital asset management. However, the progress had been slow. Directive 29 of Order 101/23 again directed Manitoba Hydro to file an independent assessment of its progress towards maturing its asset management approach.

In response to Directive 29 in Order 101/23, AMCL performed an asset management maturity assessment in December 2024 and concluded that Manitoba Hydro’s asset management maturity increased from 1.81 to 2.33. This improvement in maturity moves Manitoba Hydro out of the “developing” band and into the “competent” band. According to AMCL, Manitoba Hydro is making steady progress on its asset management journey and on track for achieving maturity level 3 by the end of 2032. Per the guidance of the Institute of Asset Management, a maturity level of 3 constitutes asset management competence and a level of 5 constitutes excellence, as shown in Figure 10.1.



Figure 10.1 — Asset Management Maturity Levels

### **10.1.2 Strategic Asset Management Plan and Asset Management Plan**

In 2019, Manitoba Hydro developed a Strategic Asset Management Plan (“SAMP”) which defined its asset management objectives and described Manitoba Hydro’s path to maturing its asset management processes. At the 2023/24 & 2024/25 General Rate Application, Manitoba Hydro was in the process of updating its SAMP and developing its first Asset Management Plan (“AMP”). Directive 30 of Order 101/23 required Manitoba Hydro to file the updated SAMP and AMP at the next general rate application.

Manitoba Hydro’s updated 2025 SAMP sets a vision to stabilize energy reliability by 2032 and progress towards an optimal balance of cost, risk, and performance for its assets. Achieving this vision will require additional human and financial resources.

In this hearing, Manitoba Hydro filed its AMP which lays out the work to be prioritized and the timelines to achieve the SAMP objectives. Further, the AMP outlines the need to increase asset renewals and replacements, as well as increase maintenance to maximize the economic life of assets. The AMP has a goal to complete 100% of the recommended annual maintenance by 2032.

The asset renewal rates suggested by the AMP would result in significant sustainment spending over the 20-year forecast. However, Manitoba Hydro’s financial forecast does not incorporate these levels of spending as it must balance many priorities and risks when establishing its operating and financial plans.

### **10.1.3 Capital Expenditure Forecast**

At the 2023/24 & 2024/25 General Rate Application, Manitoba Hydro planned to spend \$18.2 billion over 20 years on capital projects. The spending was primarily on business operations capital items in order to renew and sustain its existing assets, with \$1.4 billion earmarked for new dispatchable capacity resources which were expected to be combustion turbines. Manitoba Hydro argued that this level of investment was necessary to provide safe, reliable service.

In the current Application, Manitoba Hydro plans to spend \$31.2 billion on capital projects, as shown in Figure 10.2. This is a substantial increase over what Manitoba Hydro proposed only two years ago. Manitoba Hydro has provided the following explanation for this increase:

- The recently developed AMP shows that investment must increase compared to what was presented at the last general rate application. The AMP specifies that spending should increase to \$1.6 billion per year by the end of fiscal year 2032, with an immediate ramp-up to that level, in order to address the following pressing asset needs:
  - \$380 million for sustainment of existing assets at historical spending levels;
  - On average, \$500 million per year for sustainment investment in HVDC assets for Bipoles 1 and 2;
  - An additional \$255 million in sustainment spending to achieve long-term sustainable renewal rates for asset populations. The \$200 million increase identified at the last general rate application was a preliminary analysis that was further refined when the AMP was finalized;
  - A \$70 million temporary increase in sustainment spending to address priority renewals of generators, medium voltage switchgear, and HVDC electrodes;
  - \$310 million investments in growth and capacity, including new generation resources and advanced metering technology, such as Advanced Metering Infrastructure (“AMI”) which is an integrated system that automatically collects, monitors, and manages energy consumption and demand data from smart meters installed at customer service end points; and
  - \$90 million investments in business support infrastructure.
- While the need to invest in the HVDC assets was known at the last general rate application, the required investments were not fully defined and so Manitoba Hydro only had a “placeholder” budget of \$1 billion to \$1.8 billion. As this was only a placeholder, it was not included in the \$18.2 billion 20-year total. The current estimate is \$6.8 billion which is included in the \$31.2 billion updated 20-year total.

- Cost escalation for transformers, turbines, electrical transmission equipment, and general construction that has exceeded the consumer price index in recent years.

Project Category (\$ in millions)	2025/26 Test Year	2026/27 Test Year	2027/28 Test Year	2025/26 to 2034/35 10-Year Total	2025/26 to 2044/45 20-Year Total
<b>Major Capital</b>					
System Renewal	\$26.2	\$341.4	\$551.7	\$6,072.4	\$6,826.5
Capacity & Growth	\$17.9	\$35.3	\$56.0	\$1,432.4	\$3,924.2
<b>Business Operations Capital</b>					
Sustainment	\$472.3	\$534.4	\$447.1	\$5,020.3	\$12,117.0
Capacity & Growth	\$152.4	\$111.2	\$151.1	\$2,135.1	\$5,879.8
Business Operations Support	\$152.0	\$145.8	\$113.1	\$1,197.7	\$2,436.6
<b>Total Business Operations Capital</b>	<b>\$776.7</b>	<b>\$791.4</b>	<b>\$711.3</b>	<b>\$8,353.1</b>	<b>\$20,433.4</b>
<b>Total Capital</b>	<b>\$820.9</b>	<b>\$1,168.2</b>	<b>\$1,319.0</b>	<b>\$15,857.9</b>	<b>\$31,184.1</b>

Figure 10.2 — Manitoba Hydro’s Planned Electric Capital Expenditures

Manitoba Hydro submits that the reliability of its existing assets is in decline and significant investment is required to stabilize system performance and sustain reliable operation. In particular, the reliability of the HVDC system has critically declined and is a significant concern. Addressing HVDC reliability is an enterprise priority goal, and this will take many years and significant investment to complete.

While Manitoba Hydro’s goal is to maintain its historical level of system performance, as this is the level of performance that its customers have come to expect, it expects system performance to decline and then to stabilize by 2032. According to Manitoba Hydro, there is a “bow-wave” of investments required to address a surplus of backlogged or incoming priority investments, particularly for HVDC and generation assets.

Capital expenditures do not immediately affect the utility’s revenue requirement in the year the expenditure is made. The revenue requirement incorporates the costs related to assets that have been placed in commercial service through the depreciation expense, finance expense, and operating expenses related to those assets. While Manitoba Hydro plans to spend over \$1 billion on major projects in the rate period, those major projects will not enter commercial service during the 2026-2028 rate period. This includes

Manitoba Hydro’s AMI initiative, which is currently estimated to total approximately \$180 million by fiscal year 2032, with mass deployment of gas and electric meters only expected to begin in 2027/2028. As a result, none of this major capital spending affects the revenue requirement upon which the Board must base its rate decision in accordance with subsection 39(5) of the *Manitoba Hydro Act*.

Manitoba Hydro has a long-standing financial target of being able to fund business operations capital expenditures from internally-generated funds. The specific metric used by Manitoba Hydro to determine whether it is meeting that financial target is the Capital Coverage Ratio which is a measure of cash generated from operations divided by business operations capital expenditures. As shown in Figure 10.3, the forecast of business operations capital (blue area) is predominantly aligned with the forecast of cash from operations (green line). When determining the revenue forecast implicit in Figure 10.3, the utility assumes a 3.5% rate increase for each year of the rate period. Spending on major capital projects including the HVDC refurbishment is not funded from internally generated cash flow, as shown by the arrow pointing to the pink and orange areas above the green line.

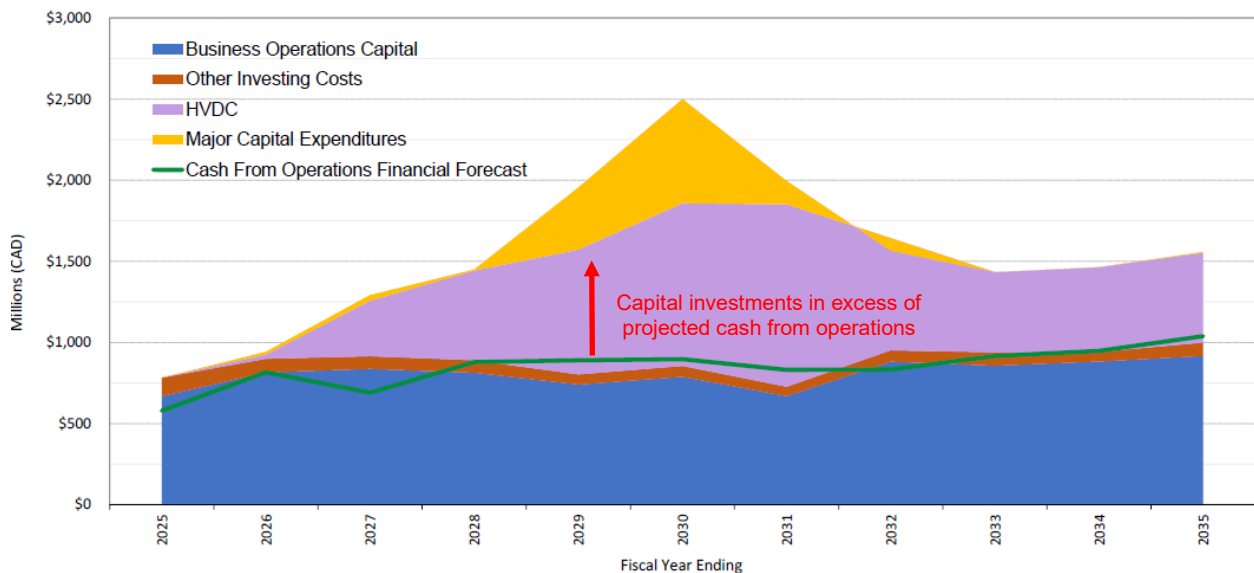


Figure 10.3 — Cash Flow Cost Coverage

#### **10.1.4 HVDC Reliability Project**

Bipoles 1, 2, and 3 are HVDC transmission lines that transmit approximately 70% of Manitoba Hydro's electricity from the northern generating stations on the Nelson River to the southern load centres. The HVDC system consists of three converter stations near the Nelson River generating stations which convert the alternating current electricity from the generating stations to direct current for long-distance transmission to two converter stations near Winnipeg. Bipole 1 entered service in 1976, Bipole 2 in 1979, and Bipole 3 in 2018. While Bipole 1 underwent upgrades to its converters in the early 1990s and 2000s, there have been no converter upgrades performed for Bipole 2.

Manitoba Hydro explained that the reliability and availability of Bipoles 1 and 2 have been declining in recent years. The Bipole 1 converters are currently 32 years old, the Bipole 1 controls are 53 years old, and the Bipole 2 converters and controls are 45 years old. Manitoba Hydro stated that there is a 30-80% chance that at least one Bipole permanently fails before 2032. When the Bipoles are not available, northern generation cannot be transmitted to the south; it is said to be "bottled", meaning it is stranded and cannot be used, resulting in water being spilled past the generating stations.

Manitoba Hydro showed that with its current system, if either Bipole 1 or 2 are out of service, Manitoba Hydro is unable to fully serve the Manitoba winter peak load and contracted exports. This is in contrast to a similar analysis shown to the Board at the 2017/18 & 2018/19 General Rate Application, which showed that if Bipoles 1 and 2 are out of service, with the addition of Bipole 3 in 2018, Manitoba Hydro would have a surplus and be able to serve the winter peak demand through 2041. In this hearing, Manitoba Hydro explained that the two presentations are not comparable for a number of reasons. The 2017 analysis assumed non-firm imports up to the physical import limit as well as contributions from the Selkirk Generating Station. However, Manitoba Hydro can only rely on imports for which it has contracts in place and the Selkirk Generating Station has since been decommissioned. Other differences are that the 2017 Load Forecast differs from the 2024 Load Forecast, there are differences in the assumed amounts of demand-side management savings, the 2017 analysis assumed curtailment of exports, and the 2017

analysis did not include the planning reserve margin. Manitoba Hydro characterized what it showed the Board in 2017 as a non-firm, instantaneous view of the supply-demand balance, while the current view is Manitoba Hydro's plan for reliable, continuous operations.

With its critical importance to Manitoba Hydro's system, the reliability of the HVDC system has been identified as a top enterprise goal. Manitoba Hydro has embarked on a project to replace the Bipole 1 and 2 converters and controls. Hitachi Energy has been retained to complete the front-end design on a "brownfield" replacement of Bipoles 1 and 2. The project scoping and design activity are expected to be completed in 2026 for Bipole 2 and in 2027 for Bipole 1. Manitoba Hydro will then seek further approvals from its board of directors and the provincial Treasury Board. The expected in-service date is 2032 for Bipole 2 and 2037 for Bipole 1.

At the present time, the cost estimate is \$6.8 billion, although Manitoba Hydro concedes this is a preliminary, Class 10 estimate. Per the Association for Advancement of Cost Engineering ("AACE") recommended practices, 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.

Manitoba Hydro notes that the HVDC market currently demands a target price reimbursable contract model as opposed to a fixed price contract due to a limited number of suppliers that offer HVDC equipment in North America.

Midgard, the Consumers Coalition's expert, recommended deferral of the Bipole 1 replacement by six years and the deferral of the Bipole 2 replacement by three years. According to Midgard, while upgrading the HVDC converter assets may be necessary in the future, current conditions do not justify the scale or urgency of the proposed scope. A more prudent approach would be to prioritize targeted lower-cost investments, such as HVDC electrode replacements and a new transmission line connecting the northern converter stations. This would provide clear and immediate reliability value, while allowing longer-term planning for converter renewals and potential technology changes to be

better grounded in evidence-based, risk-driven analysis, with associated higher quality cost estimates.

### **10.1.5 Combustion Turbines**

Manitoba Hydro expects to need new resources to meet winter peak demand as early as 2029/30. With the extension of the long-standing Curtailable Rate Program, the need date for new resources is delayed one year to 2030/31. To balance electricity demand with supply over the next 20 years, Manitoba Hydro developed a Proxy Development Plan consisting of combustion turbine generators, the Curtailable Rate Program and other demand response initiatives, in addition to supply-side enhancements to its existing hydroelectric generating stations. The estimated costs of this Proxy Development Plan were incorporated into Manitoba Hydro's financial forecast for this Application, but until a recommended development plan is established through an IRP process and subsequently approved by government, a proxy plan is used as a placeholder input to various Manitoba Hydro planning functions.

The combustion turbine component of the Proxy Development Plan, currently labelled by Manitoba Hydro as dispatchable capacity resources, consists of five 250 MW combustion turbines. At the time this Application was filed, these turbines were estimated to cost \$3.8 billion, with the first two turbines expected to enter service in 2030/31 at a cost of \$1.36 billion, the third in 2039/30, the fourth in 2041/42, and the fifth in 2043/44.

Subsequent to the development of the Proxy Development Plan, the Manitoba government announced that Manitoba Hydro would construct three new combustion turbines totaling 750 MW in the Westman region of the province. Based on the original Class 10 cost estimate at an 80% confidence level (known as a "P80" estimate), the third turbine increased the cost from \$1.36 billion to \$2 billion. This estimate will be further refined as details are prepared for an upcoming Major New Facilities Review submission to the Board.

Manitoba Hydro has been working to refine and improve the cost estimate for the combustion turbines. Manitoba Hydro now has a Class 4 estimate for the turbines and a Class 5 estimate for the natural gas pipeline and electric transmission that must be constructed to serve them. The revised estimate is \$2.5 billion. While the capital expenditure forecast for the Proxy Development Plan underpinning the financial forecast includes \$3.8 billion for combustion turbines, the timing of the expenditures and the ultimate cost of the capital plan are now different. Manitoba Hydro did not update its financial forecast to reflect the change in turbine costs or timing of the expenditures.

#### ***10.1.6 Customer Surveys and Ratepayer Willingness to Pay***

To track customer perspectives on various issues, including rate affordability and system reliability, Manitoba Hydro periodically conducts customer surveys. In support of its Application, Manitoba Hydro performed a Customer Value Assessment research study in 2025 that included reliability valuation questions and a range of \$6, \$9, and \$12 monthly bill increases that could result from reliability-driven investments. This survey found that 56% of Manitobans supported a monthly bill increase to maintain reliability. Specifically, the survey showed that there was 64% support for investments at the \$6 monthly bill impact amount. The proposed rate increases in this Application result in monthly bill impacts of \$3.69, \$3.81, and \$3.94 for customers using 1,000 kWh per month or \$7.05, \$7.28, and \$7.53 for customers using 2,000 kWh per month in each of the respective years of the rate period, which is in line with the \$6 per month used in the survey. However, it is noted that survey responses varied depending on a number of factors, including the level of the presented bill increases, the household income of the survey respondent, and whether the respondent self-identified as Indigenous.

In this hearing, Manitoba Hydro referenced other surveys in support of its Application, including Electricity Canada's 2024 survey called the National Customer Satisfaction Study. The Electricity Canada study found that the majority (54%) of Manitobans and 65% of Manitoba Hydro's major customers understand increasing rates is necessary to support infrastructure investment. The actual rate increases are not mentioned in this survey.

### **10.1.7 Treasury Board Approval of Capital**

Manitoba Hydro provides Treasury Board with a five-year outlook of capital expenditures. However, Treasury Board only approves the capital expenditures for the upcoming fiscal year, not for the future years. Subsection 39(5) of *The Manitoba Hydro Act* states that the Board may not reduce for rate-setting purposes the amount required to support the capital expenditure program approved by Treasury Board for the rate period. At the time of the oral hearing for this application, Treasury Board had approved the capital expenditures for 2025/26 but not for the remaining two years of the rate period.

## **10.2 Position of the Parties**

### **10.2.1 Manitoba Hydro**

Manitoba Hydro submits that it is facing declining reliability in most energy system performance metrics and has experienced high-impact asset failure events. Bipoles 1 and 2 have each lost approximately 20% of average annual availability. Generation forced outage rates have been climbing for five straight years and are now at an all-time high with 300 MW of generation currently out of service. This declining system performance results in lost revenues and increased costs, affecting Manitoba Hydro's financial health. Distribution system outage duration is also trending unfavourably. Certain assets are at risk of catastrophic failure which can put employee safety at risk. Without sustained and necessary investment, Manitoba Hydro anticipates there will be an unstable increase in risks for the foreseeable future.

To address the declining reliability in the most cost-effective manner, Manitoba Hydro submits that it has made significant progress in maturing its asset management capabilities, with its maturity score increasing from 1.81 to 2.33 since the last general rate application (i.e., from "aware" status to "developing" status). In the event that the Board continues to have concerns over Manitoba Hydro's asset management maturity progress, Manitoba Hydro recommends that the Board again consider retaining an independent expert consultant to conduct a review and report on Manitoba Hydro's progress towards maturing the utility's asset management approach.

Manitoba Hydro's AMP recommends renewal rates that will prevent long-term escalation in risk and achieve an optimal balance between risk, cost, and performance. In order to balance a safe and reliable electrical system with affordability for customers and the financial health of the utility, business operations capital investment in the financial forecast has been set at a level that is less than what the AMP recommends.

In response to Midgard's assertions that Manitoba Hydro focuses only on specific assets and not the role of the asset within the system, Manitoba Hydro states that it aligns system-level risks to specific asset risks in all asset investment planning and decision-making activities.

Manitoba Hydro intends to accelerate the work on the HVDC Reliability Project as Manitoba Hydro considers the risk posed by the loss of Bipoles 1 and 2 to be unacceptable. Manitoba Hydro further argues that it cannot rely on non-firm market purchases to cover prolonged system outages such as HVDC transmission system failures. The MISO market faces growing resource adequacy risks and is shown to be at an elevated risk state. Moreover, securing capacity from the MISO market requires approximately an 18-month lead time. As such, diversity agreements (discussed in section 8.0) should not be relied upon to defer long-term need for new supply but can be used as a bridging resource to pre-emptively mitigate risks such as HVDC outages.

According to Manitoba Hydro, the combustion turbines in the Proxy Development Plan are not merely placeholders; rather, they are indicative of near-to-medium term capital requirements to ensure energy supply is safe and reliable. There is no future scenario that does not include significant investments to ensure safe, reliable energy.

In Manitoba Hydro's view, customers are asking for balance in the trade-off between power outages and rate increases. Manitoba Hydro used best practices when conducting surveys of its customers by specifying the monthly bill increases in dollar amounts to support the reliability investments, without identifying what that percentage increase would be. Manitoba Hydro chose not to express the bill increase in percentages as this reduces the clarity of the bill impact to survey respondents. Another best practice followed

by Manitoba Hydro was to pre-test the survey through one-on-one interviews to ensure that questions and responses were clear and that they provided survey respondents the context needed to answer trade-off questions. The research was not intended to be a specific investment trade-off on the successive 3.5% rate increases. However, the results demonstrated that the majority of Manitobans and Major Account customers understand the need for increasing rates to invest in the province's electric system, with 56% of respondents saying that Manitoba Hydro should make the necessary investments to maintain reliability. Manitoba Hydro noted that it consistently receives one of the highest satisfaction scores of any province for the price of electricity and overall value.

### **10.2.2 *Intervenors***

#### **Assembly of Manitoba Chiefs**

The AMC submitted that Manitoba Hydro's capital investment priorities, while framed as necessary for system reliability, do not adequately account for the reliability and service realities faced by First Nations on-reserve customers.

Further, the AMC argues that Manitoba Hydro's Customer Values Assessment Survey does not reflect the actual experience of First Nations on-reserve residential customers and does not assess the impacts of multiple annual rate increases on high-consumption, low-income households.

#### **Consumers Coalition**

In the Consumers Coalition's view, Manitoba Hydro must continue to pursue competence in asset management in order to support evidence-based decision making. Despite its 18-year asset management journey, Manitoba Hydro's asset management program is unlikely to achieve competence until at least 2032. Failure to optimize cost, performance, and risk calls into question the aggressive spending targets in business operations capital, including the "bow wave" of additional required investments. As a result of Manitoba Hydro's lengthy asset management journey, the Board must set just and reasonable rates without Manitoba Hydro's asset management methodologies being at a competent level and in the absence of mature capital spending plans.

In the Consumers Coalition's view, Manitoba Hydro's capital forecasts are unreliable. Of the \$31.2 billion in the 20-year capital expenditure plan, \$11.7 billion or 38% is based on Class 10 cost estimates or other placeholders.

The Consumers Coalition criticizes Manitoba Hydro for trying to create a sense of inevitability and to back the Board into a corner by claiming there are limited options available to it, which is not the case. For example, the need date for the new combustion turbines has been pushed back by three to four years because of the recent signing of new diversity exchange contracts, the HVDC investments are still being scoped, and the AMP is not based on asset management methodologies that are at the competent level. Further, the Consumers Coalition submits that Manitoba Hydro has not taken steps to reduce its capital expenditures in response to the drought. This is contrary to the Board's prior findings that management action in the form of reducing expenditures is one component of the appropriate response to a drought, along with rate increases and reductions in retained earnings. Reducing capital expenditures and determining which expenditures to reduce is one of the hard choices that Manitoba Hydro must make.

The Consumers Coalition is critical of the AMP which, with only a few exceptions, uses age as a proxy for asset condition at the asset population level. In the Consumers Coalition's view, this will tend to yield an upward bias in capital expenditure estimates. Further, Manitoba Hydro has not yet determined the economic life for all of its asset populations, which is in turn necessary to optimize costs, performance, and risk. As a result, the AMP is not yet employing best-practice whole-life cost modeling and relies heavily on asset population age to make assumptions about condition. Manitoba Hydro therefore cannot demonstrate that its proposed spending optimizes cost, performance, and risk.

Further calling into question Manitoba Hydro's spending plans, the Consumers Coalition submits that Manitoba Hydro's asset performance continues to be strong in relation to its peers. According to the Coalition's expert witness, Midgard, Manitoba Hydro's characterization of declining system performance overstates the extent of degradation. When major events such as wildfires are removed from the performance metrics, Manitoba Hydro's system has acceptable performance.

Midgard opines that the capital plan shows a continued asset focus rather than a system focus to risk assessment and capital planning, which is contrary to Manitoba Hydro's Asset Management Policy and SAMP which set the principles, objectives, and strategy for the asset management program. In Midgard's view, Manitoba Hydro's corporate value framework focuses on the asset and not the overall system. For example, Manitoba Hydro assumes full generating capacity loss upon asset failure without accounting for other system assets that could compensate for the loss.

Midgard further submits that, by proposing business operations capital investments lower than the AMP recommendation, Manitoba Hydro does not appear to believe its AMP outputs. If it did, it would present an AMP that respected its resource constraints and would provide an objective analysis of the spending trade-offs resulting from those constraints. As a result, despite advances in its asset management strategy and practices, Manitoba Hydro's capital plan was compiled largely using historical planning and corporate cultural practices.

Midgard therefore recommends that certain capital expenditures be deferred or re-paced. These include the hydraulic generator refurbishments, medium voltage switchgear replacements, AMI, HVDC refurbishment, and the proposed combustion turbines.

The Consumers Coalition also questions Manitoba Hydro's conclusions regarding customer support for rate increases as being needed to maintain system reliability. Specifically, this intervenor points out that the price and reliability trade-off outlined in the 2025 Customer Values Survey was not adequately contextualized to survey respondents and that the methodologies used were inconsistent with best practices in social

permission surveying. Instead, the Consumers Coalition argues that the surveys referenced in this hearing show that Manitoba Hydro's residential customers consistently express higher satisfaction with the reliability of energy than with price, and rank affordability as their top priority.

Midgard similarly criticizes Manitoba Hydro's customer surveys which Manitoba Hydro purports indicate acceptance of rate increases in order to maintain reliability. In Midgard's view, the survey questions are framed in a manner that guides residential respondents towards specific answers without clearly communicating associated risk, trade-offs, or alternatives. The survey questions also do not test the three successive 3.5% rate increases proposed by Manitoba Hydro in this application, but rather test lesser rate increases that bound Manitoba Hydro's forecast rate of inflation of 2.1%.

#### **GSS/GSM Representative**

The GSS/GSM Representative argues that there are cost savings initiatives that Manitoba Hydro can implement in the rate period. This includes re-pacing or reworking of business operations capital as highlighted by Midgard.

#### **Manitoba Eco-Network and Environmental Defence**

MEED is opposed to the construction of new combustion turbine generating stations, as more fully explained in section 9.0. Instead, MEED supports the proposed investments in grid modernization, such as advanced metering, and the personnel spending required to plan for the energy transition to consider non-wires alternatives. MEED therefore recommends that Manitoba Hydro's capital planning processes be updated to consider several different scenarios for how decarbonization will be achieved, and the load forecast for each scenario.

## Manitoba Industrial Power Users Group

MIPUG argues that Manitoba Hydro retains considerable discretion as to the development of its business operations capital spending forecasts. While the utility attempted to budget with an eye to risk and external conditions, the end result is neither prudent nor credible and the Board should not accept the current business operations capital forecasts.

### 10.3 Presenter Evidence and Board Comments

While not in the Board's jurisdiction, the Board recognizes the concerns expressed by Chief Gordie Bear and representatives of the Mathias Colomb Cree Nation with respect to the Cree Nation's efforts to procure and install a back-up generator to serve the community in the event of future wildfires or other emergencies. The concerns of this First Nation are outlined in Appendix B. The Board also encourages Manitoba Hydro to further engage with Mathias Colomb Cree Nation and other stakeholders to explore and address the reliability concerns raised in this hearing.

### 10.4 Board Findings

#### 10.4.1 *Asset Management*

The Board recognizes Manitoba Hydro's continued maturation of its asset management methodologies. In the six years from 2016 to 2022, Manitoba Hydro was only able to improve its maturity score from 1.5 to 1.81, which the Board characterized as slow progress in Order 101/23. In the two years since then, the maturity score improved from 1.81 to 2.33, which is substantially more progress than in the previous six years. The Board finds Order 101/23 Directive 29, requiring an independent update on its progress towards maturing asset management, to be complete.

While the Board finds that Manitoba Hydro has made good progress from 2022 to 2024, more work remains to be done. The Board is concerned that Manitoba Hydro does not expect to reach a maturity level of "competent", being a maturity score of 3.0, until 2032. Considering Manitoba Hydro has been working to mature its asset management since at least 2016, achieving asset management competence in 16 years is, in the Board's view,

an excessively long time. The Board directs Manitoba Hydro to file, at the next general rate application, an independent assessment of its asset management process maturity and an update on the progress made since its last external assessment completed in 2024.

With respect to specific actions Manitoba Hydro should be taking in maturing its asset management methodologies, the Board encourages Manitoba Hydro to take a systems-approach to its asset management as recommended by Midgard. Manitoba Hydro should also continue to prioritize and develop the whole-life cost models which help determine the optimal point to intervene in the lifespan of an asset through either refurbishment or replacement. In the Board's view, these improvements have the potential to further optimize the prioritization of Manitoba Hydro's capital expenditure plans over the short and long-term, resulting in a better balance of short-term expenditures and related impacts on rates.

#### **10.4.2 *Strategic Asset Management Plan (SAMP) and Asset Management Plan (AMP)***

The Board supports the objectives of the SAMP to stabilize reliability by 2032 and mature the asset management system's capabilities. The Board notes that the SAMP and AMP objectives are among several corporate objectives that must be balanced when determining the appropriate levels of business operations capital and major capital spending. The Board accordingly finds that Directive 30 of Order 101/23, requiring Manitoba Hydro to file its updated SAMP and AMP, is complete.

#### **10.4.3 *Capital Expenditure Forecast***

In reviewing Manitoba Hydro's capital expenditure forecast, the Board continues to find that Manitoba Hydro has discretion in its capital spending and that this is one tool that can be used to manage the financial impacts of a drought, along with rate increases and the use of retained earnings. The Board expects Manitoba Hydro to reflect its cost control in the forecasts presented to Treasury Board.

When Manitoba Hydro filed this Application, it proposed business operations capital expenditures of \$777 million in 2025/26, \$791 million in 2026/27, and \$711 million in 2027/28. In 2024/25, Manitoba Hydro had experienced slightly below average water conditions, with two of the three previous years having experienced drought conditions. Manitoba Hydro did not know what the water conditions were going to be in 2025/26. As this Application proceeded, Manitoba Hydro experienced an intensifying drought as explained in section 4.0. Despite the intensifying drought and the negative financial consequences, including a projected \$409 million loss for 2025/26, Manitoba Hydro did not make any adjustments to its capital spending plans. While the Board does not expect substantial changes to have been made to the current 2025/26 year as many of those projects have already started, the Board expected Manitoba Hydro to have taken action to improve its finances by reducing its capital spending forecast in 2026/27 and 2027/28. Manitoba Hydro did not do so. As explained in Order 9/22:

*If the drought continues and Manitoba Hydro's cash flow concerns continue next year, the Board finds that Manitoba Hydro shall seek savings in its Business Operations Capital, just as it committed to do at the NFAT proceeding when it explained how it would confront financial liquidity concerns related to drought.*

The Board further explained in Order 101/23:

*If another drought should arise during the test years, the Board expects Manitoba Hydro to take steps to control business operations capital expenditures. During the 2014 Needs-For-and-Alternatives-To (NFAT) review of Manitoba Hydro's preferred development plan, and as explained in Order 9/22, Manitoba Hydro committed to using cash conservation as one of several measures to manage a drought. With respect to business operations capital spending, the Board finds that Manitoba Hydro has significant discretion as to how such spending should be paced and prioritized. As such, it should be one of the key areas in which to exercise cost control during a drought.*

While Manitoba Hydro has made progress maturing its asset management, the Board is concerned about the variability of the costs presented by Manitoba Hydro from one proceeding to the next. At the 2023/24 & 2024/25 General Rate Application, Manitoba Hydro's capital expenditure forecast totalled \$18.2 billion over 20 years. Now, only two years later, the total capital expenditures have nearly doubled to \$31.2 billion. Despite Manitoba Hydro's assurances at both general rate applications that the capital expenditure forecast was the optimal amount that balances performance, risk, and affordability, with such a large change in forecast, the Board is uncertain the \$31.2 billion is the optimal amount. The Board is also concerned that the forecast will change significantly again at the next general rate application for the next three year rate period. The magnitude of the change in the capital program calls into question the corporate maturity level of Manitoba Hydro as an organization, not just of its asset management methodologies. It also speaks to the importance of Manitoba Hydro improving its long-term capital expenditure forecasting process.

The Board considered the evidence of Midgard and its recommendations that certain capital expenditures be deferred or re-paced, such as hydraulic generator refurbishments, medium voltage switchgear replacements, Advanced Metering Infrastructure, HVDC refurbishment, and the proposed combustion turbines. The Board's findings on HVDC refurbishment and combustion turbines are explained below. With respect to the other deferrals recommended by Midgard, the Board is not convinced on the evidence that Manitoba Hydro's proposed expenditures and timing are unreasonable or inappropriate. The Board is also concerned about relying upon imports from the United States. The Board accepts the proposed business operations capital expenditures in the rate period as proposed, recognizing Manitoba Hydro is to reflect its cost control in the capital expenditure forecasts for 2026/27 and 2027/28 presented to Treasury Board.

At the previous general rate application, the Board found that Manitoba Hydro's test year capital forecasts had been overstated for a number of years. The Board considered this in finding that rate increases of less than the 2.0% requested by Manitoba Hydro were appropriate in each of the test years. In Order 101/23, Directive 31 required Manitoba Hydro to report on the capital expenditures forecast at previous general rate applications as compared to the actual spending. In contrast to recent historical practice, for the past two years Manitoba Hydro has overspent the capital expenditure budgets used to justify its revenue requirement and rates requested at the last general rate application. As shown in Figure 10.4, the rolling five-year average of over- and underspending shows that the trend has reversed compared with the trend seen at the 2023/24 & 2024/25 General Rate Application. Consequently, the Board does not expect that the capital spending forecast in the current application has a high bias that would inherently lead to underspending. However, as discussed above, the Board expects Manitoba Hydro to improve its capital expenditure budgeting processes and to find efficiencies where required to minimize the eventual impacts of these expenditures on rates. Directive 31 from Order 101/23, requiring Manitoba Hydro to update the table below, remains in place for future general rate applications.

(\$ millions)	2017	2018	2019	2020	2021	2022	2023	2024
Forecast Used at GRA	\$610 <sup>1</sup>	\$575 <sup>2</sup>	\$563 <sup>2</sup>	\$511 <sup>3</sup>	\$521 <sup>4</sup>	\$523 <sup>5</sup>	\$495 <sup>6</sup>	\$538 <sup>6</sup>
Actual	\$530	\$498	\$466	\$545	\$482	\$504	\$531	\$613
Variance	-\$80	-\$77	-\$97	+\$35	-\$39	-\$19	+\$36	+\$76
5-Year Rolling Average:			-\$69	-\$53	-\$52	-\$39	-\$17	+\$17

Sources: 1 – CEF 15, 2 – CEF16; 3 – CEF18; 4 – CEF18; 5 – 2021/22 Budget; 6 – CEP23

Figure 10.4 — Manitoba Hydro's Business Operations Capital Actual Expenditures Compared to Forecasts

#### **10.4.4 HVDC Reliability Project**

The Board is concerned that Manitoba Hydro's current cost estimate for the HVDC Reliability Project may materially increase again by the time the project is complete. The 2023/24 & 2024/25 General Rate Application capital expenditure forecast included a placeholder of \$1 billion to \$1.8 billion to renew Bipoles 1 and 2, although these amounts were excluded from the \$18.2 billion total. In the current application, that number has ballooned to \$6.8 billion, which Manitoba Hydro describes as a Class 10 estimate.

The Board finds that the \$6.8 billion cost estimate for the HVDC Reliability Project is unlikely to be the final cost for a number of reasons. First, the Board is concerned that it is only a Class 10 estimate, meaning that the estimate is not associated with any expected accuracy range due to the long-term nature of the planning horizon and the high potential for uncontrolled scope changes. Practically, the range for a Class 10 estimate could exceed the high-side range of +100% of the estimate. Second, Manitoba Hydro intends to use a "cost reimbursable contract with a target price", with risks to the owner as described below. Third, Manitoba Hydro stated that it does not see a scenario where it would terminate the project, as there are no feasible or less expensive alternatives to renewing the Bipole 1 and 2 facilities.

The Board heard that Manitoba Hydro intends to use a cost reimbursable contract with a target price for the replacement of Bipoles 1 and 2. As explained in Order 59/18:

*The "target price" aspect means that the contractor's profit erodes if the target price is exceeded and the contractor's profit increases if the actual cost is less than the target price. The target price and this so-called 'pain/gain' pricing mechanism are intended to incent the contractor to perform well.*

*In a cost reimbursable contract, the owner (Manitoba Hydro) is at risk for quantities, productivity, and inefficiency of the contractor. As an example, under a cost reimbursable payment structure, the contractor would be paid in full for 10 hours of work even if the contractor's successful bid was based on the contractor taking only six hours to perform the specific work task. Other types of payment structures are 'fixed price' or 'unit price' structures.*

A target price contract is the same type of contract that Manitoba Hydro used for the general civil contract for the Keeyask Generating Station. As the Board found in Order 59/18, the nature of the target price contract directly led to cost overruns on the general civil contract as the contractor's productivity was insufficient to allow it to achieve the target price, rapidly depleting the profit available to the contractor:

*Manitoba Hydro expected that tying the contractor's profit to the target price in the general civil contract would provide sufficient motivation to the contractor to meet the productivity levels in its bid, but that did not occur. It further appears that Manitoba Hydro never contemplated that the contractor's profit could erode to zero so early in the project. Once the profit eroded to zero, with no chance of re-establishing profit, the contractor had little or zero motivation to progress the project expediently. In the Board's view, this was a principal failing of the original GCC.*

The independent expert consultant retained by the Board in 2017 to review the Keeyask project, MGF Project Services, explained that in construction, "time is money". For a cost reimbursable contract, time is the owner's money, while for fixed or unit price contract, time is the contractor's money. The Board is thus concerned that the same type of contract – cost reimbursable with a target price – is being contemplated for Bipoles 1 and 2, which means the labour time or productivity is Manitoba Hydro's money, not the contractor's. The Board repeats its recommendations from Order 59/18:

*For future projects, if the cost reimbursable payment structure of a contract is used, effective oversight of the contractor must be exercised. The results for Keeyask indicate there was not effective oversight under the cost reimbursable contract arrangement.*

[...]

*7. Use the services of an external construction management expert, particularly for high value projects and those with cost reimbursable payment structures, beginning with the initial study and planning through to project execution;*

The Board finds that the criticality of this project to Manitoba Hydro and its customers cannot be understated, both in terms of its role in maintaining a reliable electric supply as well as the cost. The Bipole 3 Reliability Project had a final cost of \$4.6 billion. This project is nearly 50% more expensive. Like Bipole 3 but unlike Keeyask, the HVDC Reliability Project is not a directly revenue-generating project. Further, a 3% cost increase over the \$6.8 billion estimate is of the same dollar magnitude as a 100% increase to the SAP S/4HANA Core replacement budget described in section 11.1.3 below. While these expenditures will not affect the revenue requirement in the rate period, they will affect the level of new debt incurred by the corporation in the near and medium term, and also affect rates in the long term when the assets are placed in commercial service. Accordingly, the Board directs Manitoba Hydro to file status reports on a quarterly basis on the HVDC Reliability Project.

The quarterly reports on the HVDC Reliability Project are to be filed within 45 days after the end of each fiscal quarter, commencing with the January to March 2026 quarter until project completion. To reduce the effort in generating these quarterly reports, Manitoba Hydro can provide the same report it provides to its board of directors, which the Board expects is provided to the Manitoba Hydro-Electric Board no less frequently than quarterly. The Board expects that the report to the Manitoba Hydro-Electric Board contains detailed information on the approved budget or most current estimate, expenditures to date, whether expenditures to date are tracking the budgeted expenditures, the current forecast at completion costs and schedule, and remaining risks affecting the project. Manitoba Hydro may file public and confidential versions of these reports with commercially sensitive information redacted. If the content of the initial report is insufficient for the Board's purposes, the Board will provide additional direction to Manitoba Hydro in due course.

#### **10.4.5 Combustion Turbines**

The Board finds that for the purposes of approving rates for the rate period, it does not need to make a finding on the combustion turbine expenditures included in the Proxy Development Plan. The Board expects to review the cost estimate for the combustion

turbines in an upcoming public Major New Facilities Review in accordance with subsection 16(3) of *The Manitoba Hydro Act*. Section 9.0 addresses the need for the project. The expenditures in the rate period do not affect the rate period revenue requirement as the project is not expected to enter commercial service before March 31, 2028.

As with the HVDC Reliability Project, the Board directs Manitoba Hydro to file status reports on the combustion turbine project on a quarterly basis, commencing with the October to December 2026 quarter until project completion. The reports are to be filed within 45 days after the end of each fiscal quarter and reflect similar content as the HVDC Reliability Project reports. These reports can be the same reports as provided to Manitoba Hydro's board of directors. Manitoba Hydro may file public and confidential versions of these reports with commercially sensitive information redacted.

#### **10.4.6 Treasury Board Approval**

The Board finds that it is permitted to reduce the rate increases for the second and third years of the rate period where Treasury Board has not yet approved the capital expenditure program. The Board notes that Manitoba Hydro's 2025/26 capital expenditures have already been approved by Treasury Board. *The Manitoba Hydro Act* indicates that the Board is not permitted to reduce the rate increase that is required to support the capital expenditures approved by Treasury Board. However, based on the evidence received during the hearing, Treasury Board has not approved Manitoba Hydro's 2026/27 and 2027/28 capital expenditures. The Board finds there to be a disconnect between the Board's process of thoroughly reviewing Manitoba Hydro's three-year rate application, which involves evidence from multiple parties and cross-examination, and Treasury Board's process of approving Manitoba Hydro's capital expenditures one year at a time. This disconnect has made it difficult for the Board to carry out its role, as it does not know what Treasury Board will later approve for the second and third years of the rate period.

While the Board finds that it is permitted to reduce the rate increases for the second and third years of the rate period, this creates a situation where the Board could reduce the rate increase in one or both years based on the Board's assessment of the appropriate level of capital expenditures, but Treasury Board could subsequently approve a higher level of expenditures based on its own assessment. Manitoba Hydro would then not have the rate revenue that it requires to support those capital expenditures, which may constitute a material difference that justifies a reconsideration of the Board's approved rates under subsection 39.4(1) of *The Manitoba Hydro Act*. For this Application, this situation is not expected to arise as the Board accepts the capital expenditure forecasts proposed by Manitoba Hydro for the second and third years of the rate period, with the expectation that Manitoba Hydro will reflect its exercise of cost control in the capital expenditure budgets for 2026/27 and 2027/28 when presented to Treasury Board.

#### **10.4.7 Customer Surveys and Ratepayer Willingness to Pay**

The Board finds that while customer surveys are vital to ensuring that Manitoba Hydro's services are optimized and respond to customer needs, adequate context must be provided when conducting surveys in order to obtain meaningful results. The Board acknowledges the complexities involved in developing and conducting detailed customer surveys that are intended to inform technical issues, and that these surveys are not always commonly understood by Manitoba Hydro's customer base. However, best practices must always be used in order to avoid presenting an either-or situation (or forced choice) without first providing useful context that directly affects the responses that are obtained.

Given this, the Board finds that the theoretical \$6, \$9, or \$12 monthly bill increases in the 2025 Customer Values Survey does not provide sufficient support for Manitoba Hydro's proposed 3.5% rate increases in each of the 2025/26, 2026/27, and 2027/28 years of the rate period, nor for additional rate increases in future rate periods as continued reliability-related investments are made. The survey did not disclose to the survey participants the average percentage increase from the proposed \$6/\$9/\$12 monthly increase. Manitoba Hydro's customer surveys should not exclude the percentage impact on customers' bills

when attempting to ascertain customers' preferences for the trade-offs between reliability and price. Further, more context should be provided in terms of the level of investments needed to sustain reliability and the level of bill increases these may cause over the longer term. The Board expects Manitoba Hydro to continue consulting with ratepayers with respect to its proposed rate changes and to improve its existing customer survey methodologies in order to obtain meaningful results that adequately inform Manitoba Hydro's plans going forward. The Board was also surprised that Manitoba Hydro does not review customer surveys used by other utilities in Canada to consider improvements to the form, content, or results of its surveys.

#### **10.4.8 Reliability**

The Board does not require Manitoba Hydro to prepare a report on the value of unserved energy to these customers, as was recommended by Mr. Friesen. As summarized in Appendix B, several presenters to the Board representing large industrial customers explained how momentary interruptions of their electric service cause harm to their operations. The Board also heard from MIPUG's witness Mr. Friesen who explained that these momentary interruptions are not captured in Manitoba Hydro's system average interruption duration index ("SAIDI") or system average interruption frequency index ("SAIFI"), which are two industry standard metrics for measuring reliability. The Board encourages Manitoba Hydro to work with the customers experiencing these interruptions and develop solutions which, in some cases, will require capital investments.

#### **10.4.9 Inconsistency of Manitoba Hydro's Evidence**

In the case of the near doubling of the capital expenditure forecast from the last general rate application, the Board is concerned about the accuracy of the current long-term capital expenditure forecast. The Board recognizes that inflation contributes to the increase and that the HVDC Reliability Project was not included in the previous capital expenditure forecast. However, Manitoba Hydro appears to have come to a new understanding of the state of its assets such that an additional \$3.9 billion is needed for business operations capital over the next 20 years.

During this hearing, Manitoba Hydro demonstrated the need for the HVDC Reliability Project by showing a deficit in meeting the winter peak demand in the event of either Bipole 1 or 2 failing. However, the Board finds that this is contradictory to what Manitoba Hydro presented at the 2017/18 & 2018/19 General Rate Application. At that time, Manitoba Hydro was attempting to demonstrate the importance of Bipole 3, which was under construction and subject to a review by the Board pursuant to Order in Council 92/2017. Manitoba Hydro's evidence was clear and unambiguous that with the loss of Bipoles 1 and 2, Manitoba Hydro would have a deficit in meeting the winter peak demand, but with Bipole 3 in service, there would be no deficit through 2041. Similar evidence was presented by Manitoba Hydro's witnesses at the 2015/16 General Rate Application. Manitoba Hydro's explanation in this current Application has now completely changed. It is problematic when the protection expected of a multibillion-dollar capital project fails to materialize and, as a result, requires another multibillion-dollar capital project on an urgent basis.

As with the change in the capital expenditure forecast from the previous general rate application of \$18.2 billion to the current forecast of \$31.2 billion, the evidence provided by Manitoba Hydro from one application to the next has changed drastically and calls into question its accuracy. The Board relies upon evidence adduced in its proceedings to make informed decisions in the public interest. The evidence must be accurate and complete. While the Board recognizes that forecasts and estimates are continually updated and that new information may render old forecasts inaccurate, that does not appear to be the case here. In the case of the supply-demand deficit without Bipoles 1 and 2, at the 2017/18 & 2018/19 General Rate Application Manitoba Hydro sought to justify the need for Bipole 3, while in the current application, Manitoba Hydro seeks to justify the capital spending on the HVDC Reliability Project. It would lessen the urgency to address Bipoles 1 and 2 if Manitoba Hydro could continue to meet the winter peak demand with only Bipole 3 and its other resources.

## **11.0 OPERATING AND ADMINISTRATIVE EXPENSES**

### **11.1 Background**

#### ***11.1.1 Overall increase in O&A Expenses***

Operating and administrative (“O&A”) expenses are Manitoba Hydro’s second-largest expense category, after finance expense. These expenses are comprised primarily of wages and benefits, materials, contracted services, and overhead costs associated with operating and maintaining Manitoba Hydro’s facilities and assets, as well as to provide services to customers. Over the three-year rate period, the utility projects to incur O&A expenses totalling \$2.62 billion. Given the overall magnitude of O&A expenses within Manitoba Hydro’s revenue requirement, the Board has previously confirmed the need for Manitoba Hydro to prudently manage O&A expenses. This included the Board’s findings at the last general rate application in Order 101/23.

Manitoba Hydro describes that it budgets for O&A using both a “bottom-up” and “top-down” approach. Bottom-up budgeting gathers and consolidates each department’s needs, whereas top-down budgeting sets high-level financial targets for the entire corporation that are then passed down to the departments. Manitoba Hydro’s O&A expenses are also reviewed and approved by Treasury Board on a one-year forward basis.

As illustrated in Figure 11.1, O&A costs have increased by \$221 million (38%) from 2021/22 through 2025/26. When considering the rate period, Manitoba Hydro expects O&A to increase from 2024/25 to 2027/28 by \$107 million (14%). This is an average increase of \$36 million (5%) per year over the rate period, excluding the SAP S/4HANA costs discussed further below.

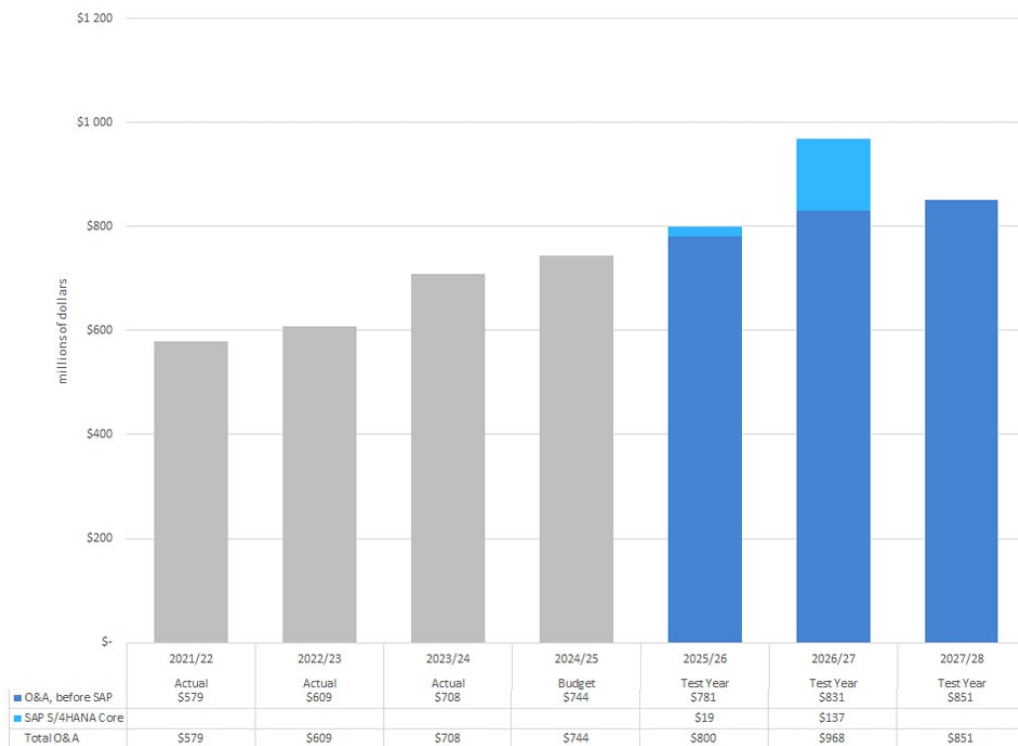


Figure 11.1 — Projected Increase in O&A Expenditures

In addition to inflationary factors and the need to increase work in certain areas of the company, a major contributor to the O&A increase during the rate period includes costs related to the planned replacement of the on-premise SAP enterprise management software used by Manitoba Hydro with a new cloud-based solution called SAP S/4HANA Core. However, the actual expenses included on the operating statement in the rate period are attenuated by Manitoba Hydro’s request for approval of a regulatory deferral account for the SAP S/4HANA expenses discussed in section 14.2.

Manitoba Hydro’s O&A expenditures were controversial in this hearing because of a significant increase in the expenditure projections, both during the three-year rate period and for the 20-year expenditure forecast as a whole, compared to those from the last general rate application. Figure 11.2 illustrates the increase over the three-year rate period compared to the projection at the last general rate application and provides a breakdown of the increase into individual cost components. As illustrated in the figure, the total O&A expenditure estimate has increased by 25% since the last general rate

application, amounting to an increase of \$528 million. Most of that increase relates to wages, salaries and benefits, which together account for 12% of the 25% increase. The next-highest impact relates to Manitoba Hydro’s initiative to implement SAP S/4HANA Core. The third-highest impact relates to increased construction and maintenance costs, which include costs related to vegetation management near Manitoba Hydro’s assets.

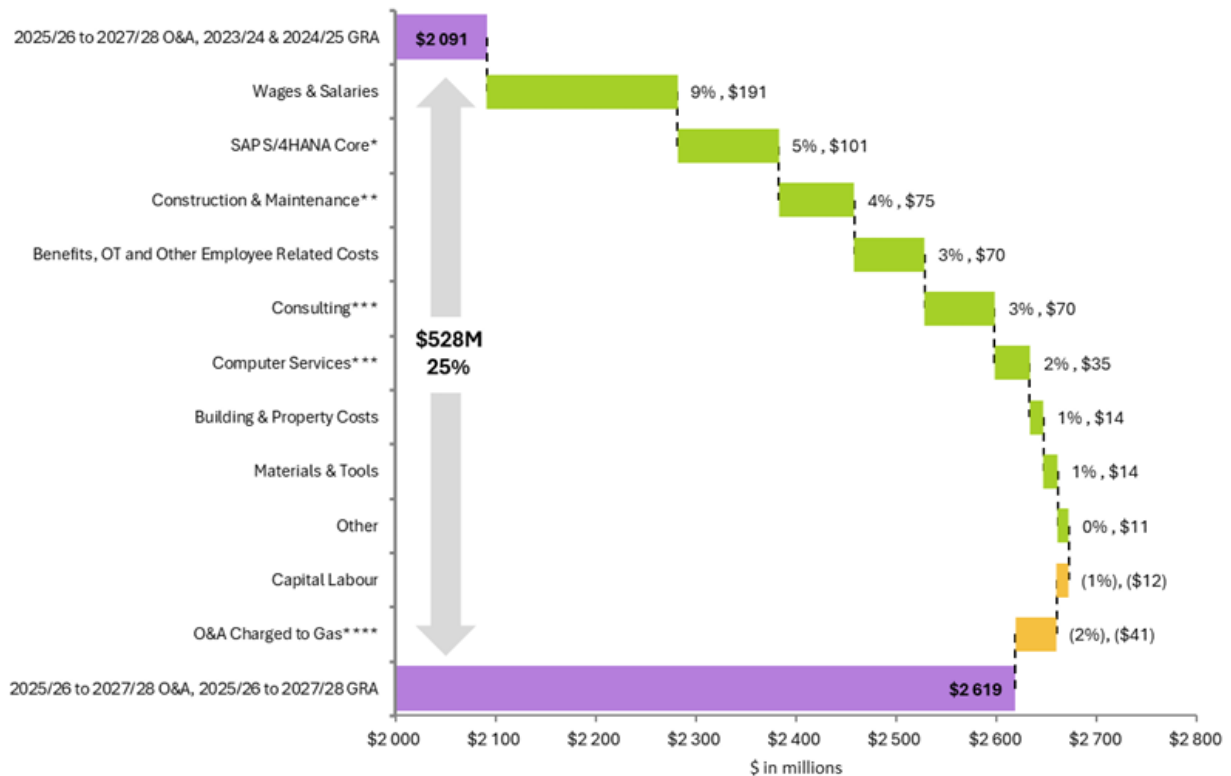


Figure 11.2 — 3-Year Comparison with Last Rate General Application

The increase in forecast O&A expenses since the last general rate application presented in Figure 11.2 is exacerbated over the 20-year period for which Manitoba Hydro prepares a financial forecast. As pointed out by the Consumers Coalition’s witness Mr. Rainkie, over the period from 2025 to 2042 (the last year included in the forecast of the previous general rate application), total O&A expenditures are \$4.2 billion higher than previously projected, which amounts to an increase of 30% from the 20-year forecast from the 2023/24 & 2024/25 General Rate Application.

The major cost drivers for the increase in Manitoba Hydro’s O&A expenses are discussed below.

### 11.1.2 Wages, Salaries, & Benefits

Wages, salaries, and benefits are primarily related to the number of employees and their current wage and salary levels. During the 2016/17 fiscal year, Manitoba Hydro instituted a voluntary departure program to reduce its labour force, eventually decreasing the number of full-time equivalent (“FTE”) employees from 6,411 in 2016/17 to 4,954 in 2020/21. Since that time, the number of employees has been increasing, reaching a projection of 5,706 in 2025/26, the first year of the current rate period. In this hearing, Manitoba Hydro advises that the most recent increase relates in large part to the recruitment of trades trainees. As shown in Figure 11.3, during the time of the voluntary departure program, the utility decreased the number of trainees hired, eventually culminating in zero trades trainees being hired in 2020.



Figure 11.3 — Annual Trades Trainee Recruitment

Since that time, Manitoba Hydro has focused on rebuilding its core workforce to sustainable levels, including trades, technical trainees, and professional trainees, as well as adding necessary positions to address increased capital demands, a changing digital environment, and building necessary skillsets. Reduced recruitment, attrition, and hiring freezes in these areas since 2016/17 have contributed to insufficient levels of staffing, causing delays in meeting customer in-service dates and falling behind on preventative maintenance work. Given this, Manitoba Hydro has worked on rebuilding its trades trainee program. As part of those efforts, Manitoba Hydro has agreed, in a collective agreement

with the International Brotherhood of Electrical Workers (“IBEW”), to hire an additional 548 people between 2024/25 and 2026/27. Manitoba Hydro plans to fulfill this commitment largely by hiring trades trainees. The utility points out that any FTE increases in 2025/26 and 2026/27 relate solely to the hiring of trades trainees. However, this is in relation to the budgeted FTEs in 2024/25, not the actual FTEs in that year. The planned increase in hires is 213 in 2025/26, as shown in Figure 11.4. This figure also shows that Manitoba Hydro’s current FTE level is lower than in 2016/17, when it first introduced its voluntary departure program.

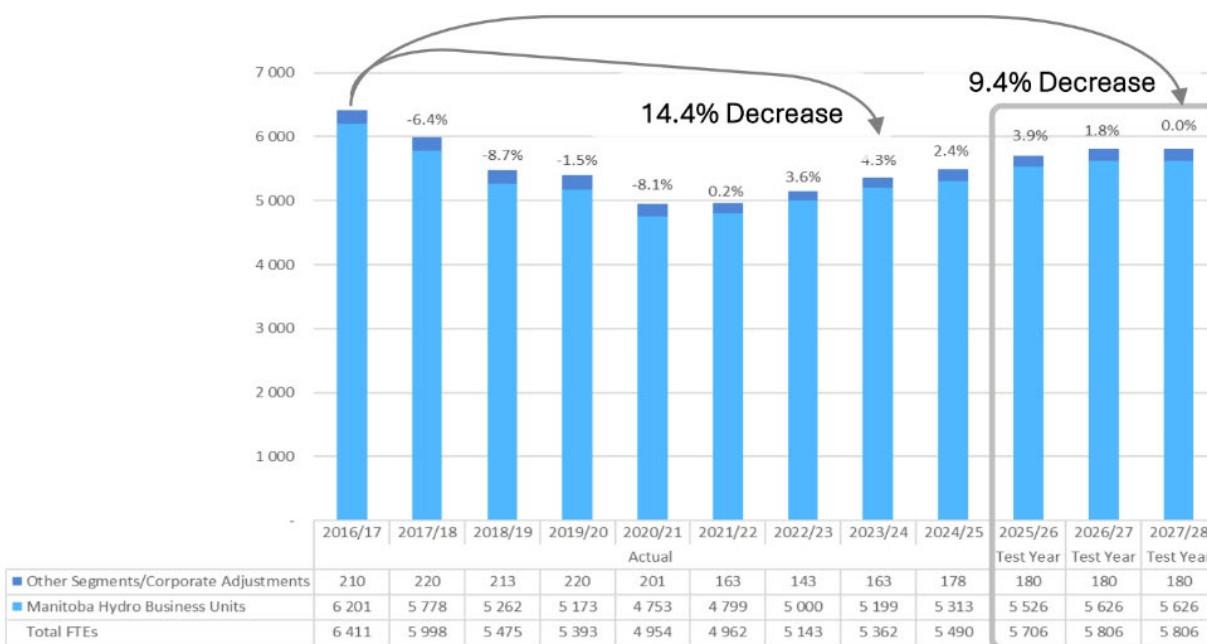


Figure 11.4 — Annual Full Time Equivalent Levels

Manitoba Hydro also explains that because its workforce is 80% unionized, the utility has limited control over salary levels. Several unions have recently negotiated wage increases of 3.0% for the 2025/26 and 2026/27 fiscal years. In addition, travel-related costs have been rapidly increasing, including a 100% increase for hotel costs and an 18% increase for flights costs that enable Manitoba Hydro staff to travel to northern locations within Manitoba.

### **11.1.3 SAP S/4HANA Costs**

Manitoba Hydro states that it implemented its current SAP enterprise resource planning software in the mid-1990s. At the 2023/24 & 2024/25 General Rate Application, Manitoba Hydro explained that its current software, called SAP ECC, will no longer be supported by SAP beyond 2027. At the time, Manitoba Hydro was still assessing its SAP options, was developing a business case for the SAP upgrade and had retained EY, a large consulting firm, to complete the business case. The electric operations of Manitoba Hydro were projecting to spend \$156 million between 2023/24 to 2029/30 on the SAP S/4HANA project. In Order 101/23, the Board stated that it would not approve a regulatory deferral account for SAP replacement costs until Manitoba Hydro had filed a business case for the project.

In the current hearing, Manitoba Hydro confirms that support for the current SAP ECC system is coming to an end in 2027 and that this obsolescence presents both a risk to Manitoba Hydro's day-to-day operations and an unacceptable cybersecurity risk. The risk of obsolescence is compounded by Manitoba Hydro having heavily customized SAP ECC when it was implemented in the 1990s, making it exponentially more difficult to maintain and update once SAP support ends. Manitoba Hydro also acknowledges that it paused the development of a formal business case after the replacement of its Chief Executive Officer ("CEO") in 2024. Following the arrival of the utility's current CEO, and as discussed in section 6.0, upgrading to SAP S/4HANA Core by December 2026 was established as an enterprise goal.

Accordingly, the corporation re-commenced efforts toward the SAP replacement project and engaged directly with SAP to further refine the project scope and cost estimate.

Manitoba Hydro has elected to replace the existing on-premises SAP software with the RISE Private Enterprise Edition of SAP S/4HANA, a cloud-based solution. The utility has divided the project into three distinct project segments: (1) the "out of the box" implementation of the SAP S/4HANA Core, (2), the replacement of Manitoba Hydro's current Banner billing system, and (3) future enhancements. Manitoba Hydro's current focus is only on the upgrade to the Core system (Phase 1) and does not include future

upgrades or enhancements, such as the implementation of replacement Customer Information Systems (Phase 2), or additional enhancements that may be required to the initial Core version (Phase 3).

The current enterprise goal of implementing and deploying SAP S/4HANA Core by December 2026 results in Manitoba Hydro having SAP S/4HANA Core in place before support for the existing software ends. Following the “out of the box” principle, the utility plans to change its internal processes to accommodate the new software and, in the process, develop properly ring-fenced (secure) data. This is expected to reduce risks and control costs. To accommodate this, the utility established a steering committee that includes the vice-presidents of each of the functional business units, with any customization requiring the sign-off of Manitoba Hydro’s CEO and Vice President of Digital & Technology. The utility anticipates dedicating 50 internal employees to the Phase 1 SAP S/4HANA Core project.

To implement the SAP replacement project, Manitoba Hydro retained EY as an external software integrator on a fixed price contract, the price of which is subsumed in Manitoba Hydro’s cost estimate for the project.

Manitoba Hydro does not yet have a cost estimate for all three phases of the project. In its original filing, the utility presented a Phase 1 cost estimate of \$172 million over two years for SAP S/4HANA Core, with most of the expenses arising during the 2026/27 fiscal year. Over the course of the hearing, the utility updated those Phase 1 project costs to a total of \$193 million, with \$176 million attributed to the electric operations and \$17 million attributed to the gas operations of Centra Gas Manitoba Inc. (“Centra”). However, the utility advises that some of these costs were already subsumed in its O&A budget, so that the incremental impact is \$155 million, with \$141 million to electric operations and \$14 million to gas operations. During the hearing, Manitoba Hydro advised that it had drafted an Investment Justification based on the updated budget information shown above, and expected to obtain the necessary project approvals from the Manitoba Hydro-Electric Board during the fall of 2025. However, the utility indicated that the Manitoba Hydro-Electric Board had already approved the EY contract and was being kept fully informed

on the budget as the non-capital project is being executed. As of October 2025, approximately \$29 million has been spent on the SAP S/4HANA Core project, of which \$26 million relates to electric operations.

#### **11.1.4 Construction and Maintenance (including Vegetation Management)**

Manitoba Hydro's construction and maintenance expenses relate to the planned and unplanned maintenance activities needed for the continued operation of Manitoba Hydro's generation, transmission, and distribution assets, as well as for its corporate facilities. Included in these O&A cost categories are third-party maintenance services as well as vegetation management expenditures, which are needed to ensure system reliability, as well as public and employee safety. Vegetation management programs include tree trimming, mechanical brush control, herbicide tree control, surveys, and right of way widening.

In this hearing, Manitoba Hydro submits that it has not been able to keep up with preventative maintenance requirements due to an increasing number of unplanned issues that take priority. These unplanned issues are due, in part, to Manitoba Hydro being behind on its maintenance plans, due to self-imposed cost reductions, the effects of the COVID-19 pandemic, and a decrease in available labour resources. Failure to catch up on planned maintenance has a compounding effect on the amount of maintenance work required and overall asset health. For example, approximately 25% of Manitoba Hydro's historical outages are caused by trees falling on its assets or by vegetation growing into contact with energized wires. Tree contacts in 2024 also caused more outages than in any of the previous 14 years.

To address this issue, Manitoba Hydro's construction and maintenance costs are increasing throughout the forecast period, as illustrated in Figure 11.5. Most of the increase relates to a plan to increase spending on vegetation management, which is being doubled during the rate period. The utility currently contracts out all vegetation management of the distribution system and approximately half of the vegetation management on the transmission system. Manitoba Hydro estimates that its current province-wide tree trimming cycle time is 17 years, while the industry standard is six

years. Historically, Manitoba Hydro has also spent significantly less than its Canadian and U.S. peers on vegetation management, at \$270/km compared to a peer mean of \$2,692/km.

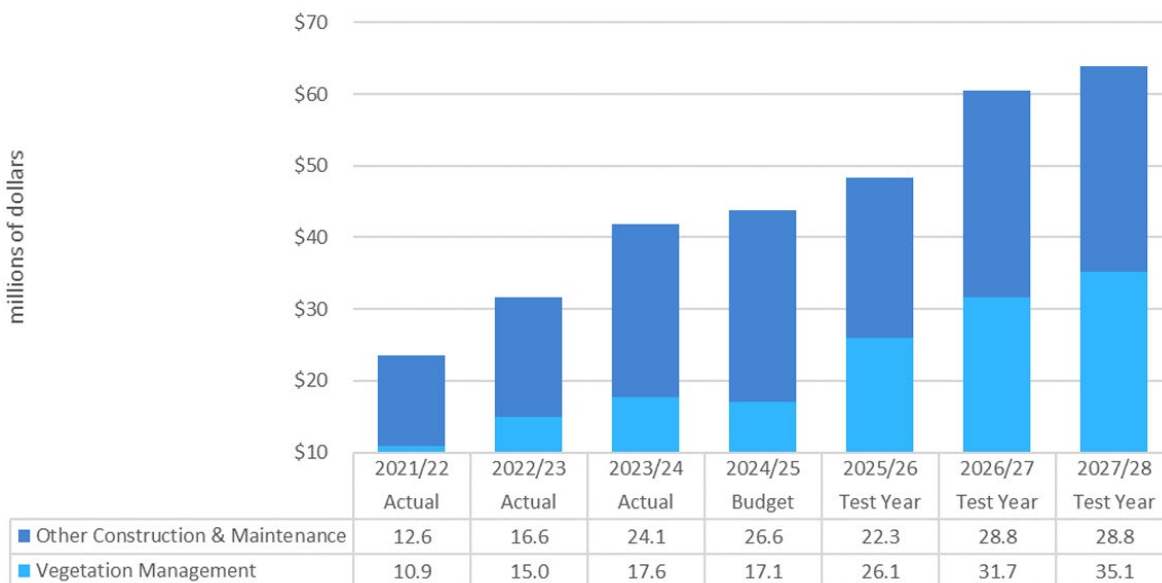


Figure 11.5 — Projected Construction and Maintenance Costs

## 11.2 Position of the Parties

### 11.2.1 Manitoba Hydro

Manitoba Hydro submits that its projected O&A increases are reasonable and that any attempts to limit those increases to inflation are unrealistic. The utility emphasizes that almost 70% of its O&A expenses are affected by wage and salary increases and that, aside from the SAP project, the increases in O&A expenditures since 2021 relate to a combination of high consumer price index (“CPI”) increases post-COVID, as well as a series of arbitration awards and negotiated collective agreements for Manitoba Hydro’s unionized labour force.

According to Manitoba Hydro, for 2025/26, 77% of O&A expenses are employee-related. The utility states that its FTE growth is limited to 100 in 2025/26 and an additional 100 in 2026/27, with no FTE growth in the last year of the rate period. Most of these will be trades trainees hired under the IBEW hiring commitment set out in the collective

agreement. Manitoba Hydro submits that, even with those hires, its labour force will still be 9.4% less than at the start of the voluntary departure program a decade earlier.

Manitoba Hydro resists the suggestion by interveners to restrict travel costs and notes that its employees are working across the province, away from their homes. The utility submits that out-of-province travel must already be approved at the vice president level, and that intra-provincial travel is required for Manitoba Hydro's labour force to construct, maintain, and operate Manitoba Hydro's assets.

Manitoba Hydro similarly resists the suggestion of the Consumers Coalition's witness Mr. Rainkie that it is stuck in the details of a bottom-up approach to budgeting. The utility notes that there have now been many years of cost cutting measures, and that the utility cannot continue to cut costs and push off work that is affecting safety, reliability, and service to customers.

Manitoba Hydro argues that it has taken measures and made decisions within the context of lower water conditions to manage costs for a number of years, including during the current fiscal year. For example, the utility has maintained the FTE reduction from the voluntary departure program and has limited FTE growth through 2026/27 to its contractual agreements even as the Corporation's asset base has increased and there is a backlog of maintenance and complex projects to execute. Further, Manitoba Hydro has maintained growth of non-staff O&A costs within a 2% target and continues to reduce consulting contracts, choosing not to extend some existing agreements. Manitoba Hydro also monitors all cost categories monthly to identify saving opportunities.

Manitoba Hydro further argues that arbitrary limitations to year-over-year increases in O&A expenditures, as proposed by some interveners, are unrealistic. In particular, Manitoba Hydro submits that Mr. Rainkie's suggestion to tie O&A growth to the consumer price index ("CPI") lacks nuance. Manitoba Hydro notes that the CPI is a basket of household items, does not include labour costs, and bears little relation to Manitoba Hydro's costs.

The utility acknowledges that a significant driver of O&A costs in the rate period is the upgrade to SAP S/4HANA, which is required to maintain core processes and address cybersecurity risks. The existing SAP system underpins over 65% of Manitoba Hydro's business processes and must be replaced to avoid financial, cybersecurity, and operational risks, as well as enable automation and data-driven decisions.

Similarly, Manitoba Hydro argues that increased vegetation management expenditures are required to address a backlog of vegetation work to ensure safety and reliability, and that it will take years until the utility achieves a managed state of vegetation.

### **11.2.2 Interveners**

#### **Assembly of Manitoba Chiefs**

The AMC does not propose any specific reductions to Manitoba Hydro's O&A budget, but emphasizes that Manitoba Hydro's long-term forecasts contemplate sustained above-inflation rate increases, placing growing pressure on customers who already devote a significant portion of their income to electricity costs.

#### **Consumers Coalition**

The Consumers Coalition submits that Manitoba Hydro is avoiding hard choices in the context of ongoing drought conditions. It emphasizes that, even in the face of an ongoing drought, Manitoba Hydro has added an additional \$4.2 billion of O&A spending to a financial outlook already strained by placeholder major capital spending. These O&A cost escalations are not a sign of sound fiscal stewardship, are unsustainable, and are not balanced for ratepayers.

Regarding the utility's headcount, the Consumers Coalition notes that the Board previously determined that the voluntary departure program was not intended as a temporary reduction in headcount. Nonetheless, as observed by the Consumers Coalition's witness Mr. Rainkie, FTEs increase by 929 from 2021 to 2028 and by 212 from 2017 to 2028. The Consumers Coalition relies on Mr. Rainkie's evidence that Manitoba Hydro has levers to control O&A costs, and that the utility's assumption that costs are not controllable is unfounded.

The Consumers Coalition acknowledges that, to achieve meaningful control over O&A during the rate period, the utility's FTE count needs to be reduced. It recommends an attrition strategy, as well as a reduction of middle management. For non-management areas subject to potential cost reductions, the Coalition specifically identifies Governance, Support, and Services FTEs, which will have increased by 260 between 2020 and 2028, and Operating & Maintenance FTEs, which will have increased by 463 between 2020 and 2028. As additional short-term opportunities, the Consumers Coalition identifies overtime, discretionary expenditures, and external services and materials such as vegetation management spending.

Regarding vegetation management, the Consumers Coalition relies on the evidence of Midgard as well as Melissa Davies (the consultant for the GSS/GSM Representative). Midgard testified that increased spending on vegetation management provides diminishing returns, and proposed a return to the historical pacing, which would reduce vegetation management spending by \$5.1 million in 2025/26, \$9.1 million in 2026/27, and \$10.8 million in 2027/28. Accordingly, the Consumers Coalition identifies this spending as an opportunity for Manitoba Hydro to exercise discretion within the recommended envelope as part of the Board-approved revenue requirement.

For rate-setting purposes, the Consumers Coalition urges the Board to assume a 2% escalation of O&A expenditures from 2025 to 2035, as suggested by Mr. Rainkie in his testimony. The Consumers Coalition emphasizes that this does not result in a disallowance or reduction of the existing level of O&A spending, but merely reduces the future growth rate. The Consumers Coalition further emphasizes that, using 2020 rather than 2025 as a baseline, this would result in an annual O&A cost escalation from 2020 to 2035 of 4% per year.

### **GSS/GSM Representative**

The GSS/GSM Representative observes that, contrary to the assertion made that cost control measures have been implemented, Manitoba Hydro's actual O&A costs during the 2023/24 and 2024/25 fiscal years exceeded the budgets for those years by \$52 million (7.8%) and \$57 million (8.3%), respectively, without any corrective action being taken to account for the drought. In this intervener's submission, there is a case to be made that no further increases to O&A costs are required at all in the rate period. The GSS/GSM Representative further notes that, between the 2021/22 and 2024/25 fiscal years, O&A expenditures have increased by 30%, or \$176 million in total. There is therefore no evidence of sustained cost control or pacing of expenditures, nor least-cost planning, and this should be factored into the Board's determination of just and reasonable rates.

Like the Consumers Coalition, the GSS/GSM Representative takes issue with the assumption that employee-related expenditures are outside Manitoba Hydro's control. While it acknowledges that 80% of Manitoba Hydro's workforce is unionized, it notes that for the remaining 20%, increases are determined at the executive table of Manitoba Hydro. The GSS/GSM Representative also submits that increases to prioritize employee experience and retention should result in measurable operational efficiencies, including FTE decreases. At minimum, it calls into question the 4.5% average increase in overtime throughout the rate period. The GSS/GSM Representative submits that Manitoba Hydro should continue a strategy of pausing hiring and repurposing roles, noting Manitoba Hydro's evidence that this achieved \$12.4 million in cost savings compared to the forecast in 2024/25.

Given the above, the GSS/GSM Representative suggests that there may be a benefit to an independent prudency review of employee-related costs being undertaken before the next general rate application. It notes that other industries with unionized workforces are expected to achieve cost savings as well since not all cost increases can simply be passed through to their customers in the face of competition.

Regarding the replacement of Manitoba Hydro's SAP system, the GSS/GSM Representative submits that the utility has not demonstrated that the replacement is least cost, and that Manitoba Hydro has not submitted an investment justification. Further, this intervener argues that Manitoba Hydro knew an investment justification (or 'business case') for its SAP project was a requirement out of the last general rate application and, despite indicating in this proceeding that its investment justification documentation would be provided, this was not done. Given the increase in estimated project costs since the last general rate application, ratepayers have a right to understand what their rates are recovering and ensure investment is being undertaken prudently.

Regarding vegetation management, the GSS/GSM Representative observes that Manitoba Hydro does not yet have a long-term vegetation management plan to support its proposed spending. While this intervener does not take issue with Manitoba Hydro's assertion of a backlog, it observes that the backlog has not shown up as a problem in Manitoba Hydro's reliability statistics. Relying on the utility's SAIDI and SAIFI values, which are further explained in section 12.3 and Appendix A, the GSS/GSM Representative observes that Manitoba Hydro has strong reliability compared to other Canadian jurisdictions. It emphasizes the need for benchmarking, as discussed by the Consumers Coalition's witness Midgard and the GSS/GSM Representative's own witness Ms. Davies. Further, Manitoba Hydro's vegetation management system should prioritize activities in an efficient manner by highest risk and make use of an evidence-based plan.

In the interim, the GSS/GSM Representative recommends a more linear rate of spending increases than proposed by Manitoba Hydro that avoids front-loading the increased spending. Relying on the evidence of its witness Ms. Davies, this intervener recommends even annual increases of 11% on vegetation management spending, which would reduce associated costs by \$4.6 million in 2025/26, \$8.2 million in 2026/27, and \$9.3 million in 2027/28. While this does not amount to substantial cost savings in the short-term, it paces the planned expenditures in a more measured and realistic manner, while still allowing for enhanced activity, the prioritizing of the highest risk backlog, improving safety and reliability, and gathering better data for long-term planning.

## Manitoba Industrial Power Users Group

MIPUG argues that Manitoba Hydro retains considerable discretion as to the development of spending forecasts, including O&A expenditures. Further, while the utility attempted to budget with an eye to risk and external conditions, the end result is neither prudent nor credible and the Board should not accept the O&A forecasts as meeting the moment.

### 11.3 Board Findings

The Board is concerned about the ongoing escalation of Manitoba Hydro's operating & administrative ("O&A") expenditures, in particular the 25% increase in the projected three-year expenditures since the 2023/24 & 2024/25 General Rate Application. While Manitoba Hydro has limited control over some of its wages and salary levels, and is bound by its signed collective agreements and the provincial government's mandate, it does have control over staffing levels, external contracts, and internal expenditures. Overall, the Board finds that Manitoba Hydro has the responsibility and the tools to efficiently manage its O&A expenditures.

The Board finds that Manitoba Hydro's drought response should include at least the following three tools: regulatory relief through rate changes, cost reductions through management action, and reliance on retained earnings. However, in the current Application, the Board finds that Manitoba Hydro did not seek rate relief at the highest allowable level, and has made no adjustments to O&A expenditures, despite a half-billion dollar degradation to its 2025/26 net income projections as a result of the ongoing drought. While Manitoba Hydro states that its planned hiring for 2025/26 and 2026/27 is limited to hiring commitments under the International Brotherhood of Electrical Workers ("IBEW") collective agreement, this is in relation to the budgeted FTEs in 2024/25, not the actual FTEs in that year. As demonstrated in 2024/25 when Manitoba Hydro paused recruitment, the Board finds that Manitoba Hydro has residual employment cost-related management tools at its disposal, such as vacancy management, overtime management, vacation liability management, and travel restrictions, for non-essential service-related travel, beyond those currently in place for out-of-province travel.

Similarly, Manitoba Hydro has some discretion regarding the timing of external services, such as vegetation management. While the Board finds that Manitoba Hydro's intention to increase vegetation management spending is prudent, the utility has discretion regarding the amount of front-loading, as identified by both Midgard and Ms. Davies. Further, the Board is concerned that Manitoba Hydro has not submitted a more detailed vegetation management plan in support of its forecasted expenses. As such, the Board directs Manitoba Hydro to include, in addition to and as part of its Order 73/15 Directive 14 quarterly O&A Expense reports to the Board, an additional comparison of its vegetation management approved budget and the actual amounts spent on vegetation management along with an explanation of any material variance of plus or minus 20%.

As noted above, the Board finds that Manitoba Hydro has not taken sufficient steps to control O&A expenditures in response to the ongoing drought. However, the Board does not have sufficient information to disallow specific O&A expenditures. Manitoba Hydro is in the best position to prioritize how the cost reductions should be achieved. Balancing the need for management response against the real cost pressures identified by Manitoba Hydro, the Board disallows 1.0% of Manitoba Hydro's projected O&A expenditures for each of the 2026/27 and 2027/28 fiscal years, exclusive of expenditures related to the SAP S/4HANA project, as set out in Figure 11.6. This will reduce the growth in O&A expenditures from 5% to 4%.

<b>Fiscal Year</b> (\$ millions, rounded)	<b>2025/26</b>	<b>2026/27</b>	<b>2027/28</b>
Projected O&A Expenditures	800	968	851
Original Projected SAP S/4HANA Expenditures*	19	137	-
Projected O&A Expenditures Excluding SAP S/4HANA	781	831	851
Required 1.0% Reduction for 2026/27 & 2027/28	-	(8)	(16)
Approved O&A Expenditures for Rate-Setting	781	960	835

\* As described in section 14.2, the projected expenditures for the SAP S/4HANA project were revised by Manitoba Hydro during the hearing. However, the original expenditures for this project are used in this table as Manitoba Hydro did not update its total O&A budget for the rate period.

Figure 11.6 — Disallowed O&A Expenditures for 2026/27 & 2027/28

The Board finds that a disallowance of 1.0% in each of those years represents a minor reduction of approximately \$8 million per year that Manitoba Hydro can readily achieve. However, the reduction may require the utility to re-prioritize some of its discretionary spending, which is an appropriate response to a major drought.

Regarding Manitoba Hydro's updated \$193 million cost projection for the SAP S/4HANA Core implementation project, the Board has little confidence in Manitoba Hydro's estimate, even with a fixed price arrangement with EY. In the view of the Board, a two-year timeline for the replacement is an extremely ambitious schedule, especially with the need, as identified by Manitoba Hydro, to adjust up to 65% of its business processes to the new software. The Board is also skeptical about integration costs effectively ending after 2026/27. With Manitoba Hydro's existing SAP system having been in place for approximately 30 years, the SAP S/4HANA project represents a major business transformation with significant risk. A substantial portion of that risk also relates to the second and third phases of the project, which have not yet been costed or reflected in Manitoba Hydro's financial forecast and 20-year rate path. As such, even if the first phase is on time and on budget, there is the potential for final costs (i.e., including phases 2 and 3) to be significantly higher than \$193 million.

Nonetheless, the Board accepts that Manitoba Hydro must replace its existing software in light of support for the existing software ending, and that the proposed replacement cost of \$193 million is, on its face, prudent. However, the Board finds that the "paused" business case filed in this proceeding does not provide adequate justification for Manitoba Hydro's proposed plan to implement SAP S/4HANA Core by December 2026.

While this is not a capital project, the Board finds that equivalent project expenditure approvals should be sought prior to fully committing to such a major expenditure that would have significant and immediate impacts on Manitoba Hydro's net income in the rate period, absent the Board approving a regulatory deferral account. The Board notes that at the time of the hearing, contracts with SAP and EY had already been signed and Manitoba Hydro has already spent approximately \$29 million on the project, even though the SAP S/4HANA Core investment justification had not yet been approved by the

Manitoba Hydro-Electric Board (“MHEB”). Despite the assurances from Manitoba Hydro’s executives during the hearing that the project is being closely managed, including the commitment to provide updates to MHEB, the evidence received in this hearing suggests that the project’s aggressive timeline may be contributing to insufficient project oversight. In addition to concerns regarding total project costs, the Board is also concerned about the implications and risks regarding critical data security issues as SAP S/4HANA is a cloud-based solution that may not result in Manitoba Hydro’s information completely residing within Canadian jurisdictions. Data sovereignty issues may arise if information about Manitoba Hydro’s operations and customers are stored outside of Canada without the utility knowing or appreciating the consequences.

In order to maintain visibility of Manitoba Hydro’s SAP S/4HANA project expenditures and implementation progress, the Board directs Manitoba Hydro to file the following:

- The SAP S/4HANA Core investment justification documentation once it is approved by the Manitoba Hydro-Electric Board;
- Quarterly SAP S/4HANA Core project reports within 45 days after the end of each fiscal quarter, with the first report to address the January 1 to March 31, 2026 quarter until project completion. These reports must outline the approved budget (at time of the investment justification approval), expenditures to date, the current forecast at completion costs and schedule, and remaining risks affecting the project. Specific contract costs must also be detailed for any contracts in excess of \$50 million; and
- Standalone business cases and investment justifications when completed for Phase 2 (CIS/Banner) and Phase 3 (Core Enhancement) follow-up SAP projects.

Given that SAP S/4HANA is a high-risk project, the Board recommends that Manitoba Hydro consider using external oversight for the different phases of its transition to SAP S/4HANA, including for the Phase 1 SAP S/4HANA Core implementation project.

The Board also approves the establishment of an SAP S/4HANA Cloud Computing Arrangement Regulatory Deferral Account, which is discussed further in section 14.2.3 of this Order.

## 12.0 FINANCE EXPENSE & DEBT MANAGEMENT

### 12.1 Background

#### 12.1.1 Manitoba Hydro's Debt Level

Finance expense is currently Manitoba Hydro's biggest expense category, with a projected net finance expense of \$967 million in 2025/26, \$962 million in 2026/27, and \$945 million in 2027/28.

Over the past decade, Manitoba Hydro's debt more than doubled as a result of the utility's investment in several major projects, including the Keeyask Generating Station, the Bipole III transmission line, and the Manitoba-Minnesota transmission project. While Manitoba Hydro's debt was approximately \$10 billion as of March 31, 2013, it increased to \$24.1 billion as of March 31, 2025, following the completion of those projects. As shown in Figure 12.1, the utility's planned new major capital projects (discussed in section 10.0) contribute to an increase in debt and a similarly large increase in assets over the 20-year forecast period. However, despite the increase in debt, Manitoba Hydro's retained earnings gradually increase rather than decrease.

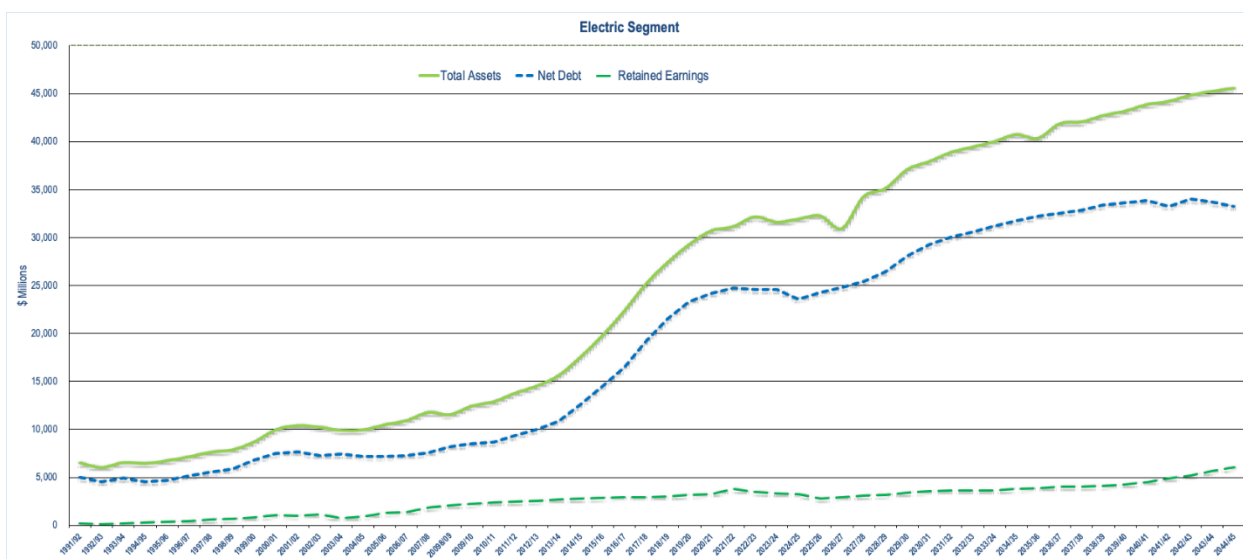


Figure 12.1 — Assets, Debt & Retained Earnings of Manitoba Hydro (Forecast Years Based on Manitoba Hydro's Application): Board Advisor Graph

As discussed elsewhere in this Order, the financial future that Manitoba Hydro projects in this Application is different from the one projected in the last general rate application. In the last general rate application, Manitoba Hydro anticipated a period of debt paydown during the early 2020s and throughout the 2030s, with the total debt level decreasing to approximately \$21 billion by 2041/42, as illustrated in Figure 12.2.

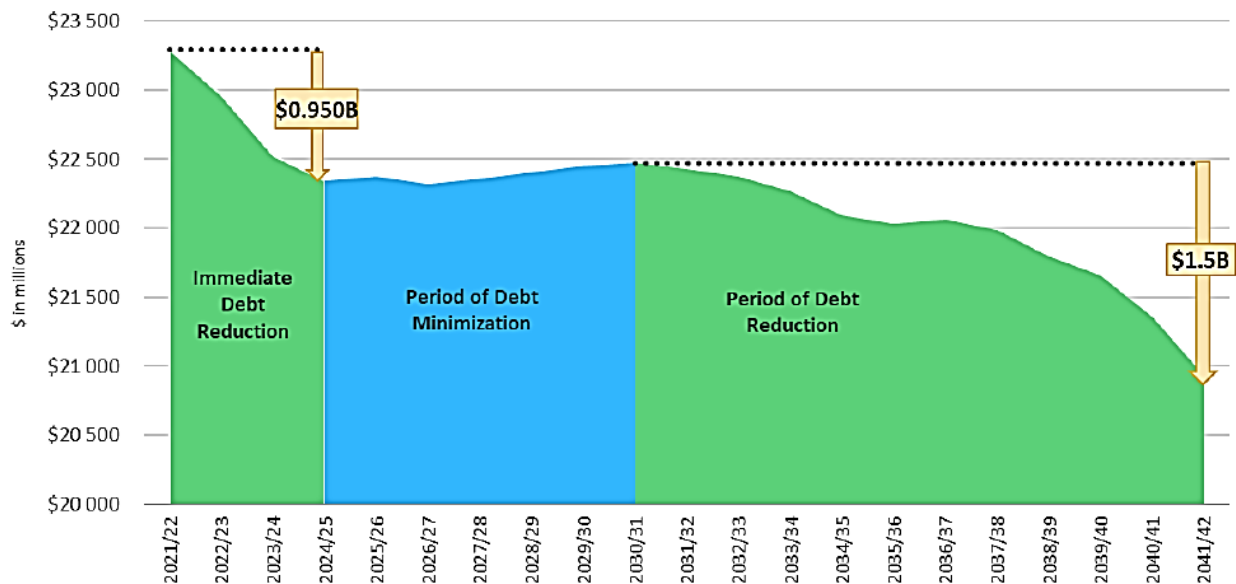


Figure 12.2 — Planned Debt Reduction (2023/24 & 2024/25 General Rate Application)

Since the last general rate application, drought and low water have resulted in lower net income than anticipated and the previously planned debt retirement did not materialize. Further, the corporation is again embarking on another period of significant asset investment, including on the HVDC Reliability Project and new dispatchable capacity resources that were not included in the financial forecast filed in the last general rate application. As a result, the utility now forecasts cash flow deficits of over \$7.2 billion in the next decade, which will result in \$6.8 billion of additional incremental borrowings in the next decade and a growth of the net debt balance to approximately \$31 billion by March 31, 2035. Cash flow deficits will also total roughly \$1.8 billion in the second decade before cash surpluses are projected in the last few years of the planning horizon.

Compared with the last general rate application, in which the corporation assumed a 2.0% rate path and anticipated reducing its debt by \$1.5 billion by 2041/42, Manitoba Hydro now forecasts increasing its long-term debt by over \$8.6 billion by 2044/45. This assumes a 3.5% rate path and reduced payments to government over the 20-year forecast period. Figure 12.3 shows Manitoba Hydro’s long-term debt changes as anticipated in this Application.

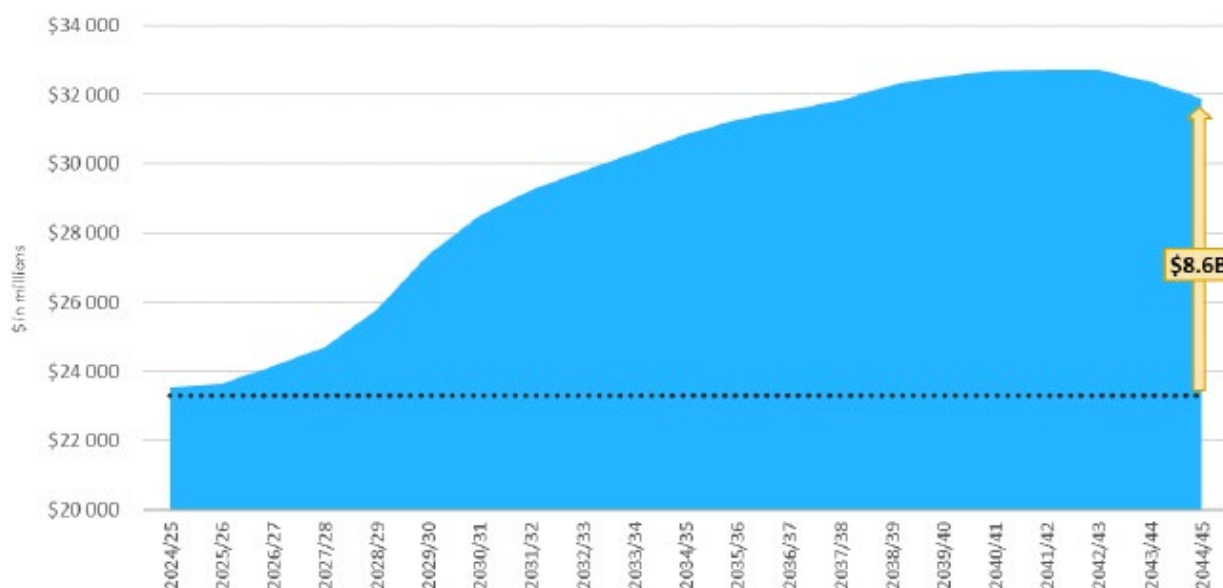


Figure 12.3 — Manitoba Hydro’s 2025/26 -2027/28 Planned Debt Change

**12.1.2 Interest Rates and Finance Expense**

Interest rate risk is a significant risk for Manitoba Hydro, with on average \$900 million in debt maturities annually that will require refinancing over the next decade. This will contribute to upward pressure on finance expense as maturing debt is currently projected to be refinanced at higher interest rates. New borrowings will also create additional interest rate risk.

During the period since the financial crisis of 2008/2009, which saw historically low interest rates, Manitoba Hydro managed to lock in most of its recent long-term debt at favourable interest rates. The weighted average term to maturity of Manitoba Hydro’s debt is currently just over 19 years, with a weighted average interest rate of 3.5% at March 31, 2025, excluding the provincial debt guarantee fee.

The most recent consensus interest rate forecast relied on by Manitoba Hydro predicts an interest rate for long-term debt of 4.25% to 4.35% for 2026/27 and 2027/28, as well as an interest rate for short-term debt of 2.20% for 2026/27 rising to 2.45% in 2027/28, excluding the provincial debt guarantee fee. Based on Manitoba Hydro’s consensus interest rate forecast, all maturing debt is expected to be refinanced at interest rates higher than the current embedded rates, resulting in higher future finance expense. The higher refinancing rate than the existing weighted interest rate on debt maturities is illustrated in Figure 12.4.

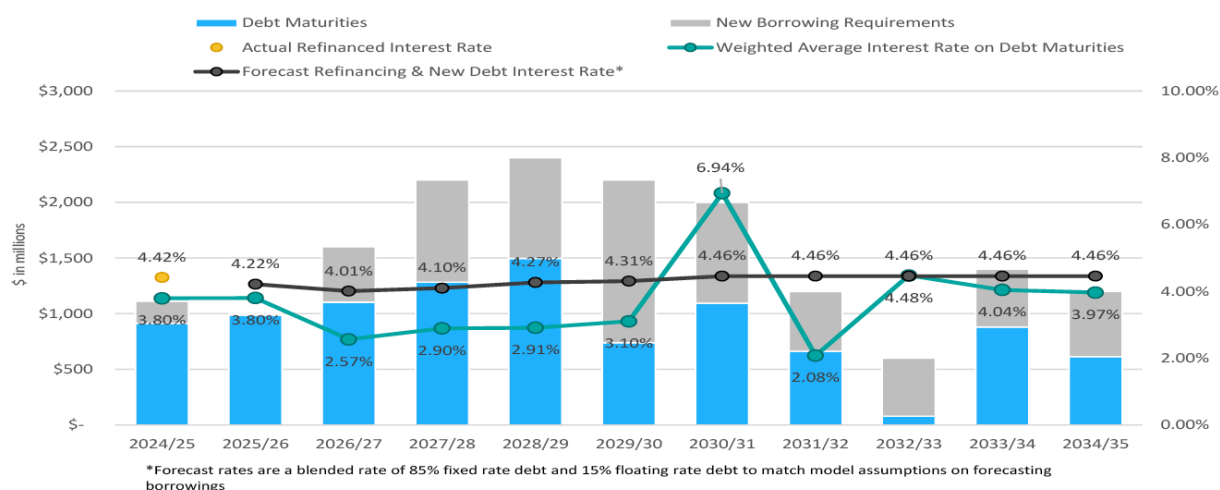


Figure 12.4 — Manitoba Hydro’s Projected Refinancing Rates

Between the expected \$7 billion of new debt and the refinancing of \$9 billion of maturing debt at higher rates over the next 10 years, Manitoba Hydro expects its annual finance expense to increase from approximately \$1 billion per year currently to approximately \$1.35 billion per year by the end of the 20-year forecast period, as illustrated in Figure 12.5. This increase is despite the provincial government’s reductions to the debt guarantee fee discussed in section 3.1.2.

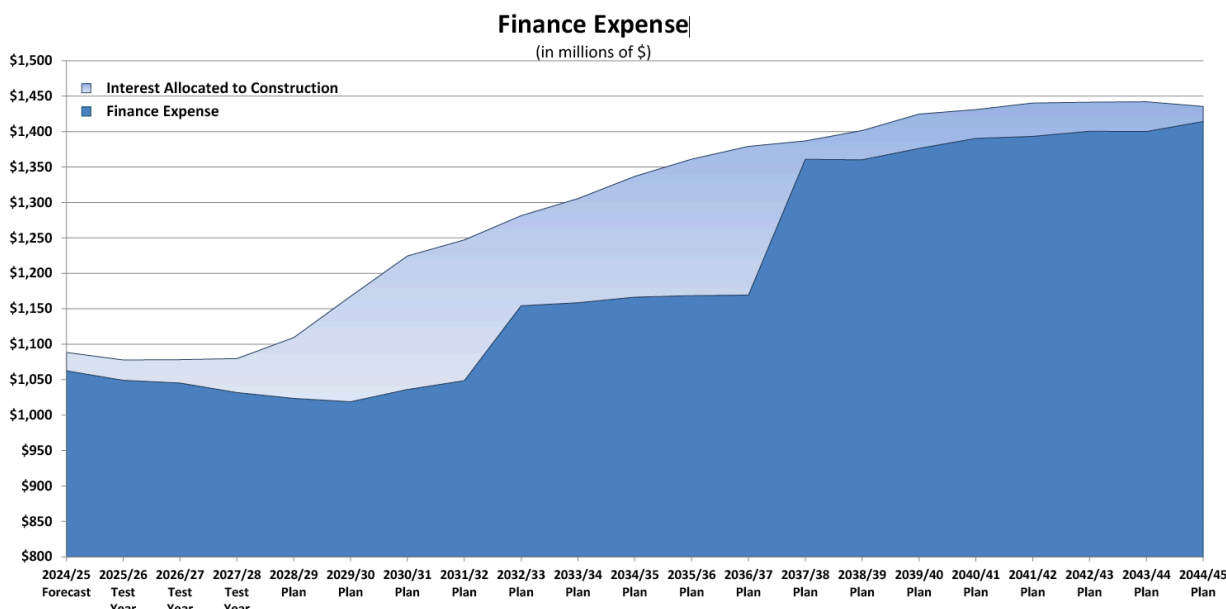


Figure 12.5 — Manitoba Hydro’s Projected Annual Finance Expense (Consolidated)

**12.1.3 Fixed-Rate vs. Floating-Rate Debt**

To mitigate liquidity risk and ensure financing flexibility, Manitoba Hydro maintains a \$1 billion pre-funded cash balance, equivalent to approximately six months of cash requirements (40% short-term debt and 60% long-term debt at March 31, 2025). Further, the utility seeks to smooth its debt maturity schedule by targeting debt issuance into a portion of the schedule which is currently lacking debt maturities, and continues to favour longer-dated debt maturities, in line with asset service life.

As a result, Manitoba Hydro’s debt management guidelines include maintaining an aggregate of short-term debt and floating rate long term debt within 0%-20% of the total debt portfolio target range. Manitoba Hydro’s existing interest rate policy for its existing debt portfolio is also to limit interest rate risk profile, which is the aggregate of long-term floating rate debt, short term debt, and fixed-rate long-term debt to be refinanced within the subsequent 12-month period, to a maximum of 25% of the total debt portfolio. However, Manitoba Hydro maintains the interest rate risk profile below 10% to minimize overall exposure. At March 31, 2025, Manitoba Hydro’s interest rate risk profile is forecast to be 6.5% (or \$1.8 billion).

As in previous applications, a point of contention in this Application was Manitoba Hydro's optimal proportions of floating-rate and fixed-rate debt. In 2009, Manitoba Hydro commissioned a modelling study by National Bank that concluded that the optimal range is 14 to 27 percent floating-rate debt. At the 2023/24 & 2024/25 General Rate Application, Manitoba Hydro submitted that due to its increased debt balance, the model now indicated an optimal range of 8 to 15 percent, which was contested by some interveners as an artificially low constraint. In Order 101/23, the Board found that Manitoba Hydro's debt management strategy was cautious given that its financing risk profile at the time was decreasing. As a result, Directive 32 of Order 101/23 directed Manitoba Hydro to conduct a review of the 2009 National Bank model on floating-rate versus fixed-rate financing and file a report detailing the review's outcome at the next general rate application.

In the course of the hearing of this Application, and pursuant to Directive 32 of Order 101/23, Manitoba Hydro filed a new study by OXARO Inc. ("OXARO"), a consulting firm. OXARO noted that Manitoba Hydro faces a unique and elevated interest rate risk profile because of its significant reliance on hydroelectric generation, which accounts for approximately 97% of its energy production. It said that while this reliance provides environmental and cost advantages during favorable water conditions, it also exposes the utility to substantial financial volatility during drought periods. Additionally, OXARO said that Manitoba Hydro operates with one of the highest debt-to-equity ratios among its peers, at 85-86%, which has remained stable over the past five years despite other utilities improving their financial positions. This high leverage, combined with capital inadequacy and regulatory constraints, limits the utility's financial flexibility and risk-bearing capacity.

OXARO further observed that Manitoba Hydro has adopted a conservative approach to interest rate risk management, maintaining 94.6% fixed-rate debt and only 5.4% variable rate exposure, making it the second most conservative utility after Newfoundland Power among its peer group. However, while Manitoba Hydro's current interest rate risk exposure might appear manageable in isolation, the combination of capital inadequacy, regulatory constraints, financing limitations, and operational vulnerabilities creates a

substantially elevated risk profile compared to peers. According to OXARO, this unique constellation of compounding risk factors requires more sophisticated risk management approaches calibrated to the organization's limited risk-bearing capacity.

Given the above, OXARO recommends maintaining the current conservative approach to interest rate risk exposure, while introducing a formal risk tolerance statement that defines the utility's interest rate risk limits based on its capital adequacy and current market conditions. OXARO also suggests defining escalation protocols when capital adequacy limits are approached or breached and developing formal protocols that automatically enforce stricter interest rate risk management when capital hits set thresholds, protecting remaining capital during stress conditions.

To address its capital inadequacy and operational vulnerabilities, OXARO advises Manitoba Hydro to utilize and maintain the forward-looking model the firm provided, which projects capital adequacy under various scenarios. The report also recommends establishing key risk indicators and reporting mechanisms to monitor when capital nears minimum levels needed to support current interest rate exposure, triggering prompt risk mitigation actions.

## **12.2 Position of the Parties**

### **12.2.1 *Manitoba Hydro***

Manitoba Hydro submits that the primary objectives of its debt management strategy are to provide low cost, stable funding to meet the financial and liquidity needs of the utility while maintaining risk at prudent levels. Further, the utility is prudently managing its financing requirements and is again embarking on another period of significant capital investment, resulting in a projected need to issue roughly \$16 billion of debt over the next decade. Given the corporation's elevated leverage, the upcoming period of significant capital investment and its risk profile, it is critical that the utility remains profitable, generates sufficient cash flow, and protects the debt ratio from growing beyond the current level. Manitoba Hydro also points out that credit rating agencies and bond investors continuously monitor the utility's financial health and creditworthiness.

Manitoba Hydro emphasizes that its 20% limit for the aggregate of short-term debt and floating-rate debt is a maximum and not a target. Similarly, Manitoba Hydro maintains a 25% limit for the aggregate of short-term debt, floating-rate debt, and fixed-term debt to be refinanced within the next 12 months. In Manitoba Hydro's submission, the utility's current proportion of variable rate debt and its near-term strategy to maintain an interest risk profile below 10% both fall within its current policy and guideline range.

The utility disagrees with the recommendation of the Consumers Coalition's witness, Mr. Rainkie, that it should increase the percentage of floating-rate debt. In particular, it submits that a 1% increase in short-term debt would result in Manitoba Hydro using \$900 million of its \$1 billion short-term authority, leaving only \$100 million for contingencies. In contrast, under Manitoba Hydro's current approach, the utility maintains a contingency of \$300 million. Manitoba Hydro points out that, in 2025/26, it already has used up its contingency because of the drought and will have to raise its level of short-term borrowing.

Manitoba Hydro also states that it is conceptually flawed to consider floating-rate debt as having a lower or higher cost than fixed-rate debt, as one should not consider the rate differential for less than the full term of the debt. According to Manitoba Hydro, the utility is economically indifferent to fixed versus floating-rate debt over the entire term to maturity, and there is no arbitrage opportunity between the two.

Given the above, Manitoba Hydro argues that proposals for increasing short-term debt and the proportion of variable rate debt do not account for the critical factors that shape Manitoba Hydro's high-risk profile and the interest rate exposure. In Manitoba Hydro's view, the OXARO report supports the reasonableness of Manitoba Hydro's debt management strategy.

### **12.2.2 *Interveners***

The Consumers Coalition is the only intervener specifically taking a position on Manitoba Hydro's debt management strategy. It submits that Manitoba Hydro's debt management strategy is in a holding pattern pending the review of the recently completed OXARO

report, which was filed late in the hearing, with no opportunity for information requests or intervener evidence to test the report's findings. The Consumers Coalition observes that in the meantime, the utility continues to hesitate to hold more than minimal levels of variable-rate debt, despite Manitoba Hydro having the lowest level of variable-rate debt in the peer group identified by OXARO.

Mr. Rainkie, who appeared on behalf of the Consumers Coalition, notes Manitoba Hydro's total variable-rate debt of 4% to 7% in the rate period is well below the corporation's existing 20% policy limit. Similarly, the interest rate risk profile range of 8% to 13% in the rate period is also well below the guideline maximum of 25%. According to Mr. Rainkie, this analysis demonstrates that Manitoba Hydro remains relatively risk-averse toward higher levels of variable-rate debt and interest rate risk.

According to Mr. Rainkie, Manitoba Hydro's sensitivity analysis indicates that a 1% increase in short-term debt and 1% increase in floating-rate debt would decrease finance expense in the rate period by \$5 to \$6 million per year. Mr. Rainkie further observes that Manitoba Hydro has one of the lowest levels of variable-rate debt in OXARO's peer group. In Mr. Rainkie's opinion, given Manitoba Hydro's very long-term planning horizon, it should have more risk tolerance for variable rate debt.

Mr. Colaiacovo, who appeared on behalf of the Consumers Coalition, notes that there is no evidence that the significant increase in Manitoba Hydro's debt over the past decade has affected the cost of funds for the Province of Manitoba or the utility. However, investors continue to pay attention to Manitoba Hydro's financial results and Board decisions.

### **12.3 Board Findings**

The Board finds that Manitoba Hydro's debt management strategy and its projections for finance expense are reasonable, given current market conditions and the corporation's financial outlook. In the context of the utility embarking on a significant increase in debt, the Board considers it prudent for Manitoba Hydro to maintain its current balance between

fixed- and variable-rate debt, especially in the context of the volatile interest rate environment of recent years.

While the Board has reviewed the OXARO report and Board Counsel was able to ask questions related to the report to Manitoba Hydro, the Board notes that the report was filed late in the proceeding and has not been fully tested. While the Board does not rule out that short-term savings could be achieved by increasing the percentage of variable-rate debt, as suggested by Mr. Rainkie, the Board considers it important not to prioritize short-term cost reductions at the expense of increased volatility or risk, particularly given the scale of new borrowing required for major capital projects.

Overall, the Board finds Manitoba Hydro's finance expense forecasts, including the assumptions about interest rates and debt structure, appropriate for rate-setting in the rate period.

The Board encourages continued monitoring of capital markets for potential opportunities, while emphasizing that major strategic shifts in debt management should remain justified by a robust assessment of risks and long-term impacts on ratepayers. The Board also supports Manitoba Hydro's initiatives to pursue alternative sources of reliable resources, such as federal funding.

While Manitoba Hydro has filed the OAXRO report in response to Directive 32 of Order 101/23, which directs Manitoba Hydro to conduct a review of the 2009 National Bank model on fixed-rate versus variable-rate financing, the Board is not satisfied that this report has answered the Directive. As such, the Board directs Manitoba Hydro to provide its assessment of the 2025 OXARO report and how it affects Manitoba Hydro's financing strategy at the next general rate application. Pending a more thorough review of the OXARO report in the next general rate application, the Board will keep Directive 32 of Order 101/23 open.

## **13.0 DEPRECIATION AND RELATED DEFERRAL ACCOUNTS**

### **13.1 Background**

#### ***13.1.1 Depreciation and Amortization Expense***

Depreciation and amortization is Manitoba Hydro's third-highest expense category, with a projected depreciation and amortization expense of \$644 million in 2025/26, \$662 million in 2026/27 and \$686 million in 2027/28.

Depreciation involves systematically allocating the cost of tangible assets, such as power generation facilities and infrastructure, over their estimated useful lives. The useful life of an asset is determined and periodically reassessed through depreciation studies. Depreciation reflects the wear and tear and obsolescence of these physical resources over time.

Amortization relates to intangible assets, such as licenses and software, allocating their cost over the estimated useful life of the asset. Depreciation and amortization rates in Manitoba Hydro's application are based on periodic depreciation studies typically conducted in five-year intervals.

Under utility accounting principles, capital investments by Manitoba Hydro do not form part of the utility's revenue requirement. Instead, Manitoba Hydro recovers the capital cost of its physical and intangible asset investments through depreciation and amortization over the expected lifetime of the assets. As such, depreciation and amortization is a non-cash expense that generates cash flow for Manitoba Hydro.

#### ***13.1.2 The 2024 Depreciation Study***

In this hearing, Manitoba Hydro filed its 2024 Depreciation Study prepared by Concentric Energy Advisors. The 2024 Depreciation Study introduces several changes and updates to Manitoba Hydro's depreciation rates and methodologies. This includes a change in the depreciation methodology from the Equal Life Group ("ELG") to the Average Service Life ("ASL") methodology, consistent with Directive 19 of Order 101/23.

As discussed in Order 101/23, Manitoba Hydro was previously seeking to transition to the ELG methodology when it adopted International Financial Reporting Standards (“IFRS”), based on its conclusion that the ASL methodology would not be IFRS-compliant without additional componentization of the asset groups used in the depreciation study. In the 2024 Depreciation Study, which Concentric considers to be IFRS-compliant, Manitoba Hydro has used the same componentization as in the 2019 Depreciation Study, with changes only to the following four asset groups:

- Hydraulic Generation Dams, Dykes, and Weirs;
- Transmission Line Conductors and Devices;
- Distribution Serialized Equipment Pull-Up Mounts; and
- Building Across All Functions.

Manitoba Hydro notes that the updated depreciation and amortization rates from the 2024 Depreciation Study have not been reflected in the financial forecast underpinning the current general rate application as the study was not received in time to incorporate into the forecast. Instead, the financial forecast utilizes the 2019 Depreciation Study. This is a departure from the approach taken in the recent Centra Gas general rate application, in which depreciation rates were approved based on the 2024 Depreciation Study for that utility. Compared to the 2019 Depreciation Study, the updated 2024 Depreciation Study results in retained earnings being \$88 million higher by 2044/45. However, Manitoba Hydro maintains that the update yields minimal change to cash, net debt, and the debt ratio, which remains projected at 79% in 2044/45.

### ***13.1.3 The Change in Depreciation Method Deferral Account***

During the decade-long period that Manitoba Hydro sought to change its depreciation methodology to ELG (as discussed in detail in section 12.0 of Order 101/23), Manitoba Hydro established, without prior Board approval, a deferral account into which it accrued the difference between ASL depreciation and ELG depreciation in each year. This deferral

account, known as the Change in Depreciation Method Deferral Account, had accrued a balance of \$310 million as of March 31, 2024.

In the 2023/24 & 2024/25 General Rate Application, Manitoba Hydro sought permission from the Board to amortize the deferral account, which the Board rejected. Manitoba Hydro subsequently sought to review and vary this decision, which the Board rejected in Order 51/24.

In the recent Centra general rate application, Manitoba Hydro’s natural gas subsidiary restated accrued depreciation and sought to recover the difference previously accumulated in that utility’s Change in Depreciation Method Deferral Account through regular depreciation rates. However, in Manitoba Hydro’s current Application, the electric utility once again seeks approval to amortize a deferral account.

Manitoba Hydro advises that, if the Centra Gas approach were to be followed, the annual amount to be recovered from the previously established deferral account would increase in each year, as illustrated in Figure 13.1. Under a 33-year linear amortization, Manitoba Hydro would recover \$10 million in each year, without any escalation.

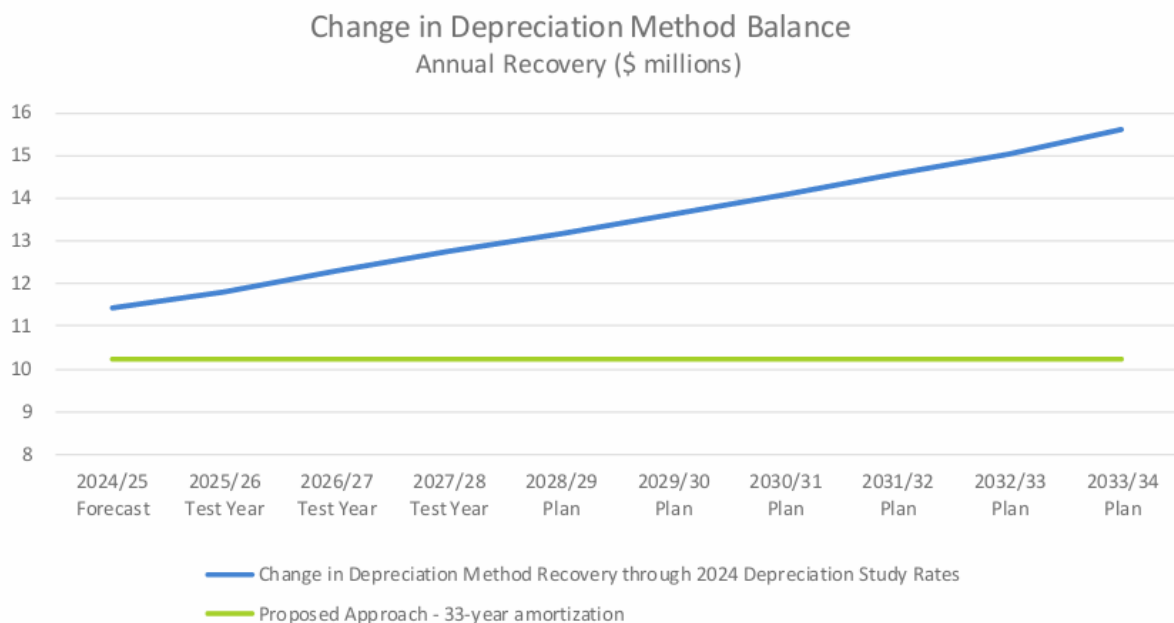


Figure 13.1 — Recovery of Change in Depreciation Methodology Account Balance

The utility explains that the increased recovery results from depreciation rates being based on gross plant in service, with increases in gross plant accelerating recovery of the balance in the deferral account. While the utility acknowledges that future depreciation rates would true up any accelerated recovery, it states that this would result in increased and unpredictable depreciation rates.

Manitoba Hydro therefore requests Board approval to modify the recovery mechanism for the Change in Depreciation Method Account balance for rate-setting purposes by recognizing it as a formal regulatory deferral account. This would involve recovery through net movement based on an amortization period of 33 years, rather than embedding the account in regulatory accumulated depreciation with recovery through depreciation rates. The utility acknowledges that this could be seen as a further request to review and vary Directive 20 of Order 101/23, which denied the utility approval to amortize the account.

## **13.2 Position of the Parties**

### **13.2.1 *Manitoba Hydro***

Manitoba Hydro submits that the forecast of depreciation and amortization expense is driven by the utility's current and future investments in physical and intangible assets, as well as any gains or losses on disposal of assets. The corporation also maintains that it aims to ensure that new regulatory deferral accounts, as well as the proposed amortization periods, promote intergenerational equity and rate stability for its customers with respect to when cost and revenue items are recognized into income for rate setting purposes.

Pursuant to Directive 19 of Order 101/23 and the follow-up communications with the Board, Manitoba Hydro transitioned to ASL for financial reporting for fiscal year 2023/24, without phase-in. Further, interim gains and losses were deferred and \$43 million of terminal losses were written off in 2023/24 (for the Selkirk and Brandon Unit 5 thermal stations). In accordance with Order 51/24, Manitoba Hydro also used the level of componentization from the 2019 Depreciation Study, with minimum change to some asset groups for 2023/24 and 2024/25.

Manitoba Hydro submits that the current approach to accounting for the accrued balance in the Change in Depreciation Method Deferral Account is complex, lacks transparency, and requires the maintenance of offline records to support the different accounting treatment for rate setting purposes. Manitoba Hydro argues that the approach adds significant administrative complexity and greatly increases the risk of human error, as Manitoba Hydro's existing SAP ECC system cannot be modified to apply different depreciation rates to single sets of assets for financial reporting versus rate setting. In addition, as the current recovery is based on plant in service, the portion of depreciation and amortization expense pertaining to recovery of the account balance increases over the forecast period as plant in service balances increase. Should the Board accept Manitoba Hydro's recommendation to establish a formal deferral account with a linear 33-year amortization, net income would improve by \$2 to \$3 million in the rate period.

### ***13.2.2 Interveners***

None of the interveners commented on Manitoba Hydro's request to amortize the Change in Depreciation Method Deferral Account. However, MIPUG's witness Mr. Bowman observed that the financial forecast scenario filed in the Application overstates depreciation expense by approximately \$10 million per year, as it does not yet include reductions arising from the 2024 Depreciation Study.

### **13.3 Board Findings**

The Board finds that Manitoba Hydro has adequately implemented the ASL depreciation methodology for rate setting purposes per the requirements of Order 101/23. As such, Directive 19 of Order 101/23 is deemed complete.

The Board directs Manitoba Hydro's depreciation and amortization expense for the rate period to be determined utilizing the 2024 Depreciation Study rather than the 2019 Depreciation Study, beginning January 1, 2027. For clarity, the 4.0% rate increase effective January 1, 2026 will utilize the 2019 Depreciation Study, so as to not affect the rates approved for January 1, 2026. Similar to its findings in the recent Centra general

rate application, the Board sees no benefit in this proceeding to continuing with an outdated study if a newer study is available and ready to be implemented.

While the Board is not required to approve specific depreciation rates for Manitoba Hydro, it considers the additional componentization in the 2024 Depreciation Study to be reasonable.

However, the Board is not prepared to revisit its decision regarding Directive 20 of Order 101/23, and subsequent review and vary decision in Order 51/24, on Manitoba Hydro's proposal to amortize the Change in Depreciation Method Deferral Account.

Under the Board's *Rules of Practice and Procedure*, an application to review and vary a decision of the Board can be justified one of three ways:

- a) there has been an error in fact, law or jurisdiction;
- b) there have been new facts or a change in circumstances; or
- c) the order is no longer in the public interest.

In the Board's view, none of these factors apply to the Board's earlier decision on the issue. Furthermore, the approach taken by Centra Gas in the recent natural gas general rate application demonstrates that it is possible for Manitoba Hydro to restate its accrued depreciation and embed any needed change in the depreciation study. As such, the Board finds that Directive 20 of Order 101/23 should not be reviewed and varied and denies Manitoba Hydro's proposed amortization.

## **14.0 OTHER DEFERRAL ACCOUNTS**

A regulatory deferral account is an accounting mechanism used by rate-regulated utilities such as Manitoba Hydro, to defer recognition of certain expenses (or revenues) until a future time period when those expenses are expected to be recovered from customers through the rates approved by the Board. Regulatory deferral accounts (for assets and liabilities) are permitted by IFRS Accounting Standards and generally promote intergenerational equity and rate stability for its customers, striking a balance between customer and utility priorities. In addition to the regulatory deferral account discussed in section 13.0, Manitoba Hydro seeks the following Board approvals regarding other deferral accounts to be used for rate setting purposes:

- Final approval of the interim Joint Keeyask Development Agreement (“JKDA”) Preferred Distributions Deferral Account, including annual revaluation adjustments related to the preferred distribution obligation in the deferral account and approval of an amortization period of 106 years;
- Approval to establish a Cloud Computing Regulatory Deferral Account for the costs related to the SAP S/4HANA Core project and approval of an amortization period; and
- Approval to establish a Cloud Computing Regulatory Deferral Account for Small-Scale Software Systems and approval of an amortization period.

### **14.1 Joint Keeyask Development Agreement (JKDA) Preferred Distribution Deferral Account**

#### **14.1.1 *Background***

The Keeyask Generating Station (“Keeyask”) is Manitoba Hydro’s most recently constructed hydroelectric generating station. Manitoba Hydro developed Keeyask under a shared equity model with partial First Nations ownership, using a limited partnership structure in which four First Nations, collectively known as the “Keeyask Cree Nations”, hold a preferred equity stake. The Keeyask Cree Nations consist of the Tataskweyak Cree Nation, War Lake First Nation, York Factory First Nation, and Fox Lake Cree Nation. In 2023, the signatories of the original JKDA executed a restated and amended

agreement as a result of the erosion of the anticipated long-term economic benefits to the Keeyask Cree Nations and a subsequent renegotiation of the terms of the agreement. Under the terms of the JKDA, Manitoba Hydro is required to make annual preferred share distributions to the Keeyask Cree Nations.

In Order 60/24, the Board approved, on an interim *ex parte* basis, the establishment of a regulatory deferral account for the net present dollar value of the JKDA preferred distribution payments to the Keeyask Cree Nations. Manitoba Hydro had applied on an interim *ex parte* basis for approval of this deferral account after the utility was advised by its financial auditor that, under IFRS 32 *Financial Instruments: Presentation*, the net present value of the future payments under the agreement would have to be recognized as an expense during the 2023/24 fiscal year unless the Board approved a regulatory deferral account. In Order 60/24, Manitoba Hydro was directed to include the following information regarding the JKDA in the present general rate application:

- a) The exact amount of the deferral and how it was determined, including any assumptions made with respect to the applicable discount rate, the anticipated annual amount of the preferred distributions, and the expected duration of the distributions;
- b) Confirmation as to whether it seeks the approval granted by Order 60/24 to be finalized, and
- c) A proposed amortization schedule or, if Manitoba Hydro does not seek final approval of the deferral account, a proposal for winding down the account.

In Order 35/25, the Board approved, again on an interim *ex parte* basis, Manitoba Hydro's request to adjust the JKDA Preferred Distributions Deferral Account to include any revaluation adjustment for the 2024/25 fiscal year. When the JKDA Preferred Distributions Deferral Account Obligation was established in 2023/24, it was valued at \$264 million. This represented the present value of the estimated future preferred distribution payments resulting from the Keeyask Cree Nation's conversion of their common units to preferred units under the amended JKDA, and was calculated based on 95 years of expected payments. For 2024/25, a \$23 million adjustment was applied to the JKDA Preferred

Distributions Obligation. Revaluation adjustments are expected to be common in most years, as driven by revised financial forecasts and required to account for the factors influencing the calculation of the preferred distributions based on the formula outlined in the amended JKDA. At this time, the amortization of the JKDA Preferred Distributions Obligation is \$3 million per year, as outlined below Figure 14.1:

<b>Impact to Net Income Establishment and Amortization of JKDA Preferred Distributions Obligation Deferral (in \$ millions)</b>	<b>Actuals 2023/24</b>	<b>Forecast 2024/25</b>	<b>Test Year 2025/26</b>	<b>Test Year 2026/27</b>	<b>Test Year 2027/28</b>	<b>Plan 2028/29</b>	<b>Plan 2029/30</b>	<b>Plan 2030/31</b>	<b>Plan 2031/32</b>	<b>Plan 2032/33</b>
Net income before JKDA Preferred Distributions Obligation deferral	(399)	(87)	221	190	130	171	223	169		50
Deferral of JKDA Preferred Distributions Obligation	264	23	-	-	-	-	-	-	-	-
Amortization of JKDA Preferred Distribution Obligation	-	-	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
<b>Net Income including deferral and amortization of JKDA Preferred Distributions Obligation</b>	<b>(135)</b>	<b>(64)</b>	<b>218</b>	<b>187</b>	<b>127</b>	<b>168</b>	<b>220</b>	<b>166</b>	<b>113</b>	<b>47</b>

Figure 14.1 — JKDA Preferred Distributions Regulatory Deferral Account Obligation

Manitoba Hydro now seeks final approval of both the interim JKDA Preferred Distributions Deferral Account, and the revaluation adjustment in the deferral account for the 2024/25 fiscal year. Manitoba Hydro also seeks approval to include annual revaluation adjustments related to the preferred distributions obligation in the regulatory deferral account, and for an amortization period of 106 years over which to recover the balance from electricity ratepayers through equal annual payments.

#### **14.1.2 Position of the Parties**

##### **Manitoba Hydro**

Manitoba Hydro states that the JKDA Preferred Distributions Obligation is a result of Manitoba Hydro's economic reconciliation efforts. These costs were not eligible for capitalization as part of the Keeyask capital project. As such, the establishment of the deferral account helps smooth the impact of rate increases and mitigates the rate impact on current customers resulting from the recognition of the preferred distributions obligation related to the Keeyask Cree Nations' unit conversion. This provides transparency and aligns with the principle of intergenerational equity. By contrast, recognizing the full financial impact of subsequent revaluation adjustments in profit or losses, without the use of a regulatory deferral account, as would otherwise be required by IFRS, would be viewed as inconsistent with the long-term nature of the obligation and would create net income volatility.

Manitoba Hydro submits that revaluation adjustments are expected to be common in most years due to its revised financial forecasts. These adjustments are required to account for fluctuations in projected domestic rate increases, projected export prices, and the operating costs of Keeyask. All of these factors influence the calculation of the preferred distributions based on the formula outlined in the amended JKDA.

Manitoba Hydro further submits that an amortization period of 106 years will mitigate rate impacts of this deferral account, and ensure these deferred costs are recovered over an appropriate period of time relative to the life of Keeyask and the generations of customers that will benefit from its use. The proposed amortization period of 106 years represents the updated weighted average life expectancy of Keeyask's assets based on the 2024 Depreciation Study discussed in section 13.1.2.

## Consumers Coalition

The Consumers Coalition supports Manitoba Hydro's request for final approval of the JKDA Preferred Distributions Regulatory Deferral Account and the proposed amortization period of 106 years.

### **14.1.3 Board Findings**

The Board approves the finalization of the interim Joint Keeyask Development Agreement ("JKDA") Preferred Distributions Deferral Account and revaluation adjustment in the deferral account for the 2024/25 fiscal year. The Board also approves annual revaluation adjustments to the preferred distribution obligation in the deferral account going forward. As discussed in Order 35/25, the Board finds revaluation as consistent with good regulatory practices and the principle of intergenerational equity, and is consistent with the Board's ruling in Order 60/24. Notionally, Manitoba Hydro's annual preferred distributions under the JKDA are made out of the revenues generated by Keeyask, which reflects the spirit of the "shared equity" model of project development. At the 2023/24 & 2024/25 General Rate Application, Manitoba Hydro assumed that the annual distributions would form part of the utility's revenue requirement in each year and provided evidence as to the estimated amounts of those distributions. It is just and reasonable for ratepayers to have to pay for such distributions, and a deferral account is the most practical manner of continuing such treatment. A revaluation adjustment is also consistent with these principles.

The Board further approves an amortization period of 106 years for the deferral account. The Board finds that Manitoba Hydro's evidence demonstrates that this period reflects the remaining weighted average service life of the Keeyask assets. This was not disputed by any intervener, and aligns with the period over which Keeyask is expected to provide service to customers.

The Board accordingly confirms that Directives 1 and 2 of Order 60/24 and Directive 1 of Order 35/25 which directed Manitoba Hydro to file information on the valuation and amortization related to this deferral account, are deemed complete.

## 14.2 SAP S/4HANA Deferral Account

### 14.2.1 Background

At the 2023/24 & 2024/25 General Rate Application, Manitoba Hydro presented its plan to shift to cloud computing arrangements, including a replacement of the utility's legacy enterprise resource planning system with the SAP S/4HANA cloud computing solution. As discussed in section 11.1.3, Manitoba Hydro's current platform will no longer be supported by SAP beyond 2027.

At the time of the 2023/24 & 2024/25 General Rate Application, Manitoba Hydro had requested that a regulatory deferral account be established for these expenditures, as they do not meet current International Financial Reporting Standards ("IFRS") criteria for capitalization. In advance of Manitoba Hydro spending to replace its SAP system, the utility sought the Board's approval to establish a regulatory deferral account related to the implementation expenses and amortization and recovery of the deferred balance of those expenses over 10 years. Despite presenting preliminary project cost estimates of \$156 million incurred between 2023/24 and 2029/30, Manitoba Hydro noted at that time that the project was still at the pre-planning stage, but considered it likely that any software solution chosen to replace the existing SAP system would be cloud-based.

In Order 101/23, the Board stated:

*With respect to Manitoba Hydro's consulting cost estimate, the Board accepts that cloud computing arrangements must be recognized as O&A expenditures absent an approved regulatory deferral mechanism. [...]*

*The board denies Manitoba Hydro's proposal to establish an SAP S4 HANA deferral account at this time. However, the board invites the utility to apply for the establishment of a cloud computing deferral account once the business case for such a software solution has been completed.*

*The Board finds Manitoba Hydro's arguments for a deferral of cloud computing costs persuasive. However, the board considers it premature to establish such an account before a business case has been completed. The Board is concerned about escalating costs for the project and finds it inappropriate to prove a deferral account before a business case has been completed and a software solution has been chosen.*

In the current application, the utility's transition to SAP S/4HANA Core was highlighted as an enterprise goal with executive support to commence the design phase in 2025/26, despite no final business case being submitted to the Manitoba Hydro-Electric Board for approval. Phase 1 of the project, referred to as SAP Core, is currently in the test stage, with Manitoba Hydro committing to the software going live by December 31, 2026.

In this general rate application, Manitoba Hydro again seeks Board approval for the establishment of a regulatory deferral account to record the operating and administrative ("O&A") Cloud Computing expenses related to the implementation of SAP S/4HANA Core and to amortize the deferred balance for rate setting purposes over a period of 10 years. SAP S/4HANA Core will allow Manitoba Hydro to upgrade and run its critical cost processes, such as finance, human resources, supply chain, and procurement. However, the SAP S/4HANA Core implementation does not include the Customer Information System ("CIS") or any future upgrades or enhancements to Core.

When Manitoba Hydro filed its application, the utility expected to defer \$172 million, split as \$156 million for Manitoba Hydro and \$16 million for Centra, in relation to the SAP S/4HANA cloud computing arrangements. During the course of this Application, Manitoba Hydro revised this expected deferral to \$183 million, split as \$167 million for Manitoba Hydro and \$17 million for Centra. Manitoba Hydro currently projects deferrals of approximately \$70 million for 2025/26, \$95 million for 2026/27, and \$2 million for 2027/28 for the integration expenses. Manitoba Hydro has proposed that the deferral account be amortized over 10 years or the estimated service life of SAP S/4HANA Core. The utility also expects to begin amortizing the deferred project costs in 2027/28, once the SAP S/4HANA Core project is placed into service.

### **14.2.2 Position of the Parties**

#### **Manitoba Hydro**

Manitoba Hydro submits that under IFRS accounting rules, the SAP S/4HANA project implementation costs must be expensed as they cannot be capitalized. According to Manitoba Hydro, deferring the SAP S/4HANA Core costs promotes fairness to customers by matching the cloud computing arrangement (“CCA”) expenses to the period in which the associated investments provide benefits to the customers. The proposed regulatory deferral is only for SAP S/4HANA Core, as plans for future phases are ongoing.

Manitoba Hydro proposes an amortization period of 10 years for this account, which it submits is based on the expected life of the SAP S/4HANA Core license agreement and the effort needed to transition to a cloud-based solution. For example, Manitoba Hydro signed a 5 year software licensing term with a 5-year renewal option, and there are no firm commitments to SAP S/4HANA beyond this initial 10-year period.

#### **Consumers Coalition**

The Consumers Coalition submits that the Board should adopt the proposal of its expert witness Mr. Rainkie, and only provide interim approval of the SAP Core Deferral Account at this time. Further, the Coalition recommends that the Board set an upper limit on the amount that can be deferred without additional Board approval, and require that final approval of this deferral account be subject to the receipt and review of an adequate project justification in a separate regulatory proceeding with intervener participation.

#### **GSS/GSM Representative**

To avoid the revenue requirement impacts of the ongoing SAP S/4HANA Core project in the rate period, the GSS/GSM Representative submits that the Board should approve a deferral account for the SAP project costs and set the amortization period at 15 to 20 years. This intervener is of the view that there are sufficient grounds to warrant this longer amortization period than Manitoba Hydro’s 10-year timeframe. The GSS/GSM Representative views that, if the SAP project only has a useful life of 10 years, the amount of expenditure and employee time being put into it is quite worrisome.

However, for the purposes of rate setting, the GSS/GSM Representative submits that the Board should not approve the amortization of this deferral account until the next rate period.

The GSS/GSM Representative agrees with its expert witness Ms. Davies that, ideally, an amortization period would consider the underlying assumptions used in an investment justification to match costs and benefits. A 15-year amortization period would provide an average between Manitoba Hydro's existing SAP contract lengths, the 30-year life of the current SAP ECC system, and the 13 to 20 year life used for comparable SAP projects in other jurisdictions. Alternatively, the GSS/GSM Representative suggests deferring the project implementation costs in rates until the next general rate application when investment justification is certain, the benefits are both known and incorporated into Manitoba Hydro's financial forecast, and the expenditures can be properly tested as just and reasonable by the Board.

#### **14.2.3 Board Findings**

The Board approves the establishment of the SAP S/4HANA Cloud Computing Arrangement Regulatory Deferral Account effective for the 2025/26 fiscal year. However, the approval is limited at this time to the Phase 1 "Core" implementation costs of SAP S/4HANA, up to a maximum of \$167 million for Manitoba Hydro. For clarity, no additional Phase 1 costs or costs related to the future phases of the implementation of SAP S/4HANA may be deferred without further investment justifications and prior approval from the Board.

The Board further approves an amortization period of 10 years for the deferral account. The Board finds that Manitoba Hydro's evidence demonstrates that this amortization period reflects the current timelines associated with the utility's contract commitments for the SAP S/4HANA software licences. However, given the criticality of the SAP software system to Manitoba Hydro's core operations and the costs associated with a future conversion to another platform, the Board anticipates SAP S/4HANA to serve ratepayers for the foreseeable future. However, given the possibility of future developments associated with SAP software licensing, the Board expects Manitoba Hydro to provide an

update at the next general rate application regarding the anticipated service life of the SAP S/4HANA system and propose changes to the approved 10-year amortization period as required to balance the interests of both the utility and its ratepayers.

The Board accepts the deferral account related to Manitoba Hydro's SAP implementation costs in order to protect ratepayers from the immediate effects of these costs in the rate period. However, the Board finds that approval of the deferral account should only extend to expenditures relating to Phase 1, up to a maximum of \$167 million for Manitoba Hydro. With the future phases of implementing SAP S/4HANA still being planned at this time, and without an approved investment justification, it is premature to extend the deferral account beyond the costs put forward by Manitoba Hydro for Phase 1 of the project. As such, any subsequent phase implementation work, such as a CIS replacement or SAP enhancements, as well as any Phase 1 cost overruns, will require further review and approval from the Board upon submission of related investment justifications and business cases as previously ordered.

While the Board recognizes that it has previously stated it would not approve Manitoba Hydro's deferral account for SAP S/4HANA until it reviewed Manitoba Hydro's business justification, which the Board has yet to receive, the Board accepts the urgency for Manitoba Hydro to transition to SAP S/4HANA before support for Manitoba Hydro's current SAP system ends. However, the Board remains concerned about the lack of information and business justification on this project from Manitoba Hydro.

As explained in section 11.3, the evidence in this proceeding suggests that Manitoba Hydro's "paused" SAP S/4HANA business case was not updated as part of the decision to accelerate the implementation of SAP S/4HANA Core by December 31, 2026. Further, the Manitoba Hydro-Electric Board's approval of the Phase 1 Core project investment justification was not expected until Fall 2025, despite the utility already having approved contracts with SAP and EY and incurring significant expenditures on the project. As such, if Manitoba Hydro does not file its Phase 1 investment justification and advises the Board that it has exceeded, or anticipates exceeding, the currently estimated deferred allocation of \$167 million for Manitoba Hydro for Phase 1 of the SAP S/4HANA project, the Board

will not approve any further cost deferral beyond the approved maximum. Additionally, the Board will not approve any deferral of the expenditures for Phases 2 or 3 of the SAP S/4HANA project unless Manitoba Hydro provides its business justification to the Board. Based on the evidence, the Board does not see Phases 2 or 3 as urgent like Phase 1 to justify the Board granting a deferral without first reviewing Manitoba Hydro's business justification. Manitoba Hydro should provide information about its spending on SAP S/4HANA Core as part of its quarterly O&A report to the Board as explained in section 11.3.

The Board recognizes that the SAP S/4HANA project also encompasses the Centra gas operations, and that \$17 million of the SAP S/4HANA Core implementation is projected to be allocated to Centra starting in 2025/26. In Order 120/25, which addressed Centra's 2024/25 General Rate Application, the Board did not address the issue of the SAP S/4HANA regulatory deferral account as this issue was to be adjudicated in this Manitoba Hydro general rate application. To address the costs incurred by Centra for the SAP S/4HANA Core project starting in 2025/26, the Board intends to review and vary Order 120/25 to be consistent with its treatment of the electric utility, and allow Centra to defer the SAP S/4HANA expenses up to a maximum of \$17 million starting in 2025/26. This matter will be addressed in a separate order that is expected to be released in March 2026.

As referenced in section 11.3, the Board is concerned about Manitoba Hydro engaging in SAP project spending prior to the Board's receipt and approval of its final business case. The Board is also concerned about the risk and prospect of escalating costs for Phase 1 and subsequent phases based on the Phase 0 draft business case filed in this hearing. Deferral accounts can be used in matching the timing of significant, often one-time, expenditures to the time periods over which customers receive the benefit, provided that adequate evidence and justification are filed. However, in the case of SAP S/4HANA, the Board finds that Manitoba Hydro proceeded with substantial spending commitments ahead of a full business case review and Board approval, contrary to prior Board directives. The Board emphasizes the importance of timely, transparent, and compliant filings in response to current and future directives by Manitoba Hydro.

### 14.3 Small-Scale Software Systems Cloud Computing Deferral Account

#### 14.3.1 *Background*

Costs currently incurred for on-premises software development and implementation are capitalized as intangible assets, and recovered in revenue requirement via amortization expense. However, per IFRS guidelines, costs related to implementing CCAs must be recorded as an O&A expense in the year incurred. This is because ownership of the software code remains with the vendor and the user only obtains a licence.

Manitoba Hydro is seeking Board approval to establish a regulatory deferral account to record the annual O&A expenses related to CCA for small-scale software systems and to amortize the deferred balance over six years commencing with the actual in-service date of each investment.

The implementation of small-scale CCA arrangements is related to a shift from on-premise small information technology system toward cloud-based solutions. The small-scale CCA program is intended to provide the Digital & Technology Business Unit of Manitoba Hydro with the ability to implement small-scale CCA technology solutions to address changing Enterprise business needs throughout the year while leveraging available staff resources.

At this time, Manitoba Hydro's CCA expenditures for small-scale software systems total approximately \$41 million in the rate period. These expenditures are needed to replace existing on-premises solutions or for new requirements and do not include the costs for the replacement of any of the corporation's major software systems, such as SAP or Banner.

In Order 120/25, related to the recent Centra 2024/25 General Rate Application, the Board approved the establishment of a cloud computing deferral account for small information technology systems beginning in 2024/25, with a six-year amortization period.

Manitoba Hydro requests as part of this Application that this same proposal apply to the electric segment of its operations. Manitoba Hydro expects small-scale software system deferrals of approximately \$8.2 million, \$8.4 million and \$8.6 million for the 2025/26, 2026/27 and 2027/28 years, respectively, for the integration expenses.

#### **14.3.2 *Position of the Parties***

##### **Manitoba Hydro**

Manitoba Hydro submits that its request aligns with the regulatory deferral sought by Centra in its most general rate application and ensures consistent accounting treatments between the two companies. This approach also standardizes the accounting treatment for all CCA expenses, regardless of whether they are small or large-scale systems, and promotes fairness to customers by matching the CCA expense recognition to the period in which the associated investments provide benefits to the customers.

The amortization period of six years currently reflects the estimated service life of the small-scale CCAs, which is based on the expected life of these cloud-based solutions.

##### **Consumers Coalition**

The Consumers Coalition submits that the Board should not approve the proposed small-scale CCA regulatory deferral account, as the lower materiality of the net deferral amount and the benefits from the special treatment of these costs through a deferral account do not outweigh the concerns that there would be less regulatory scrutiny. The Consumers Coalition's witness Mr. Rainkie also expresses concern that the \$25 million of placeholder small-scale CCA spending and the proposed six-year amortization period results in \$8 million of amortization in the rate period without specific evidence on the record showing how it would be spent.

### **14.3.3 Board Findings**

In alignment with the Board's prior approval of Centra's small system cloud computing deferral account in Order 120/25, the Board approves the establishment of a cloud computing deferral account for small-scale information technology systems, beginning with the 2025/26 year, and with a 6-year amortization. For future general rate applications, the Board expects Manitoba Hydro to provide additional specifics regarding the expenditures included in its small-scale software systems cloud computing deferral.

## **15.0 OTHER REVENUE REQUIREMENT COMPONENTS**

### **15.1 Corporate Allocation**

#### ***15.1.1 Background***

Manitoba Hydro purchased Centra from Westcoast Energy in 1999. At the time, one of the stated objectives was to achieve synergies by Manitoba Hydro owning and operating both the electric and natural gas utilities in the province. Manitoba Hydro financed the acquisition through the placement of a \$250 million debenture against which it subsequently executed three interest rate swaps, financed at a weighted average interest rate of 6.4%. This acquisition debt is one of the highest-interest debts currently held by Manitoba Hydro.

Manitoba Hydro's annual debt financing costs related to the Centra acquisition are approximately \$19 million. While Centra presented a potential 30-year amortization schedule during the 2005/06 General Rate Application, it indicated that it had no intention of paying off the acquisition debt and was instead planning to refinance it at maturity. The Board accepted Manitoba Hydro's revised plan since the gas operation was assumed to have a continuing value. As a result, the financing costs for the acquisition have remained largely the same over the past decade.

During a series of general rate applications in the 2000s, Centra and the Board deliberated over how the acquisition costs, as well as the resulting synergies, should be divided between electric and natural gas ratepayers. As part of Order 208/02, the Board held that ratepayers should not be responsible for the effects of the purchase:

*The shareholders of Hydro initiated the purchase of Centra. The ratepayers of Hydro and Centra should be held harmless as a consequence of the Transaction. Therefore, the risks and benefits associated with the Transaction and the Integration should accrue to the shareholders of Hydro.*

Beginning with the 2005/06 & 2006/07 General Rate Application, the Board approved Manitoba Hydro's allocated share of the annual acquisition costs as approximately \$7 million, with the remaining \$12 million allocated to Centra as a proxy for synergy savings.

The corporate allocation forms part of both Manitoba Hydro's and Centra's approved revenue requirement. Centra's \$12 million share, when taken together with the previously approved \$3 million in net income, represented an approved annual profit of \$15 million flowing to Manitoba Hydro as Centra's shareholder.

More recently, there have been several changes that have affected Manitoba Hydro's treatment of the corporate allocation. Beginning with the 2022/23 fiscal year, the provincial government reduced the debt guarantee fee applicable to Manitoba Hydro's debt from 1.0% to 0.5%. This caused the total corporate allocation to decrease by \$1 million, to total approximately \$17 million. With the Board having previously approved a fixed corporate allocation of \$12 million to Centra, Manitoba Hydro allocated the reduction entirely to electric ratepayers in that year.

On January 9, 2024, Manitoba Hydro invested excess funds of \$100 million in a sinking fund at an average interest rate of 3.7% until 2029, at which point the funds will be applied against the acquisition debt. The excess funds related to Manitoba Hydro International's ("MHI"), sale of its investment in Real Time Digital Solutions Inc. Leading up to the 2029/30 fiscal year, Manitoba Hydro plans to offset a portion of the annual interest cost on the \$250 million acquisition debt. On maturity of the debt on September 1, 2029, Manitoba Hydro plans to discharge \$100 million of the debt while refinancing the remaining \$150 million.

The offsetting interest earned from the sinking fund currently reduces the corporate allocation to approximately \$13 million per year. In the recent Centra 2024/25 General Rate Application, Manitoba Hydro proposed to stop allocating a flat \$12 million per year to natural gas ratepayers and instead allocate the acquisition financing costs through Centra's integrated cost allocation methodology, known as ICAM. The ICAM allocates shared costs incurred for both the electric and gas segments of Manitoba Hydro through a series of allocators and was extensively reviewed in the recent general rate application for Centra. Centra proposed to use the Number of Customers allocator, which allocates 1/3 of costs to Centra and 2/3 of costs to Manitoba Hydro. This resulted in a corporate

allocation of \$4 million to Centra for 2024/25, with a higher allocation of \$9 million to Manitoba Hydro than before the sinking fund was established.

Directive 6 of Order 120/25 approved Centra’s proposal to lower its corporate allocation to \$4 million annually for each of the 2024/25, 2025/26, and 2026/27 fiscal years. To explore whether any amount of corporate allocation even remains justified for Centra’s ratepayers, Directive 11 of Order 120/25 directs Centra to file, with its next general rate application, a plan to eliminate or transition towards an elimination of the corporate allocation, or alternatively provide a rationale for retaining it.

The reductions to Centra’s corporate allocation have a bearing on the corporate allocation charged to Manitoba Hydro’s electric operations. With Manitoba Hydro now being apportioned 2/3 of the finance expense related to the debt incurred for the acquisition of Centra, Manitoba Hydro’s share of the corporate allocation is forecast to be \$10 million for each fiscal year from 2024/25 to 2027/28. Figure 15.1 provides a schedule of Manitoba Hydro’s portion of the corporate allocation for 2021/22 to 2027/28.

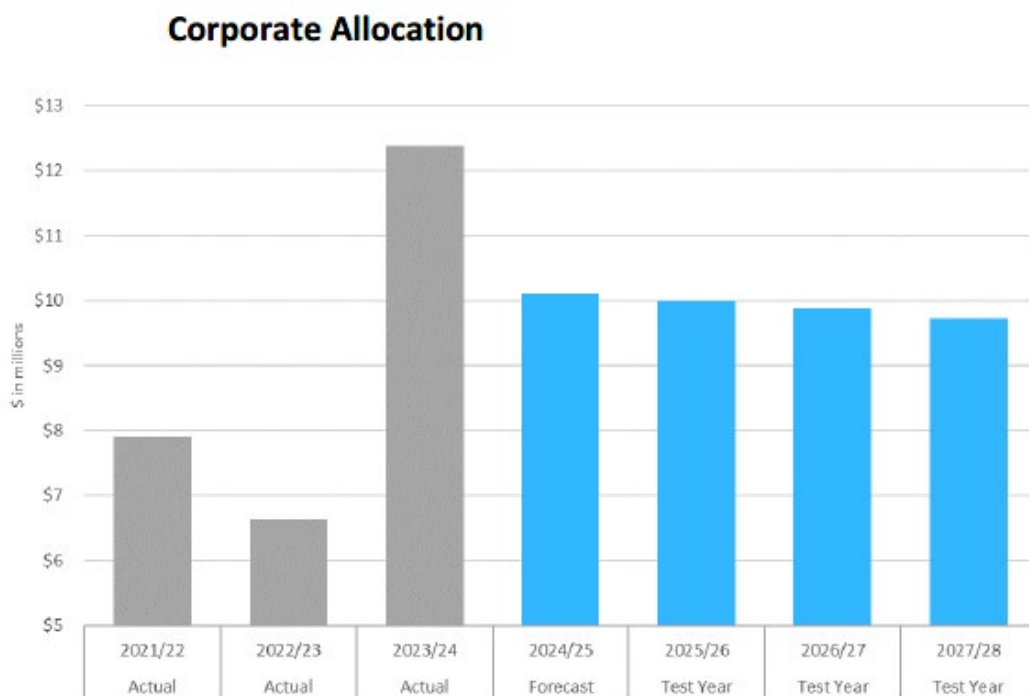


Figure 15.1 — Schedule of Manitoba Hydro’s Corporate Allocation

### **15.1.2 Position of the Parties**

#### **Manitoba Hydro**

Manitoba Hydro states that both electric and gas customers benefit from the reduction in the corporation allocation resulting from the establishment of the sinking fund. According to Manitoba Hydro, it is logical to conclude that the natural gas system provides benefits to the electric segment, as acknowledged in Order 120/25. Manitoba Hydro accordingly submits that it is appropriate that a portion of the Centra acquisition costs be allocated to the electric segment.

Manitoba Hydro disagrees with Mr. Bowman's recommendation to exclude the corporate allocation from Manitoba Hydro's revenue requirement. The utility's primary concern is that, because the Board already approved a fixed allocation of the acquisition financing costs to Centra in the recent natural gas general rate application, if an allocation of the remaining costs to Manitoba Hydro is denied, neither the electric nor the gas utility would be responsible for covering those costs.

Further, Manitoba Hydro submits that the natural gas system continues to provide benefits to the electric segment. Without Centra, Manitoba's energy needs could not be met and Manitoba Hydro's electric asset base would need to be substantially larger. In turn, electric customers would be required to cover the costs of this larger asset base. As such, it remains appropriate that a portion of the Centra acquisition costs be allocated to the electric segment.

#### **Manitoba Industrial Power Users Group**

MIPUG submits that the costs to finance the acquisition of Centra are not a valid component of the electrical system revenue requirement. As such, these costs should be excluded from the electricity statements, and debt balances should be excluded from the electricity balance sheet.

MIPUG relies on its witness Mr. Bowman's finding that the corporate allocation is of no ongoing relevance to electric operations. According to Mr. Bowman, the corporate allocation reflects no used or useful electricity assets, and should not be included in the

“properly allocated” electricity operations revenue requirement as set out in *The Manitoba Hydro Act*.

MIPUG submits that Manitoba Hydro’s justification in support of electric ratepayers paying for the natural gas utility infrastructure is a statement of fact that, if true today, was equally true in 2002 when the Board concluded in Order 208/02 that electrical ratepayers should be held harmless from paying for the acquisition. Furthermore, the logical extension of this premise is that Manitoba Hydro could equally include in revenue requirement annual payments to every Red River Co-op Gas Bar, or to pay Winnipeg Transit to run diesel buses rather than electric vehicles. Given this rationalization, there would appear to be no principled manner to compute what cost should be included in the electric revenue requirement.

MIPUG also points to the adverse impact of Manitoba Hydro’s approach on all electric customers that cannot benefit from accessing gas for winter heating. These customers would be bearing costs related to a gas utility which provides no service to them, thereby increasing their all-electric winter heating bills.

MIPUG notes that *The Manitoba Hydro Act* was revised to define the revenue requirement of the electric utility and the recent Order 120/25 concluded that any justification for cost allocation based on synergies “may have outlived its usefulness”. Despite this diminishing basis for allocating Centra costs to electrical ratepayers, the allocation in the rate period is increased to \$9 million as compared to a \$6 million allocation in past periods based on resulting “synergies”.

MIPUG concludes that electrical ratepayers should not be exposed to interest costs for this debt. It recommends excluding the acquisition cost debt balance from the long-term borrowings reported on the electrical statements. According to MIPUG, financing of the debt could be achieved through any measure that the shareholder sees fit to implement, potentially including income and gains from unregulated subsidiaries.

### **15.1.3 Board Findings**

The Board approves Manitoba Hydro's proposal to include the \$10 million corporate allocation in Manitoba Hydro's revenue requirement for each of the three years of the rate period.

The Board accepts that the \$10 million reflects the Number of Customers allocator in Centra's integrated cost allocation methodology ("ICAM"), which was approved as part of Order 120/25 and allocates 2/3 of the cost to Manitoba Hydro. As the Board previously approved Centra's proposal to reduce its proportion of the corporate allocation to \$4 million in the recent 2024/25 Centra General Rate Application, the Board finds the allocation of the remaining \$10 million to be reasonable and consistent with the Number of Customers allocator.

Once the Board has received Centra's plan to eliminate, or its rationale for retaining, the corporate allocation at the next Centra general rate application, the Board can re-evaluate the reasonableness of Manitoba Hydro's plan to refinance the outstanding acquisition debt and the manner in which the costs of doing so should be allocated between electric and natural gas ratepayers.

## **15.2 Water Rentals, Fuel & Power Purchases, and Capital & Other Taxes**

### **15.2.1 Background**

Similar to prior general rate applications, water rentals and assessments, fuel and power purchases, and capital and other taxes are included as line items in Manitoba Hydro's proposed revenue requirement. These items are closely tied to the corporation's load forecast and export revenue forecast, which are discussed further in sections 7.0 and 8.0.

Water rentals are prescribed by subsection 48(3.2) of the *Water Power Regulation* and consist of a nameplate-capacity based fee as well as an output-based fee. Because the fees are prescribed by government and are tied to the available water flows with which to generate power, Manitoba Hydro has no control over the amount of water rentals it must pay. The utility has projected its water rentals to average \$80 million annually over the planning horizon. Water rentals are paid to the Province of Manitoba in exchange for

Manitoba Hydro’s use of water resources to operate its hydraulic generating stations. Assessments are paid to various regulatory and market organizations.

Fuel and power purchased includes purchased energy from external Canadian and U.S. suppliers, wind power purchased from existing and future independently owned wind farms, transmission charges, fuel for the thermal generating stations and remote diesel sites, as well as the amortization of the intangible asset and transmission charges associated with the Great Northern Transmission Line.

In the short term, Manitoba Hydro expenses for fuel and power purchased are influenced by the 2025/26 drought, and the Board has reviewed the purchases for 2025/26 in confidence. In the medium term, as seen in Figure 15.2, the projected fuel and power purchased over the forecast period begins to increase in 2029/30 as new wind Power Purchase Agreements (“PPAs”) are added in 200 MW increments every two years for a total installed capacity of 600 MW by 2033/34. Further, the impact of the new wind PPAs, together with the expiration of several export contracts and declining export volumes, is that net export revenue eventually decreases over the forecast period to the point where expenses exceed revenue by 2042/43.

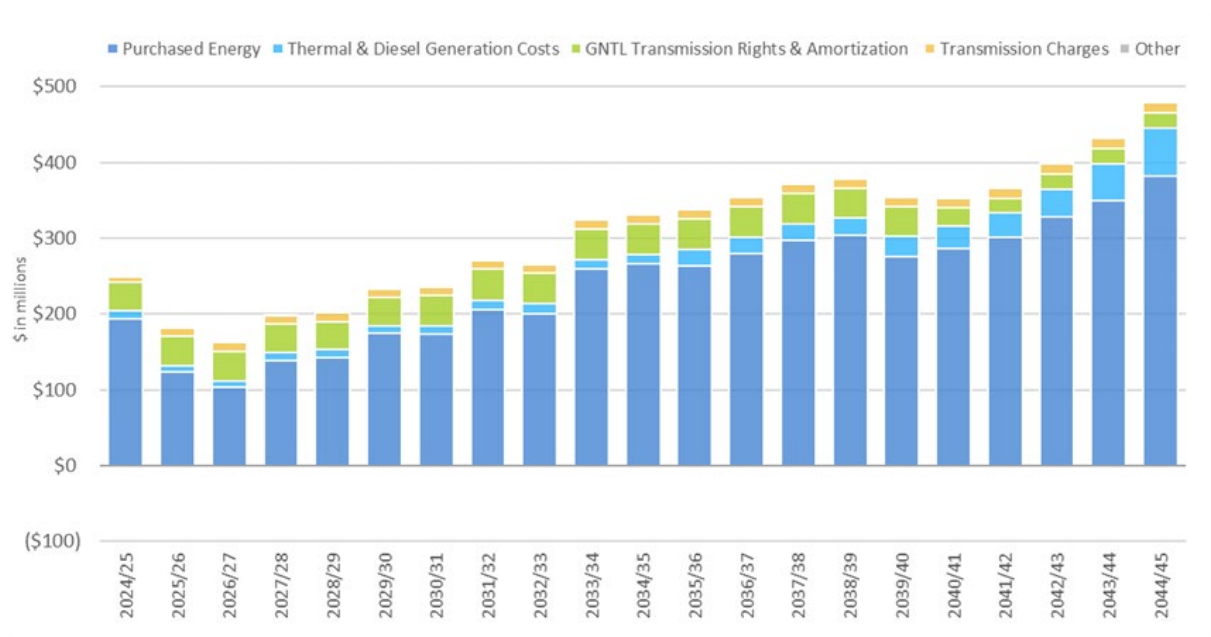


Figure 15.2 — Projected Fuel and Power Purchased

Capital and other taxes primarily consist of payments made to the Province of Manitoba for capital and payroll taxes, as well as to municipalities within Manitoba for grants in lieu of property taxes. Effective April 1, 2025, the Province of Manitoba eliminated the capital tax for Crown Corporations, including Manitoba Hydro. Manitoba Hydro estimates that the elimination of the capital tax reduces its revenue requirement by approximately \$395 million over the rate period and \$3.4 billion over the 20-year planning horizon. Figure 15.3 shows the projected capital and other taxes over the forecast period.

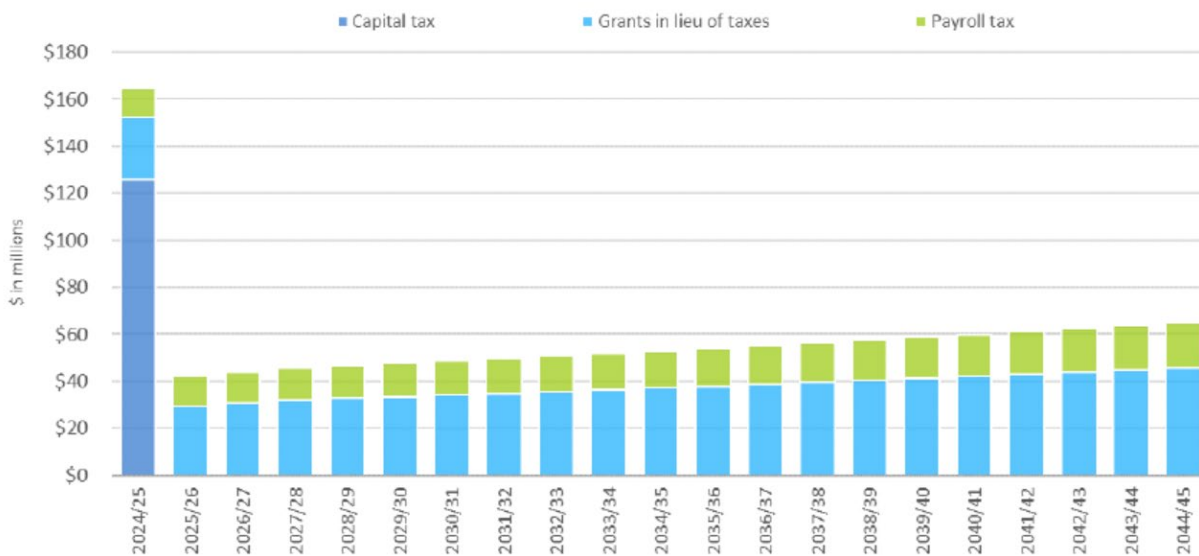


Figure 15.3 — Projected Capital and Other Taxes

The reductions in the water rentals and debt guarantee fee in 2022, as well as the elimination of the capital tax and the further reduction in the debt guarantee fee for the 2025/26 test year, has caused Manitoba Hydro’s total payments to government to decline from \$495 million in 2020/21 to \$111 million in 2027/28. Manitoba Hydro has stated that absent the recent government fee relief, it would have required rate increases of 5.5% to achieve the same financial results.

**15.2.2 Board Findings**

The Board accepts Manitoba Hydro’s projected revenue requirement for water rentals, fuel and power purchases, and capital and other taxes for the 2025/26 to 2027/28 rate period.

The Board recognizes that, absent the reductions in government fees and the elimination of capital taxes, Manitoba Hydro's rate proposal would have needed to be higher than its requested 3.5% rate increase. As such, any changes which reverse these reductions in government fees would have an upward impact on rates.

### **15.3 Other Expenses**

#### **15.3.1 Background**

Another line item in Manitoba Hydro's proposed revenue requirement is other expenses. The forecast of other expenses is comprised primarily of demand-side management ("DSM") expenditures, in addition to site remediation, revaluation adjustments to the JKDA Preferred Distributions Obligation, and regulatory costs. These expenses are removed from the income statement, deferred, and then amortized through net movement in regulatory balances. Manitoba Hydro projects incurring \$88 million for other expenses for 2025/26, \$78 million for 2026/27, and \$83 million for 2027/28.

Effective April 1, 2020, Manitoba Hydro transitioned certain DSM programs to Efficiency Manitoba. While the DSM programs are administered by Efficiency Manitoba, the programs are funded by Manitoba Hydro. Under *The Efficiency Manitoba Act*, Efficiency Manitoba is required to achieve electrical energy savings of least 1.5% of the consumption of electricity in the preceding year. Further, Manitoba Hydro must provide Efficiency Manitoba with the funding necessary for it to implement an approved efficiency plan and to carry out its responsibilities under the Act, less any funds Efficiency Manitoba has available from other sources.

Site remediation expenditures include those incurred for the remediation of contaminated corporate facilities and diesel generating sites. Manitoba Hydro has projected lower site remediation costs for the rate period, with higher DSM costs.

Regulatory costs are those incurred as a result of regulatory hearings and other regulatory applications or compliance matters. Manitoba Hydro has projected higher regulatory costs for the rate period, primarily because of the costs associated with this Application, as well as the reviews of its integrated resource plan, preliminary estimates, and major new facilities in accordance with the requirements of *The Manitoba Hydro Act*.

In 2023/24, Manitoba Hydro included a one-time non-recurring expense related to the recognition of the preferred distributions obligation due to the impact of the ownership changes at final closing of the amended JKDA. In Order 61/24, the Board approved a deferral account for this expense on an interim basis, to be amortized over the expected life span of the Keeyask Generating Station. The 2024/25 forecast also reflects the impacts of the annual revaluations of the preferred distributions obligation. The Board approved the initial revaluation in Order 35/25.

### **15.3.2 Board Findings**

The Board accepts Manitoba Hydro's projected revenue requirement for other expenses for the 2025/26 to 2027/28 rate period. Please see section 14.1 regarding the Keeyask Preferred Distributions Deferral Account.

## **16.0 OVERVIEW OF MANITOBA HYDRO'S CUSTOMER CLASSES AND COST OF SERVICE STUDY**

As explained in section 2.5, establishing rates for electricity sales is a multi-step process. Generally, a utility must group its customers into various customer classes and establish its revenue requirement. For Manitoba Hydro, this information, together with other inputs such as the load forecast, then informs the results of a cost of service study. In turn, these results inform, together with various rate design choices, the rates that are ultimately charged to consumers.

In this section, additional background information is provided on Manitoba Hydro's customer classes and cost of service study in order to supplement the cost of service and rate design matters discussed in sections 17.0 and 18.0.

### **16.1 Customer Classes**

Manitoba Hydro's customer classes are defined by grouping customers that have similar electricity usage characteristics (e.g., load shape) and similar service levels (e.g., voltage level or whether the customer or Manitoba Hydro owns the on-site transformers). Manitoba Hydro's customers are currently divided into the following major customer classes:

- Residential: Individually metered single-family housing or multi-residential dwellings;
- General Service Small Non-Demand ("GSS-ND"): Commercial customers, including bulk-metered apartment buildings, with a billing demand up to 50 kVA and that rely on utility-owned transformers;
- General Service Small Demand ("GSS-D"): Commercial customers with a billing demand of more than 50 kVA and up to 200 kVA, and that rely on utility-owned transformers;
- General Service Medium ("GSM"): Commercial customers with a billing demand of more than 200 kVA, and that rely on utility-owned transformers;

- General Service Large 750 V – 30 kV (“GSL 750V-30kV”): Industrial customers receiving electricity at a voltage exceeding 750 V but not exceeding 30 kV, and that use their own transformers;
- General Service Large 30 – 100 kV (“GSL 30-100kV”): Industrial customers receiving electricity at a voltage exceeding 30 kV but not exceeding 100 kV, and that use their own transformers;
- General Service Large > 100 kV (“GSL >100kV”): Industrial customers receiving electricity at a voltage exceeding 100 kV, and that use their own transformers; and
- Area & Roadway Lighting (“A&RL”): Street lights and sentinels such as floodlights for parking lots.

As of April 1, 2025, the Board must set Manitoba Hydro’s rates under section 39 of *The Manitoba Hydro Act*. Under this section, the Board is required to take into account the seven ratemaking rules listed in subsection 39(5), as well as the policies set out in subsection 39.1. Rule 5 of subsection 39.1(1) and clauses 39.1(1)(a) and (b), reproduced below, relate to Manitoba Hydro’s customer classes and the setting of rates for those classes:

*39(5) The following rules apply to the approval or variation of rates by the regulator:*

*[...]*

*5. Rates for different customers or classes of customers must not differ based on affordability or other socio-economic factors.*

*[...]*

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

*(a) the rates charged by the corporation to each class of grid customers in Manitoba are to be based on the revenue requirements properly allocated to that class;*

*(b) the rates charged to a class of grid customers in Manitoba are to be the same throughout the province; [...]*

Manitoba Hydro's existing customer class definitions have been in place for a long time, mainly because the characteristics of Manitoba Hydro's customers have not undergone material changes over the years.

## 16.2 Cost of Service Study

Once Manitoba Hydro's revenue requirement has been determined, the next step in the rate-setting process is to determine which customer class should be responsible for paying which portions of the revenue requirement. Because so many of the costs incurred by Manitoba Hydro are to provide service to more than one customer class, an organized, methodological approach to determining each class's responsibility for the shared or common costs is required.

As part of its general rate applications, Manitoba Hydro typically prepares prospective cost of service studies ("PCOSS") to determine how the utility's costs for a future test year, which the Board approves as Manitoba Hydro's revenue requirement, should be allocated between the various customer classes. The output of the cost of service study is used as a tool in determining the rate design and rates for each of the different customer classes. In determining customer rates, the Board also considers other factors, such as fairness and equity, in the final rate design. This is further addressed in section 18.0 below.

A cost of service study consists of three steps. For Manitoba Hydro, those steps are as follows:

1. Step One: Functionalize or categorize the total annual costs into one of five electric utility functions (Generation, Transmission, Subtransmission, Distribution, Customer Service).

2. Step Two: Classify the functionalized costs into one of three categories based on the system design and operating characteristics that cause the costs to be incurred. The three categories include:
  - a. Energy costs, that vary based on the amount of electricity consumed;
  - b. Demand costs, that are driven by the maximum amount of electricity consumed at any particular point in time; and
  - c. Customer costs, that vary by the number of customers.
3. Step Three: Allocate the functionalized and classified costs among Manitoba Hydro's customer classes through allocators. Generally, the allocators relate to the way that each customer class contributes to the three cost classifications. Costs that are clearly attributable to only a single customer class may be directly assigned to that class instead of being allocated to several classes.

The functionalization, classification, and allocation process is illustrated in Figure 16.1:

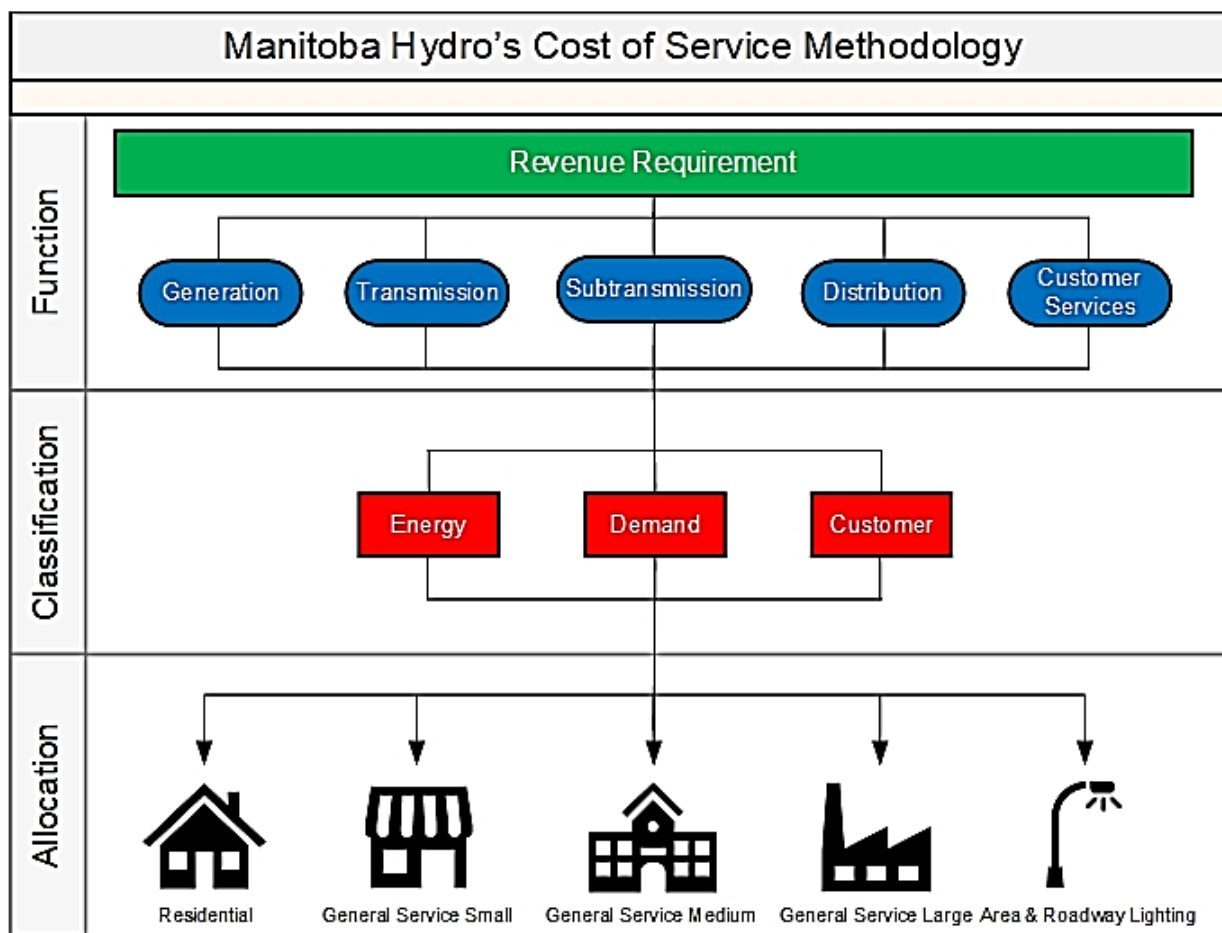


Figure 16.1 — Manitoba Hydro Cost of Service Methodology (Simplified)

Manitoba Hydro's cost of service study methodology was last fully reviewed in 2016, and addressed in Order 164/16. In Manitoba Hydro's 2017/18 General Rate Application, the utility implemented the Order 164/16 methodology changes in PCOSS18, with small refinements to the methodology further approved by the Board in Order 59/18. These changes were subsequently implemented in PCOSS24 for the 2023/24 & 2024/25 General Rate Application and approved in Order 101/23.

In the current application, Manitoba Hydro based its proposed cost allocations on its most recent cost of service study, PCOSS26.

### **16.3 Cost of Service Changes from PCOSS24**

PCOSS26 uses the Board's approved cost of service methodology. While PCOSS26 does not incorporate new cost of service methodology changes, PCOSS26 does reflect various changes to the inputs to the cost of service study. Specifically, PCOSS26 was prepared using Manitoba Hydro's 2025/26 revenue requirement proposals, as well as using the results from the 2024 Electric Load Forecast. Notably, the cost of service study input changes include updated load research results (as discussed in section 17.3 below), a \$280 million reduction in export revenue compared to the record level included in PCOSS24, as well as the elimination of capital tax and the reduction of the debt guarantee fee announced as part of the 2025/26 Provincial Budget.

### **16.4 Cost of Service Study Results and Revenue-to-Cost Coverage Ratios**

The results of Manitoba Hydro's cost of service study show the costs the utility incurs to provide service to each customer class. These allocated costs can be compared to the revenues that are projected to be received from each customer class in the chosen year of the rate period. The revenues and allocated costs may not align, meaning some classes may be paying more than their allocated costs while other classes are paying less.

The ratio of a customer class's forecasted revenue to the total costs allocated to that class is known as the revenue-to-cost coverage ratio ("RCC"). For example, an RCC of 100% means that a class is at "unity" (i.e., the class pays 100% of those costs allocated to that class). An RCC ratio of more than 100% means that a class pays more than the costs allocated to that class, while an RCC ratio of less than 100% means the class pays less than the costs allocated to it.

Figure 16.2 presents the RCCs resulting from PCOSS26 as compared to those from PCOSS24 at the last general rate application.

<b>Customer Class</b>	<b>PCOSS24 RCC</b>	<b>PCOSS26 RCC</b>
Residential	94.4%	96.9%
General Service Small Non-Demand	109.7%	108.0%
General Service Small Demand	101.8%	96.0%
General Service Medium	100.3%	97.8%
General Service Large 750V-30kV	97.9%	100.9%
General Service Large 30-100kV	112.4%	110.4%
General Service Large >100kV	113.2%	110.6%
Area & Roadway Lighting	108.2%	104.2%

Figure 16.2 — PCOSS26 RCC Results Compared to the PCOSS24 RCC Results

The above PCOSS26 results are further discussed in section 18.0 of this Order.

## 17.0 COST OF SERVICE ISSUES

The following subsections address the cost of service methodology issues that were raised by the interveners in this proceeding.

### 17.1 Jurisdiction on Cost of Service and Rate Design

#### 17.1.1 *Background*

As discussed throughout this Order, subsection 39(5) of *The Manitoba Hydro Act* now contains seven ratemaking rules that the Board is required to take into account when setting rates. Rule 4 of subsection 39(5) states as follows:

#### **Rules for approving or varying rates**

**39(5)** The following rules apply to the approval or variation of rates by the regulator:

[...]

4. Subject to the policies set out in section 39.1, the corporation may propose changes to its cost allocation method or rate design, and the regulator may approve or disallow those changes or require the corporation to make other changes to them. But the regulator may not require a change to the classification of customers for rate-setting purposes that has not been proposed or agreed to by the corporation.

#### **Règles d'approbation ou de modification des tarifs**

**39(5)** Les règles qui suivent s'appliquent à l'approbation et à la modification des tarifs par l'autorité de réglementation:

[...]

4. Sous réserve des politiques énoncées à l'article 39.1, la Régie peut proposer des modifications à sa méthode de répartition des coûts ou à sa conception tarifaire, et l'autorité de réglementation peut approuver ou refuser ces modifications ou demander à la Régie d'y apporter d'autres modifications. Toutefois, elle ne peut pas demander une modification à la classification des clients à des fins de fixation des tarifs si cette modification n'a pas été proposée ou acceptée par la Régie.

As part of this Application, Manitoba Hydro did not incorporate or propose any changes to its existing cost allocation methods or rate design. However, several interveners have proposed such changes for the Board to consider. The issue has arisen whether, in light of rule 4 of subsection 39(5), the Board has the jurisdiction to direct Manitoba Hydro to make changes to its cost of service methodology or rate design if the utility has proposed no such changes.

### 17.1.2 *Position of the Parties*

#### **Manitoba Hydro**

Manitoba Hydro's Application does not incorporate any changes to its existing cost of service methodology or rate designs. Despite this, Manitoba Hydro has considered the various recommendations made by the interveners' witnesses and proposes some changes to its cost allocation methods for the Board's consideration.

Manitoba Hydro submits that the Board only has jurisdiction to approve, vary, or disallow the changes proposed by Manitoba Hydro, and that it cannot direct Manitoba Hydro to make changes to the cost of service methodology or its rate design. Interpreting subsection rule 4 of 39(5), Manitoba Hydro submits that the legislation does not contemplate that any party other than Manitoba Hydro can propose changes to its cost allocation method or rate design. Manitoba Hydro further submits that the French version of the Act does not alter its interpretation and that there is no discrepancy between the English and French versions of rule 4. In Manitoba Hydro's view, the Legislature chose to include reference to the corporation proposing changes in rule 4, and a reasonable interpretation of the provision is that the Board can only require Manitoba Hydro to make changes once a change has been put in issue by Manitoba Hydro.

#### **Consumers Coalition**

The Consumers Coalition disagrees with Manitoba Hydro's interpretation of subsection 39(5), rule 4 of *The Manitoba Hydro Act*. According to this intervener, the English version of rule 4 makes a stark distinction between "require the corporation to make other changes to them" and "But the regulator may not require a change to the classification of customer [...]." The Consumers Coalition submits that the key word "But" after the period makes it clear that the first part of the rule is talking about what the Board can do, contrasted against what the Board clearly cannot do. The French version confirms this and as such, the Board can propose and require changes to the cost of service study methodology and rate design even if Manitoba Hydro did not propose or support the change.

### **GSS/GSM Representative**

The GSS/GSM Representative submits that Manitoba Hydro's position regarding rule 4 of subsection 39(5) is not consistent with a reasonable interpretation of that section. Neither subsection 39(5) nor any other section of *The Manitoba Hydro Act* prohibits the Board from considering changes to the cost allocation or rate design put forward by interveners, with the exception of changes to the classification of customers for rate-setting purposes. As a result, the GSS/GSM Representative submits that the suggestion that Manitoba Hydro dictates the Board's scope of review of cost of service methodology and rate design is contrary to any reasonable statutory interpretation of *The Manitoba Hydro Act* and undermines the important role that the Board and interveners play in ensuring that cost of service methodology is appropriately updated.

### **Manitoba Industrial Power Users Group**

MIPUG submits that when the rules of statutory interpretation are properly applied, it is clear that subsection 39(5), rule 4 provides the Board with jurisdiction to require changes to Manitoba Hydro's cost allocation method or rate design, without Manitoba Hydro first proposing the change. To determine otherwise would be inconsistent with general rate regulation principles of fairness, *The Manitoba Hydro Act* as a whole, and the sections surrounding this rule.

Firstly, when reading *The Manitoba Hydro Act* as a whole, the qualifier "subject to the policies set out in section 39.1" cannot be ignored. Clause 39.1(1)(a) states that one of the policies is that rates must be based on the revenue requirement properly allocated to that class. As such, the qualifier to rule 4 preserves the Board's requirement to properly allocate revenue requirement, and the Board must ensure that such policy is adhered to when considering cost allocation methods under this subsection.

Secondly, MIPUG submits that it must be assumed that each of the words in rule 4 has meaning and that the Legislature did not intend to create any redundancy. With respect to the phrase "or require the corporation to make other changes to them", MIPUG submits that the only possible interpretation of this phrase which ensures compliance with these

principles is to interpret “them” as referring to the “cost allocation method or rate design”. Manitoba Hydro’s interpretation of “them” as meaning the changes proposed by Manitoba Hydro would lead to redundancy and render some of the phrase meaningless or unclear. Further, given that more precise language is used elsewhere in the Act to refer to Manitoba Hydro’s proposals, the decision to use less precise language later in the same sentence should be assumed to indicate the “other changes” power is broader than suggested by Manitoba Hydro. Regarding the second sentence starting with “But”, it would also be unnecessary to include this specific exception or restriction on the Board’s ability to require changes if the Board had no ability whatsoever to require changes as suggested by Manitoba Hydro’s interpretation.

Thirdly, MIPUG states that its interpretation of rule 4 is further supported when considering the Board powers under the French version of the provision. Specifically, the French version uses the language “ou demander à la Régie d’y apporter d’autres modifications”. In the French language, “d’y” does not refer to the changes proposed by Manitoba Hydro and leaves no doubt that the Board has independent jurisdiction to require Manitoba Hydro change its cost allocation methodologies without being conditional on Manitoba Hydro first proposing such a change.

### **17.1.3 Board Findings**

The Board finds that it has jurisdiction to direct Manitoba Hydro to make changes to its cost of service methodology or rate design regardless of whether the utility has proposed such changes.

The principal rule of statutory interpretation in Canada is what is known as Driedger’s modern principle:

*Today there is only one principle or approach, namely, the words of an Act are to be read in their entire context in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act and the intention of Parliament.<sup>3</sup>*

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<sup>3</sup> Elmer A. Driedger, *The Construction of Statutes*, 2nd ed., Toronto, Butter

Under clause 2(2)(a) of *The Manitoba Hydro Act*, it is an express purpose of the statute to establish a regulatory framework for determining rates for the provision of power. Clause (a) of rule 2 of subsection 39(5) specifically requires the Board to take into account and be guided by the policies set out in section 39.1 in determining such rates. Clause 39.1(1)(a) makes it a policy of the Government of Manitoba that rates charged to each class of grid customers in Manitoba are to be based on the revenue requirements properly allocated to that class. It would be inconsistent with that policy to interpret rule 4 in a manner that prevents the Board from directing changes to Manitoba Hydro's cost of service methodology, as this would prevent the Board from being guided by the government's policy in the absence of Manitoba Hydro's consent.

Furthermore, to the extent that there is any ambiguity in the English version of rule 4, the Board must consider the equally authoritative French version and the rules of bilingual interpretation as developed in *R. v. Daoust*, 2004 SCC 6 and summarized as follows in *The Law of Bilingual Interpretation*:<sup>4</sup>

1. The first step consists in examining the two versions to determine whether there is a discordance between the two versions. "Discordance" here has the same meaning as "conflict" does in any of the earlier cases: If the two versions are the same, there is really no issue. If there is a discordance, the interpreter must proceed to the next step.
2. The second step consists in determining the nature of the discordance, and determining the shared meaning. There are three possibilities here:
  - a) The versions are in "absolute conflict". Each is clear and no shared meaning can be found.
  - b) One version is ambiguous and the other clear. The clear version provides the shared meaning.

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worthington, 1983, at 87.

<sup>4</sup> Metallic, Bastarache, Morris and Essert, *The Law of Bilingual Interpretation* (Toronto: Butterworths, 2008), at pp. 47-48.

- c) One version is broad and the other narrow. The narrow version provides the shared meaning.
3. At the conclusion of the second step, the interpreter is armed either with (i) a shared meaning, arising out of (b) or (c), or (ii) a conclusion that no shared meaning exists, arising out of (a).
  4. The third step consists of an appeal to extrinsic methods of determining the intention of the legislator with respect to the provision. There are two possibilities here:
    - a) The extrinsic evidence of intent allows for a choice between the two conflicting versions as to which provides the true meaning of the provision.
    - b) The extrinsic evidence of intent is examined to ensure that the shared meaning is not inconsistent with it.

In the Board's view, to the extent that there is any discordance, it can be resolved at the second step of the bilingual interpretation process, since the meaning of the French version is clear. As submitted by MIPUG, the reference "d'y" in the French version refers to the cost of service methodology and rate design and makes it clear that the Board has the jurisdiction to require the utility to make changes to either.

Lastly, the Board agrees with the Consumers Coalition that the first sentence of rule 4 must be read in conjunction with the second sentence, which creates an express prohibition against the Board directing new customer classes. The Legislature chose not to add a similar prohibition to the first sentence, which highlights that the sentence is not intended to foreclose such jurisdiction.

## **17.2 Review of Customer Class Definitions**

### ***17.2.1 Background***

Manitoba Hydro's customer classes are described in section 16.1.

In response to its commitments during the 2023/24 & 2024/25 General Rate Application, in this hearing, Manitoba Hydro filed an analysis of the General Service Large 750V-30kV subclass that sought to assess the homogeneity of customers within this class and

whether there was merit in adjusting the subclass. Manitoba Hydro's analysis shows that the General Service Large 750V-30kV subclass includes a diverse mix of customers that vary considerably in size and usage patterns.

### **17.2.2 Position of the Parties**

#### **Manitoba Hydro**

Manitoba Hydro states that its assessment indicates that, despite the lack of customer homogeneity in the General Service Large 750V-30kV, there is no evidence of excessive cross-subsidies within the class and that no changes to customer classifications are necessary. As a result, Manitoba Hydro opposes MIPUG's witness Mr. Friesen's suggestion to allow General Service Large 750V-30kV customers to pay for dedicated utility assets. Manitoba Hydro cites fairness issues and submits that it is unclear whether the four customers affected would constitute a new customer class, how a transfer of asset ownership would occur if assets are located in public rights of way, and whether these customers would pay a rate rider or one-time payment.

Manitoba Hydro further notes that it previously committed to evaluating the further flattening of the General Service Medium rate structure and to seek feedback from customers prior to implementing changes. This work has not been completed and in the interest of rate stability, no changes are being proposed at this time.

#### **GSS/GSM Representative**

The GSS/GSM Representative adopts the recommendation put forth by its witness Ms. Davies that, given the diversity of customer mix within the General Service Small and General Service Medium classes, Manitoba Hydro should also undertake a review of these classes similar to the analysis filed for the General Service Large 750V-30kV subclass. In Ms. Davies view, a review of the General Service Small and General Service Medium classes should focus on potential cross-subsidies and overlap, bill volatility, potential de-harmonization between the General Service Small Demand and Non-Demand classes, and potential simplification to the current rate structure.

Accordingly, the GSS/GSM Representative submits that the Board should direct Manitoba Hydro to review the General Service Small and General Service Medium rate structures, in conjunction with workshops with the customers in these two classes, and consider updates that promote bill stability and minimize cross-subsidization. The GSS/GSM Representative submits that informal workshops and rate design applications are common in many other jurisdictions and provide an efficient and focused process to implement matters of customer rates without clogging up a general rate application.

### **Manitoba Industrial Power Users Group**

MIPUG's witness Mr. Friesen submits that Manitoba Hydro's analysis of the General Service Large 750V-30kV subclass does not address his concern that larger customers located near substations and served by dedicated assets may impose lower costs on the system than smaller customers relying on shared and higher cost infrastructure. Accordingly, Mr. Friesen recommends Manitoba Hydro's analysis should be refined to consider differences in embedded unit costs for energy and demand that reflect the non-homogenous use and value of distribution assets used by larger customers connected to the distribution system via dedicated distribution substations and transformers or dedicated distribution feeders. Further, Mr. Friesen submits that Manitoba Hydro should develop a process by which larger General Service Large 750V–30kV customers be permitted to pay directly for dedicated Manitoba Hydro-owned distribution equipment used to connect their facility to the sub-transmission or transmission system, and pay General Service Large 30–100kV rates that are more representative of the costs such customers actually impose on the system.

#### **17.2.3 Board Findings**

Based on the amended requirements in *The Manitoba Hydro Act*, specifically subsection rule 4 of 39(5), the Board does not have jurisdiction to direct Manitoba Hydro to create new, or make amendments to existing, customer classes unless such changes are proposed or agreed to by Manitoba Hydro. However, the Board concludes that this limited jurisdiction does not prevent the Board from directing Manitoba Hydro to further study its existing customer classes and bring back possible change proposals for the Board's

consideration in future proceedings if compelling concerns are identified during rate proceedings.

In regards to proposals in this hearing for a further review of the General Service Large 750V-30kV customer subclass and the possibility of allowing customers within this subclass to pay directly for dedicated distribution assets, the Board finds that this is an unworkable proposal. There is the issue of how such customers would pay for the dedicated assets and whether they would pay a lump sum for the undepreciated cost of the assets, or an ongoing rate rider, or whether they would pay for their specific assets serving them or be pooled with the small number of other similarly situated customers served by dedicated assets. There remains other unanswered questions, such as whether such customers would have to pay the full cost for any new or replacement assets. Further, the Board finds that the possible changes identified during this proceeding could lead to issues of fairness within the class and complications regarding the transfer of asset ownership to uniquely situated customers that would be able to pay directly for dedicated assets.

Given Manitoba Hydro's commitments at the last general rate application to review the General Service Medium rate structure, the Board directs Manitoba Hydro to complete its planned evaluation of a further flattening of the General Service Medium rate structure. The Board also directs Manitoba Hydro to further analyze and assess the General Service Small and General Service Medium classes for potential cross-subsidies or overlap, and to consider the potential deharmonization of the General Service Small Demand and General Service Small Non-Demand classes. Manitoba Hydro is directed to report on its evaluation findings at the next general rate application. In addition to the Board's finding above on the limited jurisdiction on directing changes to customer classes, the Board expects this review to allow Manitoba Hydro to more expeditiously investigate concerns regarding existing customer classes and propose changes in a future proceeding if deemed necessary.

## 17.3 Load Research Results and Class Coincident Peaks

### 17.3.1 Background

Manitoba Hydro's load research program, which encompasses data collection, processing, and analysis, generates the Load Research Report that aids in the analysis and design of rates. For example, this report determines the domestic classes' contribution during electricity system peak times, which then informs the allocators used within Manitoba Hydro's cost of service studies. Load Research data are also utilized to inform the electric load forecast, which is further discussed in section 7.0 above, as well as complex customer billing, on-line energy profiling services, and for various planning efforts within the utility.

The Load Research Report aims to demonstrate the typical consumption behaviours by developing hourly load shapes for the various customer classes. The hourly load shapes are models that characterize one year (8,760 hours) of typical hourly energy demand of a particular customer class based on previous years of historical interval data collected from the sample meters included in Manitoba Hydro's load research program.

Using the hourly load shape data from its Load Research Report, Manitoba Hydro calculates the coincident and non-coincident electricity peak values for each class, which are then used as inputs into Manitoba Hydro's cost of service study. These peak allocators are based on the classes' share of the total electricity demand experienced during the time of a system peak.

At the 2023/24 & 2024/25 General Rate Application, Manitoba Hydro's PCOSS24 utilized the averaged load and coincident factors from the previous eight load research studies (2007/08 to 2014/15), each of which were based on a single year of load research data.

In the current application, PCOSS26 utilizes the updated load and coincident factors from the 2022/23 Load Research Report, which was developed using five years of historical metered interval data and a Rank and Average methodology to create the class hourly load shapes. The updated methodology, which was reviewed by DNV Energy Insights in 2023, is intended to create class hourly load shapes that are more reflective of a typical

representation of customer energy profiles and system peak contributions. This improvement was sought in order to improve Manitoba Hydro's load forecast methodology, as well as support rate designs and integrated resource planning activities.

The updated 2022/23 load research data result in updated class contributions to the system coincident peak, which in turn affect the PCOSS26 results. Manitoba Hydro attributes the changes in load factors mainly to its evolving customer mix over time, as well as to adoption of demand-side management measures and customer activity levels, which together have altered the load profiles of certain classes.

Figure 17.1 provides a comparison of the PCOSS26 RCC ratio results based on the new load research methodology compared to the modified PCOSS26 results based on the 2014/15 Load Research Report.

Customer Class	PCOSS26 As Filed		PCOSS26 Previous Load Research	
	Net Cost Allocation (\$M)	PCOSS26 RCC	Net Cost Allocation (\$M)	PCOSS26 RCC
Residential	936.7	96.9%	942.2	96.3%
General Service Small Non-Demand	191.8	108.0%	191.3	108.3%
General Service Small Demand	185.4	96.0%	176.5	100.8%
General Service Medium	269.2	97.8%	264.7	99.4%
General Service Large 750V-30kV	132.5	100.9%	136.7	97.8%
General Service Large 30-100kV	108.2	110.4%	110.3	108.3%
General Service Large >100kV	170.4	110.6%	172.6	109.2%
Area & Roadway Lighting	26.1	104.2%	25.9	104.8%

Figure 17.1 — Comparison of Allocated Costs and RCCs Between the New and Old Load Research Methodology

Like previous cost of service studies generated since 1999, the coincident peak demand allocators used in PCOSS26 are based on the Load Result Report results and the average demand over the top 50 winter peak hours. The implementation of the top 50 winter peak hours to calculate the coincident peak demand allocators was originally intended to avoid year-over-year variation in the cost of service study results, especially for the Area & Roadway Lighting class.

At the 2023/24 & 2024/25 General Rate Application, MIPUG criticized Manitoba Hydro's use of the top 50 hours to determine the demand-related cost allocators and instead advocated for the use of a smaller number of peak hours. In Order 101/23, the Board determined that MIPUG's proposal to review the number of hours contributing to the coincident peak was premature given the lack of updated load research data available at that proceeding.

In this hearing, the PCOSS26 calculations reflect the updated load research methodology and data but continue to make use of coincident peak demand allocators based on the top 50 hours, consistent with prior Board directives. Figure 17.2 is a comparison of the PCOSS26 RCC ratios based on the long-standing top 50 peak hours methodology to the modified PCOSS26 ratios based on a scenario where the top 10 peak hours are used to determine the class coincident peak load factors.

<b>Customer Class</b>	<b>PCOSS26 RCCs - Top 50</b>	<b>PCOSS26 RCCs - Top 10</b>
Residential	96.9%	96.8%
General Service Small Non-Demand	108.0%	107.8%
General Service Small Demand	96.0%	95.4%
General Service Medium	97.8%	97.5%
General Service Large 750V-30kV	100.9%	100.3%
General Service Large 30-100kV	110.4%	112.3%
General Service Large >100kV	110.6%	111.6%
Area & Roadway Lighting	104.2%	104.6%

Figure 17.2 — RCC Ratio Effect of Smaller Number of Hours to Calculate Peak Demand

### **17.3.2 Position of the Parties**

#### **Manitoba Hydro**

Despite criticisms from MIPUG's witness Mr. Bowman and the GSS/GSM Representative's witness Ms. Davies, Manitoba Hydro maintains that the Rank and Average method is not artificial, is suitable for deriving inputs to the PCOSS, captures typical hourly demand patterns while smoothing out anomalies (e.g., the impacts of a single abnormal year), preserves hourly magnitude and seasonal variation, and provides granular insight used for other purposes. For example, class regional load differences can be assessed, and the residential hourly load shapes can inform potential demand response programs targeting electric space heating.

While Manitoba Hydro stands by the new methodology used for the 2022/23 Load Research Report in PCOSS26, it states that the information needed to produce results with the previous methodology is readily available within the Load Research analysis should the Board recommend a return to the previous approach for future cost of service studies. However, Manitoba Hydro submits that the use of five years of data provides a reasonable balance between moderating year-over-year variations while still reasonably reflecting more recent consumption patterns.

Further, Manitoba Hydro recommends continued use of 50 hours to calculate class coincident peak demand, which it considers to be a reasonable approach that captures all conditions and coincident class behaviour under which a system peak could reasonably occur, and is representative of peak conditions, as demonstrated for all five fiscal years used in the 2022/23 Load Research Report. While Manitoba Hydro agrees that increasing the number of hours eventually transforms the allocator from a demand allocator into an energy allocator, there is no clear demarcation as to when it has fully transformed into an undeniable energy allocator. Manitoba Hydro submits that fifty hours is not that transition point as it represents only 0.6% of annual hours. Additionally, reducing to the top 10 hours provides for a range that is simply too narrow and will result in higher volatility in the classes' contributions to system peak in every new Load Research study, regardless of using the old or new methodology.

### **Consumers Coalition**

The Consumers Coalition argues that there is insufficient evidentiary support in this proceeding to reduce the number of hours used to determine the class contribution to the coincident peak. It notes that using too few hours will exclude the contributions of some customer classes to peak demand, and that the current approach is already compliant with the 10% NARUC principle. Further, the anticipated changes to Manitoba Hydro's services and system peak (e.g., from Demand Response offerings) also support not making adjustments at this time.

The Consumers Coalition witness Ms. Derksen characterizes the existing top 50 hours methodology as being more cost causal than a methodology using fewer hours. However, Ms. Derksen submits that Manitoba Hydro should pause its load research revisions at this time due to the risks of muting winter coincident peak responsibility in a way that materially shifts class RCC ratios. As a result, Ms. Derksen proposes that the revised methodology should undergo an impact analysis at the next general rate application.

### **GSS/GSM Representative**

The GSS/GSM Representative asserts that the Board should reject the proposed change to Manitoba Hydro's load research methodology. Instead, the underlying data should be used for peak-related allocators without adjustment. To more appropriately capture each classes' contribution to peak demand on the system, Manitoba Hydro should also be directed to conduct a study with respect to the appropriate number of hours used to calculate the coincident peak and non-coincident peak allocators, with a proposal included in the next general rate application.

The GSS/GSM Representative's witness Ms. Davies concludes that the new load research methodology is less transparent and results in muted system cost drivers and price signals. Further, averaging 50 hours already attenuates the peak impacts on the PCOSS results and averaging the load research data over five years compounds this effect. As a result, Ms. Davies submits that the new 5-year hourly load shape approach should not be accepted for use in PCOSS26.

## Manitoba Industrial Power Users Group

MIPUG argues that the new methodology should not be used for developing PCOSS coincident peak allocators. Instead, the previous load research approach (actual data and top-hour analysis) should remain in use for the purposes of the cost of service methodology. According to MIPUG, the allocators should be based on fewer peak hours (such as top 10), rather than 50 hours, but the use of five to eight years of data remains reasonable. Overall, MIPUG maintains that coincident peak allocators should reflect capacity cost causation at peak. This is because Manitoba Hydro plans and builds the bulk power system to meet the highest expected winter peak plus reserve margins, not some average of many high and near-peak hours like the 50<sup>th</sup> highest peak. According to MIPUG, the correct way to address year to year volatility is multi-year averaging of the same acute-peak metric, not broadening the window of hours measured within each year or relying on only one year of measured data.

MIPUG's witness Mr. Bowman concludes that the new Load Research Report should not be used for PCOSS purposes because it mutes coincident peak estimates as compared to the past methodology and the output of the load research methodology is a synthetic load shape that does not represent an actual year. Further, Mr. Bowman describes the top 50 hours methodology as too blunt since it mutes the acute demand signal imposed by the class on the system. Instead, the PCOSS methodology should focus on a more refined method of estimating each class's share of peak load, and incorporating fewer peak hours.

### **17.3.3 Board Findings**

As part of Manitoba Hydro's compliance filing resulting from this Order, the Board directs Manitoba Hydro to update PCOSS26 by using the previous load research methodology to determine the class coincident peak factors, together with the eight years of data from the 2014/15 Load Research Report and a change from the top 50 to the top 10 winter peak hours method. For future cost of service studies, Manitoba Hydro is to use the previous load research methodology with the most recent eight years of data. Manitoba

Hydro may propose more substantiated load research methodology changes specifically for PCOSS purposes in the future.

While the Board agrees that the new load research methodology is useful to inform Manitoba Hydro's load forecast and for the planning of future rate or energy efficiency measures, the Board finds that Manitoba Hydro has not provided sufficiently compelling reasons for applying the new load research methodology and results to the cost of service study. Further, the Board previously approved just and reasonable rates that were informed by prospective cost of service studies based on the 2014/15 Load Research Report, including at the last general rate application. However, for the next general rate application, the Board agrees that, subject to alternate Manitoba Hydro proposals, new load research data should be processed through the previous load research methodology, to produce updated class coincident peak allocators for PCOSS purposes. Regarding the use of the top 10 hours, the Board finds that this approach is more cost causal while still addressing concerns of year-to-year variations in class coincident peak load factors and the attenuation of the highest winter peaks. As such, the top 10 winter peak hours approach should be used for the compliance filing in this proceeding, as well as future cost of service studies.

## **17.4 Treatment of the Reduction in Payments to Government**

### **17.4.1 Background**

As explained in sections 12.0 and 15.0 of this Order, Manitoba Hydro includes various payments to the Province of Manitoba and municipalities as part of its revenue requirement. On April 1, 2022, the provincial government reduced the water rental payments under *The Water Power Act* and the debt guarantee fee by 50%.

In Order 101/23, the Board reviewed submissions relating to the cost of service treatment of these fees and found that their allocation should remain identical to prior cost of service studies. Notably, as Generation and Transmission functions have more valuable assets than the Distribution function in terms of Manitoba Hydro's overall net asset base, a large portion of the debt guarantee and water rental fees are functionalized as either

Generation or Transmission. In turn, and because Generation and Transmission costs make up a larger proportion of total costs for industrial customers than for residential customers, industrial customers tend to receive a greater percentage reduction in their total allocated costs than residential customers when the debt guarantee fee and water rental fee are reduced. The opposite effect would result in a scenario where the government increases the debt guarantee fee or water rental fee.

In this hearing, Manitoba Hydro's proposed revenue requirement reflects the further reduction in the provincial debt guarantee fee and the elimination of the corporate capital tax. For PCOSS26, consistent with Orders 164/16, 59/18, and 101/23, Manitoba Hydro maintains the existing cost of service treatment for its payments to government. Overall, the elimination of the capital tax and the reduction of the debt guarantee fee reduces costs and results in an offsetting increase in net income. Since all three cost elements are functionalized in proportion to rate base in the PCOSS, there is no RCC ratio impact due to the reduction in payments to government.

#### ***17.4.2 Position of the Parties***

##### **Manitoba Hydro**

Manitoba Hydro suggests that in the absence of any evidence that the government intended that the reduction in fees would provide specific benefits to only certain classes, there is no rationale for implementing any changes to the cost of service methods used to allocate payments to government nor a need for any specific considerations in rate design.

##### **Assembly of Manitoba Chiefs**

The AMC argues that it is imperative that the reduction in government payments is equitably incorporated in the cost of service study to benefit First Nations residential customers, as First Nations in Manitoba have never ceded their rights to lands and waters.

## Consumers Coalition

The Consumers Coalition submits that the treatment of payments to government should reflect the nature of the payment relief and not drive favourable differentiation for the General Service Large classes.

The Consumers Coalition's witness Ms. Derksen asserts that the PCOSS treatment of government payment relief in PCOSS26 results in disproportionate benefits to the General Service Large classes and negatively affects the Residential and General Service Small Non-Demand classes. For example, Ms. Derksen points out that while the reduction in government payments provides a directional overall 13.2% reduction in revenue requirement, the cost of service study RCC ratio for the Residential class declines by 0.5% while the General Service Large >100kV class's RCC ratio increases by nearly 3%.

### **17.4.3 Board Findings**

The Board finds that the cost of service treatment of payments to government should remain identical to prior cost of service studies. The Board already determined at the last general rate application that PCOSS24 and its treatment of the reduction in water rental fees and the debt guarantee fee appropriately reflected the Board's previous rulings on Manitoba Hydro's cost of service methodology. Each customer class experiences the same percentage change in their allocations of government fees. The Board finds no compelling rationale raised in this proceeding to support changing the existing PCOSS treatment of the debt guarantee fee, water rental fees, or the corporate capital tax at this time.

## **17.5 Treatment of Operating and Administrative Costs**

### **17.5.1 Background**

Manitoba Hydro's existing SAP software system is used to track labour costs through work orders that will be allocated to internal accounting cost centers. As these cost centers are assigned to specific functions within SAP, the O&A work order costs are initially functionalized as part of that internal accounting process, with subsequent

functionalization performed within the cost of service study. As further explained in section 11.0, Manitoba Hydro's projected O&A costs have materially increased for the rate period compared to projections from previous general rate applications. However, despite the increase in O&A costs included in its revenue requirement, Manitoba Hydro maintains the existing cost of service methodology treatment for its O&A costs in PCOSS26, consistent with Orders 164/16, 59/18, and 101/23.

Included as part of the O&A costs allocated in PCOSS26 are customer service-related costs such as those attributable to line locates, safety watches, building moves, marketing research and development, outages, meter reading, billing, collections, advertising, sales, inspections, and other costs.

The cost of service treatment of Manitoba Hydro's customer service costs was addressed in Orders 164/16 and 59/18. Those Orders resulted in customer service costs related to line locates, safety watches, building moves, and marketing and development costs, which were previously allocated to all customer classes through the C10 allocator in Manitoba Hydro's PCOSS, being no longer allocated to General Service Large 30-100kV and >100kV classes. At the time, the Board found these costs were primarily related to distribution-level assets or were already allocated through an industrial-specific allocator in PCOSS (e.g., the C23 allocator). In response, Manitoba Hydro implemented the C16 allocator for general customer service costs excluding the General Service Large 30-100kV and >100kV classes, which was approved in Order 101/23.

### **17.5.2 *Position of the Parties***

#### **Manitoba Hydro**

Manitoba Hydro submits that the allocation of O&A costs for General Service Large >100kV appropriately reflects both the reduced consumption levels forecast for this class and the allocation methodology, even if these amounts for this class have increased only 8% compared to an overall 54% increase since PCOSS18. Manitoba Hydro maintains that the relatively lower increase in allocated O&A costs for the General Service Large

>100kV class since PCOSS18 is primarily because this class decreased its energy consumption by 21% while other classes had a 10% increase during this time.

For similar reasons as Mr. Bowman, Manitoba Hydro also supports the existing treatment of costs allocated through the C16 allocator. However, the utility acknowledges that building moves, safety watches, and line locates contribute to the public good and therefore benefit all customer classes. As such, these costs could potentially be allocated more broadly. Similarly, Residential customers do not benefit from marketing research and development initiatives intended to enhance business development and could arguably be allocated a reduced portion of these specific costs.

### **Consumers Coalition**

The Consumers Coalition's witness Ms. Derksen raises concerns regarding the General Service Large >100kV class only experiencing an 8% increase in O&A costs in PCOSS26 compared to an overall 54% increase in these costs since PCOSS18 (from the 2017/18 & 2018/19 General Rate Application). Accordingly, the Consumers Coalitions submits that the PCOSS treatment of O&A expenditures has diverted considerable cost growth away from the General Service Large >100kV class. Given these outcomes, the Consumers Coalition argues that some changes to the cost of service methodology warrant consideration but that these changes should be reviewed in a separate process to better assess the scope of their impacts.

The Consumers Coalition's witness Ms. Derksen also asserts that it is difficult to rationalize how a General Service Large customer does not benefit from safety-related services associated with public streets, roadways, protection of the broad electric system, system outages, and line locates, which in the absence of such services, could result in the shutdown of portions of the electric system. Similarly, Residential customers contribute to the costs of enhanced business development despite these services not being directly aimed at them. Ms. Derksen accordingly submits that it would be appropriate that the larger General Service Large classes also be allocated these costs given the overall public benefits received.

## Manitoba Industrial Power Users Group

MIPUG's witness Mr. Bowman asserts that the customer service costs allocated using the C16 allocator are for distribution services that are not used by large industrial customers. Further, industrial customers have their own C23 customer service allocator, which allocates General Service Large-related costs for surveys, consultations, and dedicated customer service representatives.

### **17.5.3 Board Findings**

The Board accepts Manitoba Hydro's explanation for why O&A costs allocated to the General Service Large >100kV class only increased by 8% from PCOSS18, even as overall O&A costs increased by 54%. The disparate increase is due to changes to the inputs to the COSS methodology and not to a failing of the methodology. The Board considers this specific outcome of the COSS in its decisions on rate differentiation discussed in section 18.3.2.

With respect to the C16 customer service general allocator, the Board finds that its reasoning in Order 59/18 remain sound: the costs for these activities relate primarily to distribution-level assets or service to smaller customers, or are already solely allocated to the General Service Large 30-100kV and General Service Large >100kV classes through the Industrial & Commercial Solutions sub-function. The Board finds that the evidence in the current general rate application does not establish that General Service Large 30-100kV and General Service Large >100kV customers cause these costs to be incurred. Therefore, the Board finds that no changes to the approved COSS methodology are required.

## **17.6 Classification of Wind Generation**

### **17.6.1 Background**

In Order 164/16, the Board found that Generation costs should be classified as both Energy and Demand based on the system load factor method. System load factor is the average demand divided by peak demand. An exception to this rule included costs related to wind generation, which were to be classified as 100% Energy. This was based on the

evidence at the time that wind generation did not contribute to the system capacity serving the winter peak as it was understood that wind generation did not reliably serve any portion of the winter peak.

At the 2017/18 & 2018/19 General Rate Application, Manitoba Hydro started to include wind generation in its winter peak capacity resource planning assumptions. This change was in recognition of Manitoba Hydro's operational experience with its wind power purchases during winter peaks. Despite this change in capacity resource planning assumption, the Board re-affirmed the classification of wind as 100% Energy in Order 59/18. At the time, the Board found that wind was transacted on an energy basis through contracts with suppliers and that Manitoba Hydro's investment in wind was not to specifically serve peak demand.

During the 2023/24 & 2024/25 General Rate Application, MIPUG advocated to change the current classification of wind from 100% Energy to 80% Energy / 20% Demand given that Manitoba Hydro continued to attribute 20% of its installed wind generation capacity as capable of meeting the winter peak demand. In Order 101/23, the Board found that this proposed change was premature to consider without first having reviewed Manitoba Hydro's integrated resource plan, which could provide additional information on the roles of wind generation and demand side management on Manitoba Hydro's winter peak capacity.

In this hearing, consistent with Orders 164/16, 59/18, and 101/23, PCOSS26 continues to classify wind-related costs as 100% Energy, with all other generation-related costs (except water rentals and variable hydraulic operating and maintenance costs) classified based on the system load factor methodology (60.7% Energy and 39.3% Demand per PCOSS26). However, Manitoba Hydro submits that with the expectation that the commitment to building new wind generation resources will increase the value of wind purchases in subsequent PCOSS studies, it is reasonable to re-evaluate the appropriate classification in this current proceeding.

Specifically, Manitoba Hydro submits that individually, Manitoba Hydro's generation resources will operate at a range of load factors that may be above or below the system average. For example, while wind has a low load factor, thermal generation and the Curtailable Rate Program are also used at very low load factors. Manitoba Hydro therefore suggests that treating wind as an exception to the high-level approach of classifying generation-related costs based on the system load factor is not consistent with the premise of a simple and straight forward methodology.

### ***17.6.2 Position of the Parties***

#### **Manitoba Hydro**

Manitoba Hydro argues that the most reasonable and consistent approach to classifying generation resources in the PCOSS is to consider the generation portfolio in its entirety. As such, the utility endorses the modified approach to classify all generation, including wind, water rentals, variable hydraulic operation and maintenance, and future generation resources, on the basis of the system load factor. Additionally, Manitoba Hydro submits that changing the classification of wind to use the system load factor will neither simplify nor add complexity to the PCOSS.

#### **Consumers Coalition**

The Consumers Coalition's witness Ms. Derksen submits that the cost allocation methodology associated with wind generation remains reasonable, reflects cost causation, and that any change is premature without review of Manitoba Hydro's integrated resource plan.

Accordingly, the Consumers Coalition maintains that adjustments to the cost of service treatment of wind-related costs remain premature, as the integrated resource plan review has yet to take place. For example, it remains unclear how wind will be used in concert with other generation resources (both existing and new). There is also limited consistent treatment for wind-related costs in other jurisdictions, and applying the system load factor to these costs would be a drastic change from the existing approach. Further, the contemplated middle ground alternative of 20% Demand produces immaterial impacts on

class RCC ratios. In any event, the Consumers Coalition submits that these changes should be reviewed in a separate process to better assess the scope of their impacts.

### **GSS/GSM Representative**

The GSS/GSM Representative argues that the Board should direct Manitoba Hydro to classify wind generation costs, along with remaining generation related costs currently classified as 100% Energy (i.e., including water rental costs and variable hydraulic operation and maintenance), using the system load factor method. In this intervener's view, it is common practice when using the system load factor method for classification to include wind assets. This position is based on its witness Ms. Davies who supports the change in the cost of service treatment of wind generation such that all generation-related costs (i.e., including wind, the curtailable rate program, demand side management, water rentals, etc.) are classified based on the system load factor.

### **Manitoba Industrial Power Users Group**

MIPUG witness Mr. Bowman, supports the change in the cost of service treatment of wind generation such that all generation-related costs (i.e., including wind, the curtailable rate program, demand side management, water rentals, etc.) are classified based on the system load factor.

Accordingly, MIPUG submits that the special treatment for wind generation should be eliminated. Instead, wind costs should be classified to demand and energy using the system load factor, consistent with how Manitoba Hydro treats its other generation resources. In MIPUG's view, this change is essential to maintain consistency, transparency, and adherence to cost causation in light of Manitoba Hydro's plans to add significant wind capacity. This approach also ensures that all generation resources are treated under the same portfolio-based methodology, avoiding arbitrary carve-outs and providing clarity for future planning. Further, the system load factor approach was adopted precisely to avoid resource-specific dispatch proofs and to classify costs based on the integrated portfolio, not guaranteed performance of any single resource at the peak hour.

### **17.6.3 Board Findings**

Consistent with the Board's previous findings in Order 101/23, the Board finds that it is premature to consider proposals regarding changes to the classification of wind generation resources (and other generation-related costs not currently classified through the system load factor) without first having reviewed Manitoba Hydro's integrated resource plan. However, for the Manitoba Hydro general rate application that follows the Board's review of Manitoba Hydro's integrated resource plan, the Board directs Manitoba Hydro to file prospective cost of service study results based on the existing treatment of these costs along with alternate results based on classifying these costs using the system load factor approach, together with Manitoba Hydro's detailed reasons supporting its preferred classification approach.

## **17.7 Classification of Distribution Poles and Wires**

### **17.7.1 Background**

Distribution poles carry a number of components, including distribution transformers and primary and secondary wires. In Order 164/16, the Board found that distribution poles and wires should be classified as 100% Demand to reflect the fact that the sizing of poles and wires is based on demand, and that the previous 60% Demand and 40% Customer classification split, which had been used for many years, was based on an arbitrary and insufficiently supported assumption that the number of customers influences the cost of poles and wires. Additionally, the Board confirmed the historical 70% primary / 30% secondary adjustment split for distribution poles and wires, which was introduced to reflect the fact that the General Service Large 30-100kV and >100kV classes do not make use of the secondary voltage distribution system.

In Order 164/16, the Board also found that the costs of distribution substations and distribution transformers should be classified as 100% Demand, with service drops, meter investment, and meter maintenance classified as 100% Customer.

In this hearing, consistent with the Board's previous cost of service study rulings, PCOSS26 makes use of the following classification treatment for distribution plant:

Distribution Facilities	Cost Classification	
	Demand	Customer
Substations	100%	
Line Transformers	100%	
Pole, Wire, and Related Facilities	100%	
Meters and Metering Transformers		100%
Service Drops		100%

Figure 17.3 — PCOSS26 Classification of Distribution Plant

The Consumers Coalition's witness Ms. Derksen asserts that the existing 100% Demand classification of poles and wires, as well as transformers, should be retained since it is more cost causal, is well within the accepted industry practice, and because Order 164/16 found that the previous 60% / 40% classification split for poles and wires was arbitrary.

In contrast, the GSS/GSM Representative's witness Ms. Davies asserts that using 100% Demand for classifying distribution assets results in weak cost causality and is not consistent with standard industry practice and the NARUC cost allocation manual. This is because the existing approach ignores that there is a minimum level of the distribution system that must be built to serve each customer, independent of the amount of demand the customer imposes. As such, Ms. Davies maintains that distribution assets should be classified based on professional judgement that is in line with similar utilities in Canada. Specifically, poles and wires should be classified 60% Demand and 40% Customer, and distribution transformers should be classified 60-65% Demand and 40-35% Customer. Further, the Board should confirm whether the existing 70% primary and 30% secondary adjustment split for poles and wires, as well as the secondary adjustments included in the C23 and D36 allocators, remains appropriate.

MIPUG's witness Mr. Bowman also asserts that there is no reasonable basis to consider costs related to distribution wires and poles as 100% Demand and that Manitoba Hydro is an outlier among Canadian peers in adopting this approach. As such, the previous 60% Demand / 40% Customer classification factor is reasonable and practical for the classification of poles and wires.

MIPUG's witness Mr. Friesen submits that the standardized designs of distribution feeders, whose size influences the number of customers that may be served, supports the 60% / 40% classification proposal. According to Mr. Friesen, the existing 70% / 30% primary-secondary classification for poles and wires should also be reviewed as it has not been reviewed since 1991.

In response to the above intervener witness submissions, Manitoba Hydro continues to support a 100% Demand classification for distribution transformers. However, the utility submits that common industry practice suggests that distribution assets should be classified as both Customer and Demand-related. As such, Manitoba Hydro supports a return to the previous 60% Demand / 40% Customer split for distribution poles and wires. According to the utility, this previous split remains the best advice available for classifying distribution poles and wires since the utility's existing accounting records do not provide the level of detail on asset investment that would be required to prepare commonly used minimum system and zero-intercept studies, or primary-secondary analysis, that would help inform what the Demand and Customer split should be.

### **17.7.2 *Position of the Parties***

#### **Manitoba Hydro**

Manitoba Hydro does not object to the proposed change to the 60% Demand / 40% Customer classification split for distribution poles and wires in the preparation of the next PCOSS. The utility argues that the Board previously accepted this approach as appropriate, that the range is consistent with those of other Canadian utilities, and that the directional change reflects improved cost causation. However, Manitoba Hydro notes

that there is no conclusive evidence that supports a change from the long-standing approach to classifying distribution transformers as 100% Demand.

### **Consumers Coalition**

The Consumers Coalition submits that in Order 164/16, the Board departed from the 60% Demand / 40% Customer split of poles and wires due to a lack of evidentiary support and there is no analysis in this proceeding as to why this prior use of professional judgment remains applicable today. Further, there is no consistent approach across other jurisdictions and as such, there is insufficient evidence to adopt Ms. Davies's proposal.

### **GSS/GSM Representative**

The GSS/GSM Representative argues that the Board should direct Manitoba Hydro to change the classification method for distribution poles and wires back to the 60% Demand and 40% Customer classification split, a classification that was based on professional judgement. Further, a 70% Demand and 30% Customer classification split should be used for distribution transformers. In advocating for these changes, the GSS/GSM Representative submits that Manitoba Hydro's methods of classifying distribution plant results in a classification split of 97% demand-related and only 3% as customer-related. This is an outlier position for distribution plant-related cost of service methodologies used in other Canadian jurisdictions. Specific to distribution poles and wires, the current 100% Demand classification methodology also results in weak cost causality and is not consistent with either standard industry practice or the NARUC cost allocation manual. For distribution transformers, this intervener also argues that, while the size of a transformer will be more of a demand consideration, the number of transformers and their placement will be driven by the number of customers served. As such, the GSS/GSM Representative submits that distribution transformers should be classified as both customer and demand.

While there is not one single universal classification split across other jurisdictions, there is consistent practice to split between customer and demand with consideration for the overall density of the system.

## Manitoba Industrial Power Users Group

MIPUG argues that the classification of distribution poles, wires, and transformers should be revised from 100% Demand to 60% Demand and 40% Customer. Additionally, Manitoba Hydro should be directed to review and update the 70% primary / 30% secondary adjustment used for distribution assets, which has not been revisited since 1991. According to MIPUG, NARUC explicitly states that distribution plant should be classified into demand- and customer-related components, recognizing that a minimum level of infrastructure is required to serve each customer regardless of demand. This is supported by the use of Demand/Customer classification splits for distribution assets in other jurisdictions.

### **17.7.3 Board Findings**

The Board finds that there is no compelling evidence in this proceeding that supports a change to the existing 70% primary and 30% secondary adjustment split for poles and wires, or to the 100% Demand classification of distribution transformers. However, the Board agrees that, based on the evidence filed in this proceeding, it is more cost causal to classify a portion of distribution poles and wires as Customer-related. While the Board accepts the existing 100% Demand classification of poles and wires for PCOSS26, the Board directs Manitoba Hydro to use the previous 60% Demand / 40% Customer classification split for poles and wires for the next general rate application.

In Order 164/16, the Board found that the costs of poles and wires were influenced by customer demand and by geography, but the Board did not find sufficient evidence that the number of customers was correlated with geography. Consequently, the Board found that the classification of poles and wires should be 100% demand. In reviewing the distribution classification methods used in other Canadian jurisdictions for distribution plant provided in the current general rate application, the Board finds that there is an element of cost causation by the number of customers. There does not appear to be a clear correlation, as the industry practice in this area is inconsistent, which is what the Board found in Order 164/16. However, the number of customers in some instances

determines the geography of pole and wire installations and therefore influences the cost of poles and wires.

Absent a specific correlation, and due to the wide range of Demand-Customer classification proportions used elsewhere, the Board finds professional judgement must be applied. Manitoba Hydro indicates that its account records do not provide sufficient granularity to support more mathematically driven classification results through minimum system or zero-intercept studies. However, the Board's recent findings in Order 120/25 for Centra Gas suggest that even these studies can yield widely differing classification proportions that may not necessarily appear superior to proportions determined through professional judgment. As the previous 60% Demand / 40% Customer classification split was approved for many years prior to Order 164/16, with Manitoba Hydro rates during this period viewed as just and reasonable, the Board finds a return to the 60% / 40% classification split for distribution poles and wires to be appropriate for the PCOSS filed in Manitoba Hydro's next general rate application.

## **18.0 RATE DESIGN AND RATE DIFFERENTIATION**

### **18.1 Background**

#### ***18.1.1 Cost of Service Study Results, Rate Differentiation, and Proposals for Across-the-Board Rate Increases***

As described in section 2.5 of this Order, after determining Manitoba Hydro's revenue requirement and obtaining results from its prospective cost of service study, the next step in setting rates is to determine whether to implement mitigation adjustments through differentiated rate increases or changes to class rate designs in order for revenues from individual rate components to align with allocated costs. In Order 101/23, the Board reiterated that cost of service is an important criterion in setting rates, but that these considerations must also be balanced against other ratemaking criteria, including rate stability and affordability.

In Order 164/16, the Board explained that, while a cost of service study appears to be arithmetically exact, it involves many decisions that require judgment. Because of this, and the goal of gradualism in ratemaking, many utilities, including Manitoba Hydro, recognize a "zone of reasonableness" rather than aiming for a revenue-to-cost coverage ("RCC") ratio of 100%.

A zone of reasonableness establishes a tolerance zone around the RCC ratio target of 100% (i.e., unity) for each class. Per Orders 59/18 and 101/23, Manitoba Hydro continues to use a zone of reasonableness of 95% to 105%. An RCC ratio outside that range is one factor to be considered in determining whether a differentiated rate increase is appropriate for one or more classes of customers, meaning a rate increase that is higher or lower than the average rate increase sought by the utility.

Based on the results of PCOSS26 shown in Columns 4 and 5 of Figure 18.1, three customer classes, namely the General Service Small Non-Demand, General Service Large 30-100kV, and General Service Large >100kV classes, are above the zone of reasonableness, while the rest of Manitoba Hydro's customer classes are within it. This compares to only three of the eight customer classes being within the zone of reasonableness in PCOSS24 from the 2023/24 & 2024/25 General Rate Application.

[1] Customer Class	[2] PCOSS24 RCC	[3] ZOR	[4] PCOSS26 RCC	[5] ZOR	[6] Proposed Rate Increases
Residential	94.4%	Below	96.9%	In	3.5%
General Service Small Non-Demand	109.7%	Above	108.0%	Above	3.5%
General Service Small Demand	101.8%	In	96.0%	In	3.5%
General Service Medium	100.3%	In	97.8%	In	3.5%
General Service Large 750V-30kV	97.9%	In	100.9%	In	3.5%
General Service Large 30-100kV	112.4%	Above	110.4%	Above	3.5%
General Service Large >100kV	113.2%	Above	110.6%	Above	3.5%
Area & Roadway Lighting	108.2%	Above	104.2%	In	3.5%

Figure 18.1 — PCOSS26 RCC Results Compared to the PCOSS24 RCC Results, with Manitoba Hydro's Proposal for Equal Rate Increases for all Classes

For an extended period up to the 2017/18 & 2018/19 General Rate Application, Manitoba Hydro sought, and the Board approved, across-the-board rate increases that were applied equally to all customer classes. However, in Order 59/18, the Board denied Manitoba Hydro's request for across-the-board rate increases and instead directed Manitoba Hydro to implement differentiated rate increases for fiscal year 2018/19 in order to gradually move those classes that were above the zone of reasonableness into the zone within a 10-year timeframe. As such, the classes with RCC ratios above the zone of reasonableness received below-average rate increases while the remaining customer classes received greater-than-average rate increases.

In Orders 69/19 and 137/21, which addressed rates for fiscal years 2019/20 and 2021/22, the Board also approved differentiated rate increases to continue the process of gradually moving those classes that were above the zone of reasonableness into the zone. However, for fiscal year 2020/21, the Province of Manitoba legislated a 2.9% across-the-board rate increase effective December 1, 2020, which was implemented through *The Budget Implementation and Tax Statutes Amendment Act, 2020*, S.M. 2020, c. 21. There also were no rate changes implemented for 2022/23.

In Order 101/23, the Board approved Manitoba Hydro's request to implement differentiated rate increases for fiscal years 2023/24 and 2024/25. In the current hearing, however, Manitoba Hydro proposes to evenly apply its proposed 3.5% annual rate increases for the three years of the rate period to all customer classes (as shown in Column 6 of Figure 18.1 above). Exceptions to this request apply to the Area & Roadway Lighting and Diesel customer classes, as further discussed in sections 18.1.2 and 18.1.3 below.

In support of its request for across-the-board rate increases in this hearing, Manitoba Hydro maintains that, while it still targets having customer classes within the zone of reasonableness, equal class rate increases are now sought so as to not exacerbate bill impacts and affordability for customers. Manitoba Hydro further notes that the differentiated rate increases approved in Order 101/23 have helped move the five customer classes that were outside of the zone of reasonableness in PCOSS24 towards unity in PCOSS26. As well, applying across-the-board rate increases in this case does not adversely affect the RCC ratios of any class, will not affect the ability to adjust rate structures in the future, and maintains predictability and stability of current rates.

Despite the above recommendation, and to assist the Board in assessing the impacts of potential rate differentiation applied in the rate period, Manitoba Hydro provided the information shown in Figure 18.2 below regarding the annual differentiation required to move the three customer classes currently above the zone of reasonableness into the zone within three, five, or ten years on a revenue-neutral basis and based on the results of the as-filed version of PCOSS26.

Customer Class	PCOSS26 RCC	PCOSS26 RCC Across-the-Board	3 Year Diff.		5 Year Diff.		10 Year Diff.	
			Rate Adj.	Final RCC	Rate Adj.	Final RCC	Rate Adj.	Final RCC
Residential	96.9%	97.0%	0.5%	98.2%	0.3%	98.2%	0.1%	98.2%
GSS-ND	108.0%	108.2%	-0.9%	105.0%	-0.6%	105.0%	-0.3%	105.0%
GSS-D	96.0%	96.0%	0.5%	97.3%	0.3%	97.3%	0.1%	97.3%
GSM	97.8%	97.7%	0.5%	99.2%	0.3%	99.2%	0.1%	99.2%
GSL 750-30kV	100.9%	100.6%	0.5%	102.3%	0.3%	102.3%	0.1%	102.3%
GSL 30-100kV	110.4%	109.8%	-1.7%	105.0%	-1.0%	105.0%	-0.5%	105.0%
GSL >100kV	110.6%	109.8%	-1.7%	105.0%	-1.0%	105.0%	-0.5%	105.0%
A&RL	104.2%	105.6%	0.3%	105.0%	0.2%	105.0%	0.1%	105.0%

Figure 18.2 — Annual Differentiation Required to Move the Customer Classes Within the Zone of Reasonableness in Three, Five and Ten Years on a Revenue-Neutral Basis.

The Consumers Coalition's witness Ms. Derksen supports across-the-board rate increases for all three years of the rate period. Her recommendations are based on the following reasons:

- The PCOSS26 results suggest that Residential and General Service Small Non-Demand customers receive less benefit from government fee reductions while General Service Large >100kV customers receive a minimal increase to O&A cost allocations;
- Based on their rate base composition, Residential and General Service Small customers already contribute to greater levels of net income meant to fund future generation and transmission assets;
- There is no allocation of the costs of line locates, building moves, and other customer service costs to General Service Large 30-100kV or >100kV classes despite these classes benefiting from the overall public safety benefits received;
- General Service Large customers require greater system reliability, which is not accounted for in the PCOSS or the interpretation of RCC ratios;

- The evaluation of RCC ratios calculated without Net Export Revenue support an across-the-board rate increase;
- The estimation error in Manitoba Hydro's load research results suggests that RCC ratios can vary by nearly the size of the zone of reasonableness;
- Net Export Revenues are forecasted to decline over the test period and Manitoba Hydro plans large generation and transmission capital spending, both of which will tend to push the RCC ratios lower for the General Service Large classes. If rates are differentiated now to move some classes to 105%, it will result in overshooting the desired outcomes, necessitating an unwinding through future rate changes; and
- Since Order 101/23, the Residential class has moved into the zone of reasonableness, which reduces the rationale for "catch up" rate differentiation and affects how PCOSS26 should be interpreted, including unresolved energy poverty concerns.

The GSS/GSM Representative's witness Ms. Davies submits that Manitoba Hydro's proposal for across-the-board rate adjustments will result in General Service Small Non-Demand customers continuing to overpay their allocated costs. Instead, Ms. Davies recommends rate increases to ensure all customer classes are within the zone of reasonableness by the end of the rate period, without offsetting increases to the customer classes already within the zone of reasonableness. Any remaining revenue reductions that may result from this proceeding should then be uniformly applied to all customer classes.

MIPUG's witness Mr. Bowman asserts that the as-filed version of PCOSS26 is appropriate for use in this hearing, as such studies are always based on annual forecast conditions and are not updated for water conditions. To achieve 100% RCC ratios for all classes after the three years of the rate period, Mr. Bowman recommends that classes above the zone of reasonableness receive increases that are 2.5% below the average rate increases awarded. Classes that are below 100% RCC ratios should receive increases that are 1.0% above average, with the remaining classes receiving average rate increases. Mr. Bowman also rejects Ms. Derksen's claim that estimation error in

Manitoba Hydro's load research results suggests that RCC ratios can vary by nearly the size of the zone of reasonableness. In Mr. Bowman's view, this is not supported by Manitoba Hydro's evidence. While there is variability in the COSS results and RCC ratios due to variability in load research, Mr. Bowman suggests this is justification for setting rates to achieve RCC ratios at 100%.

In response to Ms. Derksen, Manitoba Hydro submits that Ms. Derksen generally disregards the fact that changes to Manitoba Hydro's costs and customer consumption levels will directly affect the amount of costs allocated to each class. Further, Ms. Derksen misinterprets class responsibility for funding net income and reserves and overstates the significance of changes to the load research report.

As discussed in section 3.1.5 above, in Order 161/25, the Board approved a 4.0% rate increase effective January 1, 2026 on an interim basis. This increase was applied equally to all customer classes and rate components, with the exception of customers in the Diesel Zone. However, the Board indicated that the appropriateness of rate differentiation in the rate period would be reviewed as part of its final order for this Application.

### ***18.1.2 Area & Roadway Lighting Class Rates***

Manitoba Hydro's Area & Roadway Lighting customer class consists of customers with street lights and sentinel lighting such as floodlights for parking lots. The two primary types of lighting technology used are high-pressure sodium ("HPS") lamps and light-emitting diode ("LED") lamps. Area & Roadway Lighting fixtures are not metered, and each fixture is billed a flat monthly charge depending on the type and wattage of the luminaire. As a result, Manitoba Hydro makes use of several different rates within the Area & Roadway Lighting customer class to accommodate the different luminaires and supporting pole configurations operated by its customers.

Proposal for Intra-Class Rate Differentiation

At the 2023/24 & 2024/25 General Rate Application, Manitoba Hydro filed an updated version of its Lighting Cost of Service Study (“LCOSS24”), which was an extension of PCOSS24 in that the costs allocated to the Area & Roadway Lighting class from PCOSS24 were further allocated in LCOSS24 to each lighting rate type. As seen in Figure 18.3 below, the results of LCOSS24 indicated that the RCC ratios of rates within the Area & Roadway Lighting class ranged from a low of 40% to a high of 165%. As a result, Manitoba Hydro proposed, and the Board approved in Order 101/23, additional rate differentiation within the Area & Roadway Lighting class to begin the process of moving all rates within the class to within the established 95% to 105% zone of reasonableness on a revenue-neutral basis. Specifically, individual rates within the Area & Roadway Lighting class received either a 0%, +/-1%, or +/-5% increase over and above the average rate increase awarded to the class (0% for this class per Order 101/23), depending on the magnitude of the RCC ratio difference shown in Figure 18.3 below.

Lighting Type	LED RCC	HPS RCC
Sentinel – Flat Rate	148%	120%
Sentinel – Rental Only	165%	126%
Exclusive	111%	97%
High Mast (100’)	40%	44%
Shared	96%	109%

Figure 18.3 — LCOSS24 Results for the Area & Roadway Lighting Groups

In this hearing, Manitoba Hydro did not update its lighting cost of service study. However, the utility proposes to continue the Area & Roadway Lighting intra-class differentiation process approved in Order 101/23. Specifically, Manitoba Hydro proposes to apply the additional intra-class differentiated adjustments shown in Figure 18.4 below to the 3.5% rate increase proposed for the Area & Roadway Lighting class as a whole. Consistent with Order 101/23, these intra-class differentiated rate adjustments are based on the results from LCOSS24, use the same sub-differentiation adders of 0%, +/-1%, or +/-5%,

and are applied on a revenue-neutral basis, meaning Manitoba Hydro expects to receive the same revenue from this class as it would without differentiation.

Lighting Type	A&RL Differentiated Adjustment		Combined A&RL Increase (including 3.5%)	
	LED	HPS	LED	HPS
Sentinel – Flat Rate	-5.0%	-1.0%	-1.5%	2.5%
Sentinel – Rental Only	-5.0%	-1.0%	-1.5%	2.5%
Exclusive	0.0%	1.0%	3.5%	4.5%
High Mast (100')	5.0%	5.0%	8.5%	8.5%
Shared	1.0%	0.0%	4.5%	3.5%

Figure 18.4 — Proposed Rate Adjustments for the Area & Roadway Lighting Groups

Proposal for Changes to the LED Rate Descriptions

To accommodate recent advancements in LED technology, Manitoba Hydro is also requesting approval to modify the description of several LED Lighting rates, which are summarized in Figure 18.5 below.

Tariff Schedules	Revised	Previous
Outdoor Lighting & Seasonal Lighting	10 LED (1-20 W) Exclusive	10 LED (1-30 W) Exclusive
	40 LED (>20-50 W) Shared	40 LED (>30-50 W) Shared
	40 LED (>20-50 W) Exclusive	40 LED (>30-50 W) Exclusive
Sentinel Lighting	60 LED (1-80 W)	60 LED
	90 LED (>80 W)	90 LED

Figure 18.5 — Proposed Revisions to Various Area & Roadway Lighting LED Rate Descriptions

In support of this request, Manitoba Hydro submits that the current “10 LED (1-30W)” rate was developed for a specific type of decorative light that has five 10 Watt luminaires mounted on a shared lighting standard. The rate only recovers 1/5 of the cost of the lighting standard and is therefore significantly lower than the “40 LED” rate (31-50W). Reducing the upper threshold of the “10 LED” rate from 30 to 20 W will clarify that, even with continuing improvements in efficiency, any future generations of “40 LED” roadway luminaires do not qualify for the 10 LED lower specialty lighting rate. Further, modifying

the description of the Sentinel lighting LED rates to include a range of applicable wattages is consistent with the nomenclature used for roadway lighting.

In Order 161/25, the Board approved a 4.0% rate increase effective January 1, 2026, with no rate differentiation applied between the customer classes or within the Area & Roadway Lighting class. However, the Board indicated that the appropriateness of rate differentiation for fiscal years 2025/26 to 2027/28 would be finalized as part of this Order. In Order 1/26, the Board approved Manitoba Hydro's revised rate schedules filed in compliance of Order 161/25. At the time, the Board noted that the inclusion of revised rate descriptions for LED luminaires for the Area & Roadway Lighting customer class was being accepted on an interim basis, pending this Order.

### ***18.1.3 Diesel Zone Rates***

Four communities in Manitoba (Lac Brochet, Brochet, Shamattawa, and Tadoule Lake) are not connected to the electric transmission and distribution grid and are served by separate diesel-generated electricity. Full reviews of the rates for these communities are conducted infrequently, with the last diesel rate application filed in 2011. Diesel Zone customers are categorized as either Diesel-Residential, Diesel-General Service, or Diesel-Government & First Nation Education, and are charged both a basic monthly charge and an energy rate. Until 2018, the basic monthly charge for all Diesel Zone customers, the energy rate for Diesel-Residential, and the first block energy rate for Diesel-General Service were set at the same level as the rates paid by similar grid-connected customers, with the remaining Diesel Zone rate components designed to recover the majority of the remaining Diesel Zone revenue requirement.

Since 2004, Diesel Zone rate changes have been approved on an interim basis. Finalization of these rates first depended on the receipt of an executed Diesel Zone settlement agreement with the Federal Government, then a separate diesel-specific rate application to be filed by Manitoba Hydro. While the executed Diesel Zone settlement agreement was filed with the 2023/24 & 2024/25 General Rate Application, Directives 3(c), 3(d), and 4 of Order 134/10, Directive 36 of Order 59/18, and Directive 4 of Order 100/20 all remain open pending the filing of a separate Diesel Zone rate application.

At the 2017/18 & 2018/19 General Rate Application, Manitoba Hydro requested that its proposed rate increases apply equally to all classes, including the Diesel Zone rate components linked to the grid-equivalent rates. However, no increase was proposed for the Diesel-General Service runoff energy rate (also known as the tail block rate) or the Diesel-Government & First Nation Education energy rate. Through Orders 80/17 and 85/17, the Board provided interim approval to this Diesel Zone rate request. As such, both the Diesel-General Service runoff energy rate and Diesel-Government & First Nation Education energy rate have since remained unchanged from the levels approved for August 1, 2016.

In Order 59/18, the Board froze the Diesel-Residential rates and established a First Nations On-Reserve Residential customer class for some of Manitoba Hydro's grid-connected residential customers. In June 2020, the Manitoba Court of Appeal struck down the establishment of the First Nations On-Reserve Residential customer class. While Order 100/20 unwound the First Nations On-Reserve Residential customer class, the Board ordered Diesel-Residential rates to remain frozen at the levels approved for August 1, 2017 until a diesel-specific rate application could be reviewed. Since that time, the Diesel-Residential customer rates have remained unchanged from the levels approved for August 1, 2017.

Manitoba Hydro's Diesel Cost of Service Study ("DCOSS") determines the revenue requirement needed to serve existing Diesel Zone customers. However, the DCOSS revenue requirement does not include any capital-related costs. This is consistent with the framework of the 2010 diesel settlement agreement, which relies on upfront capital funding, primarily from the Federal Government. At the 2023/24 & 2024/25 General Rate Application, Manitoba Hydro submitted that between 2011 and 2018, Manitoba Hydro received \$24.4 million in diesel capital cost payments from Indigenous Services Canada but had not received any contributions since 2018. As of March 31, 2022, there was approximately \$5.8 million in outstanding capital expenditures for diesel facility maintenance and upgrades completed since March 2019. Manitoba Hydro's 2023/24

capital plan projected \$61 million of additional diesel-related capital costs over the next five years.

In the current application, Manitoba Hydro advises that a resolution on capital funding from the Federal Government is required in order to advance its next diesel rate application. While a resolution has not yet been obtained, according to Manitoba Hydro the Federal Government has confirmed its intention to pay the outstanding capital funding related to already completed capital works. In addition, Manitoba Hydro is having ongoing discussions to secure funding for upcoming capital investments (approximately \$90 million in Diesel Zone-related capital costs over the next five years). Per the 2010 diesel settlement agreement, additional matters need to be addressed before a diesel rate application can be filed and the interim Diesel Zone rates finalized, including engagement and decisions between Manitoba Hydro, MKO, and the remaining parties of the settlement agreement. Given the above, Manitoba Hydro maintains that it is unable to specify whether a Diesel Zone rate application will be filed before the next general rate application.

Consistent with the framework established by the 2010 diesel settlement agreement, Manitoba Hydro submits that the 2025/26 revenue requirement for the Diesel Zone is \$11 million (excluding all capital-related costs), which is \$1.3 million more than the \$9.7 million revenue currently collected from Diesel Zone customers. Based on forecasted consumption, the forecast diesel full cost rate is 60.7 ¢/kWh.

Despite uncertainty regarding capital funding, Manitoba Hydro asserts that the updated DCOSS and the adjustments proposed in this hearing for grid rates provide all necessary information required to update the Diesel-Residential and Diesel-General Service rates. Accordingly, the utility is requesting that the Diesel-Residential rates no longer be held at the August 1, 2017 approved levels. Specifically, Manitoba Hydro is proposing annual increases of 3.5% to the Diesel-Residential class in all three years of the rate period to avoid further increases in the gap between grid and off-grid Residential rates. For similar reasons, Manitoba Hydro is also requesting to apply the requested 3.5% rate increases to all components of the Diesel-General Service rates, as well as to the Government &

First Nation Education basic monthly charge. However, consistent with the Board approvals since the 2017/18 & 2018/19 General Rate Application, Manitoba Hydro is proposing to maintain the Government & First Nation Education energy rate at the existing \$2.59/kWh level until an adequate capital funding agreement is reached and the level of subsidies provided by Manitoba Hydro is further evaluated.

In support of the above Diesel-Residential rates proposal, Manitoba Hydro submits that Diesel-Residential rates are not based on the full cost rate but have been determined on a policy basis in reference to grid rates. These rates are not affected by the resolution of capital funding issues, and in Manitoba Hydro's view, the risk of future rate shock for diesel customers outweighs the uncertainty risk regarding future capital funding. This proposal is also conservative as Diesel Zone rates would have to increase even further if a capital funding arrangement is not reached.

In Order 161/25, no rate increase was approved for any of the existing Diesel Zone rates as the Board did not consider it to be in the public interest to approve a drought-related interim rate increase for January 1, 2026 for these off-grid customers, who are not served by any of Manitoba Hydro's hydroelectric generating stations. However, the Board noted that it would consider Manitoba Hydro's request to increase Diesel Zone rates for fiscal years 2025/26 to 2027/28 as part of this final Order.

#### ***18.1.4 Other Rate Design Matters***

##### **Residential Rate Design**

Manitoba Hydro currently makes use of a grid-connected Residential class rate design that consists of a basic monthly charge and an energy rate. In this hearing, Manitoba Hydro is not requesting changes to the existing Residential rate design but is proposing to apply the proposed 3.5% rate increases equally to the basic monthly charge and the energy rate on January 1, 2026, January 1, 2027, and January 1, 2028.

MIPUG's witness Mr. Bowman asserts that the Residential customer rate design is poorly matched to the costs to serve this customer class. For example, the demand costs allocated to this class are recovered through an energy rate that is constant throughout

the year. This rate design drives concerns about appropriate price signals being given to customers, especially during the winter peak, that can affect intra-class fairness but also about the impacts of increased winter peak consumption on Manitoba Hydro's system. As a result, Mr. Bowman asserts that efforts should be made to improve cost recovery using other tools, such as increases in basic customer charges, seasonal rates based on higher winter energy rates than summer, or second block rates which charge higher prices for larger use in a month. In Mr. Bowman's view, these measures do not require waiting for Advanced Metering Infrastructure to be installed.

In response to Mr. Bowman's criticisms, Manitoba Hydro acknowledges that the use of a single energy rate for the Residential class over-recovers costs through the summer, as winter capacity costs are recovered throughout the year. However, Mr. Bowman's recommended Residential rate designs, such as seasonal rates, would be administratively complex given the existing customer billing processes and would likely trigger many customer concerns and complaints. Further, without the implementation of advanced interval meters to confirm when the energy was consumed, customer acceptance of a seasonal rate design may be limited.

#### *Rebalancing of the General Service Large Demand and Energy Rates*

Manitoba Hydro's existing rate design for General Service Large customers within the 750V-30kV, 30-100kV, and >100kV subclasses includes an energy rate and a demand rate.

With Directive 12 of Order 101/23, the Board approved Manitoba Hydro's proposal to apply the rate increases for the three General Service Large subclasses entirely to the demand component of the General Service Large rates. The intent of this approval was to better align, or rebalance, cost drivers with the class revenues. That is, the intention was to increase the proportion of revenues from the demand rate and decrease the proportion of revenues from the energy rate in order to better match the class allocated costs classified as demand and energy.

In this hearing, Manitoba Hydro submits the results of PCOSS26 show that the General Service Large energy and demand unit costs are more closely aligned with approved rates than was the case at the 2023/24 & 2024/25 General Rate Application. Figure 18.6 illustrates the demand, energy, and customer cost classification results from PCOSS26 compared to the revenues collected from the demand and energy rates that were in effect prior to the current Application. While these results still suggest that it would be reasonable to continue the rebalancing, given the closer alignment, and in the interest of not creating additional bill impacts for certain customers within these classes, Manitoba Hydro is proposing to apply the 3.5% equally to both the energy and demand rates for each of the years of the rate period.



Figure 18.6 — PCOSS26 Cost Components vs. Rate Components for the General Service Large Classes

MIPUG's witness Mr. Bowman does not agree with Manitoba Hydro's proposal to equally increase the individual General Service Large rate components. Instead, Mr. Bowman recommends that the firm rates for each of the General Service Large classes should be rebalanced (on a revenue-neutral basis for Manitoba Hydro) such that demand cost recovery is increased by 2% (as a percentage of overall class revenues) and energy rates reduced by an equal and offsetting dollar amount. This would cause an incremental bill increase up to 3% for low load factor General Service Large customers and a 1% decrease for high load factor General Service Large customers, on top of the class average rate increase.

Similar to Mr. Bowman, MIPUG's witness Mr. Friesen asserts that, given the existing General Service Large class rate designs, Manitoba Hydro's proposal for uniform rate increases will delay efforts to rebalance demand and energy rates and correct unacceptable RCC ratios for the three General Service Large subclasses. Differentiated component rate increases (e.g., increase the demand rate with a corresponding decrease to the energy rate) for these three subclasses should therefore be approved.

In response to Mr. Friesen's rebalancing proposals, Manitoba Hydro submits that equal but opposing demand rate increases and energy rate decreases are not revenue neutral. They would cause a \$20 million revenue shortfall for Manitoba Hydro and effectively award the General Service Large classes a rate decrease, which would result in a shift in costs to other classes. As such, a reduction in energy rates by 3.5% would require a much higher increase to demand rates to collect the full revenue requirement. Consequently, Manitoba Hydro recommends, like Mr. Bowman, that if the Board chooses to rebalance the General Service Large demand and energy rates, it should be implemented in a revenue-neutral way in order to allow the utility to recover its full revenue requirement.

*Billing Demand Definition for the General Service Large 30-100kV and >100kV Customer Classes*

For customers in the General Service Large 30-100kV and >100kV classes, Manitoba Hydro determines billing demand on a monthly basis in order to levy the demand rate that forms part of those customers' bills. Prior to the last general rate application, billing demand for these two classes was defined as the greatest of measured demand, 25% of contract demand, or 25% of the highest measured demand in the previous 12 months. To help send improved price signals to the largest General Service Large customers, Manitoba Hydro sought approval at the 2023/24 & 2024/25 General Rate Application to introduce a revised billing demand definition. Specifically, the utility proposed to change the first part of the definition (i.e., measured demand) to the greater of measured demand during peak hours or 90% of measured demand during off-peak hours.

At the time, Manitoba Hydro submitted that this change would allow customers to achieve limited savings by moving consumption from peak to off-peak hours. Further, the proposed 90% cap on off-peak demand was required to avoid unmitigated load growth during off-peak hours when customers would not pay their full capacity costs. As Manitoba Hydro expected the proposed changed definition to result in an approximate 1% reduction in the forecast aggregate billed demand for these classes, it also proposed a 1% increase to the demand rate for both subclasses in order for the proposal to remain revenue neutral.

With Directive 13 of Order 101/23, the Board approved the implementation of the minimum factor of 90% of measured off-peak to the billing demand definition used for the General Service Large 30-100kV and >100kV classes. However, in consideration of MIPUG submissions at the time advocating for a factor lower than 90%, Manitoba Hydro was directed to report at the next general rate application on its experience and customer consultations with respect to the definition change and whether it would be appropriate to use a different off-peak factor in the determination of a customer's billing demand.

In this hearing, Manitoba Hydro reports that, prior to the implementation of the revised billing demand definition on April 1, 2024, the utility communicated with affected customers to explain the definition change. Manitoba Hydro also performed customer-specific billing analysis. While customers posed some clarifying questions, no negative feedback was received. Further, review of the limited data available since implementation shows that impacts of the change are consistent with expectations. As such, Manitoba Hydro does not believe an adjustment to the 90% off-peak load factor is warranted at this time.

MIPUG's witness Mr. Friesen maintains that opportunities for General Service Large customers to manage load and achieve bill savings are limited by the 90% demand minimum billing threshold. Consequently, Mr. Friesen submits that the definition for billing demand approved in Order 101/23 should be revised to adjust the off-peak threshold from 90% to 80% of measured off-peak demand. In his view, this would provide greater flexibility for customers to maintain production and provide greater incentives to shift

usage to off-peak hours. It would also mitigate the customer risks of high demand charges in the event of accidental usage during the peak period.

Mr. Friesen also asserts that the implementation of the new billing demand definition resulted in an average 1.0% reduction in billing demand determinants for customers in the two higher voltage General Service Large subclasses. However, this perceived benefit to these customers was negated by the 1% additional increase in demand rates intended to offset the anticipated revenue losses arising from the change. In the view of Mr. Friesen, this degraded the value of any customer usage shifts to non-peak hours and was deemed punitive by customers. As a result, this 1% increase should be removed prior to the application of any increase to demand rates resulting from this Application.

In response, Manitoba Hydro submits there is no reason why the 1% adjustment to the demand rate approved in Order 101/23, which performed exactly as expected, and kept both the customer classes and Manitoba Hydro in a revenue-neutral position, should be removed. Doing so would require either an adjustment to the energy rate, which contradicts Mr. Friesen's recommendations on rate rebalancing, or an adjustment to another customer class.

## **18.2 Position of the Parties**

### ***18.2.1 Manitoba Hydro***

Manitoba Hydro is proposing to apply the rate increases in each of the fiscal years equally to all customer classes and to each rate component, with some exceptions for Area & Roadway Lighting and certain rate components for diesel service in off-grid communities. Further, Manitoba Hydro is of the view that its PCOSS should be based on average water inflows as these studies incorporate the average cost of production over a range of water conditions including under both extreme high and low water flows. The PCOSS based on average water inflows provides appropriate guidance for rates in forecast periods when water conditions cannot be predicted.

Consistent with its request at the last general rate application, Manitoba Hydro proposes to continue the revenue-neutral rate differentiation within the Area & Roadway Lighting class. This is because the RCC ratios for certain lighting groups in LCOSS24 fell well outside the zone of reasonableness and continued differentiated rate adjustments to the lighting groups is warranted. Further, Manitoba Hydro submits that no specific feedback was received from customers since implementing the first series of Area & Roadway Lighting rate differentiation, as approved in Order 101/23, and no intervener took a position on this matter in this proceeding.

In regards to Diesel Zone rates, Manitoba Hydro maintains that the existing Diesel-Residential energy rate (8.196 ¢/kWh) is well below the full cost rate (60.7 ¢/kWh) and 17% below the Residential grid energy rate effective April 1, 2024. As such, the proposed annual increases of 3.5% for the Diesel-Residential class will avoid further increases in the gap between grid and off-grid Residential rates. Similarly, the proposal to apply the 3.5% rate increases to all components of the Diesel-General Service rates and the Diesel-Government & First Nation Education basic monthly charge maintains parity between grid and off-grid rates for the first 2,000 kWh per month, and avoids increasing the shortfall compared to the full cost to serve. As the Diesel-Government & First Nation Education energy rate consists of the DCOSS full cost rate plus a surcharge to fund the shortfall between total costs and revenues, and as this surcharge could dramatically change based on decisions related to capital funding and subsidies, Manitoba Hydro proposes to continue to maintain this rate at the existing level. Once the outstanding issues related to Diesel Zone capital funding and the settlement agreement are resolved, Manitoba Hydro will bring forward a separate diesel rate application to the Board for review and approval.

Overall, Manitoba Hydro submits that it balances five objectives when designing rates for each customer class, namely that rates reflect the cost of providing service, stability, flexibility, efficiency, and affordability. In the interest of not creating additional bill impacts for some General Service Large customers, Manitoba Hydro proposes to apply the 3.5% equally to the General Service Large energy and demand rates for each year of the rate period.

Manitoba Hydro argues that PCOSS26 shows that the General Service Large energy and demand unit costs are more closely aligned with approved rates than was the case at the last general rate application. Despite this, the utility agrees that energy and demand rebalancing aligns with the cost of service study results and increases intra-class equity. Therefore, Manitoba Hydro is not opposed to incorporating some rebalancing in each of the three rate periods. However, while above-class average bill impacts for lower load factor customers are reasonable at this time in consideration of cost causation principles, they nevertheless must be done in a manner that considers total bill impacts.

In regards to submissions regarding the 1% demand rate adjustment approved in Order 101/23 in response to the implementation of the revised billing demand definition for the General Service Large 30-100kV and >100kV classes, Manitoba Hydro submits there is no reason to remove the revenue-neutral adjustment related to the billing demand definition change as it performed exactly as expected. Further, removing this revenue-neutral adjustment would require either an adjustment to the energy rate, which contradicts rebalancing proposals for the General Service Large class, or an adjustment to another customer class.

### **18.2.2 *Interveners***

#### **Assembly of Manitoba Chiefs**

The AMC supports efforts to minimize the impact of any rate increase on Residential customers, including by allowing an equal rate increase across customer classes. This intervener further argues that government payment reductions were not intended to make large industrial classes proportionally more affordable than residential or small consumer rates. Rather, these were clearly intended to be an affordability initiative, and the Province of Manitoba has signaled that affordability for families is a key concern. As well, this intervener asserts that it is imperative that the reduction in government payments, which the Board understands to include the reduction in water rental charges, is equitably incorporated in the cost of service study and resulting rates to the benefit of First Nations residential customers as First Nations in Manitoba have never ceded their rights to lands and waters.

With respect to Diesel Zone rates, the AMC supports MKO's opposition to any rate increase for the Diesel Zone where affordability and service conditions are uniquely constrained.

### **Consumers Coalition**

The Consumers Coalition argues that even with the recent amendments to *The Manitoba Hydro Act*, the post-Order 164/16 approach to considering RCC ratios alongside rate design objectives remains appropriate. Additionally, this intervener submits that returning to the 10-year deadline of 2028 from Order 59/18 for all classes to be in the zone of reasonableness, as advocated by some witnesses during this hearing, is inappropriate in light of worsening energy poverty and the magnitude of the proposed rate increases. In fact, considerable progress toward the zone of reasonableness has been made since the last general rate application, with only three classes remaining outside. Further, if the PCOSS was re-run with the reduced net export revenues in 2025/26 from the current drought, all but one class are inside the zone. In the future, increasing spending on generation and transmission assets will also disproportionately move the General Service Large classes toward the zone of reasonableness, self-correcting the RCC ratios and further reducing the need for differentiated increases in the rate period.

### **GSS/GSM Representative**

The GSS/GSM Representative argues that by every metric, the General Service Small Non-Demand class is overpaying its allocated costs and has done so over the long term. As such, this class should receive below-average rate increases. To this end, rate differentiation using 5- or 10-year timeframes should be implemented. This means those classes within the zone of reasonableness would receive 0.3% or 0.1% increases, respectively, on top of the overall rate increase.

The GSS/GSM Representative recommends that Manitoba Hydro consider a reduction in the first tier energy rate that is balanced with an increase to the third tier energy rate for the General Service Small Non-Demand and General Service Small Demand classes. Adjusting these rates in this manner over a longer-term basis should move the General

Service Small Non-Demand class into the zone of reasonableness, without unduly burdening customer classes already within the zone.

This intervener argues that, normally, updating the PCOSS for temporary or abnormal conditions, such as the recent drought financial forecast information, should not be a major consideration for RCC ratio rebalancing. However, in this instance the magnitude of the expected 2025/26 drought impacts will likely affect the overall rate decision, and as such, it is reasonable that it should also be a consideration within rate differentiation. Either way, this intervener submits that the General Service Small Non-Demand class is extensively overpaying above cost in both the original PCOSS26 and when results incorporate drought impacts.

The GSS/GSM Representative also argues that Manitoba Hydro is lagging behind other Canadian jurisdictions in providing multiple rate and program options that support efficient system use and customers managing their bills. Optional rates and programs for bill management should be prioritized for commercial customers and included in future rate design reviews in an effort to maximize the least-cost options included in the upcoming integrated resource plan. To the extent that this requires Advanced Metering Infrastructure, prioritization of this project should occur in a least-cost manner, starting with customers who identify themselves as interested in these types of rate offerings.

### **Manitoba Industrial Power Users Group**

MIPUG argues that the current legislation requires targeting RCC ratios of unity, subject only to a secondary policy, “to the extent practicable” of rate stability and predictability from year to year. Further, the Board can apply a standard of just and reasonable rates, but the new legislation does not provide broad discretion to use this concept in any way to undermine the explicit government policy that rates are to be based on costs. As such, MIPUG adopts Mr. Bowman’s rate differentiation recommendations in stating that rate increases should be applied on a differential basis such that all classes achieve 100% RCC ratios within the three-year rate period. This requires increases of 2.5% below the average rate increase for classes above the zone of reasonableness, 1.0% above

average rate increases for classes below a 100% RCC ratio, and average rate increases for the remaining classes.

To support the above recommendations, MIPUG submits that PCOSS26 is slightly closer to unity than PCOSS24 primarily because of the end of the high water period, and not because of the modest differentiated rates approved at the last general rate application. Further, there have been 35 years where General Service Large 30-100kV and >100kV RCC ratios have remained mostly near 110%. Therefore, no weight should be given to hypothetical mathematical projections based on self-correcting ratios. This intervener further asserts that in PCOSS26, the Board has clear evidence of the costs for the rate period being properly allocated to the classes and that it should use the results of the study to address this long-standing problem.

MIPUG further argues that the Board should approve demand rate increases and energy rate decreases to close the identified gaps between the General Service Large revenues and allocated costs. MIPUG also submits that the billing demand definition for the two largest General Service Large subclasses should use a revised off-peak factor of 80% instead of the existing 90%. Further, the 1% revenue-neutrality adjustment to the demand rate approved in Order 101/23 should be eliminated before applying the approved rate increase in this hearing. As an alternative to the 1% revenue-neutrality adjustment, an equivalent reduction to the energy rate could be applied prior to applying the approved rate increase.

Instead of the 1% neutrality adjustment, MIPUG argues that the cost of lost revenue should be shared by all ratepayers, consistent with practices for recovery of costs for energy efficiency programs. Further, the RCC ratios for the two higher voltage General Service Large subclasses are well above the zone of reasonableness and the 80% factor definition change would reflect this imbalance.

## Manitoba Keewatinowi Okimakanak

MKO argues that it is forced into a position of tactically and formally advocating a 0% rate increase for all residential customers and diesel community customers because that appears to be the only way to provide some relief to First Nation residential customers under *The Manitoba Hydro Act*. MKO submits that this position is only superficially extreme as it would not actually reduce electricity costs on reserve. Instead, it would only stop the energy burden on reserves from increasing as much as the 10.87% increase that Manitoba Hydro is requesting in this hearing.

### 18.3 Board Findings

#### ***18.3.1 Board Jurisdiction on Cost of Service and Rate Design Matters***

The Board reiterates that it finds that it has jurisdiction to direct Manitoba Hydro to make changes to its cost of service methodology or rate design regardless of whether the utility has proposed such changes. The Board's reasons for this finding were discussed in section 17.1.3.

#### ***18.3.2 Cost of Service Study Results, Rate Differentiation, and Proposals for Across-the-Board Rate Increases***

The Board finds that no rate differentiation between the various customer classes is to be implemented for fiscal year 2025/26, meaning the across-the-board rate increase approved on an interim basis on January 1, 2026 remains unchanged.

In conjunction with the overall annual rate increases on January 1, 2027 and January 1, 2028, the Board finds that inter-class rate differentiation is appropriate, meaning the customer classes will receive varying rate increases. The differentiation is to be structured in a manner that brings the General Service Small Non-Demand, General Service Large 30-100kV, and General Service Large >100kV classes into the zone of reasonableness within five years. The rate differentiation is to be revenue-neutral, with the revenue shortfall from these three classes recovered from all other classes within or below the zone of reasonableness, so long as the rate differentiation does not push these other classes above the zone. The end result of this differentiation is that the classes currently

above the zone of reasonableness are targeted to be at 105% in five years, while the classes currently within the zone will remain in the zone. The differentiation is to be based on the results of PCOSS26 as amended using the 2014/15 load research results and calculating class peak demand using the top 10 hours.

The actual amounts that rate increases will be differentiated are to be calculated and shown in the compliance filing required as part of this Order, at which time the Board will review and, if consistent with the Board's directives and expectations, approve as just and reasonable rate increases. Figure 18.7 below shows preliminary and indicative rate adjustments to accomplish the rate differentiation over a five-year period. Once validated by Manitoba Hydro's compliance filing, these adjustment amounts would be added to the overall rate increases on January 1, 2027 and January 1, 2028 to determine the rate increases for each class. In the compliance filing, Manitoba Hydro is to include the PCOSS26 RCCs as amended by the directives in this Order and the targeted RCCs expected at the end of five years of differentiated rate changes.

<b>Customer Class</b>	<b>PCOSS26 Starting RCC</b>	<b>Indicative 5-year Differentiated Rate Adjustment</b>
Residential	96.9%	0.3%
GSS-ND	108.0%	-0.6%
GSS-D	96.0%	0.3%
GSM	97.8%	0.3%
GSL 750-30kV	100.9%	0.3%
GSL 30-100kV	110.4%	-1.0%
GSL >100kV	110.6%	-1.0%
A&RL	104.2%	0.2%

Note: PCOSS26 RCCs are based on original filing and do not reflect the Board's directives in this Order

Figure 18.7 — Indicative Differentiated Rate Increases (to be confirmed in a subsequent Board Order)

As found in Order 101/23, the Board continues to be of the view that cost of service is an important tool in setting rates, and that an RCC ratio that is persistently above or below the zone of reasonableness for any class should be addressed. However, as set out in section 2.3 of this Order, the Board must balance cost of service considerations against other ratemaking criteria, including rate stability and affordability.

Order 161/25 approved an across-the-board interim rate increase of 4.0% for all classes. The Board determines that, since the 2025/26 year is over, it is both impractical and not in the public interest to adjust these interim rates in order to implement interclass rate differentiation for the 2025/26 fiscal year. However, the Board finds it in the public interest to continue the previous rate differentiation efforts, which started with Order 59/18, gradually bringing all the classes within the zone of reasonableness.

While the level of rate differentiation approved in Order 59/18 assumed annual differentiated rate adjustments over 10 years, the Board has only had the opportunity to order differentiated rate adjustments for five of the fiscal years prior to receiving the current Application. Accordingly, the Board finds it just and reasonable to adjust the time period over which the customer classes above the zone of reasonableness will be brought into the zone. At this time, the Board finds that a five-year adjustment period, with the next two interclass rate differentiation adjustments implemented for the 2026/27 and 2027/28 fiscal years, strikes a reasonable balance between cost of service considerations and other ratemaking criteria.

Clause 39.1(1)(a) of *The Manitoba Hydro Act* requires the rates charged by Manitoba Hydro to each class of grid customers to be based on the revenue requirements properly allocated to that class. The Board has previously explained that, to the extent that a customer class's RCC ratio falls within the zone of reasonableness, it is accepted that its revenues are recovering the allocated costs. The Board finds that clause 39.1(1)(a) is satisfied when the RCC ratios fall within the zone of reasonableness.

That said, clause 39.1(1)(d) requires that to the extent practicable, rates or changes in rates should be stable and predictable from year to year. The Board's direction to move the classes into the zone of reasonableness over five years and not the current rate period reflects this clause and is consistent with the principle of gradualism that the Board has long endorsed.

### ***18.3.3 Area & Roadway Lighting Class Rates***

The Board approves Manitoba Hydro's proposal for further rate differentiation within the Area & Roadway Lighting class. For consistency with the implementation timing of the overall rate increases and interclass rate differentiation approvals specified elsewhere in this Order, the additional rate differentiation within the Area & Roadway Lighting class shall be implemented as part of the rate changes on January 1, 2027 and again on January 1, 2028. For reasons similar as those outlined in section 18.3.2 above, the Board finds that continuing the Order 101/23 process of gradually moving the RCC ratios of all the rates within the Area & Roadway Lighting class into the zone of reasonableness is just and reasonable.

The Board finds that the LCOSS24 results are sufficient to inform the level of intraclass rate differentiation in this Application because the RCC ratios are far from the 95% to 105% zone of reasonableness. The Board directs Manitoba Hydro to update its LCOSS for the next general rate application in order to provide updated RCC results to support any additional intraclass rate differentiation requests for the Area & Roadway Lighting class.

The Board also approves as final the updated LED lighting rate descriptions proposed by Manitoba Hydro. The Board finds that these changes contribute to improved clarity regarding the ranges of LED lighting wattages that are applicable to these Area & Roadway Lighting rates. As the updated rate descriptions were already incorporated in the interim rate schedules approved in Order 1/26, no further changes to the descriptions included in Manitoba Hydro's Area & Roadway Lighting rate schedules are expected to be needed as part of the compliance filing required elsewhere in this Order.

#### **18.3.4 Diesel Zone Rates**

The Board confirms as final the Order 161/25 interim finding that no increase shall apply to any Diesel Zone rates for fiscal year 2025/26. As found in Order 161/25, the Diesel Zone customers are not served by hydroelectrically generated electricity or by Manitoba Hydro's provincial grid. As such, the Board does not consider it to be in the public interest to approve a drought-related rate increase for January 1, 2026.

The Board approves the rate increases required elsewhere in this Order for grid-connected customers on January 1, 2027 and January 1, 2028 for all components of the Diesel-Residential and Diesel-General Service rates, as well as for the Government & First Nation Education basic monthly charge. However, consistent with the Board's approvals since the 2017/18 & 2018/19 General Rate Application, the Board maintains the Government & First Nation Education energy rate at the existing \$2.59382/kWh level until an adequate capital funding agreement is reached and a diesel-specific rate application is reviewed. The Board finds it is appropriate to recover some of the 2025/26 forecast revenue deficiency of \$1.3 million through higher rates. The Board is not approving rates that fully recover this revenue deficiency as doing so would result in a large rate increase that does not promote stable and predictable rate changes. Approving these rate increases will also prevent the current gap between the Diesel Zone rates and grid rates from growing wider. As with all Diesel Zone rates approved since 2004, the Diesel Zone rates resulting from this Order will remain interim until Manitoba Hydro files a diesel-specific rate application.

As further explained in section 19.3 below, the Board is concerned with the lack of effective Government action over the last decade or more on targeted bill affordability and energy poverty matters affecting Manitoba Hydro's residential ratepayers. Presentations from ratepayers received by this Board in multiple proceedings since at least the 2014 Needs For and Alternatives To ("NFAT") proceeding have highlighted bill affordability and energy poverty issues affecting Manitoba Hydro's most vulnerable residential ratepayers, including those located in both grid-connected and Diesel Zone First Nations reserves. Further, there appears to be a lack of resolution regarding the Federal Government's

funding of prior and ongoing capital costs related to Manitoba Hydro's diesel generation facilities in the four diesel communities, despite a settlement agreement in 2010 that would purportedly address future funding issues. Keeping the existing Diesel Zone rates interim since 2004, which is now over twenty years after the rates were initially approved, does not reflect efficient regulatory processes and only serves to add risks for both the utility and all of its ratepayers.

In balancing various ratemaking objectives, and in consideration of the previously accepted policy decision to maintain some of the Diesel Zone rates equivalent to those paid by equivalent grid-connected customers, the Board notes that Diesel-Residential rates are now significantly lower than grid-connected Residential rates. The Order 161/25 decision for January 1, 2026 also introduced a difference between the grid-connected General Service rates and the Diesel-General Service and Diesel-Government & First Nation Education basic monthly charges, as well as the Diesel-General Service first block energy rate. While this situation may potentially be viewed as equitable for ratepayers located within the diesel communities, there are outstanding fairness and equity issues affecting grid-connected customers, including those that face similar energy poverty and bill affordability issues as those living within Diesel Zone communities. As such, the Board finds it just and reasonable to implement grid-equivalent rate increases to most Diesel Zone rates effective January 1, 2027 and January 1, 2028.

These Diesel Zone rate increases will stabilize the growing gap between grid and off-grid rate components and minimize the impacts of any possible future proposals to “catch-up” Diesel Zone rates to those of grid-connected customers.

For years, the Board has been requesting Manitoba Hydro to file a diesel-specific rate application in order to finalize the Diesel Zone interim rates. Without such a rate application, the Board finds that the status of Directives 3(c), 3(d), and 4 of Order 134/10, Directive 36 of Order 59/18, and Directive 4 of Order 100/20, which require Manitoba Hydro to file information regarding capital funding for the Diesel Zone, information on Diesel Zone rates, and to seek Board approval for Diesel Zone rates, will remain open until Manitoba Hydro files a diesel-specific rate application.

### **18.3.5 Other Rate Design Matters**

#### **Residential Rate Design**

The Board finds that no changes are required to the existing Residential class rate design for the test period. Based on concerns raised in this hearing regarding bill impacts for electric heat customers, customer billing complexity, and the potential for increased customer complaints should such changes be implemented without a detailed customer communication plan, the Board requires additional evidence in support of such a rate design change for this class. Furthermore, an increase to the basic monthly charge, as suggested by Mr. Bowman, would be offset by a lower energy rate to remain revenue neutral and send the opposite price signal than is needed to address the winter peak demand.

#### **Rebalancing of the General Service Large Demand and Energy Rates**

The Board finds that the demand and energy rate components for the three General Service Large subclasses should continue to be rebalanced on a revenue-neutral basis such that the resulting rates are better aligned with the PCOSS26 unit cost results. Specifically, the Board approves the implementation of Mr. Bowman's proposal to rebalance the General Service Large demand and energy rates on a revenue-neutral basis such that demand rates increase by an additional 2% over the class average rate increase and energy rates reduced by an equal and offsetting dollar amount. This rate rebalancing shall be implemented for January 1, 2027 and January 1, 2028.

The above decision is consistent with the General Service Large rate rebalancing approved in Order 101/23 and furthers the adoption of cost causation considerations based on the results of Manitoba Hydro's PCOSS26 results in this hearing. The Board notes that this decision may result in higher bill impacts for lower load factor General Service Large customers. Such bill impacts will depend on the final rates approved following Manitoba Hydro's compliance filing for this Order and on the affected customers' electricity consumption characteristics and behaviours.

Billing Demand Definition for the General Service Large 30-100kV and >100kV Customer Classes

The Board approves a further change to the billing demand definition for the General Service Large 30-100kV and the General Service Large >100kV classes. Specifically, the Board approves a change to the minimum factor of measured off-peak demand from 90% to 80%, effective January 1, 2027.

Should an additional revenue-neutrality adjustment be required as a result of the change to the revised off-peak factor of 80%, Manitoba Hydro is to include, and separately identify, this additional adjustment as part of its compliance filing required elsewhere in this Order. The Board further finds that it is just and reasonable to implement this change on a revenue-neutral basis. As such, MIPUG's request to eliminate the 1% revenue neutrality adjustment approved in Order 101/23 is denied.

The Board is convinced in this case of the need for additional opportunities for customers to manage their electricity bills while also seeking to mitigate increases in overall system demand. Based on the evidence in this proceeding, the Board finds that additional tolerance should be provided to General Service Large customers to help promote a shift from (or mitigate further growth in) on-peak consumption to off-peak consumption. However, the Board finds that changes to the billing demand definition in this case should not also seek to address separate RCC ratio concerns relative to the zone of reasonableness. The change in billing demand definition is therefore to be done on a revenue-neutral basis. Like the above General Service Large demand-energy rate rebalancing approval, the updated change in the billing demand definition may further accentuate the bill impacts actually experienced by the customers within the two largest General Service Large classes, depending on their load factor and their on-peak demand consumption.

Directive 13 of Order 101/23 required Manitoba Hydro to report to the Board on its experience and customer consultations with respect to the change of the definition of "billing demand" for General Service Large 30-100kV and General Service Large >100kV

classes. While Directive 13 of Order 101/23 is now deemed complete, Manitoba Hydro is directed to report back to the Board at the next general rate application on its experience related to the latest change in the General Service Large billing demand definition, together with the results of Manitoba Hydro's consultations with affected customers and the overall class load-shifting trends experienced since April 1, 2024. The utility is also to advise at that time whether it considers the 80% off-peak factor to remain appropriate or whether a different off-peak factor should be used.

## **19.0 BILL AFFORDABILITY AND ENERGY POVERTY ISSUES**

### **19.1 Background**

As explained in Order 101/23, Manitoba is a cold-weather jurisdiction where space heating is a necessity for significant portions of the year. This heating requirement results in significant heating costs for many of Manitoba Hydro's consumers. Currently, approximately 41% of Manitoba Hydro's residential customers use electricity to heat their homes. Historically, heating with electricity is more expensive than heating with natural gas, although it is less expensive than heating with fuel oil or propane. However, natural gas service does not extend to all regions of Manitoba, in particular the north, where heating requirements can be further elevated due to climatic differences and other factors.

Although Manitoba Hydro's rates are among the lowest in Canada, this does not mean that all Manitoba ratepayers can afford to pay their electricity bills. The term "energy burden" relates to the proportion of household income (usually pre-tax) that goes toward energy bills. The energy poverty threshold is often set at an energy burden of 10%, although other threshold levels and assessment methods are used in some jurisdictions. Beyond the energy poverty threshold, households may be required to make sacrifices or trade-offs in order to procure sufficient energy from their utility to adequately meet their heating and other electrification needs.

#### **Prior Board Findings on Bill Affordability and Energy Poverty and Associated Responses**

In every Manitoba Hydro rate proceeding since at least 2008, the Board has received submissions related to bill affordability and energy poverty issues, including affordability issues affecting First Nations communities. As a result, the Board has often expressed its concerns regarding these matters and consequently has made related recommendations to both Manitoba Hydro and to the Province of Manitoba.

For example, the Board's 2014 Needs For and Alternatives To ("NFAT") Report noted the significant (and cumulative) rate increases that were anticipated over 20 years, which resulted from the incremental costs of building the Keeyask Generating Station

(“Keeyask”) and other new transmission assets. The Board also noted the substantial incremental revenues that would accrue to the Province of Manitoba from water rental fees, debt guarantee fees, and the corporate capital tax upon Keeyask entering service. To address this concern, the Board recommended that the provincial government direct a portion of the incremental capital taxes and water rental fees from the development of Keeyask to mitigate the impact of rate increases on lower-income, northern, and Indigenous customers.

In 2016, pursuant to Directive 5 of Order 73/15, Manitoba Hydro established the Bill Affordability Working Group (“Working Group”), which was comprised of a variety of stakeholders who represented, worked with, or provided services to lower-income Manitoba Hydro customers. The Working Group, through a collaborative process that culminated in a report that was filed at the 2017/18 & 2018/19 General Rate Application, reviewed various issues affecting Manitoba Hydro’s low-income ratepayers and various supporting measures that could potentially be implemented. As further explained in Order 59/18, the Working Group’s primary findings included the following:

- The planned electricity rate increases will result in higher energy costs that will have more pronounced effects on households that already spend a significant proportion of their total income on energy; and
- Ultimately, energy poverty is deeply complex, multi-faceted, and spans issues of income, geography, cultural identity, family size, awareness of available support programs, and more. Further, no single initiative or program will solve the issue of energy poverty.

While improvements to Manitoba Hydro’s then-existing bill affordability programs were recommended, the Working Group did not reach consensus on any specific rate options or rate assistance program for Manitoba Hydro’s low-income ratepayers.

In Order 59/18, following the review of various submissions on bill affordability and energy poverty matters received during the 2017/18 & 2018/19 General Rate Application, the Board noted that there may not be a single solution to a multifaceted bill affordability problem. Further, the Board found that while government has an important role to play in

addressing the issue of affordability, so too does Manitoba Hydro. Consequently, the Board recommended, among other things, that the provincial government introduce a comprehensive bill affordability program run by a government department to address energy poverty issues faced by Manitobans. Further, a majority of the Board directed Manitoba Hydro to implement a new First Nations On-Reserve Residential customer class. In its decision, the Board was guided by evidence that 96% of First Nations people on reserve lived in poverty and that First Nations reserves had poor housing stock and no access to the more economical option of heating with natural gas.

As described in Orders 59/18, 90/18, 100/20, and 101/23, the Board's authority to order the creation of the First Nations On-Reserve Residential customer class was subsequently challenged by Manitoba Hydro. Ultimately, the Manitoba Court of Appeal considered the First Nations On-Reserve Residential customer class in *Manitoba (Hydro-Electric Board) v. Manitoba (Public Utilities Board) et al*, 2020 MBCA 60. In that decision, delivered in June 2020, the court ruled that the creation of the class violated subsection 43(3) of *The Manitoba Hydro Act*, which states that Manitoba Hydro's funds are not to be used by the government to serve any purpose other than that of Manitoba Hydro. The court also found that the First Nations On-Reserve Residential class contravened clause 39(2.2)(b) of *The Manitoba Hydro Act*, which prohibits the classification of customers based on geographic location. In the view of the court, initiatives to address broad social issues such as poverty should be left to the government.

As a result of the Manitoba Court of Appeal's ruling, the First Nations On-Reserve Residential customer class was unwound in Order 110/20, and those customers now pay the same rates as other residential consumers. However, and as described in section 18.1.3 of this Order, the separate off-grid Diesel-Residential class rates were left frozen at the levels approved for August 1, 2017 until a diesel-specific rate application is reviewed. Since that time, the provincial government has amended *The Manitoba Hydro Act* to clarify, among other things, some aspects of the Board's jurisdiction over Manitoba Hydro. For example, rule 5 of subsection 39(5) of *The Manitoba Hydro Act* now explicitly states that Manitoba Hydro's rates cannot differ based on affordability or other socio-economic factors.

Another legislative change affecting bill affordability is the *Efficiency Manitoba Act*. Effective April 1, 2020, Manitoba Hydro transitioned the majority of its demand-side management (“DSM”) programs to Efficiency Manitoba. In 2019 and 2020, the Board reviewed Efficiency Manitoba’s 2020/21 to 2022/23 Efficiency Plan, including the proposed costs related to residential income-qualified and Indigenous programs, which sought to address equity and affordability issues related to the adoption of energy efficiency retrofit solutions. Since that time, the Province of Manitoba has extended Efficiency Manitoba’s 2020/21 to 2022/23 efficiency plan through 2025/26.

At the 2023/24 & 2024/25 General Rate Application, Manitoba Hydro provided evidence that it considers bill affordability on a holistic basis, involving different supports provided by different agencies. Specifically, this includes non-rate-related Manitoba Hydro programs such as a flexible payment program and a customer arrears assistance program, energy efficiency programs delivered by Efficiency Manitoba, and referrals to other social service agencies. While more specific evidence regarding its bill affordability offerings was provided at the time, Manitoba Hydro did not offer low-income electricity rate options, nor does it offer rebates or credits on its bills based on a customer’s energy burden.

In Order 101/23, the Board expressed its deep concerns about energy poverty issues in Manitoba and found that little progress had been made since Order 59/18 to help Manitoba Hydro’s poorest customers for whom energy bills are a heavy burden. The provincial government reduced its debt guarantee and water rental fees in 2022, which allowed Manitoba Hydro to reduce its requested rate increases. This affected affordability for all ratepayers, but there continued to be a lack of targeted energy poverty measures in Manitoba. Further, the Board stated that if the 2020 Manitoba Court of Appeal decision means that social policy and bill affordability issues are matters reserved for the government, then the government must devote resources to those matters and develop policies in order to alleviate energy poverty issues in Manitoba, especially in the face of continued Manitoba Hydro rate increases over the next 20 years.

Accordingly, Recommendation 18.3.1 of Order 101/23 recommended that the provincial government establish an energy poverty program to relieve the energy burden of households facing energy poverty. In regards to Manitoba Hydro's bill affordability programs, Recommendation 18.2.1 of Order 101/23 recommended that Manitoba Hydro evaluate its existing suite of bill affordability programs to assess the effectiveness of those programs in mitigating or eliminating energy poverty. Further, Recommendation 18.2.2 of Order 101/23 recommended that Manitoba Hydro consult with First Nations about creating targeted programs to alleviate energy poverty faced by the utility's customers living in First Nation communities.

On March 20, 2025, the Province of Manitoba announced the elimination of capital taxes for Manitoba Hydro and a further staged reduction of the provincial debt guarantee fee from 0.50% to 0.40% for 2025/26, to 0.30% for 2026/27, and to 0.15% for 2027/28 onwards. Similar to the government's reduction to the debt guarantee and water rental fees in 2022, these more recent fee reductions addressed affordability for all ratepayers and were not specifically targeted to lower-income ratepayers, reducing the need for even higher rate increases in the current rate period of this application.

#### Current General Rate Application

In this hearing, Manitoba Hydro submits that, similar to other Canadian utilities, its bill affordability programs are focused on crisis support and arrears management, and are not meant to reduce energy burden. Specifically, Manitoba Hydro focuses on supporting service continuity, improved bill payment behaviour, as well as utility savings from reduced collection costs and write-offs. Further, Manitoba Hydro is limited in its capability to design targeted programs to reduce energy poverty as it does not have individual customers' incomes and that any existing data on energy poverty of its customers is based on aggregated surveys.

In response to the Board's recommendations in Order 101/23, Manitoba Hydro submits that it undertook several activities to further evaluate the corporation's existing bill affordability programs. These activities included conducting a jurisdictional review of utility

bill affordability programs and grouping these as: crisis support (one-time help), prevention (government funded, utility-administered), and conservation (DSM). Based on this review, Manitoba Hydro categorizes its existing programs as follows: Neighbours Helping Neighbours (crisis support), Payment Arrangements (crisis support), Customer Arrears Assistance Plan (crisis support), Load Limiters (crisis support), Equal Payment Plan (prevention), Waiving Security Deposits (prevention), and Home Energy Efficiency Loan (conservation).

Overall, Manitoba Hydro states that its bill affordability programs align with other Canadian utilities, that its programs focus primarily on crisis support, and that prevention programs in other jurisdictions that provide ongoing bill credits or subsidies to reduce energy burden are taxpayer funded at the provincial or territorial level.

To address the recommendation from Order 101/23 for Manitoba Hydro to consult with First Nations regarding targeted energy poverty programs, Manitoba Hydro evaluated the level of participation in bill affordability programs by customers living in First Nation communities, initiated informal discussions on bill affordability at a community level to assess barriers, and explored opportunities to enhance Indigenous community engagement on various policy issues, including affordability. Manitoba Hydro submits that it found that enrollment in existing bill affordability programs by customers in First Nations is exceptionally low. Further, there is a high degree of variability in arrears and energy consumption between First Nations, and affordability issues for customers living in First Nations communities are unique, in part because of federal income assistance funding.

Given the above findings, Manitoba Hydro implemented a number of improvements to its bill affordability programs. For example, the utility completed a pilot project for its Neighbours Helping Neighbours program, which is administered by the Salvation Army. Specifically, Manitoba Hydro extended the program's eligibility to customers who are receiving social assistance, eliminated the one-time award limit, increased the grant to \$500 for electrically heated homes, and worked directly with First Nations for wider-scale program enrollments. Further, Manitoba Hydro is working to understand the impact of federal income assistance funding on the energy burden of its low-income customers,

and is continuing to engage with customers and First Nations to understand barriers to low program participation. Manitoba Hydro has also signed an agreement with the AMC to fund a liaison position to lead and facilitate engagement on broad policy issues, including affordability.

The Consumers Coalition's witness Dr. Das asserts that energy poverty produces cascading social and psychological stressors, and is influenced by energy prices, household incomes, dwelling energy efficiency, household composition, energy use behaviours, and geography. This witness also submits that energy poverty is a significant, though unevenly distributed, challenge across Canada. Using the 10% energy poverty threshold, between 6% and 9% of Canadian households, on average, are classified as experiencing energy poverty, with the average in Manitoba being lower than in other provinces. Despite these results, certain households and communities face disproportionate burdens due to intersecting social, demographic, and economic conditions. Further, while Manitoba Hydro emphasizes that its rates remain among the lowest in North America, this aggregate picture masks significant inequities in how households experience the costs associated with using energy services, with Indigenous households, particularly First Nations on-reserve, facing the highest burdens in the province.

In this case, Dr. Das submits that the proposed 3.5% rate increases in this hearing will exacerbate existing inequities unless paired with stronger affordability measures. Manitoba Hydro's existing affordability programs provide important but limited relief. Specifically, tools such as the Customer Arrears Assistance Plan, Equal Payment Plan, and Neighbours Helping Neighbours grants prevent disconnections and help manage arrears, but do not reduce underlying energy burdens. Dr. Das also notes that participation is low in First Nations communities, awareness of programs is limited, and efficiency loans disproportionately benefit higher-income households. Moreover, Manitoba lacks ongoing bill credit programs and the Neighbours Helping Neighbours program relies on fixed annual contributions from Manitoba Hydro and customer donations, resulting in limited program funding each year and instances where the

program is fully subscribed before year-end and some eligible households are left without support.

Overall, Dr. Das concludes that addressing energy poverty in Manitoba will require strong coordination and clear roles among Manitoba Hydro, Efficiency Manitoba, and the Province. For example, Manitoba Hydro should continue to deliver bill affordability and arrears management programs, Efficiency Manitoba should scale its income-qualified and Indigenous efficiency programs to ensure households receiving Manitoba Hydro support also access efficiency programs, and the Province of Manitoba should provide policy direction and stable funding mechanisms for ongoing affordability supports. Such supports could take the form of an on-bill credit or regulated low-income fund (similar to the Ontario Electricity Support Program or the Ontario Low-Income Energy Assistance Program) and facilitate data-sharing agreements between agencies.

Given the above, Dr. Das recommends the following:

- Strengthen disconnection policies, building on the COVID-19 precedent;
- Enhance crisis support through targeted outreach and expanded eligibility;
- Refine arrears management so payment terms are realistic and linked to long-term solutions;
- Invest in energy literacy and customer engagement (e.g., simplify bills, enhance digital tools, and develop targeted literacy campaigns);
- Introduce outcome-based program evaluation (e.g., to assess whether programs deliver lasting reductions in hardship);
- Improve data collection and reporting;
- Partner with Efficiency Manitoba and communities to design no-cost, equity-focused retrofit programs; and
- Consider legislative reform to enable income-based affordability measures and recognize energy as an essential service.

In response, Manitoba Hydro maintains that energy poverty is a complex issue that engages considerations of social policy, which in turn cannot be solved by Manitoba Hydro alone. Further, the bill credit programs referenced by Dr. Das are mostly taxpayer funded. For example, the Ontario Electricity Support Program has been taxpayer funded since 2017. Similarly, the PEI Home Heating Program is funded by the PEI Government, and the Nova Scotia Home Energy Assistance Top-up is primarily funded by the Province of Nova Scotia.

Manitoba Hydro also submits that Dr. Das unfairly critiques Manitoba Hydro's affordability programs. Specifically, the utility's bill affordability programs are not meant to reduce energy burden and, as such, the evaluations of the programs are not measured on that criterion. Further, Manitoba Hydro already partners directly with Efficiency Manitoba on various efficiency programs, including an extensive suite of offerings for lower income customers, which have eligibility thresholds that could enable 40% of Manitobans to participate. Similarly, the Neighbours Helping Neighbours has never had a funding cap and has recently expanded program eligibility. The utility also currently has a moratorium period on disconnections from October to April that applies to customers regardless of energy burden, location or heat type, and there are further disconnection protections provided to customers who participate in Payment Arrangements and the Customer Arrears Assistance Plan. Expanding the disconnection moratorium as proposed by Dr. Das does not address the gap between income and energy costs, and would further increase arrears.

## **19.2 Position of the Parties**

### **19.2.1 *Manitoba Hydro***

Manitoba Hydro states that when measuring and framing energy poverty, it is crucial to consider both relative and absolute metrics. Overemphasis on percentage changes alone can misrepresent the scale of the issue and potentially overstate the number of customers affected. Manitoba Hydro notes that while the number of households affected by energy poverty has declined from 15,507 in 2014 to 12,419 in 2023, this shift is primarily due to a substantial decrease in the number of households earning less than \$25,000: from

61,052 in 2014 to 32,816 in 2023. Manitoba Hydro states that while the total number of energy-burdened households has declined due to a shrinking low-income population, the proportion of those remaining in poverty who are experiencing high energy burdens has increased.

Manitoba Hydro argues that it offers bill affordability programs that align with those offered by other utilities in Canada. The utility continues to make improvements to its programs and has addressed the recommendations of Dr. Das. Such improvements include reducing eligibility and accessibility barriers to the Neighbours Helping Neighbours program, supporting Efficiency Manitoba's income-based programs, and developing an energy literacy campaign to promote informed decision making by customers regarding their energy consumption and adoption of new technologies.

Manitoba Hydro maintains that it does not collect the customer income information required for the outcome-based program evaluations proposed by Dr. Das. Further, government action would be required to change Manitoba Hydro's mandate and implement forms of income-based billing, although this would not align with Dr. Das's own position that energy burden is fundamentally a societal issue that should be addressed through comprehensive public policy rather than utility-specific initiatives. As well, understanding energy burden, for both on- and off-reserve First Nations customers, is important to Manitoba Hydro for targeting supports to customers who need assistance with paying their energy bills. Manitoba Hydro is committed to working directly with First Nations with dedicated customer service to community engagement, ongoing dialogue with leadership, survey improvement, and funding a liaison position at the AMC. These efforts reflect Manitoba Hydro's commitment to collaborative approaches that help address the multifaceted issue of energy affordability.

While Dr. Das's recommendation for legislated reform or low-income based affordability would require government action, Manitoba Hydro notes that the existing uniform rates legislation also provides a level of cost protection for customers residing in rural and remote areas since the costs to serve these regions are typically higher.

### **19.2.2 Interveners**

#### **Assembly of Manitoba Chiefs**

The AMC argues that evidence in this proceeding demonstrates that First Nations on-reserve residential customers experience uniquely high electricity consumption due to structural factors, including the absence of natural gas service, reliance on electric heating, and housing conditions. Combined with significantly lower median income, these factors result in the highest energy burdens in the province. Expert evidence confirms that the proposed rate increases will deepen energy poverty for First Nations on-reserve households, which will in turn increase the number of customers exceeding accepted affordability thresholds. In its Application, Manitoba Hydro did not meaningfully assess these impacts, did not employ available affordability metrics, and did not demonstrate that existing programs, income assistance, or other mechanisms offset the harm.

The AMC also notes that Manitoba Hydro acknowledged that its bill affordability programs are largely reactive and arrears-focused, do not reduce underlying energy burdens, and have limited reach among First Nations on-reserve customers. In the view of this Intervener, this shows that the bill affordability-related recommendations the Board made in Order 101/23 have not been fulfilled. Furthermore, Manitoba Hydro's reliance on Federal Income Assistance to discount energy poverty impacts is not supported by evidence. Federal Income Assistance is aligned with provincial income assistance and there is no evidence that it adjusts for higher energy needs, rising rates, or arrears accumulation.

#### **Consumers Coalition**

The Consumers Coalition argues that, while having some of the lowest electricity rates in Canada is beneficial to all Manitobans, some Manitobans are facing very difficult and unacceptable choices – in some cases, needing to decide whether to purchase electricity or food for their family. As such, three years of 3.5% increases will deepen the energy poverty gap, with low income ratepayers increasingly left behind. Accordingly, this Intervener submits that the Board should make a finding that energy poverty persists in Manitoba and has intensified for Manitoba Hydro's most vulnerable customers.

The Consumers Coalition's witness Dr. Das states that energy poverty – defined as households spending a disproportionate share of income on essential energy services – affects at least 22,000 Manitoba households. In 2023, the average Manitoba household spent about 3.5% of its income on energy costs (often called the “energy burden”). However, for nearly 4.3% of households, energy costs exceeded more than 10% of their income, a level widely recognized as indicating severe hardship.

As reviewed in previous Manitoba Hydro rate proceedings, energy poverty is a pressing and complex issue, requiring an integrated, multi-faceted approach to address it. While Manitoba Hydro acknowledges that it has a role to play, it continues to be sluggish on energy poverty, lagging behind other provinces in its offering (and evaluating) of bill affordability measures and programs that meaningfully address energy poverty.

Despite the above, the Consumers Coalition acknowledges that Manitoba Hydro cannot address energy poverty in isolation. As such, the Consumers Coalitions submits that the Board should make recommendations to the Government of Manitoba, Manitoba Hydro, and Efficiency Manitoba for an integrated and systematic approach to addressing energy poverty by consistently defining the problem, tracking, and measuring the effect of existing efforts to address energy poverty and identifying policy gaps. Further, the Board should also recommend to Manitoba Hydro that it implement the recommendations put forward by Dr. Das and report back on implementation at the next general rate application.

### **Manitoba Industrial Power Users Group**

MIPUG does not disagree with the Board's concerns in prior orders over the importance of socio-economic considerations broadly in considering the importance of affordable rates. However, there is no indication that the Board's previously desired low-income considerations for bill relief have been accepted by government. Indeed, the clear decisions of the Government of Manitoba are focused on reducing and controlling Manitoba Hydro's costs broadly across all classes, without any variance in charging each class the properly allocated costs.

## Manitoba Keewatinowi Okimakanak

MKO argues that whatever energy poverty exists in Winnipeg or in Manitoba outside of First Nation reserves — and there is no denying that it exists and is a serious problem — the magnitude is more severe on First Nation reserves and especially on MKO's 25 First Nation reserves in Manitoba, who heat their homes with electricity. In support of this position, MKO asserts that despite comprising less than 4% of Manitoba Hydro's residential customers, First Nations customers are responsible for approximately 60% of the arrears for all residential ratepayers.

MKO therefore submits that recommending legislative changes could be considered appropriate or necessary to carry out the Board's broad mandate under *The Manitoba Hydro Act* generally, and specifically under clause 39(4)(b), to set just and reasonable rates. Specifically, the Board could make a recommendation that the Government of Manitoba amend *The Manitoba Hydro Act* either to create a new First Nations On-Reserve Residential customer class in the legislation or to permit the Board to create one in the course of an application before it.

### 19.3 Board Findings

As expressed in numerous Board orders regarding Manitoba Hydro's rate decisions or development plans, the Board remains concerned about energy poverty issues in Manitoba. Once again, the Board has received submissions in this proceeding, including from the Consumers Coalition's ratepayer panel summarized in Appendix B of this order, that highlight the impacts of this multi-faceted and complex problem. Energy supply, especially Manitoba Hydro's services, is an essential service in this province. Manitoba Hydro's submissions in this hearing support this view given that this rationale underpins the utility's current multi-billion-dollar capital expenditure plans over the next twenty years to ensure safe and reliable service to customers.

As discussed at the 2014 NFAT proceeding, as well as in subsequent proceedings related to Manitoba Hydro's general rate applications, such increased capital expenditure plans necessitate, all else being equal, increased revenue requirements once the assets are

placed in service. These in turn result in projections of a prolonged series of significant rate increases that continue well beyond the current three-year rate period. However, for some customers, any rate increase creates hardship. To avoid instances where customers have to make hard choices such as heating their home or sufficiently feeding their families, Manitoba Hydro's bill affordability programs, in conjunction with other supports, are critical.

As in any Manitoba Hydro rate proceeding, the Board must balance the interests of ratepayers against the financial health of the regulated utility. In determining this balance in this proceeding, the Board is guided by its regulatory obligations as outlined in *The Public Utilities Board Act* and *The Manitoba Hydro Act*. As explained elsewhere in this Order, a 2020 decision from the Manitoba Court of Appeal and the recent amendments to *The Manitoba Hydro Act* have explicitly clarified that Manitoba Hydro's rates for different customers or classes of customers must not differ based on affordability or other socio-economic factors. The Board interprets these legislated limitations as government clearly stating that broad social issues such as poverty, specifically energy poverty, should be left for government to address. If government opts to exclude these matters from the Board's jurisdictional oversight of Manitoba Hydro, then the Board contends that government has the responsibility to meaningfully address these issues. As explained elsewhere in this Order, rate increases are being approved in all three years of the rate period and Manitoba Hydro's existing financial forecast suggests additional rate increases will be proposed for the following three-year rate period. In the Board's view, the previously identified need for mitigating the impacts of rate increases for Manitoba Hydro's most vulnerable customers therefore remains an important issue for the foreseeable future.

In 2022, and again in 2025, the provincial government cut the debt guarantee and water rental fees, and also eliminated Manitoba Hydro's capital tax payments to government. Similar to the position of several parties in this hearing, the Board finds that these significant fee reductions benefited all ratepayers. Indeed, Manitoba Hydro's evidence in this hearing is that without these government payment reductions, Manitoba Hydro would have required rate increases greater than the existing 4% annual rate cap in the rate

period. However, while the overall affordability of Manitoba Hydro's rates appears to have been taken into account, the Board notes that government has not acted upon prior recommendations. These date back to the 2014 NFAT report and to numerous Board Orders since that time, for targeted energy bill initiatives that mitigate the impact of Manitoba Hydro's rate increases on lower income customers. Targeted programs are needed as energy is an essential service and programs of general application do not help those most in need.

The evidence provided by both Manitoba Hydro and the Consumers Coalition demonstrates that tens of thousands of households in Manitoba continue to experience energy poverty. While Manitoba Hydro's electricity rates may be low compared to other jurisdictions, Manitoba's cold climate and the prevalence of electric heating in areas without access to natural gas lead to significant bills for many customers. The affordability of these electricity bills, not rates, is then dependent on many factors, although household income is a major consideration. Given the criticality of energy for heating in Manitoba, the Board once again finds that an integrated approach is needed to ensure that Manitoba Hydro's most vulnerable ratepayers are not left behind.

Given the above, and given the Board's continued concern about bill affordability for low-income ratepayers, the Board recommends that the Province of Manitoba undertake an Energy Poverty Reduction Review focusing on Manitoba Hydro's low-income ratepayers. Similar to the 2016 Working Group review on bill affordability, the Board believes there is value in the government, with input from multiple stakeholders (e.g., government agencies, Manitoba Hydro, Efficiency Manitoba, and non-governmental organizations and advocacy groups) undertaking further research to better understand energy poverty and affordability issues affecting Manitoba Hydro's low-income ratepayers. This should include a comparative review of how these issues are being addressed in other jurisdictions, and an evaluation of how additional supports can be implemented in Manitoba. The Review should be coordinated and supported by the provincial government, and culminate in an Energy Poverty Reduction Strategy that considers various mitigation measures, including a refundable income tax credit for low-income Manitoba Hydro ratepayers. This strategy should also allow for prompt implementation of

mitigation measures in order to provide incremental supports to low-income ratepayers as soon as possible, especially given Manitoba Hydro's projection for regular annual rate increases over the next 20 years.

With respect to the refundable income tax credit, the Board further recommends such a credit that specifically targets low-income ratepayers in Manitoba to alleviate the annual energy burden of those customers. The provincial government already has access to income data and the necessary infrastructure in place to administer such credits, allowing them to be implemented at a lower administrative cost than equivalent bill credit programs offered through Manitoba Hydro or non-government organizations.

In addition to the role of government in addressing energy poverty issues in Manitoba, the Board continues to find that Manitoba Hydro has a role to play. In combination with Efficiency Manitoba's Income Qualified and Indigenous efficiency programs, Manitoba Hydro's existing suite of bill affordability programs offer important supports to customers that have challenges paying their bills. The Board commends Manitoba Hydro's recent efforts in completing its pilot project for expanding the Neighbours Helping Neighbours program and encourages the utility to implement more permanent changes as soon as possible. To continually improve the effectiveness of Manitoba Hydro's bill affordability supports, the Board recommends that Manitoba Hydro continue stakeholder engagements regarding bill affordability issues and to further advance initiatives to evaluate and improve the efficiency and levels of support for low-income customers. The Board expects Manitoba Hydro to provide further updates on its program evaluations and program improvements at the next general rate application.

The Board finds that Manitoba Hydro is in a unique position to drive specific improvements given its day-to-day contacts with customers and its ability to leverage, and enhance, partnerships with Efficiency Manitoba, government, industry, social groups, First Nations groups, and individual communities to address the important needs and impacts presented during this hearing.

## 20.0 OTHER MATTERS

### 20.1 **Curtailable Rate Program (CRP) & Finalization of Interim *Ex Parte* CRP Orders**

#### 20.1.1 *Background*

Manitoba Hydro's Curtailable Rate Program ("CRP") is an optional program available to some industrial customers by which those customers receive a financial credit in exchange for agreeing to curtail (i.e., shut down) their load during periods when Manitoba Hydro has capacity constraints on its system. This enables Manitoba Hydro to utilize the customer-provided capacity as an operating reserve and energy supply option for system planning purposes as well as to respond to certain operational conditions. The intent of the CRP is to minimize disruptions for firm load customers in the event of a loss of generation or transmission.

Manitoba Hydro offers three base curtailment options (A, R, and E) and two combination options (AE and RE), each with their own terms and conditions as set out in the corporation's document, "Curtailable Rate Program for Individual Customer Loads Terms and Conditions" (the "CRP Terms and Conditions"). Manitoba Hydro must obtain Board approval for any changes to the CRP Terms and Conditions, as well as annual approvals for CRP Reference Discounts.

The CRP Reference Discounts are the amounts credited to a participant in the CRP program each month in exchange for that customer making curtailable load available to Manitoba Hydro. The Reference Discount has been calculated in relation to the utility's marginal value of the lowest cost resource required to otherwise provide capacity. In particular, beginning in 2005, the CRP Reference Discount was based on the annual carrying cost of a simple cycle combustion turbine. Since 2005, the CRP Reference Discount has been subject to an annual inflation factor and is subject to annual *ex parte* review by the Board.

In Order 101/23, the Board approved the following changes to the CRP Terms and Conditions:

- annual testing of Options A and R;
- an increase of the maximum annual number of Option A curtailments from 15 to 16; and,
- modifications to the notice period that customers must provide if converting from curtailable to firm service.

Since Order 101/23, the Board has provided interim approval of annual CRP Reference Discounts in Order 46/24 and Order 59/25. In Order 59/25, the CRP Reference Discount is \$4.39/kW-month, effective April 1, 2025.

In Order 59/25 the Board also stated its intention to explore in this Application the continued appropriateness of the existing methodology to determine the CRP Reference Discount, noting that the pricing data for a simple cycle combustion turbine has not been reviewed since 2012.

In this hearing, Manitoba Hydro provided some preliminary pricing data for simple cycle combustion turbines. Based on Manitoba Hydro's recent P80 preliminary estimate for a dispatchable capacity resource, the updated CRP Reference Discount would be \$5.88/kW-month. Using Manitoba Hydro's P50 cost estimate, which Manitoba Hydro views as a more representative value for lowest cost capacity, the CRP Reference Discount would be \$4.94/kW-month. However, despite the availability of an updated P50 cost estimate of \$4.94/kW-month for a simple cycle combustion turbine, Manitoba Hydro views the existing CRP reference discount of \$4.39/kW-month (as approved in Order 59/25) as continuing to provide fair compensation in relation to the terms and conditions of the CRP. Manitoba Hydro anticipates completing a review of the value of the CRP as part of the development process of future demand response offerings.

In this Application, Manitoba Hydro is seeking Board approval of further modifications to the CRP Terms and Conditions. The proposed modifications are summarized as follows:

- Clarification that the annual curtailment tests allow for curtailing the combined load options as either Option A or Option R;
- Clarification that if Manitoba Hydro chooses to forego the annual curtailment test, the maximum number of curtailments for that year does not change;
- A new provision to allow Manitoba Hydro to remove a customer from the CRP and convert them to firm service, either immediately if the customer breaches the CRP terms and conditions, or with 18-months written notice in the absence of a cause for termination; and
- Editorial changes, including organizational changes but also an expansion of the Reference Discount formula.

Manitoba Hydro also seeks final approval of Order 46/24, which provided interim *ex parte* approval of the 2024 Reference Discount inflation adjustments, as well as the finalization of all interim *ex parte* CRP rate orders that have been issued since Order 46/24; namely, Order 59/25.

None of the interveners made submissions on the CRP.

### **20.1.2 Board Findings**

The Board approves Manitoba Hydro's proposed changes to the CRP Terms and Conditions outlined in Appendix 7.14 of its Application, effective April 1, 2026. The Board expects Manitoba Hydro to promptly communicate the approved program changes to affected customers.

The Board also approves the finalization of Orders 46/24 and 59/25, which relate to the annual CRP Reference Discounts approved since Order 101/23.

The Board finds that the CRP reference discount should not, at this time, be updated to \$4.94/kW-month (instead of \$4.39/kW-month per Order 59/25) to reflect Manitoba Hydro's latest P50 cost estimate for a dispatchable capacity resource. However, the

Board directs Manitoba Hydro to provide an updated P50 cost estimate as part of the next annual CRP Reference Discount application, along with a detailed explanation as to how it arrived at its estimate.

## **20.2 Surplus Energy Program (SEP) & Finalization of Interim *Ex Parte* SEP Orders**

### **20.2.1 Background**

The Surplus Energy Program (“SEP”) is a program that enables qualifying commercial customers to purchase surplus energy (i.e., energy not required to meet Manitoba’s domestic demand or firm export contract obligations) at Manitoba Hydro’s weekly forecast marginal cost. It is intended to be a revenue-neutral program that allows domestic customers to buy excess energy at similar prices to those Manitoba Hydro could achieve in the export spot market. The Board approves SEP rates through weekly interim *ex parte* orders. Surplus energy service is an interruptible service, which means that customers do not pay a demand charge. However, they do make a contribution to fixed costs through a variable distribution charge.

Presently, there are 29 General Service customers participating in the SEP. Manitoba Hydro advised the Board during the 2023/24 & 2024/25 General Rate Application that it was immediately suspending new enrollments in the SEP while it reviewed the program. In Order 101/23, the Board approved revisions to the SEP Terms and Conditions and the pause on new enrollment.

In the present Application, Manitoba Hydro advised that it continues to assess the long-term suitability of SEP and investigate a potential industrial rate pilot and other demand response programming, some of which may depend on the corporation’s planned initiatives for SAP upgrades and advanced metering infrastructure.

Manitoba Hydro seeks final approval of all Interim Orders related to weekly SEP rates issued prior to this Order. In Order 101/23, the Board approved all orders up to August 24, 2023, inclusive of Order 100/23 for the weekly SEP rates.

None of the interveners made submissions on the SEP.

### 20.2.2 Board Findings

As interveners have had the opportunity to review and comment on them, the Board approves the finalization of the following SEP interim *ex parte* orders:

- 2023 Orders: 103/23, 105/23, 107/23, 109/23, 113/23, 114/23, 117/23, 118/23, 120/23, 125/23, 127/23, 128/23, 134/23, 135/23, 136/23, 138/23, 146/23, 147/23
- 2024 Orders: 3/24, 7/24, 9/24, 15/24, 17/24, 21/24, 23/24, 25/24, 29/24, 31/24, 36/24, 37/24, 40/24, 41/24, 42/24, 44/24, 47/24, 53/24, 55/24, 57/24, 62/24, 64/24, 68/24, 69/24, 73/24, 77/24, 79/24, 81/24, 84/24, 87/24, 93/24, 95/24, 98/24, 100/24, 102/24, 104/24, 105/24, 109/24, 110/24, 114/24, 116/24, 120/24, 123/24, 128/24, 130/24, 132/24, 136/24, 139/24, 141/24, 143/24, 144/24, 145/24, 147/24
- 2025 Orders: 3/25, 6/25, 9/25, 14/25, 16/25, 19/25, 24/25, 27/25, 33/25, 37/25, 40/25, 43/25, 47/25, 50/25, 52/25, 54/25, 58/25, 68/25, 71/25, 75/25, 77/25, 81/25, 85/25, 90/25, 94/25, 96/25, 100/25, 101/25, 103/25, 106/25, 107/25, 108/25, 112/25, 115/25, 116/25, 118/25, 121/25, 125/25, 128/25, 130/25, 132/25, 135/25, 137/25, 140/25, 142/25, 144/25, 147/25, 150/25, 153/25

## 20.3 Alternative Rate Proposals

### 20.3.1 Background

The Board heard submissions from Manitoba Hydro as well as several interveners on the possibility of alternative rate proposals.

Manitoba Hydro spoke to this possibility while addressing its CRP proposal. The existing CRP program is currently fully subscribed. To specifically address the issue of reducing the system winter peak and to provide additional cost-effective rate options to customers, Manitoba Hydro advised that it is developing a new industrial rate pilot, and that it had customer consultations scheduled throughout 2025. Should an industrial rate pilot receive internal approval, Manitoba Hydro advises that it would request the necessary rate approvals as part of a future rate proceeding.

In its submissions, the GSS/GSM Representative argues that Manitoba Hydro is lagging behind other Canadian jurisdictions that provide multiple rate and program options that support efficient system use and help customers manage bills. This intervener submits that optional rates and programs for bill management should be prioritized for commercial customers and ought to be included in future rate design reviews. To the extent that this requires advanced metering infrastructure, the GSS/GSM Representative submits that prioritization of this project should occur in a least-cost manner, starting with customers that identify themselves as interested.

MIPUG submits that Manitoba Hydro should accelerate the development of alternative rate proposals that could be filed for approval prior to the next rate period. Alternatively, this intervener submits that the utility should advance engagement with its customers by sharing its findings and anticipated plans for pilot rate designs in advance of rate filing to ensure alignment with load availability and customer value propositions. MIPUG observes that the CRP and SEP programs are not available to new participants. MIPUG further submits that industrial customers have been speaking to Manitoba Hydro about their desire for alternative rate options for more than a decade, and are concerned that Manitoba Hydro's minimal alternative rate options places Manitoba companies at a competitive disadvantage with those in other jurisdictions across North America.

Ms. Derksen, the witness for the Consumers Coalition, gave evidence that the load factor for the largest General Service Large customer class has improved, resulting in a shift of generation and transmission demand-related costs to the Residential, General Service Small, and General Service Medium classes, all else being equal. Ms. Derksen opines that these load shifts suggest the need for energy and demand management/reduction programs aimed at the Residential, General Service Small, and General Service Medium classes, and observes that these types of programs have been unavailable to such classes despite numerous programs being available to the largest industrial customers.

### **20.3.2 Board Findings**

The Board agrees with MIPUG and the GSS/GSM Representative that Manitoba Hydro should accelerate the completion of its alternative rate proposals. The Board would like to receive further submissions on alternative rate proposals and potential rate pilot program offerings from Manitoba Hydro, but also welcomes more complete submissions from interveners that provide examples and details of rate programs that, in their view, would benefit the customer classes that they represent.

The Board directs Manitoba Hydro to review and provide a report detailing what alternative rate programs exist in other jurisdictions as part of the next general rate application, including information setting out how other jurisdictions maintain revenue neutrality while offering such programs.

## **20.4 Completed, Closed, and Set Aside Directives.**

### **20.4.1 Updated Revenue Requirement Schedules (Directive 33 of Order 101/23)**

In Directive 33 of Order 101/23, Manitoba Hydro was directed to file, by October 31, 2023, updated schedules of its revenue requirement for the 2023/24 and 2024/25 fiscal years that reflect the decisions and rates approved in Order 101/23. In response, Manitoba Hydro filed revenue requirement schedules reflecting Order 101/23 on October 31, 2023. The Board accordingly confirms that Directive 33 of Order 101/23 has been completed.

### **20.4.2 Revised Rate Schedules from the 2023/24 & 2024/25 General Rate Application (Directive 34 of Order 101/23)**

In Directive 34 of Order 101/23, Manitoba Hydro was directed to file for Board approval revised rate schedules to be effective September 1, 2023 and April 1, 2024, along with the associated proof of revenues and bill impact tables, reflecting the decisions of the Board in that Order. On August 29 and 31, 2023, Manitoba Hydro filed its compliance filing in accordance with this directive, which was approved by the Board in 104/23. The accordingly Board confirms that Directive 34 of Order 101/23 is complete.

### **20.4.3 *Enterprise Performance Management and Key Performance Indicators (KPIs) Workshop (Directive 27 of Order 101/23 and Directives 2 and 3 of Order 103/24)***

In Directive 27 of Order 101/23, Manitoba Hydro was directed to organize and participate in a workshop with stakeholders by October 31, 2024 to assess the utility's enterprise performance management and key performance indicators ("KPIs"). Directive 27 required Manitoba Hydro to use a facilitator appointed by the Board and following the procedure recommended by the facilitator in consultation with Manitoba Hydro and stakeholders.

In August of 2024, Manitoba Hydro applied to review and vary Directive 27 of Order 101/23 to extend the deadline for hosting the workshop to February 28, 2025. In Order 103/24, the Board varied Directive 27 of Order 101/23. Directive 2 of Order 103/24 directed Manitoba Hydro to (a) cooperate with the facilitator appointed by the Board to develop a timetable for the completion of the utility's internal consultation and the workshop, and (b) file the proposed timetable with the Board by October 31, 2024. Directive 3 of Order 103/24 further directed Manitoba Hydro to include a completed assessment of the utility's enterprise performance management and KPIs, including any revisions arising from the workshop, in its next general rate application.

On March 4, 2025, the Board issued a letter setting aside Directive 27 of Order 101/23 on the premise that the consultation process regarding Manitoba Hydro's financial targets and operational KPIs, including the workshop required under Directive 27, was unlikely to lead to any meaningful resolution and it would not be in the public interest to continue the process. Accordingly, Directives 2 and 3 of Order 103/24, relating to the workshop required by Directive 27 of Order 101/23, are set aside.

### **20.4.4 *Revised Rate Schedules Effective January 1, 2026 (Directive 2 of Order 161/25)***

In Directive 2 of Order 161/25, Manitoba Hydro was directed to file for Board approval revised rate schedules to be effective January 1, 2026 and the proof of revenues and bill impact tables reflecting the interim 4.0% general rate increase decision set out in Directive 1 of Order 161/25. On December 30, 2025, Manitoba Hydro filed its compliance filing in

accordance with this directive. The accordingly Board confirms that Directive 2 of Order 161/25 is complete.

#### **20.4.5 *Notifying Customers of 2026 Interim Rate Increases (Directive 2 of Order 1/26)***

In Directive 2 of Order 1/26, Manitoba Hydro was directed to notify customers of the interim rate increase in the first bill each customer receives that uses the revised January 1, 2026 interim rates. In response, Manitoba Hydro updated their website in January, 2026 and issued a bill insert in customer bills regarding the January 1, 2026 electricity rate increases. The Board accordingly finds that this directive is complete.

### **20.5 Remaining Requests for Confidentiality**

#### **20.5.1 *Background***

Since Manitoba Hydro filed its application, the Board received several requests from Manitoba Hydro seeking permission to file information in confidence in accordance with Rule 13 of the Board's former *Rules of Practice and Procedure*. Although those rules were replaced on July 1, 2025, the former rules continue to apply as a result of the transitional provisions set out in section 3.0 of Order 79/25. Under those transitional provisions, the old rules apply to any application that was filed before July 1, 2025.

Rule 13 allows the Board to receive information in confidence if, in the Board's view, the information could reasonably be expected to result in undue financial loss or gain to a person directly or indirectly affected by the proceeding, or to harm significantly that person's financial position. Alternatively, the Board may receive information in confidence if the information is personal, financial, commercial, scientific, or technical in nature, or has been consistently treated as confidential by a person directly affected by the proceeding, and the Board considers the interest in confidentiality to outweigh the public interest in hearings being public. In Order 141/25, the Board adjudicated several requests by Manitoba Hydro to file information in confidence. The requests pertained to information from this Application contained in various minimum filing requirements, information requests, and Manitoba Hydro's rebuttal evidence. In that order, the Board approved some, but not all, of Manitoba Hydro's requests.

Since Order 141/25, Manitoba Hydro has made additional requests for confidentiality, particularly with respect to its answers to undertakings that arose over the course of the oral hearing. MIPUG has also made requests for confidentiality in relation to its answers to undertakings.

Consistent with other proceedings, Manitoba Hydro used a list of redaction codes in support of its confidentiality requests. A copy of these redaction codes was filed as Appendix 1.1 of Manitoba Hydro's Application.

### **20.5.2 Board Findings**

The Board reviewed each of the requests and the corresponding unredacted versions of the evidence filed since Order 141/25. The Board considers Manitoba Hydro's and MIPUG's requests to limit access to the remaining commercially sensitive information to be appropriate and consistent with the factors set out in Rule 13. In particular, the proposed redactions are consistent with similar information that has been routinely accepted as confidential in prior Board hearings. The public interest in protecting the confidentiality of this information outweighs the public interest in disclosure. Accordingly, the Board orders that this information be held confidential.

Regarding redactions applied to net export revenue details for fiscal year 2025/26, the Board directs that the confidentiality of the information related only to net export revenues and their calculation is to be maintained only until April 1, 2026, after which the information is to be made public.

### **20.6 Compliance Filing**

Manitoba Hydro is to file revised rate schedules effective January 1, 2027 and January 1, 2028, cost of service study results for the 2026/27 and 2027/28 fiscal years, proofs of revenue, and bill impact tables for all customer classes reflecting the rate decisions in this Order.

Manitoba Hydro is to file the results of PCOSS26 reflecting the directives in this order, along with resulting RCCs, the amount of rate differentiation for each class, and the targeted RCCs expected at the end of five years of differentiated rate changes.

If any adjustment is required to the General Service Large demand rates on account of the change in billing demand definition to incorporate the 80% factor for off-peak demand, Manitoba Hydro is to provide details of the required adjustment as part of the compliance filing.

Manitoba Hydro is also to file updated revenue requirement schedules for the rate period years reflecting the decisions in this order, including the reduction in O&A expense in 2026/27 and 2027/28 and the establishment of the SAP S/4HANA deferral account.

Manitoba Hydro is to file this information within 60 days of the issuance of this Order. The results of Manitoba Hydro's compliance filing will assist in providing transparency to customers as to how the rate differentiation will affect their electricity bill once in the rate changes take effect on January 1, 2027 and January 1, 2028.

## **21.0 RECOMMENDATIONS:**

### **21.1 Recommendations to Manitoba Hydro**

The Board makes the following recommendations to Manitoba Hydro:

1. Manitoba Hydro should consider using external oversight for the different phases of its transition to SAP S/4HANA, including for the Phase 1 SAP S/4HANA Core implementation project.
2. Manitoba Hydro should consider adding ratepayer affordability of its electricity service to its list of six enterprise goals.
3. Manitoba Hydro should continue stakeholder engagement regarding bill affordability issues and further advance initiatives to evaluate and improve the efficiency and levels of support for low-income customers.

### **21.2 Recommendations to the Province of Manitoba**

The Board makes the following recommendations to the Province of Manitoba:

1. The Province of Manitoba should consider the following legislative changes to *The Manitoba Hydro Act*:
  - a) Explicitly include net income as a component of revenue requirement in a similar manner in which reserves (a similar concept) were included in *The Crown Corporations Governance and Accountability Act* in the past; and
  - b) Grant the Public Utilities Board the power to require Manitoba Hydro to file its general rate applications with the Board on a timely basis.
2. The Province of Manitoba should undertake an Energy Poverty Reduction Review, focusing on Manitoba Hydro's low-income ratepayers, involving input from multiple stakeholder representatives (e.g., government agencies, Manitoba Hydro, Efficiency Manitoba, and other non-government agencies or advocacy groups). The Review should involve research to better understand energy poverty and affordability issues affecting Manitoba Hydro's low-income ratepayers, including a comparative review of how these issues are being addressed in other jurisdictions, and how additional supports can be implemented in Manitoba. The Review should

be coordinated and supported by the provincial government, and culminate in an Energy Poverty Reduction Strategy that considers various mitigation measures, including a refundable income tax credit for low-income Manitoba Hydro ratepayers.

3. The Province of Manitoba should implement refundable income tax credits that specifically target low-income ratepayers in Manitoba to alleviate the annual energy burden of those customers.

## **22.0 IT IS THEREFORE ORDERED THAT:**

1. The general rate increase of 4.0% previously approved in Order 1/26 as interim effective January 1, 2026, and applicable to all of Manitoba Hydro's customer class rate components except for any of the Diesel Zone rates, **BE AND HEREBY IS APPROVED AS FINAL.**
2. Manitoba Hydro's application for a 3.5% increase in general consumers revenue on both January 1, 2027 and January 1, 2028 **BE AND HEREBY IS VARIED** to approve the following:
  - a) a 3.5% increase in general consumer revenue on January 1, 2027; and
  - b) a 3.0% increase in general consumer revenue on January 1, 2028.
3. For the purposes of determining Manitoba Hydro's rate period revenue requirement and rates for January 1, 2027 and January 1, 2028, Manitoba Hydro is directed to:
  - a) reduce forecast O&A expenditures, exclusive of expenditures on SAP S/4HANA, for rate-setting purposes by 1% in each of 2026/27 and 2027/28; and
  - b) use the results from the 2024 Depreciation Study to determine depreciation and amortization expense beginning January 1, 2027.
4. For the purposes of determining Manitoba Hydro's rates for January 1, 2027 and January 1, 2028, Manitoba Hydro is directed to use the same load research methodology and eight years of data for determining the class coincident peak factors in PCOSS26 as was used in PCOSS24, but using only the top 10 winter peak hours.
5. Manitoba Hydro is directed to implement each of the two increases approved by Directive 2 of this order through differentiated customer class rate increases such that the General Service Small Non-Demand, General Service Large 30-100kV, and General Service Large >100kV classes are targeted to be brought into the 95% to 105% zone of reasonableness within five years, on a revenue-neutral basis with the revenue shortfall made up by all customer classes within or below the zone of reasonableness. This is to be done so long as the rate differentiation does

not push these other classes above the zone. The differentiation shall be based on the results of the amended cost of service study results per Directive 4 of this Order.

6. In addition to the rate differentiation set out in Directive 5 of this Order, Manitoba Hydro is directed to further differentiate rates within the Area & Roadway lighting class as proposed in the utility's application, subject to that class receiving overall increases per Directive 2 of this Order.
7. The January 1, 2027 and January 1, 2028 increases approved in Directive 2 of this order apply to all components of the Diesel-Residential and Diesel-General Service rates, as well as for the Diesel-Government & First Nation Education basic monthly charge. However, the Diesel-Government & First Nation Education energy rate is to be maintained at the existing level until an adequate capital funding agreement is reached and a diesel-specific rate application is reviewed.
8. In addition to the rate differentiation set out in Directive 5 of this order, Manitoba Hydro is directed to rebalance the demand and energy rate components for the three General Service Large customer classes on a revenue-neutral basis such that demand rates increase by an additional 2% over the class average rate increase and energy rates are reduced by an equal and offsetting dollar amount.
9. Manitoba Hydro is directed to amend the definition of billing demand for the General Service Large 30-100kV and General Service Large >100kV classes, effective January 1, 2027, such that the minimum factor of measured off-peak demand included in the definition is 80%. Should an additional revenue neutrality adjustment be required as a result of the change to the revised off-peak factor of 80%, Manitoba Hydro is to include, and separately identify, this additional adjustment as part of its compliance filing per Directive 35 of this Order.
10. Manitoba Hydro is directed to report to the Board, together with its next general rate application, on its experience related to the change in the General Service Large billing demand definition approved in Directive 9 of this order, together with the results of Manitoba Hydro's consultations with affected customers and the overall class load-shifting trends experienced since April 1, 2024. The utility is also to advise at that time whether it considers the 80% off-peak factor to remain appropriate or whether a different off-peak factor should be used.

11. Manitoba Hydro's application to revise the descriptions of some rates applicable to light emitting diode luminaires for the Area & Roadway Lighting customer class **BE AND HEREBY IS APPROVED.**
12. Beginning with the January to March 2026 quarter, Manitoba Hydro is directed to file a report with the Board, within forty-five (45) days after the end of each fiscal quarter, that contains the following information:
- a) graphs of system energy in storage, system potential hydraulic energy from inflows, actual and forecast total system inflows, and total hydraulic generation (showing the original and updated forecasts as well as the low and high range);
  - b) the original budgets and updated forecasts for extraprovincial revenues, water rentals and assessments, fuel and power purchases, net export revenue, and net income for the remaining years of the rate period;
  - c) graphs and tables of the range of expected net export revenues with respect to the percentile of possible water flow conditions for each of the remaining years of the rate period; and
  - d) a report of customer electric loads greater than the threshold amount for a large supply of power as set out in subsection 49.2(1) of *The Manitoba Hydro Act* that were added or removed from Manitoba Hydro's system supply requirements during the last quarter, and how these loads are expected to affect Manitoba Hydro's net income in the remaining years of the rate period.
13. Manitoba Hydro is directed to file, with its next general rate application, any evaluation it has undertaken with respect to updated financial targets, including memoranda provided to the Manitoba Hydro-Electric Board for the purpose of obtaining approval for new targets.
14. Manitoba Hydro is directed to file, together with its next general rate application, an uncertainty analysis that assesses the probability and likely impact of the risks faced by the utility. The uncertainty analysis must include, at minimum, the following four variables: (1) water flows, (2) export prices, (3) interest rates, and (4) capital expenditures.

15. Manitoba Hydro is directed to report back at the next general rate application on the progress made toward achieving the targets and outcomes related to each of its enterprise goals. If new enterprise goals are adopted before the next general rate application, the utility's report must include the targets and progress measurements associated with these new goals.
16. Manitoba Hydro is directed to file, with its next general rate application, an independent assessment of its asset management process maturity and an update on the progress made since the last external assessment completed in 2024.
17. Manitoba Hydro is directed to file quarterly status reports regarding the major capital projects listed below within 45 days after the end of each fiscal quarter until individual project completion.
- a) the HVDC Reliability Project, with the initial quarterly report applying to the January to March 2026 quarter; and
  - b) the new combustion turbine capacity addition project, with the initial quarterly report applying to the October to December 2026 quarter.
- The reports are expected to contain detailed information on the approved budget or most current estimate, expenditures to date, whether expenditures to date are tracking the budgeted expenditures, the current forecast at completion costs and schedule, and remaining risks affecting the project.
18. Manitoba Hydro is directed to file, together with the quarterly Operating and Administrative expenditure reports currently filed pursuant to Directive 14 of Order 73/15, a comparison of its vegetation management approved budget and the actual amounts spent on vegetation management with an explanation of any material variance of plus or minus 20%.
19. Manitoba Hydro is directed to file its SAP S/4HANA Core investment justification documentation once it is approved by the Manitoba Hydro-Electric Board.
20. Manitoba Hydro is directed to file quarterly status reports regarding the SAP S/4HANA Core project within 45 days after the end of each fiscal quarter, starting with the January to March 2026 quarter, until project completion. The quarterly status reports must contain detailed information on the approved budget (at time of the investment justification approval), expenditures to date, the current forecast

at completion costs and schedule, and remaining risks affecting the project. Specific costs must be detailed for any contracts in excess of \$50 million.

21. Manitoba Hydro is directed to file standalone business cases and investment justifications for the Phase 2 (CIS/Banner) and Phase 3 (Core Enhancement) follow-up SAP projects as soon as they are completed.
22. Directive 32 of Order 101/23 is varied to add the requirement that Manitoba Hydro provide its assessment of the 2025 OXARO report and how it affects Manitoba Hydro's financing strategy at the next general rate application.
23. Manitoba Hydro's request for approval to modify the recovery mechanism for the Change in Depreciation Method balance for rate-setting purposes, by establishing a regulatory deferral account with recovery through net movement based on an amortization period **BE AND HEREBY IS DENIED**.
24. Manitoba Hydro's request for final approval of the established Joint Keeyask Development Agreement Preferred Distributions Deferral Account, including annual revaluation adjustments related to the preferred distribution obligation in the deferral account and approval of an amortization period of 106 years, **BE AND HEREBY IS APPROVED**.
25. Manitoba Hydro's request to establish, beginning with the 2025/26 fiscal year, a Cloud Computing Regulatory Deferrals Account for the costs related to the SAP S/4HANA Core project and approval of an amortization period of 10 years **BE AND HEREBY IS VARIED** such that the deferred costs are limited to the Phase 1 "Core" SAP S/4HANA implementation costs allocated to electric operations up to a maximum of \$167 million, amortized over 10 years. No further costs related to the implementation of SAP S/4HANA may be deferred without further investment justifications and prior approval from the Board.
26. Manitoba Hydro's request to establish, beginning with the 2025/26 fiscal year, a Cloud Computing Regulatory Deferrals Account for Small-Scale Software Systems and approval of an amortization period of six years **BE AND HEREBY IS APPROVED**.

27. Manitoba Hydro is directed to file, together with its next general rate application, evaluation findings related to the possible flattening of the General Service Medium rate structure, as well as an assessment of the General Service Small and General Service Medium classes for potential cross-subsidies and overlap, and to consider the potential deharmonization of the General Service Small Demand and General Service Small Non-Demand classes.
28. Manitoba Hydro is directed to file, together with the next general rate application, a prospective cost of service study that reflects the following:
- a) use of the top 10 winter peak hours for determining the class coincident peak factors based on the utility's previous load research methodology with the most recent eight years of data;
  - b) use of a 60% Demand / 40% Customer classification split for the classification of distribution poles and wires; and
  - c) results based on the existing treatment of wind generation costs along with alternate results based on classifying wind generation costs using the system load factor approach, together with Manitoba Hydro's detailed reasons supporting its preferred classification approach.
29. Manitoba Hydro is directed to file, together with the next general rate application, an updated lighting cost of service study.
30. Manitoba Hydro's request for final approval of all interim *ex parte* Curtailable Rate Program orders as set out in this order **BE AND HEREBY IS APPROVED AS FINAL**.
31. Manitoba Hydro's application for modifications to the terms and conditions of the Curtailable Rate Program **BE AND HEREBY IS APPROVED** effective April 1, 2026.
32. Manitoba Hydro is directed to file, with its next Curtailable Rate Program Reference Discount application an update to the P50 cost estimate for a dispatchable capacity resource, along with a detailed explanation as to how it arrived at this estimate.

33. Manitoba Hydro's request for final approval of all interim *ex parte* Surplus Energy Program rate orders as set out in this order, and any other interim *ex parte* Surplus Energy Program orders issued before the date this order is issued, **BE AND HEREBY IS VARIED by** approving Order 153/25 and all prior issued orders as requested.
34. Manitoba Hydro is directed to file, together with its next general rate application, a report detailing what alternative rate programs exist in other jurisdictions, including information setting out how other jurisdictions maintain revenue neutrality while offering such programs.
35. Manitoba Hydro is directed to file, within 60 days after the day this Order is issued, a compliance filing reflecting the decisions of the Board in this Order that includes, at minimum, the following documents:
- a) updated revenue requirement schedules;
  - b) revised rate schedules to be effective January 1, 2027 and January 1, 2028;
  - c) cost of service study results for the 2026/27 and 2027/28 fiscal years, including the amount of rate differentiation for each class, and the targeted RCCs expected at the end of five years of differentiated rate changes;
  - d) details of any adjustment required to the General Service Large demand rates on account of the change in billing demand definition to incorporate the 80% factor for off-peak demand; and
  - e) proofs of revenues and bill impact tables.
36. The following directives from earlier Board orders are set aside:
- a) Directive 27 of Order 101/23; and
  - b) Directives 2 and 3 of Order 103/24.
37. Manitoba Hydro's claims for confidentiality for information filed to date in this general rate application that have not already been adjudicated in prior orders are accepted. The Board directs that the confidentiality of the information related to net export revenues during the 2025/26 fiscal year is to be maintained only until April 1, 2026, after which the information is to be made public.

Board decisions may be appealed in accordance with the provisions of Section 58 of *The Public Utilities Board Act*, or reviewed in accordance with Section 58 of the Board's Rules of Practice and Procedure. The Board's Rules may be viewed on the Board's website at [www.pubmanitoba.ca](http://www.pubmanitoba.ca).

THE PUBLIC UTILITIES BOARD

"Robert Gabor, K.C."

Panel Chair

"Rachel McMillin, B.Sc., MPA"

Secretary

Certified a true copy of Order No. 43/26  
issued by The Public Utilities Board



Secretary

**APPENDIX A – GLOSSARY**

<b>Term</b>	<b>Acronym</b>	<b>Description</b>
2019 Depreciation Study		A study of the depreciation of Manitoba Hydro's assets prepared in 2019 by Concentric Energy Advisors.
2024 Depreciation Study		A study of the depreciation of Manitoba Hydro's assets prepared in 2024 by Concentric Energy Advisors.
Advanced Metering Infrastructure	AMI	An integrated system of sensors and equipment for enhanced energy consumption and demand metering, providing real-time administrative viability of the grid and meters with technical control over the meter by utilizing communication networks.
Affordable Energy Plan		A plan published by the Government of Manitoba in September, 2024 that sets out its provincial energy policy.
Alternating Current	AC	An electric current that reverses itself many times per second based on regular intervals. All electricity provided to end users in Manitoba is alternating current.
Applicant		A party who makes an application to the Public Utilities Board. Generally, this is a utility seeking an approval from the Board.
Area & Roadway Lighting (Customer Class)	A&RL	Customer class used for streetlights and similar outdoor lighting fixtures used to illuminate roadways and private areas on a dusk-to-dawn basis. Light fixtures in the A&RL class are not metered. Instead, customers pay a flat monthly fee per fixture.
Arrear		An amount owing for which payment is overdue. Unpaid arrears may lead to a disconnection of service.
Assembly of Manitoba Chiefs	AMC	An intervener in this hearing who primarily represents the interests of First Nation residential and commercial ratepayers.
Asset Management Company Ltd.	AMCL	A company engaged by Manitoba Hydro to assess the maturity of Manitoba Hydro's asset management system.
Asset Management Plan	AMP	A plan that specifies the activities, interventions, resources, and timescales required to ensure the short-term operability and long-term sustainability of Manitoba Hydro's energy delivery and support systems.
Average Life Group	ALG	See Average Service Life (ASL).
Average Service Life	ASL	A depreciation methodology under which assets are grouped into asset groups based on the type of asset. A depreciation rate is then established based on the average life anticipated for the assets in the group. The Average Service Life methodology is also known as the Average Life Group (ALG) methodology.

Bipole Lines		Manitoba Hydro's long-distance HVDC transmission lines originating at the Nelson River. There are three Bipole lines: Bipole I (BP I), Bipole II (BP II) and most recently, Bipole III (BP III), completed in 2018.
Board	PUB	The Public Utilities Board of Manitoba.
Bonbright Criteria		A series of ratemaking principles described in Dr. James Bonbright's 1961 text <i>Principles of Public Utilities Rates</i> that reflect the balancing of various interests relevant to utility regulation.
Business Operations Capital	BOC	Capital expenditures to renew existing assets and facilities, extend the electrical system to new customers, and address both load growth and requirements for new capacity. This excludes capital expenditures for major new generation and transmission facilities.
Canadian Generally Accepted Accounting Principles	CGAAP	Accounting standards that applied to Manitoba Hydro before the adoption of International Financial Reporting Standards (IFRS) in 2015.
Centra Gas Manitoba Inc.		Also referred to as "Centra" or "Centra Gas," Centra Gas Manitoba Inc. is a wholly-owned subsidiary of Manitoba Hydro, and is the principal distributor of natural gas in the Province of Manitoba.
Classification		Step 2 in the cost of service process. Costs are classified into one of three categories: (1) Demand, (2) Energy, or (3) Customer.
Cloud Computing Arrangement	CCA	Arrangements between end users and vendors of cloud computing systems. CCAs are subject to specific accounting standards depending on the type of arrangement.
Coincident Peak		An allocation factor based on the point in time when the collective demand of all customer classes is highest. The coincident peak may not be at the same time as the peak of a specific customer class, which may occur at a different time (the "non-coincident peak").
Common Bus		The total load measured from all distribution points (substations) within Manitoba. This term excludes diesel customers, transmission losses, and station service consumption.
Conawapa		A generating station that was planned to be constructed on the Nelson River but was cancelled following a 2014 Need For and Alternatives To review by the Public Utilities Board into the economics of the project.
Consumer Price Index	CPI	An index published by Statistics Canada to measure inflation.
Consumers Coalition		An intervener in this hearing who primarily represents the interests of residential ratepayers.

Corporate Value Framework	CVF	Manitoba Hydro's structured approach to determining the net value a given investment, or investment alternative, provides to Manitoba Hydro. Value measures are applied to potential investments to quantify the probability and consequence of the benefit gained or risks being mitigated. Valued investments are then compared against one another to determine optimal investment timeframes.
Cost Causation		An inquiry into what, or who, is causing costs to be incurred by the utility, including how different customer classes contribute to overall costs.
Cost of Service		A process by which a utility's approved revenue requirement is allocated to different customer classes. The process involves three steps: (1) Functionalization, (2) Classification, and (3) Allocation. As an alternative to the Allocation step, costs attributable to a specific customer class may be directly assigned to that class.
Cost of Service Study	COSS	A method for allocating a utility's costs to the various classes of customers it serves. The purpose of a cost of service study is to assess how different customer classes contribute to a utility's overall costs. Cost of service studies are an input into ratemaking decisions by utility regulators.
Curtailable Rate Program	CRP	An optional program through which Manitoba Hydro may call on participating customers to curtail a portion of their load to assist in maintaining operating and contingency reserves in the event of a system emergency.
Customer Class		Manitoba Hydro's customers are grouped into customer classes based on their service characteristics. All customers within the same class pay the same rates. The customer classes discussed in this Order include the following: (1) Residential, (2) General Service Non-Demand, (3) General Service Demand, (4) General Service Medium, (5) General Service Large 750V-30kV, (6) General Service Large 30-100kV, (7) General Service Large >100kV, and (8) Area & Roadway Lighting.
Customer (Classification)		The classification used for costs that are directly affected by the number of customers attached to the system.
Deferral Account		An accounting mechanism that allows a delay in the recognition of revenue or expenses until a future period, in line with accounting matching principles. This in turn allows funds or future expenses to be recognized and paid out over time, rather than immediately.
Demand (Classification)		The classification used for costs that vary based on the peak demand for electricity rather than the amount of electricity consumed or the number of customers.
Demand-Side Management	DSM	Programs targeted to customers to reduce their demand, e.g., through energy efficiency incentives. Efficiency Manitoba, a Crown corporation, has a statutory mandate to provide demand-side management in Manitoba.
Dependable Energy		Energy that can be supplied by Manitoba even during the worst drought on record, which happened in 1940.

Depreciation		An accounting mechanism used to reflect that assets are used up over time. Depreciation expense forms part of a utility's revenue requirement and is calculated based on depreciation studies that calculate the appropriate amount of annual depreciation for all of a utility's asset groups.
Diesel Cost of Service Study	DCOSS	A cost of service study to determine the revenue requirement and forecast unit cost of generation required to serve existing Diesel Zone customers in four off-grid communities in Manitoba.
Diesel Zone		Four communities in Manitoba (Lac Brochet, Brochet, Shamattawa, and Tadoule Lake) are not connected to the electric transmission and distribution grid and are served by separate diesel-generated electricity. Together, these communities are referred to as the Diesel Zone.
Distribution		Utility assets used to distribute lower voltage electricity to individual customers. These assets include distribution lines operating at less than 30 kV along with associated low voltage portions of substations, as well as low voltage transformers and metering.
Earnings Before Interest and Taxes	EBIT	A measure of profitability that identifies a company's operating profit without interest expenses and income taxes.
Earnings Before Interest, Taxes, Depreciation, and Amortization	EBITDA	A measure of profitability that identifies a company's operating profit without interest, taxes, depreciation, and amortization.
Energy (Classification)		The classification used for costs that are directly affected by the amount of electricity purchased or consumed.
Enterprise Resource Planning	ERP	A software system that helps organizations streamline core business processes, including finance, human resources, manufacturing, supply chains, sales, and procurement.
Enterprise Risk Management	ERM	A program to provide an enterprise-wide assessment of risks faced by the utility.
Equal Life Group	ELG	A depreciation methodology under which assets are grouped by their projected lifespan as opposed to the type of asset.
<i>Ex Parte</i>		Latin for "without notice" (literally "without the parties"). An <i>ex parte</i> order is an order the Public Utilities Board makes without public notice and without intervener input. <i>Ex parte</i> orders are typically made on an interim basis for non-controversial matters or when there is a degree of urgency that makes public notice impracticable.
Firm Sales		Export sales made from dependable energy resources under contracts with utilities outside of Manitoba.
Full-Time Equivalent	FTE	A measure of Manitoba Hydro's staffing level. It is calculated by adding the total annual hours of all regular, seasonal, hourly, and part-time staff and dividing by 1,916 hours per year.

Functionalization		Step 1 in the Cost of Service process. Assets and costs are grouped into one of five Functions: (1) Generation, (2) Transmission, (3) Subtransmission, (4) Distribution, and (5) Customer Service.
General Rate Application	GRA	A Public Utilities Board process to review Manitoba Hydro's proposed changes to rates and their impact on various customer classes.
General Service Large (Customer Class)	GSL	Customer class containing predominantly industrial customers. These customers make use of customer-owned voltage transformation assets. This customer class is divided into three sub-categories: (1) 750V-30kV (2) 30-100kV, and (3) >100 kV, to reflect the voltage supplied to the customer by Manitoba Hydro.
General Service Medium (Customer Class)	GSM	Customer class containing predominantly large commercial customers. These customers use Manitoba Hydro-owned transformation assets and have loads exceeding 200 kW.
General Service Small (Customer Class)	GSS	Customer class containing predominantly small commercial customers with loads less than or equal to 200 kW. This customer class is divided into two sub-categories: (1) Demand (GSS-D) (2) Non-Demand (GSS-ND). Demand customers pay a demand charge based on the peak demand each month, in addition to a basic monthly charge and an energy (per kWh) charge.
Generation		Utility assets used to generate electricity, including generating facilities, northern collector transmission lines, and Manitoba Hydro's long-distance high-voltage direct current (HVDC) transmission facilities.
Gigawatt-Hour	GWh	An amount of electrical energy equivalent to 1,000,000 kilowatt-hours (kWh) or 1,000 megawatt-hours (MWh). As an example, a typical non-electrically heated home uses 10,000 kWh per year. One GWh is enough to power 100 homes for one year.
GSS/GSM Representative		An intervener in this hearing who primarily represents the interests of the General Service Small (GSS) and General Service Medium (GSM) customer classes, meaning commercial ratepayers.
High Pressure Sodium	HPS	A type of light bulb that uses pressurized sodium to emit light. They are generally recognized as energy efficient and are commonly used for industrial lighting.
High Voltage Direct Current	HVDC	An electric power transmission system that uses direct current for the bulk transmission of electrical power, in contrast with the more common alternating current (AC) systems. HVDC transmission is point-to-point, as opposed to the interconnected networks that are possible with AC systems. For long-distance transmission, HVDC systems may be less expensive and suffer lower electrical losses.

Integrated Resource Plan	IRP	A long-term strategy that seeks to provide a least-cost approach to meeting future customer energy needs. Section 38.1 of <i>The Manitoba Hydro Act</i> requires Manitoba Hydro to submit an IRP for approval by the Lieutenant Governor in Council. Manitoba Hydro issued an IRP in 2025. It is presently the subject of a separate application before the Board.
Interim Rate		A rate that is approved on an interim basis based on an abbreviated review by the Public Utilities Board. An interim rate is “at risk” until the Public Utilities Board finalizes the rate in a subsequent rate order, generally after a more detailed review.
International Financial Reporting Standards	IFRS	Accounting standards adopted by Manitoba Hydro in April 2015 which replace Canadian Generally Accepted Accounting Principles (CGAAP).
Intervener		A party to a Public Utilities Board hearing who is not the Applicant. The purpose of an intervener is to assist the Board in making a decision by bringing a perspective to an issue that may not align with that of the Applicant.
Joint Keeyask Development Agreement	JKDA	An agreement among Manitoba Hydro and the Keeyask Cree Nations – Tataskweyak Cree Nation & War Lake First Nation o/a Cree Nation Partners, York Factory First Nation, and Fox Lake Cree Nation – pertaining to the development of the Keeyask Generating Station.
Keeyask		Manitoba Hydro’s newest and fourth-largest hydroelectric generating station, which came into service in 2021.
Keeyask Hydropower Limited Partnership	KHLP	A partnership operating the Keeyask generating station. The partnership is part of a shared equity approach involving a First Nations stake in the generating station.
Kilovolt	kV	An amount of electromotive force equivalent to 1,000 volts. A volt is unit of measure for the electromotive force, and representative of the difference of potential that would drive one ampere of current against one ohm of resistance.
Kilowatt	kW	An amount of electrical power equivalent to 1,000 watts. A watt is unit of measure for electrical power.
Kilowatt-Hour	kWh	The basic unit of electric energy equal to one kilowatt of power supplied to, or taken from, an electric circuit steadily for one hour (e.g.: ten 100 W lightbulbs left on for 1 hour would use 1 kWh, or 1,000 W for one hour). A typical home without electric heat uses approximately 10,000 kWh each year.
Lighting Cost of Service Study	LCOSS	A cost of service study specifically focused on the light fixtures serving the Area & Roadway Lighting (A&RL) customer class.
Light-Emitting Diode	LED	A semiconductor device that converts electrical energy directly into light when a current passes through it.
Load Factor		The ratio of average consumption to peak consumption. A load factor of 1.0 means that a customer consumes electricity at a steady state, without swings in demand. A low load factor means that there are significant swings in demand.

Load Research Report		A report developed by Manitoba Hydro to demonstrate typical consumption behaviours by developing hourly load shapes for the various customer classes.
Major New Generation & Transmission	MNG&T	A category of Manitoba Hydro's capital expenditures that include projects that provide significant new generation and transmission capacity, and are of a substantial cost. Such major capital projects can involve new electricity generation assets or the construction of long-distance transmission lines.
Manitoba Eco-Network and Environmental Defence	MEED	An intervener to this hearing who primarily represents the interests of customers and the public in environmental protection.
Manitoba Hydro-Electric Board	MHEB	The governing body for Manitoba Hydro's electric and gas utilities for Manitoba, often referred to in this hearing as Manitoba Hydro, the corporation, or the "utility".
Manitoba Industrial Power Users Group	MIPUG	An intervener to this hearing who primarily represents the interests of the General Service Large customer classes, meaning industrial ratepayers.
Manitoba Keewatinowik Okimakanak	MKO	An intervener to this hearing who primarily represents the interests of northern First Nation residential ratepayers.
Manitoba-Minnesota Transmission Project	MMTP	The Canadian portion of a 500 kV alternating current interconnection between Dorsey converter station northwest of Winnipeg and a station near Grand Rapids, Minnesota.
Megawatt	MW	An amount of electrical power equivalent to 1,000,000 watts, or 1,000 kilowatts (kW).
Mid-Continent Independent System Operator	MISO	An independent regional organization that manages the electrical grid in the midwestern United States. The MISO market is Manitoba Hydro's principal export market.
Minnesota Trading Hub	MINN.HUB	The Minnesota Trading Hub is the nearest primary power market region for Manitoba Hydro's wholesale electricity export within MISO.
National Association of Regulatory Utility Commissioners	NARUC	An association of American utility regulators. NARUC publishes manuals and standards including a Cost Allocation Manual.
Needs For and Alternatives To	NFAT	A Public Utilities Board review of Manitoba Hydro's preferred development plan that took place in 2014.
Non-coincident peak		An allocation factor based on the point in time when the demand of a specific customer class is highest. The non-coincident peak may not be at the same time as the collective peak demand of all customer classes, which may occur at a different time (the "coincident peak").
Northern States Power Company	NSP	An electric and natural gas utility that provided service in Minnesota, Wisconsin, North Dakota, South Dakota, and parts of Michigan.
Off-Peak		Off-peak refers to periods when lower electricity prices are generally expected, coinciding with periods of low electricity usage. Manitoba Hydro's off-peak periods are defined as all night time hours from 11pm to 7am.

On-Peak		On-peak refers to periods when higher electricity prices are generally expected, coinciding with periods of high electricity usage. Manitoba Hydro's on-peak periods are defined as Monday to Friday (excluding Statutory Holidays) 12pm-8pm (May-October), as well 7am-11am and 4pm-8pm (November-April).
Operating & Administrative Expense	O&A	Expenditures to support Manitoba Hydro's day-to-day operations, including labour costs and external service providers.
Opportunity Sales		Export sales made from surplus generation, typically generation that is available in most water flow conditions except drought conditions. Opportunity sales are made at prevailing market prices.
OXARO Inc.	OXARO	A company hired by Manitoba Hydro to perform an independent assessment of Manitoba Hydro's and Centra Gas' debt interest rate risk.
Peak Demand		The instantaneous maximum amount of electricity required by a customer or group of customers
Prospective Cost of Service Study	PCOSS	A cost of service study that is prepared on a forward-looking basis. This is the approach used by Manitoba Hydro, as distinct from a fully allocated cost of service study (FACOSS) that looks backward. Prospective service studies are named based on the test year for which they are prepared, so the 2026 prospective cost of service study is named PCOSS26.
Provincial Guarantee Fee	PGF	An annual fee payable by Manitoba Hydro to the Province of Manitoba in exchange for the Province's guarantee of Manitoba Hydro's debts.
Rate Design		The process of determining how the rates charged to various customer classes should be structured. This includes the overall prices as well as how to allocate the rate between a basic monthly charge, an energy charge, and a demand charge. Rates may also be divided into different tiers based on how much energy is consumed.
Rate Period		The period of three consecutive fiscal years defined in <i>The Manitoba Hydro Act</i> that applies to Manitoba Hydro's rate requests in general rate applications filed with the Public Utilities Board. For this general rate application, the rate period includes 2025/26, 2026/27, and 2027/28.
Rate Rider		A temporary credit or charge on a utility bill that is separate from the regular monthly rate.

Regulatory Deferral Account		A specific deferral account used by rate-regulated entities to delay the recognition of revenue and expenses until a future period, in line with accounting matching principles. Such account contains an amount of expense or income that is expected to be recognized by a rate regulator in establishing the price that an entity can charge to customers for rate-regulated goods or services in the future. Such accounts may lessen the effect of large expenditures by ameliorating their impact over many years, rather than creating a price spike in the year that the expense arose.
Revenue to Cost Coverage	RCC	The ratio of the revenues recovered from a customer class divided by the costs allocated to that class. Generally, rate design aims to achieve an RCC ratio of as close to 100% as practicable or within an approved range called a zone of reasonableness.
SAP ECC		Manitoba Hydro's legacy Enterprise Resource Planning (ERP) software system. SAP stands for "Systems, Applications & Products in Data Processing," and is the name of the company that provides the software. ECC stands for "ERP Central Component." SAP ECC is currently used by Manitoba Hydro but will no longer be supported beyond 2027.
SAP S/4HANA		A cloud-based Enterprise Resource Planning (ERP) software solution that provides centralized data management capabilities. SAP stands for "Systems, Applications & Products in Data Processing," and is the name of the company that provides the software. S/4 stands for "Suite 4", being the fourth generation of SAP's business suite. "HANA" means High-Performance Analytical Appliance.
Spot Market		An electricity market in which a central system operator determines prices for generated electricity on a day-ahead or real-time basis.
Strategic Asset Management Plan	SAMP	A plan created by Manitoba Hydro that describes its approach to asset management and its path to maturing its asset management processes.
Surplus Energy Program	SEP	A rate program that allows qualifying industrial customers to purchase surplus energy at export market prices that are determined on a weekly basis for peak, shoulder, and off-peak periods.
System Average Interruption Duration Index	SAIDI	A reliability index calculated by adding the sum of all customer interruption durations over the course of a year and dividing that sum by the total number of customers.
System Average Interruption Frequency Index	SAIFI	A reliability index calculated by adding the total number of customer interruptions during the course of a year and dividing that sum by the total number of customers.

Test Year		The year for which the Public Utilities Board is asked to approve rates. A test year is aligned with the fiscal year of the provincial government and begins on April 1 of one year and ends on March 31 of the following year. For this general rate application, the applicable test years are 2025/26, 2026/27, and 2027/28. <i>The Manitoba Hydro Act</i> now uses the term “rate period” to describe the test years, as defined above.
Time of Use Rates		A rate design concept that varies the cost of electricity based on when it is used. The aim is to promote energy conservation and load smoothing in order to reduce overall system peak loads, thus deferring the need for new generation assets and to maximize the value of electricity exports during on-peak periods.
Transmission		Utility assets used to transmit electricity between load centres. In the cost of service study, Manitoba Hydro considers all transmission lines and high voltage portions of substations operating in excess of 100 kV as transmission. With respect to capital expenditures, transmission refers to assets operating in excess of 33 kV.
Water Rentals		Fees paid by Manitoba Hydro to the Provincial Government based on the amount of electricity produced from hydraulic generation.
Wuskwatim Power Limited Partnership	WPLP	A partnership operating the Wuskwatim generating station. The partnership is part of a shared equity approach involving a First Nations stake in the generating station.
Zone of Reasonableness	ZOR	An established tolerance zone around the COSS RCC target of 100% for each class. Manitoba Hydro's RCC Zone of Reasonableness currently has a range of 95 to 105 percent. A RCC ratio outside of the ZOR is one factor to be considered in the possible differentiation of rate increases.

## **APPENDIX B – SUMMARY OF PRESENTER EVIDENCE**

In addition to receiving evidence from Manitoba Hydro and registered interveners (see Appendix D), the Board also received several written and oral public presentations from interested parties. In accordance with the Board's *Rules of Practice and Procedure*, presenters were given the option to make a solemn affirmation prior to making their oral presentation. None of the presenters were cross-examined by any party, but were subject to questioning by the Board.

A summary of the public presentations made in this proceeding is provided below, in the order in which the presenters appeared.

### **Manitoba Non-Profit Housing Association**

Bailey Wall presented on behalf of Manitoba Non-Profit Housing Association, a member-based organization that offers housing support, educational tools, resources, and advocacy for its members. In partnership with SEED Winnipeg, the Association established the Rent Relief Fund which provides interest-free loans to tenants across Manitoba who fall below a certain income threshold to secure, stabilize, and maintain housing. The Rent Relief Fund covers costs such as rent arrears, damage deposits, first month's rent, and utility arrears for moderate-income to low-income households. If the loans are not sufficient to cover all of the customer's arrears, the Association also helps negotiate payment arrangements with Manitoba Hydro on behalf of their client.

Ms. Wall stated that in 2024, the Rent Relief Fund received 547 applications towards utility arrears, which represented approximately 31% of all applications to the fund. While utility arrears applications include both electricity and water arrears, the Association was able to determine that 521 applicants were applying for relief for electricity arrears. The threshold for a household without dependents is an annual income of \$67,900 and a household with dependents is an annual income of \$90,500. Ms. Wall advised that 36% of Rent Relief Fund applicants from the last 5 months were paying 5% or more of their gross income toward Manitoba Hydro costs. Ms. Wall also said that 31 percent of people coming to the program are facing utility arrears and struggling to keep up with their hydro

costs. Ms. Wall gave an example of an applicant that was at risk of housing insecurity if they encountered any unexpected financial strain.

Out of the 547 applications received, the Association approved 144 loans toward electricity arrears, representing a total sum of \$152,688. Ms. Wall shared that many users of the Fund have utility arrears in excess of what they can keep up with, leading to disconnection of services. Ms. Wall concluded that it is becoming increasingly challenging for the Association to help its clients secure Hydro payments that fit within their already tight budgets.

## Keystone Agricultural Producers

Colin Hornby presented on behalf of Keystone Agricultural Producers (“KAP”), Manitoba’s general farm organization representing farmers across commodities. KAP is a farmer-led, grassroots organization with roughly 5,000 full members, funded primarily through checkoff fees (mandatory deductions from agricultural sales) and targeted government programs. Mr. Hornby stated that Manitoba farmers contribute 7% of the provincial gross domestic product and are key supporters of rural communities, including rural development.

Mr. Hornby emphasized that due to the nature of their products, farmers are not always able to pass rising operational costs on to their customers. Mr. Hornby outlined several major pressures facing the sector, including trade uncertainty from trade tariffs, rising input costs, labour shortages, farm succession challenges, and supply chain disruptions. There are also additional cost pressures from reduced research funding, policy gaps, and sharp increases in property taxes.

Mr. Hornby explained that while Manitoba farms spent \$107 million on electricity in 2022, this rose to \$114 million within two years, and the proposed rate increases could push these costs above \$126 million by 2028. Energy costs varied widely by commodity, but in general farmers have limited control over electricity use due to production and weather requirements. Mr. Hornby also advised that high costs for three-phase power upgrades constrain producers’ efficiency improvements. As a result, Mr. Hornby concluded that stable, affordable hydro rates are critical to farm viability and to maintaining Manitoba’s competitive advantage in attracting agri-food processing, particularly given Manitoba Hydro’s monopoly and the limited effectiveness of current energy efficiency incentives.

## Ratepayer Panel

The Consumers Coalition assembled a panel of four residential ratepayers to describe their experiences with utility bills, energy poverty, and various programs. The panel explained the difficulties they anticipated facing if the rate increases proposed in this application were approved.

The first member of the ratepayer panel, Ms. Beth Forest, shared her experience as a single mother of two living on a strict annual income. She explained that she already undertakes stringent strategies to ensure that her electricity bills are as low as possible, including refraining from using her oven, ensuring lights are turned off when possible, and minimizing the use of air conditioning. In addition to energy reduction strategies, Ms. Forest shared that she also seeks to minimize her food costs and avoids purchasing certain foods to make ends meet. Ms. Forest told the Board that the proposed rate increase of 3.5% per year would take away from her ability to spend money elsewhere, and advocated for a program to assist low-income Manitobans to pay their bills. Ms. Forest further observed that some people that need assistance with utility bills have low literacy and are unable to learn about programs by online information alone. She suggested having workers at Employment and Income Assistance, Family Resolution Services, and other existing support programs inform their clientele about Manitoba Hydro's policies.

Ms. Elsie Obikile shared that she moved to Winnipeg from Nigeria three years ago and lives on her own with a low income. Ms. Obikile explained that she has had difficulty paying her electrical bills for almost two years. She obtained help from SEED Winnipeg and Employment and Income Assistance to make arrears payments to Manitoba Hydro, and has learned to implement various cost-saving strategies, such as eliminating her use of air conditioning, reducing use of the dishwasher and lights, and only heating spaces that she occupies. Ms. Obikile explained that any increase to electricity rates would set her back in her goals of addressing her debts and expenses and saving to visit family. She identified that she experiences energy poverty and advocated for a program from Manitoba Hydro to assist low income Manitobans to pay their electricity bills. Ms. Obikile

shared that she had a positive experience with Manitoba Hydro's arrears payment program, and encouraged Manitoba Hydro to work with other non-profit agencies to ensure newcomers are made aware of programs available to them.

Ms. Tahnis Saultier shared with the Board that she recently transitioned into a shared duplex from an apartment and had difficulty keeping up with electricity payments. She shared that Manitoba Hydro reached out to her landlord to advise of arrears on utility payments but not to her directly. Ms. Saultier described her experience accessing Manitoba Hydro's Neighbours Helping Neighbours program and the effects of arrears carried over from a previous residence. She explained that the assistance from that program was insufficient to help her catch up on both electricity arrears and rental arrears. Ms. Saultier expressed concern with a 3.5% rate increase for electricity, sharing that it would be difficult to manage any increase, particularly with housing and food costs also rising. She agreed with the other panelists that Manitoba Hydro should have a program to help low-income Manitobans with electricity bills, similar to GST refund payments.

Finally, Ms. Rina Hermkens shared her experience renting a house with a total of five roommates. Ms. Hermkens shared that her strategies for energy reduction included putting plastic on the windows in winter, using fans in summer, avoiding using the oven during summer months, and purchasing efficiency light bulbs. She explained she and her roommates were on either Employment and Income Assistance or the Canada Pension Plan and would struggle with any increase to their electricity bills. Ms. Hermkens explained that she spends all her income on rent, utilities or food, and since she did not want to be cold, that meant she would sometimes have to go without. Ms. Hermkens identified as being energy poor and suggested Manitoba Hydro should create a program to assist with electricity payments based on income. She suggested that Manitoba Hydro partner with Manitoba Harvest to help explain programs to low income earners and families.

In response to the Board's questions, panel members suggested a Manitoba Hydro program that allows Manitobans to round up their utility payments to the nearest dollar or two to contribute to a fund to assist low income Manitobans. The ratepayer panel also shared that they did not expect their incomes to increase over the next three years in keeping with the proposed electricity rate increases.

## Canada Packers

Jordan Gavaga presented on behalf of Canada Packers and outlined the company's significance within Manitoba's hog industry. The company manages hog production, feed mills, farms, and Canada's largest primary pork processing facility in Brandon, processing about 3.6 million hogs annually. Mr. Gavaga shared that Canada Packers' operations support thousands of jobs, strengthen rural communities, and form a key part of an industry that contributes \$2.3 billion to Manitoba's gross domestic product while competing in a global, commodity-driven market.

Mr. Gavaga stated that the cost of energy places financial pressure on Canada Packers, with an annual hydro bill of approximately \$4.3 million at their hog and feed production sites, and \$5.3 million at their Brandon processing plant. Mr. Gavaga emphasized that the hog industry operates within very tight margins and has a limited ability to pass on rising costs. Further, reliable and affordable power is essential for animal welfare, food safety, and protecting farm and processing infrastructure, which are often at the end of a power supply line.

Mr. Gavaga concluded his presentation by stressing that stable and competitive energy rates are necessary to support future growth, achieve sustainability goals, and allow Manitoba's hog industry to remain globally competitive and economically strong.

## CTD Group

Scott Crick presented on behalf of the CTD Group, a group of Manitoba-based manufacturing companies: Canadian Tool and Die, Integra Castings, and CTD Machine Works. The group produces a wide range of agricultural and industrial components.

Mr. Crick explained that the CTD Group spends approximately \$1 million annually on electricity, with Integra accounting for the majority of consumption due to its use of induction furnaces. Despite it facing significant challenges, the company is positioned for growth that could potentially double its electricity and gas usage, increasing demand charges by 50 to 100 percent. Electricity was described as one of the largest manufacturing costs after labour and raw materials.

Mr. Crick stated that the proposed hydro rate increases would have a direct and negative impact on the CTD Group by diverting limited financial resources away from capital reinvestment, technological modernization, innovation, and workforce growth. He emphasized that in an industry already operating with historically low margins and facing trade tariff uncertainty and other challenges, higher electricity costs would reduce the company's ability to remain competitive, secure new business with confidence, and invest in automation and productivity improvements needed to adapt to an evolving trade environment.

Mr. Crick also noted that, due to the nature of foundry operations, there are currently no cost-effective decarbonization or fuel-switching alternatives available, making higher electricity rates simply another unavoidable cost increase. Mr. Crick stressed that the timing of additional cost burdens is particularly challenging given ongoing uncertainty related to trade, tariffs, inflation, and market conditions facing industrial power users.

## **Koch Fertilizer Canada**

Kelly Simonson presented on behalf of Koch Fertilizer Canada, a privately owned company that has been serving Canadian farmers since 1967 and operates a major fertilizer manufacturing facility in Brandon, Manitoba. The company employs 286 people at the site, supported by dozens of daily contractors, and is a significant economic contributor to the region through high average wages, long employee tenure, major freight activity, and extensive community support.

Mr. Simonson explained that electricity is one of Koch's largest operating expenses, with the facility classified as a "General Large Service >100 kV" customer and incurring monthly power bills reaching up to \$1 million. Mr. Simonson raised concerns that proposed electricity rate increases of 3.5 percent annually over three years, combined with other regulatory pressures, would place Koch's Manitoba based operations at a competitive disadvantage. He highlighted the federal Output-Based Pricing System, a carbon pricing regime that applies to large industrial emitters, noting that Koch is the only fertilizer facility in Canada subject to this federal system, placing it at a cost disadvantage compared to similar facilities in Alberta and Saskatchewan.

Mr. Simonson concluded that Koch Fertilizer operates as a price taker in a globally competitive market and cannot pass increased electricity, carbon, or fuel costs on to customers. While the company values its long-standing partnership with Manitoba Hydro and supports reasonable rates that ensure system reliability, he cautioned that the cumulative effect of rising power rates, carbon pricing taxes on natural gas, and other regulatory burdens risked undermining the competitiveness of Manitoba-based industrial operations over time.

## York Factory First Nation

Chief Darryl Wastesicoot, Councillor Wayne Redhead, and Michael Anderson appeared on behalf of York Factory First Nation regarding the Split Lake water levels and cancellation of the ferry service in 2025.

Mr. Anderson submitted that Manitoba Hydro's revenue requirement should account for the cost of Manitoba Hydro taking or failing to take steps to ensure safety, security, and emergency preparedness. He expressed that certain customers are acutely vulnerable to repeated, extended loss of access to essential services due largely to Manitoba Hydro's drought response operations and water management practices. For example, the Split Lake ferry service was cancelled on July 16, 2025 due to low water levels. Mr. Anderson explained that this ferry is the land transportation link connecting York Landing to the provincial transportation network during the open water season, and described it as the community's lifeline providing heavy goods, housing packages, essential goods, and access. Mr. Anderson submitted that the Government of Manitoba has an obligation to maintain the ferry.

Mr. Anderson submitted that the low water levels on Split Lake were caused by Manitoba Hydro's water management and reservoir storage decisions, which were intended to maximize electricity generation later in the year. He said that since 2020, ferry operations have been disrupted or cancelled on four occasions, demonstrating a pattern of water level management decisions that prioritize higher-value fall and winter electricity generation. He submitted there was an absence of specific licence or other regulatory constraints governing minimum or maximum water levels at Split Lake.

Mr. Anderson further submitted that these repeated ferry disruptions impose significant and largely unaccounted-for costs on York Factory First Nation, individual residents, and other levels of government. The loss of ferry service forces the community to rely on costly alternatives for transporting goods and fuel, including winter roads and air transport, and results in broader social and economic impacts. York Factory urged the Board to

recognize that these costs are not reflected in Manitoba Hydro's current revenue requirement or rates and asked the Board to take them into account, particularly as Manitoba Hydro seeks extensions to its operating licences.

Councillor Wayne Redhead expressed that the clean, green energy promoted by Manitoba Hydro comes at a very high cost to York Factory residents. He emphasized that the impacts extend far beyond monthly electricity bills and include serious and ongoing hardships caused by low water levels and the repeated closure of the Split Lake ferry. He conveyed the deep concern within the community that their lives and well-being are being put at risk, and that Manitoba Hydro is prioritizing profit over people, resulting in profound disruption and a strong sense of discrimination among community members.

Chief Darryl Wastesicoot also expressed that his community was experiencing difficulty building an ice road across the lake and river as a result of it being between two hydroelectric dams, including Keeyask, which cause turbulence under the ice and affecting ice formation suitable for winter road usage. He urged Manitoba Hydro to engage with the community, and submitted that the costs of enabling his community to cross the waterways should be accounted for while setting electricity rates.

### **Mathias Colomb Cree Nation**

Chief Gordon Bear, Advisor Arlen Dumas, and Michael Anderson presented on behalf of the Mathias Colomb Cree Nation regarding the First Nation's emergency evacuation and proposal for a backup generator. Mr. Anderson explained that due to the wildfires in May of 2025, 2,200 citizens of Pukatawagan experienced mandatory evacuations and a complete and extended loss of electricity in the community. Mr. Anderson described the efforts taken by the First Nation to restore power to the community so that evacuees could return, including their efforts to create a backup generator system for the community. Starting in August of 2025, the First Nation provided the design and cost proposal for a turn-key backup generator solution from Power Safe Energy Services to all levels of government with a request to cost-share. The First Nation also worked extensively with Manitoba Hydro's consultant, the KGS Group, as well as other stakeholders, to ensure the plan was viable. However, Mr. Anderson advised that Mathias Colomb First Nation received no response from any level of government. To minimize the community impacts resulting from future electricity outages in the community, Chief Bear and his council have proceeded to find resources to buy the generators themselves.

Mr. Anderson concluded by underscoring the need for a continuous supply of power to address the energy security and emergency response requirements of Manitoba Hydro's customers. He encouraged the Board to take these requirements into account when determining rates and the utility's revenue requirement.

Chief Bear also described the profound and ongoing impacts on his community due to the repeated evacuations and prolonged power outages. He explained that after years of advocacy at multiple levels of government, the Nation continues to suffer severe harm to its health, culture, and way of life as a result of being displaced into cities and towns. He made a firm declaration that the Nation will not accept being forced to evacuate again and will not abandon the security of its homeland.

Drawing on his experience as a former Grand Chief, Advisor Arlen Dumas compared the rapid and effective responses he had witnessed in past emergencies with the delayed and fragmented response faced by Mathias Colomb Cree Nation. Despite the Nation proposing a credible, technically sound solution to restore power quickly with the purchase of a backup generator, Mr. Dumas submitted that the governments and Manitoba Hydro treated the community as a “jurisdictional football,” shifting responsibility rather than acting. He stressed that decisions were being made without meaningful involvement of Chief Bear or the community, and urged the Board to recognize the Nation’s demonstrated history of collaboration and innovation when supported by willing partners. Mr. Dumas asked that when the Board determines what rates should be, that it look out for the interests of all people in Manitoba.

## South Bow

Justin Chan and Ron Bellis presented on behalf of South Bow, which owns the Keystone Pipeline that transports oil through Manitoba. Mr. Chan emphasized the importance of Manitoba Hydro's electricity supply to the pipeline's reliable operation. The pipeline transports 500,000 to 600,000 barrels of crude oil per day from Alberta through Saskatchewan and Manitoba into the United States. Within Manitoba, the system includes approximately 350 kilometres of pipeline and six hydraulically critical pump stations, all powered by Manitoba Hydro, leading to electricity purchases of approximately \$23.5 million in 2024.

Mr. Bellis explained that oil movement depends on maintaining pipeline pressure between pump stations spaced roughly 70 kilometres apart. Even brief power outages can alter pressure profiles and cause pipeline slowdowns or shutdowns lasting hours, and disrupting the entire pipeline system between Alberta and the United States. Comparisons with other North American utilities showed that Manitoba Hydro has experienced more frequent outages since 2020, averaging one interruption every 17 days, which has resulted in more than 90 hours of full pipeline disruptions over several years. Mr. Bellis explained that these electricity supply disruptions typically relate to Manitoba Hydro's subtransmission and distribution lines. He emphasized that momentary outages, though often excluded from standard utility reliability metrics, can have major operational impacts to South Bow.

In closing, Mr. Chan and Mr. Bellis highlighted declining reliability trends in Manitoba Hydro's distribution system. Increasing utility equipment failures pose risks to South Bow's pipeline throughput, customer delivery commitments, and worker safety. South Bow therefore expressed support for Manitoba Hydro's Asset Management Plan and infrastructure upgrades, stressing that improved reliability is essential to minimizing risk and ensuring the safe, consistent delivery of crude oil to North American markets.

## **Gerdau Ameristeel**

Jeff Anthofer presented on behalf of Gerdau Ameristeel. Mr. Anthofer explained that Gerdau's Selkirk facility is an energy-intensive mini mill that melts scrap steel into a wide range of products used locally, across North America, and globally. The mill is an important economic contributor, with each Gerdau job supporting approximately five additional jobs upstream and downstream in the province.

Mr. Anthofer described how changing market conditions, including global competition and trade pressures, have narrowed profit margins and reduced the ability to pass rising costs on to customers. Historically competitive electricity prices in Manitoba have eroded, and increasing electricity costs combined with declining steel market prices have squeezed the gap between Gerdau's revenue and costs. Because corporate capital investment is directed toward the most cost-efficient mills, higher electricity costs threaten future investment in the Selkirk facility and increase the risk of stagnation or closure, as seen at other Gerdau facilities affected by high power costs in other jurisdictions.

Energy was identified as Gerdau's third-largest variable cost, and Mr. Anthofer emphasized that fixed demand charges become more expensive on a per-unit basis when production declines. Due to the nature of steelmaking, the mill has limited flexibility in managing peak demand once major equipment is operating, and Manitoba Hydro currently offers few mechanisms to mitigate these fixed costs. He highlighted how higher utilization lowers average electricity costs, but Manitoba Hydro's current rate structures make this difficult under constrained market conditions.

Drawing on experience in Ontario and several U.S. electricity markets, Mr. Anthofer outlined successful demand response, capacity, and operating reserve programs offered by electric utilities that provide customers with transparency, access to market pricing, and meaningful financial incentives for load flexibility. He recommended that Manitoba Hydro adopt similar approaches, including valuing demand reduction, reopening curtailment programs, enabling aggregators, and implementing time-sensitive rates with

sufficient peak/off-peak price differentials. He concluded that even within a regulated utility environment, Manitoba Hydro could design programs that recognize industrial load flexibility, reduce system costs, and help maintain the competitiveness of large employers in Manitoba like Gerdau Ameristeel.

## Chemtrade Logistics

Jeremy Gaudry presented on behalf of Chemtrade Logistics, a Canadian-based chemical manufacturing company with operations across North America and Brazil. Mr. Gaudry highlighted the Brandon facility, which is the largest sodium chlorate production plant in North America. The facility, originally commissioned in 1968, has undergone multiple phased expansions and technological upgrades, largely enabled by competitive electricity pricing and reliable power supply in Manitoba.

Mr. Gaudry explained that the Brandon plant is Manitoba's largest single power consumer, with a maximum load of 223 MW, and remains central to the company's operations following the closure of other chlorate facilities in Canada. While reliability and proximity to the Brandon Generating Station have been major advantages, the plant is not currently operating at full capacity due to declining pulp and paper markets, which account for the majority of sodium chlorate demand.

Mr. Gaudry emphasized that electricity represents approximately 70 percent of Chemtrade's variable costs, making electricity rates a critical factor in competitiveness and long-term decision making. Transportation costs and trade tariffs further challenge the Brandon site, given its distance from coastal pulp markets and reliance on the railways. With annual electricity costs expected to exceed \$70 million, even modest rate increases significantly affect profitability and constrain investment, forcing the company to pursue aggressive annual cost-saving and productivity initiatives that cannot always offset rising power costs. A 3.5% annual increase over three years would add over \$7 million to Chemtrade's electricity costs at the end of the term.

Looking forward, Mr. Gaudry noted that stable, predictable, and cost-based electricity rates are essential to maintaining Chemtrade's market position and enabling future opportunities, including the potential development of green hydrogen using hydrogen byproducts from chlorate production. Mr. Gaudry expressed support for working towards a 100 percent revenue-to-cost coverage rate over time, continuing flexible and curtailable

rate programs, expanding time-of-use options, and strengthening energy efficiency support. He concluded that sustained competitiveness in Manitoba's electricity pricing will be a key determinant of Chemtrade's long-term stability, investment decisions, and ability to pursue innovative projects in the province.

### **General Note on Industrial Presenters**

The Board notes that while all of the industrial presenters expressed concern about the effect of any rate increase on their operations, they also advised the Board that their companies do budget for rate increases in future years.

**APPENDIX C – APPEARANCES****PARTY****LEGAL COUNSEL**

<b>The Public Utilities Board</b>	Bob Peters, Sven Hombach, Avril Brown
<b>Manitoba Hydro</b>	Brent Czarniecki, Gwen Muirhead, Chris Bystrom, Matthew Ghikas
<b>Assembly of Manitoba Chiefs</b>	Carly Fox, Emily Guglielmin
<b>Consumers Coalition</b>	Byron Williams, Katrine Dilay, Chris Klassen, Keelin Griffin
<b>Representative of the General Service Small and General Service Medium Customer Classes</b>	Jessica Schofield
<b>Manitoba Eco-Network and Environmental Defence</b>	Kent Elson
<b>Manitoba Industrial Power Users Group</b>	Antoine Hacault, Erin Lawlor Forsyth
<b>Manitoba Keewatinowi Okimakanak</b>	Markus Buchart, Michael Jerch, Luke Young

## **APPENDIX D – PARTIES OF RECORD AND WITNESSES**

### **PARTY**

### **WITNESSES**

**Manitoba Hydro**

#### **Policy Panel**

Allan Danroth, President & Chief Executive Officer  
Hal Turner, Chief Operating Officer  
Alastair Fogg, Vice-President & Chief Financial Officer

#### **Asset Management & Capital Panel**

Dave Bowen, Vice-President, Asset Planning & Delivery  
Sandra Amorim Dew, Corporate Controller  
Jim Pawluk, Director, Asset Management  
Kevin Penner, Manager, Asset Lifecycle Management  
Tom Tonner, Director, Construction

#### **Revenue Requirement Panel**

Alastair Fogg, Vice-President & Chief Financial Officer  
Sandra Amorim Dew, Corporate Controller  
Greg Epp, Director, Treasury and Finance Planning  
Kevin Gawne, Strategic Energy Planning and Operations Lead  
Cheryl Sanclemente, Director, Energy Markets

#### **Customer, Cost of Service, & Rates Panel**

Marnie Van Hussen, Director, Rates & Regulatory  
Leo Laramée, Manager, Market Forecast & Load Research  
Colleen Galbraith, Director, Energy Service Advice & Products  
Vicky Cole, Director, Indigenous & Community Relations and Environment

**PARTY**

**WITNESSES**

**Consumers Coalition**

Peter Helland & Chris Oakley, Midgard Consulting Inc.  
Darren Rainkie, Darren Rainkie Consulting  
Dr. Runa Das, Royal Roads University  
Pelino Colaiacovo, Morrison Park Advisors  
Kelly Derksen, Kelly Derksen Consulting

**Representative of the General  
Service Small and General  
Service Medium Customer  
Classes**

Melissa Davies, MYND Consulting Inc.

**Manitoba Industrial Power  
Users Group**

Patrick Bowman, Bowman Economic Consulting Inc.  
Josh Dyck, InterGroup Consultants  
Dale Friesen, InterGroup Consultants