

Order No. 120/25

CENTRA GAS MANITOBA INC.

**FINAL ORDER
2024/25 GENERAL RATE APPLICATION**

September 16, 2025

BEFORE: Marilyn Kapitany, B.Sc.(Hon), M.Sc., Panel Chair
Carol Bellringer, FCPA, FCA, Member
Jim Hrichishen, B.A. (Hon.), M.A, Member
Susan Nemec, FCPA, FCA, Member
Kurt Simonsen, BSc., M.N.R.M., Member

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1.0 EXECUTIVE SUMMARY

1.1 Introduction

This is an order of the Public Utilities Board (“Board”) in Centra Gas Manitoba Inc.’s (“Centra”) 2024/25 General Rate Application. The order:

- finalizes an existing interim 4.5% general revenue increase for Centra that came into effect on November 1, 2024;
- approves a further 4.5% increase on November 1, 2025; and
- approves a further 4.0% increase on November 1, 2026.

These increases only apply to the cost of operating Centra’s distribution system, not the cost of natural gas consumed by Manitobans. This means they affect only a portion of each customer’s bill. Centra will file the bill impacts on individual customer classes with the Board following the issuance of this order.

Centra is Manitoba’s natural gas distributor and a wholly-owned subsidiary of Manitoba Hydro. It is a critical utility to Manitoba’s energy security. Natural gas provides approximately 1 ½ times the equivalent energy capacity of Manitoba Hydro’s electrical system during the peak winter season. Without Centra, Manitoba’s winter energy needs could not currently be met.

Centra’s importance is reflected in the mandate of the Board, which must balance the interests of ratepayers against the financial health of the utility. This mandate, affirmed by the Manitoba Court of Appeal, means that the Board must critically assess a utility’s financial needs and set rates in a manner that allows the utility to remain financially viable while being fair to ratepayers.

Centra’s application was for a single-year 4.5% general revenue increase effective November 1, 2024. After having assessed the evidence and submissions in the hearing, the Board has concluded that this is not sufficient and approves two additional years of increases. The first additional increase (4.5% on November 1, 2025) reflects Centra’s

projections, even though it did not ask for approval of this increase in the application. The second additional increase (4.0% on November 1, 2026) is higher than the 2.75% the utility projected. The Board's decision is the result of a significant deterioration in Centra's finances over the past six years, causing a need to take decisive regulatory action to return Centra to an improved financial footing.

There is precedent for the Board's approach. In Manitoba Hydro's 2003/04 General Rate Application, the Board approved a 5% one-year increase when the utility sought 3%. Similarly, in Manitoba Public Insurance's application for compulsory 2025/26 driver and vehicle insurance premiums, the Board approved a 5.7% increase when the insurance company had applied for only 3.0%. The Board makes such rulings when it believes that a rate-regulated entity is understating its rate request in a manner that does not adequately protect the financial health of that entity. While they are rare, these rulings highlight the Board's public interest mandate — a mandate that may lead to the Board adjusting rates either upward or downward if doing so is in the public interest.

The Board also directs Centra to file a three-year 2027/28 to 2029/30 General Rate Application by April 1, 2027 to ensure that the Board will be able to review rates for future years on a timely basis.

1.2 Centra's Financial Deterioration

At Centra's last general rate application in 2019, the utility projected a positive net income in the range of approximately \$7 million a year throughout the mid-2020s. In reality, Centra began to lose money in 2020/21. Losses continued to escalate annually, culminating in a \$34 million loss in 2023/24.

Despite mounting losses, Centra did not file a new rate application until directed by the Board to do so. It filed the application on October 7, 2024. This represented a gap of almost six years. Shortly after receiving the application, the Board approved an interim general revenue increase of 4.5% on an urgent basis, which took effect on November 1, 2024. Even with that increase, the utility projected a \$20 million loss in 2024/25, as illustrated in Figure 1.1. The projected loss for 2024/25 has since increased to \$23 million.

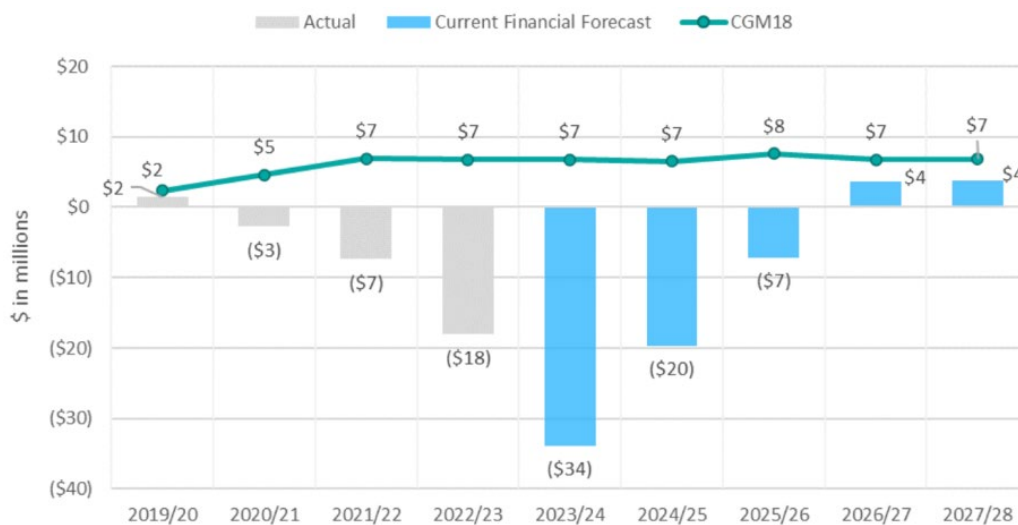


Figure 1.1 — Centra's Annual Net Losses since 2018/19 (Actual vs 2018 Forecast)

The escalating losses were caused primarily by increasing costs to run the utility without adequate revenue increases to recover those costs. As the utility began to accrue back-to-back annual losses, it also had to take on an increasing amount of debt to finance ongoing capital expenditures and operations, increasing the amount of interest it needed to pay. By the end of the 2024/25 fiscal year, the utility had almost completely eroded its retained earnings. The erosion of Centra's retained earnings is shown in Figure 1.2.

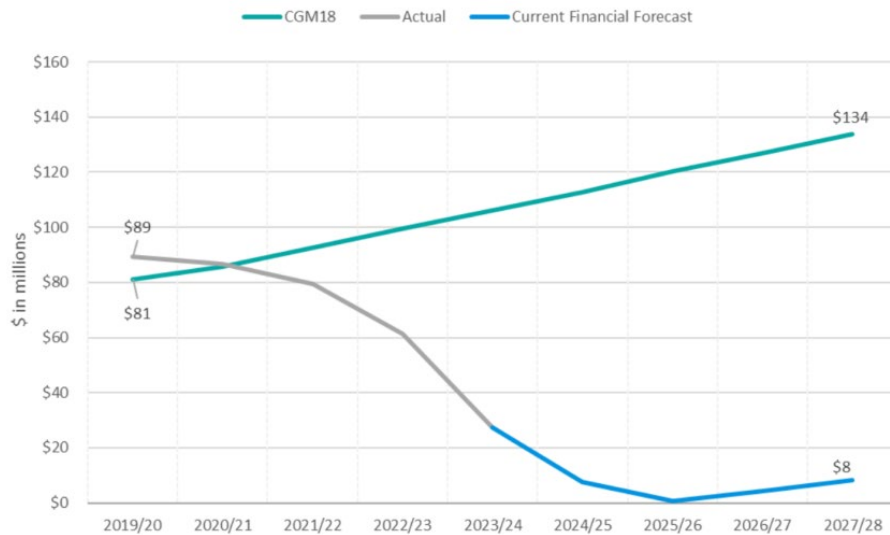


Figure 1.2 — Erosion of Centra's Retained Earnings

Figure 1.3 illustrates the increase in Centra's cost structure between the 2019/20 General Rate Application and the current hearing.

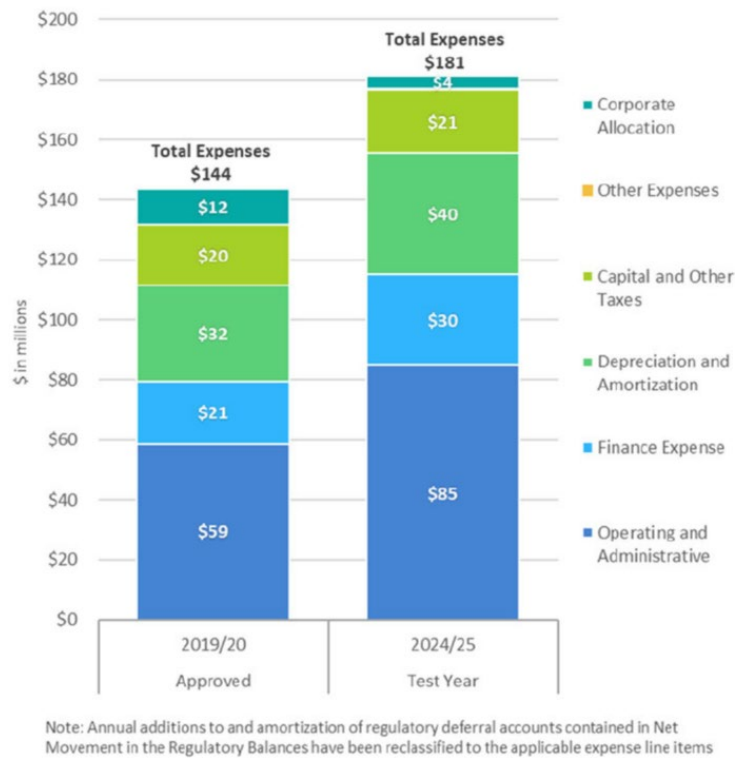


Figure 1.3 — Breakdown of Centra's Cost Increases by Category

1.3 The Need for Decisive Regulatory Action

It is clear to the Board that the one-time 4.5% general revenue increase applied for by Centra is insufficient to protect the financial health of the utility. Decisive regulatory action is required because, even with the interim increase effective November 1, 2024, Centra projects a \$23 million loss in 2024/25. The utility also projects ongoing losses in subsequent years. Despite these planned losses, the utility has no immediate plans for another rate application and acknowledged that filing such an application in the next two years would be difficult.

The Board finds that the public interest demands annual increases over three years. This enables the Board to establish gradual increases in an amount that results in an overall positive net income to Centra over the three-year period from 2024/25 to 2026/27, or at least minimizes or avoids additional losses. The increases are approved on a prospective basis, without retroactive rate adjustments.

There are several options available to a utility in Centra's position. These include increasing revenues by requesting rate relief, achieving cost savings, or using retained earnings to cushion the impact of losses. Centra only sought rate relief when the Board directed it to do so, and its retained earnings have almost fully eroded. In the view of the Board, Centra did not adequately avail itself of the remaining option of reducing costs. Accordingly, in addition to the approved rate relief, this order contains several directives mandating cost reductions.

Despite the increases approved in this order, natural gas bills for an average residential customer remain lower than they were 15 years ago. The increases are also less than cumulative inflation since the 2019/20 General Rate Application. Natural gas remains the most cost-effective heating option in Manitoba.

1.4 The Need for a Business Plan and Regular Rate Applications

In the Board's view, Centra's current financial predicament is in large part caused by Manitoba Hydro's electric operations having been continually prioritized over the needs of its natural gas subsidiary. While the utility continues to deliver safe and reliable natural gas service, its strategic and financial needs have not been adequately protected.

Given Centra's importance to meeting the energy needs of Manitobans, as well as the risks to Centra posed by the energy transition trend towards decarbonization, the current management approach to Centra cannot continue. Centra is a relatively stable utility in terms of customer growth and the volume of gas delivered. This contrasts with Manitoba Hydro, which is expecting to ramp up capital spending to address aging assets and meet the growing peak demands for electricity. Without sufficient safeguards in place, there is a risk that Centra will not be given the senior management attention and strategic oversight required for a critical energy provider in Manitoba.

In the view of the Board, it is important for Centra to critically assess its business needs and document appropriate strategies. To that extent, the Board directs Centra to develop, and file with the Board by April 1, 2027, a Centra-specific business plan.

1.5 Centra's Revenue Requirement

To determine the general revenue increases approved by the Board, the Board considered Centra's revenue requirement projections in light of Centra's cost structure. In this order, the Board approves Centra's revenue requirement projections for each of the three years for which the Board approves a general revenue increase, with several notable exceptions as summarized below.

1.5.1 Disallowance of Certain Operating & Administrative Expenses & Changes to the Integrated Cost Allocation Methodology

On a percentage basis, the largest increase to Centra's cost structure arose in the area of operating and administrative expenses, which increased at approximately twice the rate of inflation since the 2019/20 General Rate Application. The Board is concerned about these increases and does not consider this trend to be sustainable.

Because Centra is functionally integrated with Manitoba Hydro, it does not have its own employees or office space. Instead, Manitoba Hydro's operating and administrative expenses are assigned or allocated to Centra by Manitoba Hydro in one of two ways:

- If the costs clearly relate to Centra (such as costs for installing or repairing gas pipelines), they are directly assigned to the natural gas utility.
- If the costs are shared costs (such as administrative overhead), they are partially allocated to Centra through percentage-based allocators in Centra's Integrated Cost Allocation Methodology.

In this order, the Board is issuing directives to Centra regarding both of these methods.

With respect to the direct assignment of costs, the Board finds that Centra has not adequately justified an increase in departmental support costs and is disallowing \$2.0 million of operating and administrative expenses in each of 2025/26 and 2026/27. However, the Board is not retroactively adjusting those expenses for the 2024/25 test year, which is already complete.

With respect to the allocation of shared costs, the Board is directing Centra to replace two of its existing cost allocators with a three-factor allocator commonly utilized in the utility industry. The three-factor allocator is to equally weight the activity charges, assets, and revenues of each utility. On a preliminary basis, the Board expects this change to reduce the allocation of costs to Centra by approximately \$4 million to \$6 million per year. Unlike the disallowance of directly assigned costs discussed above, the change to the allocator is to take effect for the 2024/25 test year.

1.5.2 Corporate Allocation

For more than 20 years, the Board has approved the recovery of an annual \$12 million corporate allocation to Centra, which reflects that utility's share of the financing and integration costs resulting from Manitoba Hydro's acquisition of Centra in 1999. The corporate allocation arose as an estimate of efficiencies resulting from the acquisition, based on the desire to keep natural gas ratepayers in the same position as if the acquisition had not happened.

In the current hearing, Centra proposes to decrease the corporate allocation to \$4 million, through a two-part mechanism:

- Manitoba Hydro established a \$100 million sinking fund using money from an unregulated subsidiary that partially offsets the acquisition financing cost; and
- Centra proposes to use an Integrated Cost Allocation Methodology allocator for the remainder of the cost allocation that reduces the amount allocated to Centra from approximately 2/3 to 1/3.

The Board approves Centra's corporate allocation proposal for the purposes of this application. However, given that more than 25 years have elapsed since the acquisition, and that Centra has been operationally integrated with Manitoba Hydro since that time, the Board is also directing Centra to develop, and file with its next general rate application, a proposal to phase out the corporate allocation entirely.

1.6 Capital Expenditures

In addition to needing to approve Centra's revenue requirement and set rates, the Board must also analyze Centra's capital expenditures and approve the utility's rate base.

In this order, the Board approves Centra's capital expenditures incurred for the 2018/19 to 2022/23 period, as well as the additions of those capital assets to Centra's rate base. However, the Board finds that Centra has not adequately taken into consideration its current financial situation when developing its capital expenditure plans. Centra must consider its projected losses and challenging financial position and moderate its planned capital expenditures. Accordingly, the Board directs Centra to reduce its 2025/26 and 2026/27 capital expenditure budgets by \$2.0 million.

1.7 Other Issues

With this being Centra's first general rate application in almost six years, the Board is also making decisions, and issuing directives, regarding several other issues. Among other things, in this order, the Board:

- approves depreciation rates based on Centra's 2024 Depreciation Study and approves several depreciation-related changes;
- approves historical and forecast gas costs;
- directs Centra to continue to classify distribution mains using the results of its historical diameter-length study for cost of service purposes, with the exception of the 2024/25 test year for which Centra has already used a new minimum system study;
- directs Centra to prepare a new unaccounted-for gas study;
- approves several additional changes to Centra's cost of service methodology;
- directs Centra's head office credit to be eliminated in 2025/26;
- directs Centra to develop a policy paper on a potential seasonal customer rate class;
- approves an increase to the basic monthly charge for customers in the Small General Service and Large General Service customer classes;
- approves the creation of a two-part rate for the Power Stations customer class;
- directs Centra to increase the percentage of demand-related costs to be recovered through the demand charge of the High Volume Firm customer class;
- directs Centra to implement a fixed 14% tolerance band (with minimum and maximum tolerances) for balancing fees levied to Transportation Service customers; and
- finalizes various other interim orders.

2.0 BACKGROUND

2.1 The Board's Ratemaking Process

This order relates to a general rate application filed by Centra Gas Manitoba Inc. ("Centra") for the 2024/25 fiscal year.

Centra is a natural gas utility regulated by the Public Utilities Board ("Board") under *The Public Utilities Board Act*. The Board's mandate includes the fixing of just and reasonable rates. This involves balancing the interests of ratepayers against the financial health of the utility. 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 1.1.

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 1.1 — Simplified Bonbright Ratemaking Criteria

The ratemaking process is broadly divided into three steps:

1. The first step is to determine the total amount of money a utility needs to recover from rates. This is called the "revenue requirement" and addressed in section 4.0 of this order.
2. The second step is to determine how the revenue is to be recovered from different classes of ratepayers. This is called "cost of service" and addressed in section 8.0 of this order.

3. The third step is to determine how rates within a customer class are to be structured to recover fixed and variable costs. This is called “rate design” and addressed in section 9.0 of this order.

Historically, Manitoba utilities earned a return on their rate base. The rate base represents assets of a utility that are used, useful and prudently acquired. A rate base rate of return is a rate of return on the utility’s equity and common for privately owned utilities whose shareholders demand a return on their investment. In contrast, publicly owned utilities are often regulated on a cost of service basis.

Because Centra is a wholly owned subsidiary of Manitoba Hydro (a Crown corporation), Centra is regulated in that manner. Under Centra’s cost of service ratemaking methodology, the Board establishes Centra’s revenue requirement on a cost recovery basis, plus an approved return (see section 3.0) and a corporate allocation reflecting synergies from Centra’s acquisition by Manitoba Hydro (see section 4.6).

As a natural gas distribution utility, Centra incurs gas costs (supply-related) and non-gas costs (infrastructure-related). This order primarily focuses on the non-gas revenue requirement, although Centra’s gas costs are separately addressed in section 6.0.

The Public Utilities Board Act was never amended to reflect the fact that Centra is now publicly owned. As such, the Act still requires the Board to establish Centra’s rate base. To do so, the Board reviews Centra’s capital additions and forward-looking capital plans to determine whether the projects are prudent (see section 7.0).

The major approvals sought by Centra, as well as a history of this general rate application, are set out below.

2.2 Approvals Sought by Centra

In its application, Centra seeks the following approvals from the Board:

1. Approval of a general revenue increase of 4.5% effective November 1, 2024, sufficient to generate additional revenue of \$11 million (approved on an interim basis in Order 125/24);
2. Approval of Transportation (to Centra), Distribution (to Customers) and corresponding Delivery Rates, the Gas Commodity Overhead rate and the Fixed Rate Gas Commodity Service Program Cost Rate, effective November 1, 2024;
3. Approval to dispose of the balances in the October 31, 2019 Prior Period Gas Cost Deferrals Account and the Purchased Gas Variance Accounts from November 1, 2019 to October 31, 2023 through rate riders over the 12-month period commencing November 1, 2024;
4. Approval of adjustments to rates to reflect changes in forecast non-commodity related gas costs, effective November 1, 2024;
5. Approval of updated depreciation rates for rate setting purposes and regulatory deferral accounts, and the proposed amortization periods for those accounts, specifically the following:
 - a) Approval to change the amortization period on the loss on retirement or disposal of assets from 5 to 28 years (subsequently revised to 27 years);
 - b) Approval to use the CGAAP Average Service Life depreciation rates from the 2019 Depreciation Study (subsequently revised to the 2024 Depreciation Study) over 5 years;
 - c) Approval to commence amortization of the regulatory deferral established for the 2019 Depreciation Study over 5 years (subsequently expanded to seek similar relief for the 2024 Depreciation Study);
 - d) Approval to commence using four new depreciation accounts which were identified subsequent to the 2019 Depreciation Study; and

- e) Approval to establish a Cloud Computing Regulatory Deferral and to amortize the account over a 6-year period which is reflective of the estimate average service life of the cloud services;
6. Final approval of actual gas costs for November 1, 2018 to October 31, 2019 of \$212.0 million;
 7. Final approval of actual gas costs for November 1, 2019 to October 31, 2020 of \$186.4 million;
 8. Final approval of actual gas costs for November 1, 2020 to October 31, 2021 of \$201.9 million;
 9. Final approval of actual gas costs for November 1, 2021 to October 31, 2022 of \$344.5 million;
 10. Final approval of actual gas costs for November 1, 2022 to October 31, 2023 of \$312.6 million;
 11. Final approval of actual gas costs for November 1, 2023 to October 31, 2024 of \$146.6 million;
 12. Endorsement of revised approaches to updating the cost of gas in storage and the natural gas volume forecast used in quarterly Gas Commodity applications;
 13. Approval of various cost of service methodology and rate design changes as further detailed in the application;
 14. Final approval of interim orders;
 15. Confidential treatment of certain information identified as commercially sensitive information; and
 16. Such further and other approvals or relief requested that the Board deems just.

2.3 Procedural History of the Application

Centra's last general rate application was filed in 2018 and was for the 2019/20 year. In that application, the Board reduced Centra's revenue requirement, primarily because the utility was over-earning at the time and recovering more than the Board-approved net income. The Board found that it was not just and reasonable for the utility to do so and reduced rates accordingly. In between the 2019/20 application and the current application, almost six years passed without the utility requesting a general revenue increase.

In 2022, the Board approved major changes to Centra's cost of service methodology as reflected in Order 109/22. In addition to changing the cost of service methodology, Order 109/22 approved Centra's request for interim rate relief for the utility's Special Contract customer class that was offset by an additional cost assignment to the Power Station class. The interim request for rate relief was initially for one year, as Centra was planning to file a general rate application in 2023. When this did not happen, Centra applied to the Board to review and vary the interim rate relief order and extend it until the earlier of July 31, 2024 or the day the Board issued a final order in the next general rate application. In Order 106/23, the Board varied the directive to simply extend the interim rate measure until the Board issued a final order in the general rate application, without an expiry date. In issuing the order, the Board noted that Centra had indicated its intention to file a general rate application in late 2023.

Order 152/19 (the Board's final order in the last general rate application) contained a directive requiring Centra file an integrated cost allocation methodology ("ICAM") report with its next general rate application. In late 2023, Centra advised the Board that it had not done so but raised the possibility of the Board retaining an independent expert consultant to review the ICAM. At that time, the Board was also seeking confirmation from an independent expert consultant that the cost of service methodology changes approved in Order 109/22 had been appropriately implemented.

As a result, on January 8, 2024, the Board issued the first procedural order in the current hearing (Order 6/24). Among other things, the order established a scope of work for

Deloitte LLP to review Centra's ICAM as an independent expert consultant, and for Elenchus Research Associates to review the implementation of Centra's cost of service methodology for compliance with Order 109/22.

Centra first provided the Board with a confidential update outlining its deteriorated financial condition in 2023. The update was provided in accordance with Directive 26 of Order 128/09, which requires Centra to advise the Board of material changes in its financial position. By July 2024, the Board had become increasingly concerned about the lack of a general rate application despite the documented financial deterioration. Consequently, the Board, on its own accord, issued Order 92/24, which directed Centra to file its general rate application by August 30, 2024.

Centra subsequently applied to review and vary the Board's directive and extend the filing date by one month, from August 30, 2024 to September 30, 2024. The Board approved this request in Order 96/24.

On September 25, 2024, Centra filed an application to set aside the requirement to file a general rate application indefinitely, pending an application by Centra to fully integrate its finances with Manitoba Hydro. The Board denied this request and, in Order 111/24, concluded that it could not abdicate its mandate to fix just and reasonable rates. The Board was also very concerned whether customer rates were still just and reasonable given the significant erosion in Centra's net income and the changes to the cost of service methodology approved in Order 109/22. The Board accordingly reaffirmed its directive requiring Centra to file a rate application but extended the filing deadline by one week, to October 7, 2024.

Centra filed its general rate application in accordance with the Board's revised timeline.

2.4 Interim Rate Order

Centra's application also included a request for interim approval of a 4.5% general revenue increase effective November 1, 2024. The Board granted interim approval of this increase in Order 125/24, and the increase has been in effect since November 1, 2024. The Board also granted interim approval to amortize the purchased gas variance accounts over 12 months beginning on November 1, 2024 but extended the amortization periods for the Mainline and Interruptible classes from 12 months to 24 months as a rate-smoothing measure.

2.5 Interveners and Pre-Hearing Process

The Board invited applications for intervener status and adjudicated those applications following a pre-hearing conference held on October 24, 2024. In Order 127/24, the Board granted intervener status to the Manitoba branch of the Consumers Association of Canada ("CAC"), the Industrial Gas Users ("IGU"), and Koch Fertilizer. The Board also established a pre-hearing timetable and a process that involved two rounds of written information requests to the utility and one round each to independent expert consultants and intervener witnesses.

3.0 RATE PATH AND FINANCIAL TARGETS

3.1 Introduction

This is Centra's first general rate application in almost six years. During that time, the utility experienced increasing losses and an almost complete erosion of its retained earnings. Despite this situation, Centra applied for only a one-year general revenue increase of 4.5% for the 2024/25 test years. It did not request any increases for 2025/26 and 2026/27. The increase, which the Board approved on an interim basis effective November 1, 2024, is not enough to offset the utility's losses, with Centra projecting a \$23 million loss in the 2024/25 test year despite the interim increase approved in Order 125/24. Absent rate increases in 2025/26 and 2026/27, Centra further projects net losses of \$13 million and \$19 million in those respective years.

As a result, a fundamental issue in this hearing was whether the Board should approve a three-year general revenue increase to reverse Centra's deteriorating financial situation, even if the utility did not ask for it.

As set out below, the Board has determined that a three-year general revenue increase approval is in the public interest and necessary to protect the financial health of the utility. As such, the Board is finalizing the existing interim general revenue increase that was implemented November 1, 2024, but is also approving subsequent increases of 4.5% effective November 1, 2025 and 4.0% effective November 1, 2026.

3.2 Centra's Deteriorating Financial Position

Centra's financial situation has deteriorated significantly since the 2019/20 General Rate Application. As set out in Figure 3.1, beginning with the 2020/21 fiscal year, Centra began to accrue three consecutive years of net losses totalling \$28 million. In 2023/24, Centra incurred an additional net loss of \$34 million.

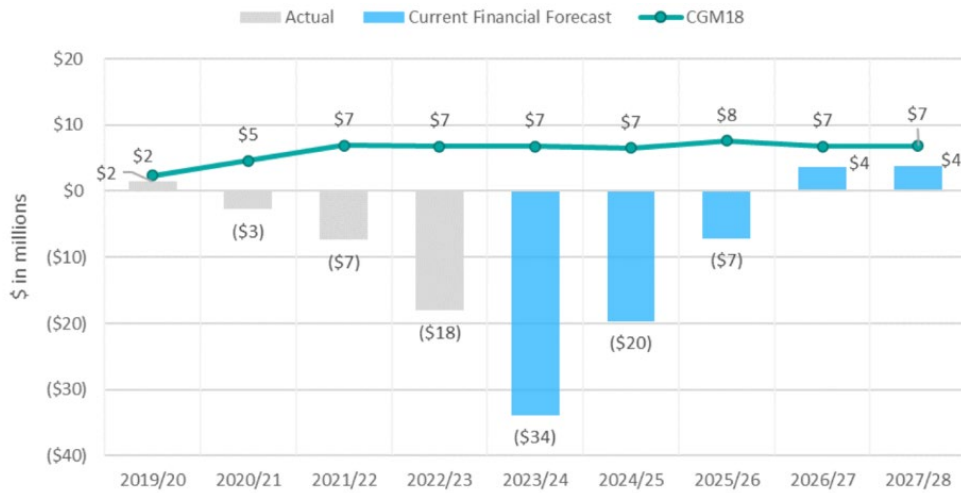


Figure 3.1 — Centra’s Annual Net Losses (Actual vs 2018 Forecast)

As described in the remaining sections of this order, the fundamental cause of the escalating losses is flat revenues at a time of cost increases, particularly operating and administrative expenses. This has been further exacerbated by Centra’s increased reliance on debt to pay for capital expenditures, which in turn has increased finance expenses. This has been partially offset by a reduction in Centra’s corporate allocation (Centra’s share of Manitoba Hydro’s acquisition costs from purchasing the utility) from \$12 million to \$4 million and a reduction in payments to government as a result of a cut in the provincial debt guarantee fee and an elimination of the corporations capital tax for Crown corporations Figure 3.2 provides a breakdown in the increase of Centra’s costs since the last general rate application.

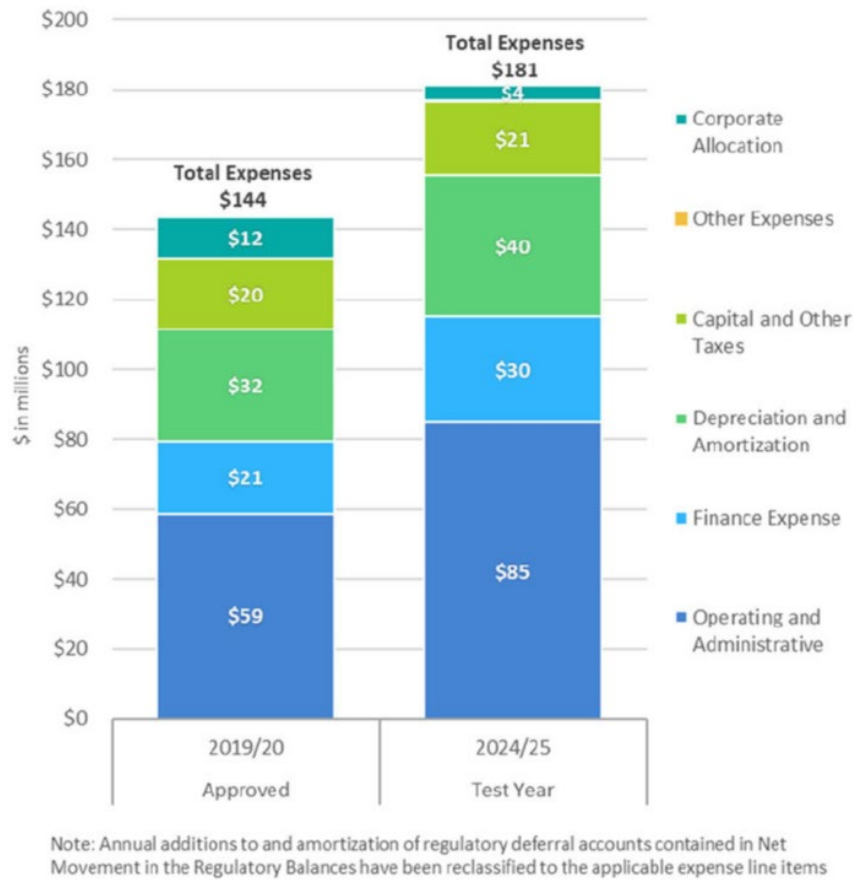


Figure 3.2 — Breakdown of Centra's Cost Increases by Category

As a result of the increasing losses, Centra's retained earnings decreased from \$89 million in March 2020 to \$27 million in March 2024, with a further decrease to \$4 million expected during the test year. The decrease in the utility's retained earnings is illustrated in Figure 3.3.

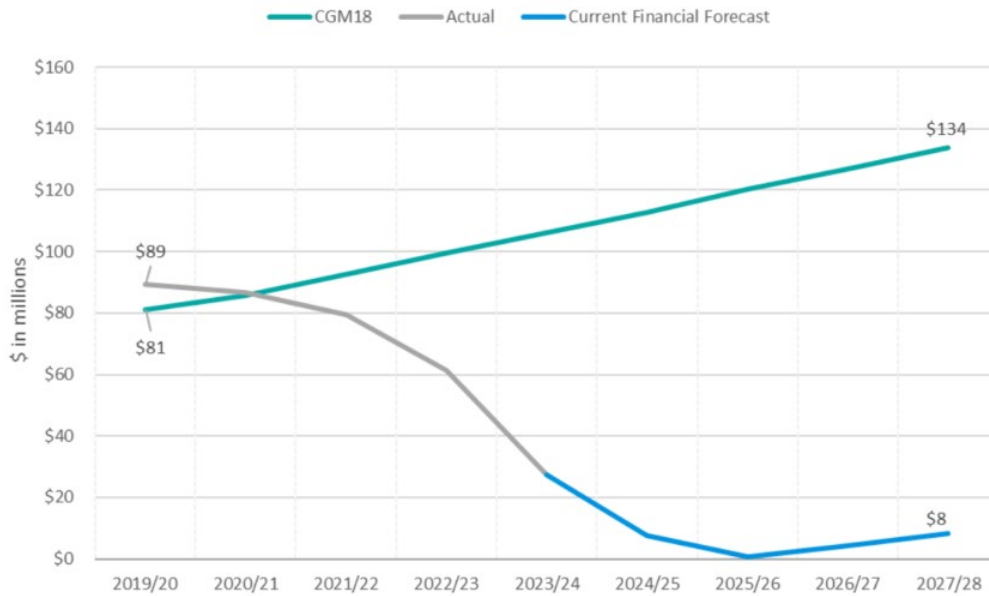


Figure 3.3 — Erosion of Centra’s Retained Earnings

Centra’s retained earnings constitute only a portion of the utility’s equity. Until its purchase by Manitoba Hydro in 1999, Centra was privately owned by West Coast Energy. At the time of purchase, Centra assumed \$121.2 million of share capital (comprised of \$82.3 million of retained earnings and \$38.9 million of share capital and contributed surplus) that remains in the utility. The Board has consistently taken the position that Centra’s debt-to-capitalization ratio must be considered on a stand-alone-basis and that shareholder capital must be considered in its determination. As shown in Figure 3.4, following the Board’s approach of including the share capital, Centra’s debt-to-capitalization ratio was 79% going into the 2024/25 fiscal year.

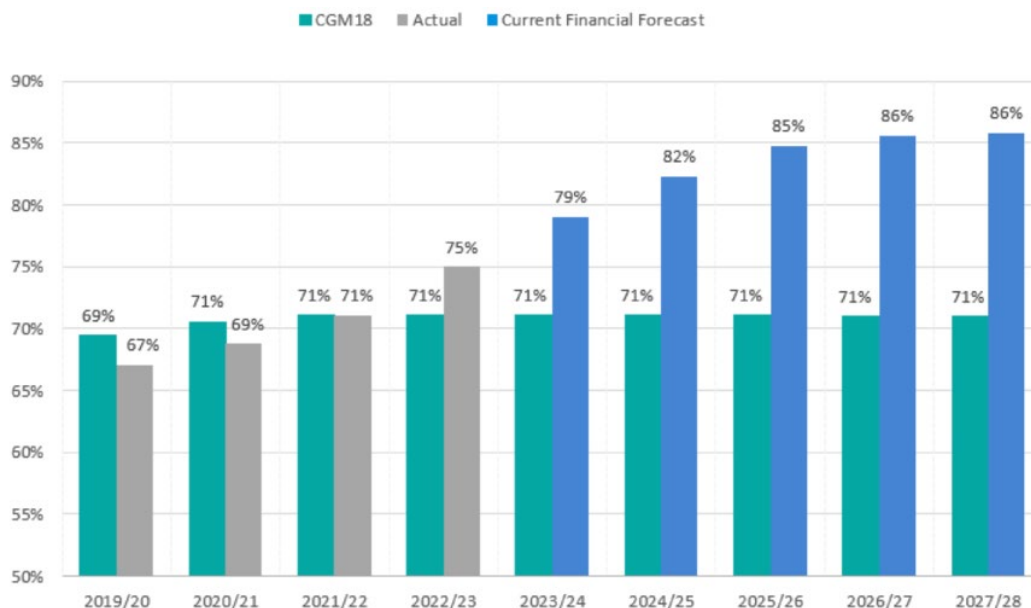


Figure 3.4 — Debt-to-Capitalization Ratio (With Share Capital)

As described further below, the parties disagreed on the severity of Centra’s financial situation, although all parties acknowledged that it required attention.

3.3 Financial Targets and Net Income

Under cost of service rate regulation, a utility is allowed to recover its prudently incurred costs plus an approved return. These elements are determined on a forecast basis for specific test years and collectively form part of the utility’s revenue requirement.

The Board’s existing financial targets for Centra include a free-standing debt-to-capitalization ratio of 70:30 and a net income of \$3 million. While Centra’s borrowings are guaranteed by the Province of Manitoba, the Board has regulated Centra on a standalone basis.

In addition, since 2005, the Board has approved a static \$12 million “corporate allocation” to Centra that forms part of the utility’s revenue requirement. The allocation was effectively a proxy for synergies realized by Manitoba Hydro acquiring the utility. Since that time, the Board has approved a total annual return to Centra’s parent of \$15 million, consisting of the \$12 million corporate allocation and \$3 million in net income. This total

return was also deemed to be aligned with the approximately \$14 to \$16 million annual return Centra earned prior to its acquisition by Manitoba Hydro.

At the 2019/20 General Rate Application, Centra's financial projections suggested that maintaining an annual net income of \$3 million would, all else being equal, result in Centra's equity level declining below 30%. To further examine, among other things, Centra's financial metrics and the appropriate level of retained earnings for Centra, Directive 22 of Order 152/19 required Centra to participate in a technical conference hosted by an independent facilitator. This directive was subsequently replaced with Directive 1 of Order 72/22, which required Centra to propose financial targets (with underlying assumptions) with its next general rate application.

In response to Directive 1 of Order 72/22, Centra's submissions in this proceeding include several long-term scenarios intended to provide directional impacts on Centra's long-term finances. Centra is of the view that these issues should be explored in a future regulatory proceeding.

With Centra now decreasing the corporate allocation from \$12 million to \$4 million as described in section 4.6, one of the questions to be resolved is whether \$3 million remains sufficient in the absence of the additional return that was provided by the \$12 million corporate allocation.

For illustrative purposes, before the 2019/20 General Rate Application, Centra commissioned Drazen Consulting Group to determine an appropriate return on equity. Drazen recommended a range of 8.3% to 8.5%. For the purposes of its return on rate base calculations in the current application, Centra has assumed a return of 8.3%. Based on this amount, and the rate base as calculated by Centra, the utility would have been allowed to earn a net income of \$7.8 million in the test year.

3.4 One-Year Rate Application vs. Multi-Year Rate Path

Under Centra’s one-year application for 2024/25, the utility is forecast to neither earn a \$3 million net income as historically approved, nor a \$7.8 million return on equity as would have been permitted under the rate base rate of return approach. To the contrary, the utility is projecting a \$23 million loss, further eroding retained earnings to \$4 million by the end of 2024/25. This prompted ongoing debate during the hearing about whether it would be appropriate for the Board to approve revenue increases for more than one year, even though the utility did not apply for such increases.

In this application, Centra originally filed its financial scenarios based on a three-year “rate path” of 4.5% general revenue increases in each of 2024/25, 2025/26, and 2026/27. Beyond those years, the scenarios differ in their approach to future revenue increases. However, they all have one thing in common — none of the rate scenarios return Centra to a 70:30 debt-to-capitalization target by the end of the 20-year forecast period.

As described in section 4.0, subsequent to the filing, the provincial government reduced the provincial guarantee fee and eliminated the capital tax for Crown corporations. Collectively, these initiatives reduce Centra’s expected future costs. Following these reductions, Centra filed new financial scenarios and revised the rate path for the initial three years from 4.5%, 4.5%, and 4.5% to 4.5%, 4.5%, and 2.75%. Figure 3.5 shows a comparison of the two rate paths.

		2024/25	2025/26	2026/27	Cumulative
Original	Proposed Increase (%)	4.5	4.5	4.5	14.12
	Net Income (\$ millions)	(20)	(7)	5	(23)
	Retained Earnings (\$ millions)	8	1	4	n/a
	Debt-to-Capitalization Ratio (%)*	82	85	85	n/a
Updated	Proposed Increase (%)	4.5	4.5	2.75	12.21
	Net Income (\$ millions)	(23)	(2)	5	(20)
	Retained Earnings (\$ millions)	4	3	8	n/a
	Debt-to-Capitalization Ratio (%)*	83	85	85	n/a

*Determined in accordance with the Board-approved methodology that considers share capital

Figure 3.5 — Key Metrics for Original vs. Amended Financial Forecasts

Under both the original and the updated scenario, Centra expects to have a positive net income in Year 3 of the forecast. However, if the three-year rate path is considered in its entirety, the utility still expects a cumulative loss of \$20 million over the three years, even with the predicted revenue increases.

Centra’s financial situation will worsen if the projected revenue increases for 2025/26 and 2026/27 do not materialize. Centra expects the modelled 4.5% revenue increase for 2025/26 to result in an additional \$11 million in incremental revenue in that year and \$16 million on an annual basis. The further 2.75% increase in 2026/27 is expected to add an additional \$7 to 8 million in the year, or \$11 million on an annual basis. Without both of these increases, Centra expects to incur losses in all three years, as illustrated in Figure 3.6.

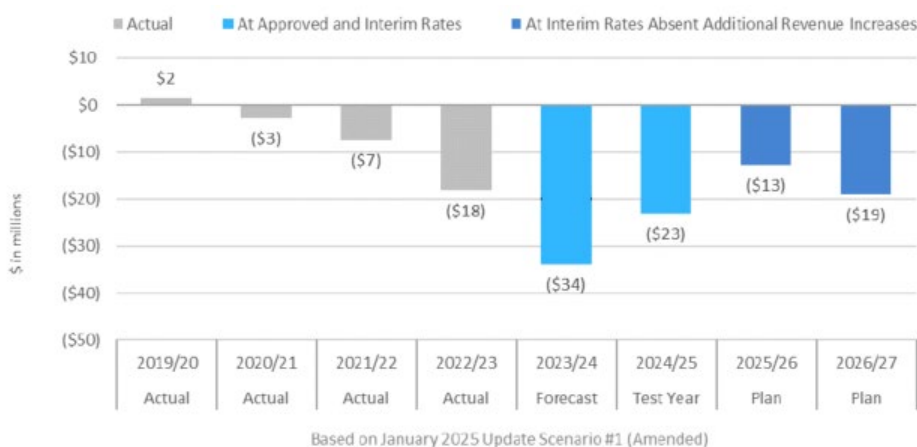


Figure 3.6 — Net Income With Only a 2024/25 4.5% Rate Increase

Manitoba Hydro’s board of directors initially granted approval for a three-year filing. However, through a period of transition, including the appointment of a new CEO and the release of Manitoba’s Affordable Energy Plan, Manitoba Hydro’s board of directors ultimately only authorized a one-year application. During the oral hearing, Centra acknowledged that it would be “extremely difficult” to file a new rate application for the 2025/26 fiscal year given the number of already initiated, or anticipated, Board proceedings involving Centra’s parent company, Manitoba Hydro.

Centra contrasts its rate path against Manitoba's CPI, which has increased by 20.8% from 2018/19 to 2024/25.

3.5 Centra-Specific Strategic Plan

In Order 85/13, resulting from Centra's 2013/14 General Rate Application, the Board found that Centra's overall strategic vision was lacking and requested Centra to provide a more articulated vision in its next general rate application.

As the above review did not occur at the 2019/20 General Rate Application, Directive 31 of Order 152/19 required Centra to file a Centra-specific strategic plan at the next general rate application that included details of Centra's management structure, strategic asset management plan, framework for assessing and evaluating risks and risk tolerance, major planned expenditures, change management arising from the Voluntary Departure Program, and financial metrics and targets.

In this proceeding, Centra addressed Directive 31 of Order 152/19 by identifying that Manitoba Hydro's integrated strategic direction from the 2023/24 & 2024/25 electric General Rate Application was being refreshed in light of the provincial government's release of the Affordable Energy Plan. Further, Centra's submissions in its 2024/25 General Rate Application provide information on the corporation's business model review, organizational structure, Enterprise Risk Management framework, strategic asset management plan, and various rate path scenarios with the resulting impacts on key financial measures.

3.6 Position of the Parties

3.6.1 Centra

Centra emphasizes the importance of natural gas in Manitoba, including that Centra's gas system can deliver 1.5 times the equivalent capacity of the electrical system on the coldest days of the year and 40% of the energy in a typical year. According to Centra, the current and near-term criticality of natural gas warrants returning the utility to a stronger financial position by returning to positive net income and stopping the erosion of retained

earnings. However, Centra states that, over the longer term, it is essential for Manitoba Hydro to take an integrated approach to managing the energy transition.

Centra acknowledges that it prepared the application by establishing a three-year path of annual general revenue increases, and states that this path balances the rate impacts to consumers against the financial health of the utility. The utility submits that a return to \$3 million of net income in the 2024/25 test year would have required a 14.1% rate increase, while a return to break-even would have still required a 12.8% increase. Instead, the utility opted for a gradual, multi-year strategy.

Centra states that both CAC's witness, Mr. Rainkie, and IGU's witness, Mr. Bowman, support finalizing the 4.5% increase that was approved on an interim basis in Order 125/24. While the utility did not apply for rate increases beyond the test year, it submits that it would be "prudent, reasonable and practical" for the Board to award rates for 2025/26 and 2026/27 as well, given the totality of the evidence on the record. Centra states that the Board has previously awarded conditional rate increases for future test years, and that the Board could make 2025/26 and 2026/27 rates conditional on the provision of updated financial information.

Centra points out that, even with the 4.5% interim revenue increase that has already been approved, its retained earnings have eroded to \$4 million by the end of 2024/25. The utility sees the three-year rate period as being about cost recovery and a return to positive net income, with the issue of an appropriate level of retained earnings to be addressed once that return is achieved. It also submits that, while Centra's debt is only 2.6% of the consolidated operations of Manitoba Hydro, weakness in Centra's financial position can reflect on Manitoba Hydro's overall financial position.

Centra is also concerned about its cash flow, noting that the utility currently spends more cash for its operations than it brings in. The utility dismisses the evidence of CAC's witness, Mr. Rainkie, that changes to Centra's presentation of cash from operations overstates the severity of Centra's financial situation. Specifically, it notes that the change to the manner cash flow is presented does not change Centra's net cash position.

3.6.2 *Intervenors*

Consumers Association of Canada

CAC states that it is unprecedented that a utility that knows its financial results are deteriorating does not seek rate relief, and that allowing matters to fester creates unnecessary complications and results in the Board having to unwind the past, unpack prior years, and reconstruct events.

CAC supports the Board approving revenue increases beyond the test years. It recommends finalizing the interim 4.5% revenue increase for 2024/25 and approving two additional revenue increases of 2.0% each for 2025/26 and 2026/27. However, any such increases should be conditional on a written review process before the Board that includes intervener participation. The process envisioned by CAC involves updated financial forecasts and cost of service study results, followed by one round of information requests by all parties and subsequent written submissions.

In recommending a 4.5% / 2.0% / 2.0% rate path, CAC relies on the evidence of its witness, Mr. Rainkie, who recommended reducing Centra's allocation under the integrated cost allocation methodology by approximately \$6 million per year (see section 5.0), refunding a \$21 million credit over three years for past over-allocations, and disallowing \$5 million of administrative support costs (see section 4.1).

CAC notes that Manitoba Hydro appears to be maintaining a holding pattern for Centra until the utility figures out the evolving energy transition requirements, and that there is no risk of Centra becoming unable to provide safe and reliable service. As such the Board should take a measured response. In CAC's view, its proposal allows Centra to return to a sound financial footing but will not reward Centra for its refusal to apply for rate increases. However, CAC considers rate increases beyond 2026/27 to be premature.

Industrial Gas Users

Like CAC, IGU recommends that the Board finalize the interim 4.5% general revenue increase approved in Order 125/24 and implemented in Order 129/24. However, IGU differs with respect to the subsequent years and recommends a single further conditional general revenue increase of 4.5% for 2025/26. IGU's witness Mr. Bowman also raised the possibility that the Board could consider an upward revision of the 2024/25 increase if it was to conclude that existing and future rate pressures create more risk.

IGU points out that the November 1, 2024 rates would have been different if Centra's 2024 Volume Forecast and 2024 Depreciation study had been available. The volume forecast is a significant input into the cost of service study, which is used to allocate costs to each customer class, as described in section 8.0 of this order. As such, the class-specific rates for November 1, 2024 should be rebalanced and finalized based on the revised information, with a rate rider to reflect the differences between the November 1, 2024 rates and those based on the updated documents.

3.7 Board Findings

3.7.1 *Multi-Year Rate Approval*

The Board's mandate requires balancing the interests of ratepayers against the financial health of Centra. In the Board's view, this requires the approval of a multi-year rate path.

In the past, the Board has approved a net income of \$3 million per year and a corporate allocation of \$12 million. The Board is not prepared to revise its interim rate approval for November 1, 2024 to allow Centra to achieve \$3 million in net income immediately. However, the Board finds that it is in the public interest to consider a three-year rate period and set rates so that, in total, Centra's projected net income during the three-year rate period is positive under normal weather conditions.

The Board finds that, in order to achieve this objective, it is just and reasonable to approve an amount higher than Centra's recommended rate path and higher than recommended by the interveners. The Board approves the following general revenue increases:

- **4.5%** effective November 1, 2024 (which finalizes the existing interim increase);
- **4.5%** effective November 1, 2025; and
- **4.0%** effective November 1, 2026.

There is precedent for the Board's approach. In Manitoba Hydro's 2003/04 General Rate Application, the Board approved a 5% one-year increase when the utility sought 3%. Similarly, in Manitoba Public Insurance's application for compulsory 2025/26 driver and vehicle insurance premiums, the Board approved a 5.7% increase when the insurance company had applied for only 3.0%. The Board makes such rulings when it believes that a rate-regulated entity is understating its rate request in a manner that does not adequately protect the financial health of that entity. While they are rare, these rulings highlight the Board's public interest mandate — a mandate that may lead to the Board adjusting rates either upward or downward if doing so is in the public interest.

In the current application, the Board sees Centra's financial situation as requiring decisive rate action. As set out above, returning the utility to a net income of \$3 million would require a one-time 14.1% rate increase. Such a one-time increase is not acceptable to the Board if it can instead be smoothed in over several years in a manner that leads to more gradual increases and stable rates. The Board observes that gas commodity prices currently remain low compared to historical levels, which mitigates the effect of the approved increases on the overall bills paid by ratepayers.

As pointed out by CAC, a six-year delay between general rate applications means that the Board is put into the unfortunate position of needing to resolve overlapping issues, including multiple revenue requirement adjustments proposed by both Centra and interveners. However, the Board's starting point is Centra's base case, which shows that, even with its proposed three-year rate path, the utility still expects a cumulative \$23 million loss over the rate period. In the Board's view, this is not an approach that adequately protects the financial health of the utility.

Currently, Centra's plans for the future financial integration with Manitoba Hydro are speculative. Centra is already integrated with Manitoba Hydro in terms of staffing, debt

financing, and internal reporting. During the hearing, Centra was unable to fully explain what additional integration would entail and how it would affect the utility. In this context, the Board considers it to be in the public interest to continue to regulate Centra as a standalone utility, commensurate with the utility's importance in meeting Manitoba's energy needs. Since Centra can provide 1.5 times the equivalent capacity of the electrical system, Manitoba's winter energy needs cannot currently be met without Centra. The Board's perspective is that this requires a coordinated multi-year approach to return Centra to a healthy financial footing. The Board notes that, while it approves a rate path higher than recommended by the parties, collectively those increases remain below the level of cumulative inflation since the last general rate application.

In this hearing, the Board dealt with numerous proposed adjustments that makes it difficult for the Board to accurately quantify the cumulative impact. As such, the Board will have to rely on a compliance filing by Centra to assess the detailed impacts of each adjustment and the cumulative impact. However, the Board's starting point was a determination to return the utility to a cumulative net positive income over a three-year rate period, with some overall rate smoothing within that period. The Board is further concerned that the reduction in Centra's corporate allocation from \$12 million to \$4 million (see section 4.6) reduces the utility's overall return in a manner not otherwise reflected in net income, even if this is affected by a reduced allocation of financing costs related to the acquisition debt.

As set out in the remaining sections of this order, the Board's ruling is reflective of the following decisions on specific recommendations made by the parties in the course of the hearing that affect Centra's revenue requirement for the period from 2024/25 to 2026/27:

- Increasing the general revenue increase for the 2026/27 fiscal year from 2.75% (the amount assumed by Centra) to 4.0%. The Board expects this to result in an increase to Centra's net income of approximately \$3 million.
- Change the %Activity allocator in Centra's integrated cost allocation methodology to a three-factor allocator, as further discussed in section 5.3.1. Because this recommendation was only made on the day of Mr. Rainkie's oral testimony towards the end of the hearing, the Board was not able to fully explore the financial impact of this change through the information request process. However, based on

estimates provided in the course of the hearing, the Board anticipates the impact of this change to be a reduction to Centra's revenue requirement by between \$4 million and \$6 million per year.

- Disallow \$2.0 million in unsubstantiated administrative costs in each of 2025/26 and 2026/27, as further discussed in section 4.1.5. This measure reduces Centra's revenue requirement by a corresponding amount in each of the two fiscal years.
- Fully remove Centra's head office credit in 2025/26 rather than phase the removal in over several years, as further discussed in section 5.3.2. The Board anticipates the impact of this decision to be a reduction in net income of approximately \$0.5 million in 2025/26 and \$0.8 million in 2026/27.
- Reduce capital spending by \$2 million in each of 2025/26 and 2026/27, as further described in section 7.5.2. Because such costs are capitalized, the Board expects this to have only a minor impact on Centra's revenue requirement during the rate period, reducing the 2026/27 revenue requirement by approximately \$0.2 million.

The anticipated adjustments are summarized in Figure 3.6. Numbers in the table may be rounded and approximate.

	2024/25	2025/26	2026/27
Centra's Forecasted General Revenue Increase	4.5%	4.5%	2.75%
Centra's Forecasted Additional Revenue from Rate Increase (millions)	\$11	\$11	\$8
Rate Path Adjustment Resulting from this Order	–	–	+1.25%
Anticipated Additional Revenue Resulting from Adjusted Rate Path	–	–	\$3
Rate Path Following Adjustment	4.5%	4.5%	4.0%
Assumed Additional Revenue Following Adjustment (millions)	\$11	\$11	\$11
Change to 3-Factor Allocator (mid-point between \$4-6M estimate)	\$5	\$5	\$5
Disallowance of Unsubstantiated Administrative Costs	–	\$2	\$2
Removal of Head Office Credit in 2025/26	–	(\$0.5)	(\$0.8)
Reduction in Capital Spending by \$2 million in 2025/26 & 2026/27	–	–	\$0.2
Centra's Assumed Net Income (\$ millions)	(\$23)	(\$2)	\$5
Anticipated Impact of Changes Approved in this Order	\$5	\$6.5	\$9.4
Anticipated Adjusted Net Income	(\$18)	\$4.5	\$14.4
Anticipated Cumulative 3-Year Adjusted Net Income		\$0.9	

Figure 3.6 — Summary of Adjustments and Anticipated Impact

Based on the anticipated adjustments, the Board expects the likely cumulative net income during the three-year rate period to be positive or near neutral on a weather-normalized basis. While there is uncertainty regarding the actual number, the Board considers it important to avoid a material cumulative loss over the three-year period, which would be likely without additional general revenue increases in 2025/26 and 2026/27. The Board emphasizes that the anticipated cumulative amount remains significantly below the previously approved annual amount of \$3 million, even with the reductions in the corporate allocation and payments to government. As such, the Board accepts the inherent uncertainty in the calculations above, pending a compliance filing by Centra before the first implementation of updated rates starting November 1, 2025. If Centra's net income exceeds what is reflected in the table, the additional income will represent a modest but meaningful step towards rebuilding Centra's retained earnings.

The Board is not making the general revenue increase for 2025/26 and 2026/27 conditional as requested by CAC and IGU. In the Board's view, there has been a sufficient deterioration in Centra's retained earnings that any unanticipated upward adjustment in Centra's net income is unlikely to lead to the approved increases becoming unjust or unreasonable. As evidenced by the current application, the Board has the ability to require the utility to appear before it, as well as the power to review and vary its own orders.

However, the current need to improve Centra's financial situation highlights the importance of submitting regular general rate applications and maintaining a consistent schedule of rate submissions that are not delayed because of Manitoba Hydro's operational mandates and hearings. In particular, the Board sees a need to complete Centra's next general rate application before Manitoba Hydro's Fiscal 2029-2031 General Rate Application, which that utility is legally required to file by March 31, 2028. The Board accordingly directs Centra to file a three-year 2027/28 to 2029/30 General Rate Application before April 1, 2027. A timely multi-year rate application will enable Centra to apply for gradual rate increases that allow the utility to remain financially viable and achieve fair and equitable rates.

The Board notes that, in this order, it is not making a finding that an annual net income of \$3 million remains appropriate. In light of the erosion in Centra's retained earnings and the risks posed by the energy transition, it is possible that a net income of \$3 million is insufficient. Similarly, the Board's ruling in this order should not be seen as an endorsement that the cumulative net income resulting from the Board's ruling is sufficient in the long term. In approving the general revenue increases of 4.5%, 4.5%, and 4.0%, respectively, the Board is motivated by the need to balance rate stability for customers against financial stability for Centra. Accordingly, the Board sets aside Directive 1 of Order 72/22 and instead includes the appropriate level of net income as one of the issues to be addressed in the business plan discussed below.

3.7.2 The Need for a Business Plan

The Board remains stymied by the contrast between Centra's representation that the natural gas utility is of vital importance to Manitoba's energy needs and the period of financial neglect commented on in this order and, previously, in Order 125/24.

As discussed in section 4.1, there has been an increase in operating and administrative costs allocated to Centra, in part because of a revision to Manitoba Hydro's and Centra's management structure. However, despite the increased management costs, there is currently no senior executive specifically in charge of Centra, nor a committee on Manitoba Hydro's board of directors that specifically oversees Centra. Business planning and financial oversight are easy to neglect when electric assets represent 97% of Manitoba Hydro and are routinely prioritized over Centra's business needs.

In the Board's view, Manitoba Hydro's overall corporate strategy does not sufficiently address Centra's specific risks and needs. The Board accordingly directs Centra to develop, and file with the Board by April 1, 2027, a Centra-specific business plan. The business plan should, in addition to any other matters, address the following issues:

- Centra's strategy for satisfying existing and future service requirements, including whether the utility will continue to expand its service territory and customer base or plans to restrict its operations in light of the provincial government's intention to transition towards a carbon-neutral economy;

- a management structure with a clear chain of accountability for administrative and regulatory decisions affecting natural gas operations and management approval levels that are tailored to the relative size of Centra and the materiality of decisions to Centra;
- a financial strategy that includes, among other things:
 - a proposed approach to setting an annual net income level appropriate for Centra and that will be included in the utility's revenue requirement, and
 - a regulatory strategy for returning Centra to a sustainable rate path and regular rate applications;
- the appropriate cost allocation methodology in light of Manitoba Hydro's future major initiatives needing to be contrasted against Centra's mature and relatively stable operations;
- business risks posed by the energy transition, including the following:
 - the risk of stranded assets and the impact, if any, on appropriate depreciation rates and amortization periods, and
 - the risk posed by increasing the number of regulatory deferral accounts, and the balances in those accounts, at a time of flattening or decreasing natural gas volumes;
- appropriate financial metrics and financial targets for the utility, including the role, if any, of retained earnings in natural gas operations; and
- the appropriate amount of insurance coverage for Centra and allocation of insurance costs to Centra.

In light of the above, the Board sets aside Directive 31 of Order 152/19 and replaces it with the new directive regarding Centra's business plan.

4.0 REVENUE REQUIREMENT

In setting rates, the Board reviews Centra's revenue requirement. The revenue requirement consists of projections of revenue and expense items, as well as Centra's proposed amount of net income, which together form the basis of a request by Centra to increase or change the amount of revenues collected from consumers in rates that are in effect at that time. Centra's revenue requirement includes gas costs, or the costs associated with purchasing, storing, and transporting the commodity, as well as non-gas costs, or the costs to build, operate, and maintain Centra's network of pipes as well as customer service-associated costs.

This section focuses on Centra's non-gas costs. Centra's gas costs are addressed separately in section 6.0 of this order. Centra's non-gas revenue requirement consists of operating and administrative expenses, finance expense, depreciation and amortization expense, capital & other taxes, other expenses, the corporate allocation, and an approved net income amount. The appropriate level of net income is discussed separately in section 3.0.

4.1 Operating and Administrative Expenses

4.1.1 *Introduction*

Centra's operating and administrative expenses consist primarily of labour and benefits, materials, contracted services, and overhead costs associated with operating and maintaining facilities and providing services to customers. As a wholly-owned subsidiary of Manitoba Hydro whose operations are integrated within the organizational structure of Manitoba Hydro, operating and administrative expenses are allocated between Centra and Manitoba Hydro through the corporation's Integrated Cost Allocation Methodology, which is further addressed in section 5.0.

Operating and administrative expenses are Centra's biggest expense category, representing between 45-50% of Centra's non-gas expenses during the 2024/25, 2025/26, and 2026/27 fiscal years. Since the last general rate application, there has been a significant increase in Centra's operating and administrative expenses, as illustrated in

Figure 4.1. Following a reduction over several years, beginning in the 2019/20 fiscal year, total operating and administrative expenses allocated to Centra increased from \$58 million to an estimated \$86.1 million during the 2024/25 test year, which represents an increase of 48%. Over six years, the increase amounts to approximately 8% annually. For future years, beginning with 2025/26, the utility assumes a 2% inflationary escalation. Centra notes that the Consumer Price Index (CPI) has risen by 21% since the 2018/19 fiscal year.

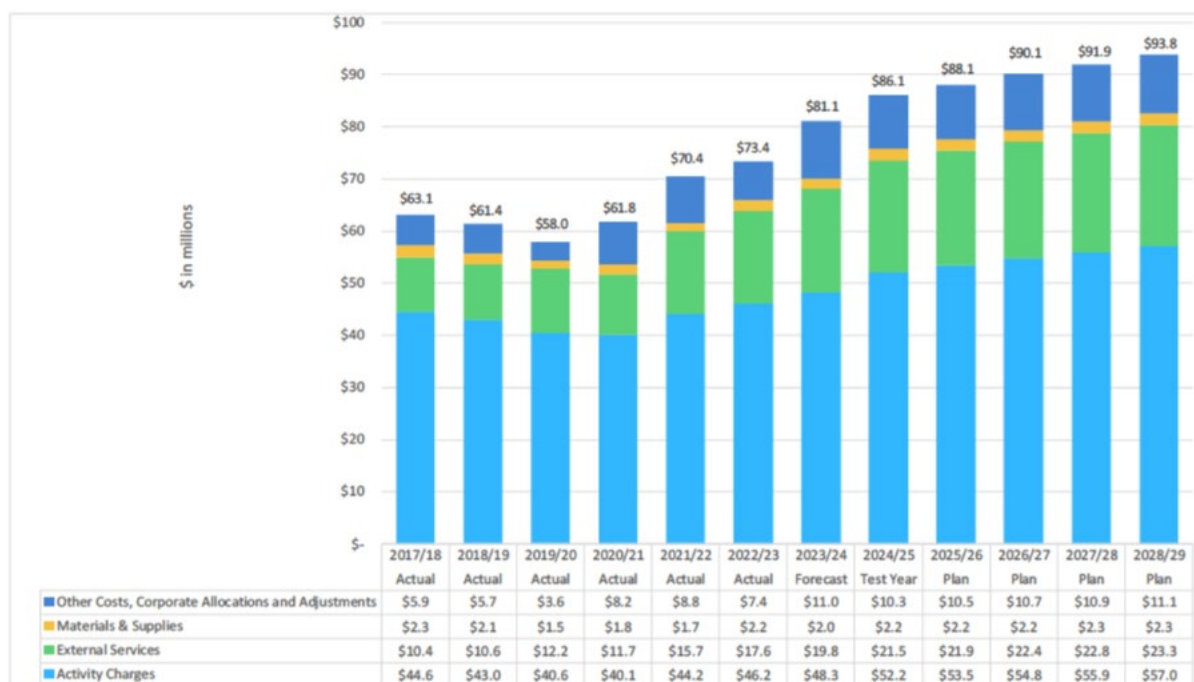


Figure 4.1 — Evolution of Centra’s Operating and Administrative Expenditures

4.1.2 Activity Charges

Approximately 60% of Centra’s operating and administrative expenses relates to activity charges, which includes wages, salaries, overtime and employee benefits, as well as safety, travel motor vehicles and office expenses. As explained in section 5.0, Centra does not have its own employees. All work is performed by Manitoba Hydro employees and charged to Centra through a combination of direct cost assignment and shared cost allocation by way of the %Activity driver, which currently assigns 9% of those costs to Centra.

Total activity hours charged to the natural gas utility have increased by 12% since 2018/19. According to Centra, the increase was required to ensure safety, reliability and the advancement of strategic initiatives.

Centra considers 1,916 hours per year to amount to one full time equivalent, or FTE. On a straight-time basis (i.e., excluding overtime), Centra's FTEs grew from 245 in 2019/20 to 280 during the 2024/25 test year.

Centra notes that approximately 80% of Manitoba Hydro employees are unionized. Since Centra's last general rate application, Manitoba Hydro has experienced three labour disruptions, involving strikes in 2021, 2022, and 2023. The unionized workforce has been able to achieve wage increases, through either settlement or arbitration, every year since 2019. In addition, eligible employees receive merit and progression increases as they advance in their careers. The combined increase in wages and salaries through these factors during the 2024/25 test year is 6%.

CAC's witness, Mr. Rainkie, opined that the majority of a utility's operating and administrative expenses are within its control. According to Mr. Rainkie, the increase in operating and administrative expenses between 2019/20 and 2024/25 represents 70% of the increase in Centra's non-gas expenses. Of these 70%, 43% relates to the increase in organizational support costs discussed in section 5.0.

Organizational support costs fall into five main program categories:

- Corporate Governance: This program includes costs associated with strategic planning and governance, legal compliance and liability claims, risk management, internal audit reviews and recommendations, treasury, corporate communication, and maintaining industry memberships.
- Corporate Infrastructure: This program includes costs associated with operating and maintaining administrative assets such as office buildings, IT infrastructure, and small tools & work equipment.
- Corporate Services: This program includes costs associated with corporate services that provide support and guidance to the operational areas of the

company, including human resources, financial advisory services, accounts payable, and workplace safety.

- Departmental Support: This program includes costs for providing training and administrative support related to employees, excluding any support costs captured under corporate governance, corporate infrastructure, and corporate services.
- Operational Management: This program includes the costs associated with directors and managers that support and work directly with field operations staff.

Mr. Rainkie highlighted that organizational support costs have increased 110% since the last general rate application, which represents an annualized increase of 16% per year and are a major factor in the weakening of Centra's financial position. Among other amounts, the increase to organizational support costs from 2019/20 to 2024/25 includes a \$2.7 million increase to corporate governance costs and a \$6.2 million increase in departmental support costs.

Corporate governance costs are largely allocated through the integrated cost allocation methodology discussed in section 5.0, with \$700,000 out of \$5.1 million being directly assigned. The increase to corporate governance costs is discussed in more detail in that section.

In contrast, for departmental support costs, there has been a shift in the allocation process since the last general rate application. Until the 2020/21 fiscal year, Centra received no direct assignment of any departmental support costs. In 2019/20, the test year for Centra's last general rate application, the utility was allocated a total of \$4.8 million of such costs through the shared allocators in the integrated cost allocation methodology. By 2024/25, the test year for the current application, the total assigned departmental support costs increased to \$11 million, including a \$5.7 million direct assignment.

The increase in departmental support costs from \$4.8 million in 2019/20 to \$11 million in 2024/25 includes a \$4.7 million increase in administrative support costs. Centra notes that those cost increases relate to administrative activities such as time spent on operational initiatives, preparing training, documenting processes, process improvement, general meetings within each section, department, division and business unit, as well as

the impact of increasing wages. As set out below, while CAC expresses concern about the overall rise in operating & administrative expenses, it is particularly critical about the \$4.7 million of administrative support costs.

4.1.3 External Services

Centra's external service costs have increased from \$12.2 million in 2019/20 to \$21.5 million during the 2024/25 test year. The utility notes that, over the years, it has increasingly utilized external services. A significant portion of the increase relates to addressing a perceived information technology debt and the transition of software services to the cloud. The utility notes that many of the traditional information technology ("IT") products used by Manitoba Hydro will no longer be supported by vendors in the near future. Those products are transitioning to cloud-based products requiring a subscription fee. Cloud-based services provide information technology over the internet, rather than through purchased on-premises software.

Accounting rules under International Financial Reporting Standards ("IFRS") also do not allow cloud computing expenses, including integration costs incurred to implement cloud-based solutions, to be treated as capital expenditures in the same manner as owned software. The need for Centra to deal with IT transition has contributed to the increase in external service costs since the last general rate application. As set out in section 4.3.6., Centra requests approval from the Board to establish a cloud computing regulatory deferral account for such expenses.

The increase in external service costs also includes a 43% increase in meter reading costs by Manitoba Hydro Utility Services and an increase in insurance premiums as a result of an overall increase in Canadian insurance premiums resulting from the COVID-19 pandemic, increasing cyberattacks, and various natural disasters. Centra notes that its insurance premiums have doubled since the last general rate application because of challenging insurance market conditions. In addition, Centra has incurred increased environmental management costs, which are related primarily to remediation obligations at Centra's former manufactured gas plant on Sutherland Avenue in Winnipeg under *The Contaminated Sites Remediation Act*.

4.1.4 Position of the Parties

Centra

Overall, Centra submits that operating and administrative costs are prudently incurred to meet operational, safety, and regulatory requirements, which aligns with its mandate and industry standards. The utility remains committed to effectively managing its costs. However, several factors such as labour disruptions and bargaining unit settlements, the need to expense cloud-based information technology solutions, and a high inflationary environment since 2020, are driving cost increases.

Centra states that it is important to consider its operating and administrative expenses within the context of the consolidated operations of Manitoba Hydro, given that the natural gas operations are fully integrated into the consolidated operations. The utility notes that, in Order 101/23 relating to Manitoba Hydro's last general rate application, the Board approved Manitoba Hydro's operating & administrative expense budget of \$830 million for 2024/25, and that Centra's \$86 million portion of those expenses represents approximately 10%. Centra emphasizes that, in Order 101/23, the Board also found Manitoba Hydro's proposed staffing level and expenses for small software systems to be reasonable and accepted that costs were increasing as a result of increased staffing levels and wage increases.

Centra notes that, on average, approximately 60% of its operating and administrative expenses, totalling \$51 million of its \$86 million, are directly assigned to natural gas operations. The utility suggests that there was little to no dispute in this proceeding regarding the directly assigned costs.

Centra disagrees with Mr. Rainkie's suggestion that organizational support costs have increased too much. The utility points to its evidence that the cost increases resulted from an increase in activity charges related to wage and cost increases, an increase in the volume of work to manage the safety of the system, an increase in the cost allocation through changes in the cost driver percentages of the integrated cost allocation methodology, and the required increase in external services.

Regarding the increase in corporate governance costs, Centra states that the increase relates to an increase in FTEs for projects such as digital & technology transformation and enterprise strategy, as well as increased insurance & liability claims, strategic initiatives, wage increases, and a percentage change to the %Hybrid driver.

Regarding the increase in departmental support costs, Centra states that the increase relates to a shift in administrative activities related to time spent on operational activities, preparing training, documenting processes, process improvement, general meetings, and the impact of increasing wages and employee-related costs. In addition, there was an increase in training costs, both for human resources and the trades.

Centra submits that the FTE increases in various support groups of the utility are not due to “dropping the ball” by anyone in the corporation, but rather are caused by legitimate business requirements that have resulted in FTE increases. As examples, Centra cites the following:

- increases in the Digital & Technology program focusing on cybersecurity and digital enhancements;
- increases in the Chief Financial Officer business unit focusing on rebuilding the accounting interns trainee program;
- increases in accounts payable, procurement and the Rates & Regulatory business unit;
- increases in the Human Resources and Safety, Health, Environment business unit related to talent management, including recruitment and HR Support Services; and
- increases in the Safety business unit, which includes the trades trainee program.

Centra emphasizes that there is increased value to gas customers following Centra’s reorganization, as Manitoba Hydro’s organizational structure has moved away from functional segments such as Generation, Transmission, and Distribution, where responsibility for the gas function was contained in a single business unit, toward a more integrated approach. While Centra acknowledges that the corporate reorganization has resulted in more costs being allocated to the natural gas utility, it states that the

reorganization allows the utility to work more effectively to focus on priority items and has resulted in greater sharing and oversight at the vice-president level.

Centra states that it seriously considers its system performance and safety obligations while balancing risk. The utility submits that Manitoba Hydro's operations are complex and cannot be abruptly adjusted to achieve cost savings.

Centra resists CAC's submission that approximately \$4.7 million in organizational support costs should be disallowed for the test years. According to the utility, such a directive would be punitive given that the costs were prudently incurred and would exacerbate Centra's poor financial health on a standalone basis.

Consumers Association of Canada

In CAC's submission, Centra has not maintained an appropriate level of FTEs since the last general rate application. CAC contends that the Voluntary Departure Program (VDP) was a long-term strategy and was not intended as a temporary reduction leading to the number of FTEs to be increased back to the pre-VDP level. CAC emphasizes that Centra is a mature operation, and that ratepayers should not be subjected to rates that reflect a large increase in controllable costs when the service to customers has not demonstrably changed or improved.

CAC is also critical of the increase in organizational support costs. In CAC's view, in the context of an environment of flat or declining revenue, a 110% increase to such costs since the last general rate application is excessive, and Centra did not justify the need for such an increase. According to CAC, these cost increases ignore the fact that Centra is captive within Manitoba Hydro, has no service level agreement, no protection from cost escalation, and nobody independently looking after Centra's interests. This suggests that, in implementing its corporate reorganization, Manitoba Hydro's leadership has ignored the negative impact of the cost increases to Centra's retained earnings.

With respect to the \$4.7 million increase in administrative support costs, CAC argues that there has been no cogent explanation as to why those costs are necessary and that Centra has not met the onus of proof required to justify those costs. In CAC's view, those

costs are a residual hangover without an identifiable allocation source or the result of a corporate reorganization under which dedicated gas departments now report to more than one business unit. CAC accordingly recommends that, for the 2024/25 test year and each of the two following fiscal years, the Board disallow \$5 million of unsupported administrative support costs.

CAC also argues that there has been an over-allocation of organizational support costs to Centra through the integrated cost allocation methodology and recommends changes to that methodology.

4.1.5 Board Findings

The Board is concerned about the increase in Centra's operating and administrative expenses since the last general rate application. An annualized increase of 8% is not sustainable. The Board finds that this is especially problematic for a utility in Centra's financial position, even if the utility succeeds in capping these increases at 2% going forward.

In assessing the prudence of Centra's operating and administrative expenses, the Board finds comparisons to Manitoba Hydro, and the Board's ruling in Order 101/23, to be of limited use. Manitoba Hydro has been undergoing a major strategic initiative related to a build-out of the electric system as part of the energy transition. In contrast, Centra is a natural gas distribution company with flat or declining sales and only incremental additions to its rate base. It is a mature operation rather than a growth-oriented company.

The Board accepts the need to train new tradespeople, as well as the need to retain external service providers to deal with information technology transitions and to pay increased insurance premiums. However, it notes that the Voluntary Departure Program initiated in 2016, under which Manitoba Hydro provided incentives for employees to voluntarily leave the organization in order to reduce the utility's labour force, was not intended as a temporary reduction in headcount, but as a long-term cost control measure. The Board also does not accept a doubling of organizational support costs since the last general rate application. This increase is disproportionate for a utility that operates in

largely the same manner as it did in 2019/20. Centra currently does not have a gas-specific business plan and was allowed to accrue multiple years of escalating losses without demonstrated cost reduction efforts or requests for rate relief. The Board finds that the benefit of Manitoba Hydro's corporate restructuring to Centra has been limited and not commensurate with the resulting increase in costs. If anything, Centra currently appears to not be receiving the required attention, as issues important to Centra are overshadowed by the priorities of Manitoba Hydro and that utility's electric ratepayers.

As set out in section 5.0, the Board directs Centra to revise its integrated cost allocation methodology to use a three-factor allocator to allocate certain common costs, the effect of which is to reduce the relative percentage of costs allocated to Centra. In the Board's view, such a factor is more commensurate with the relative strategic and operational emphasis given to Centra on the one hand and Manitoba Hydro's electric operations on the other hand.

However, the Board is also concerned about the increased direct assignment of departmental support costs to Centra, from nothing at the time of the last general rate application to \$5.7 million in the 2024/25 test year. Together with the portion of departmental support costs allocated through the integrated cost allocation methodology, the direct assignment has resulted in a doubling of this cost category. The Board agrees with Mr. Rainkie's assessment that the increase in administrative costs within this cost category has not been adequately justified.

After considering the escalation of operating and administrative expenses in their totality, as well as the doubling of departmental support costs since the last general rate application, the Board disallows \$2 million in directly assigned operating and administrative expenses during each of the 2025/26 and 2026/27 fiscal years. However, in light of the 2024/25 test year already having concluded, the Board is not retrospectively disallowing such expenses during that year. While the Board's ruling is strongly influenced by the escalation in departmental support costs, the Board is not directing Centra on how it is to achieve the reduction which, based on the \$51 million of directly assigned costs during the 2024/25 test year, amounts to a disallowance of approximately 4% of such

costs. For certainty, this reduction is in addition to any reduction in shared costs from the Board-directed changes to the integrated cost allocation methodology.

4.2 Finance Expense

4.2.1 Introduction

Centra does not borrow based on its own financial strength. Rather, Centra's debt is placed by Manitoba Hydro, the utility's parent company, as part of Manitoba Hydro's consolidated debt strategy. Centra pays the same 0.5% Provincial Debt Guarantee Fee on long and short-term advances that Manitoba Hydro is required to pay on its debt. In addition to covering capital, operational, and demand-side management expenditures, Centra also accesses short-term debt from Manitoba Hydro for seasonal gas inventory purchases, with interest rates based on Manitoba Hydro's short-term Canadian dollar financing costs.

Centra has been incurring increasing finance expenses since the last general rate application, largely as a result of a rising debt balance because of the utility's increasing cash deficits over several years. As a result of Centra having operated at a loss position for multiple years in a row, the utility's debt level has increased to a higher level than projected at the last general rate application, as shown in Figure 4.2.

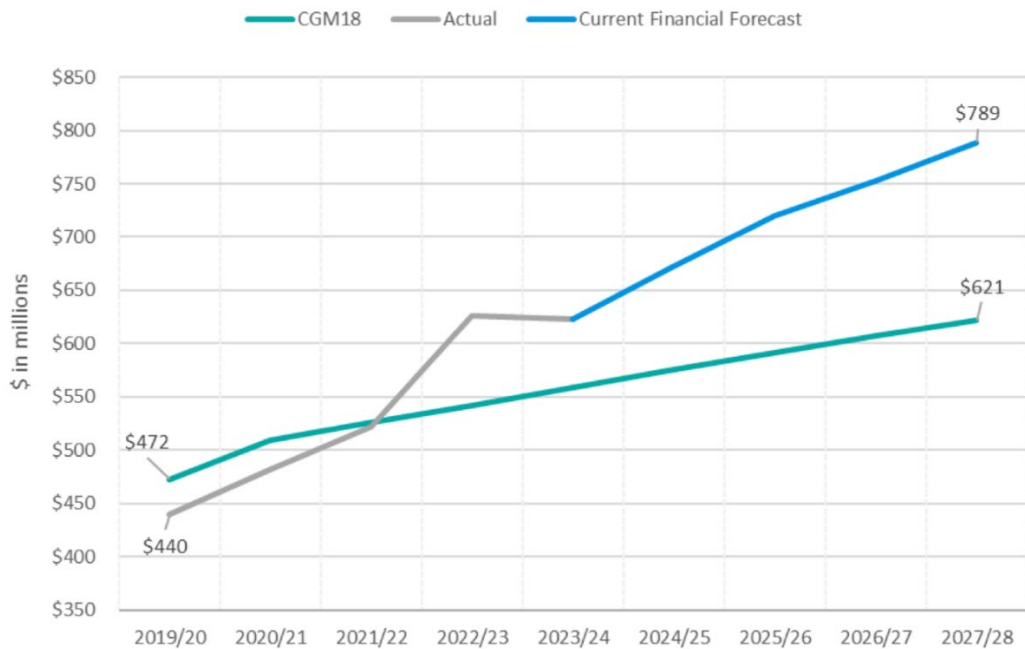


Figure 4.2 — Net Debt Compared to Projection at Last General Rate Application

Centra's overall debt level represented 2.6% of Manitoba Hydro's consolidated debt at the beginning of the 2024/25 test year. Although credit rating agencies have not raised a concern regarding Centra's performance to date or requested Centra-specific information, Centra is concerned that repeated net losses, an erosion of retained earnings, and flat long-term projections for natural gas consumption signal a utility in poor financial health.

In the wake of interest rate reductions during the COVID-19 pandemic, Centra's weighted average interest rate on the utility's debt decreased to a historic low of 3.3% in March 2022. However, since that time, the rate has been increasing and is currently at approximately 4.0%, an amount that the utility expects to remain largely stable in the near term.

As a result of Centra's increasing debt load and the increase in interest rates since the post-pandemic low, the utility's annual finance expense level has increased from \$22 million in 2019/20 to \$31 million during the 2024/25 test year, as shown in Figure 4.3.

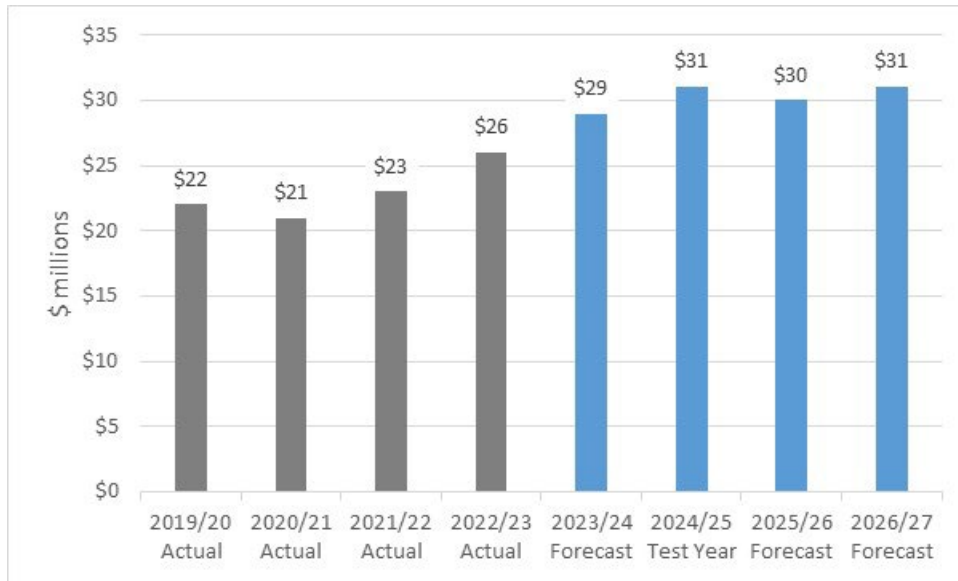


Figure 4.3 — Annual Finance Expense

4.2.2 *Impact of Government Relief*

Manitoba Hydro benefits from a debt guarantee by the Province of Manitoba and, in exchange, pays a Provincial Debt Guarantee Fee. Centra needs to pay this fee both on long-term and short-term intercompany advances. Until recently, the Provincial Debt Guarantee Fee was 1.0% of the outstanding debt before being lowered to 0.5% in 2022. However, on March 20, 2025, the provincial government announced an additional decrease in the Provincial Debt Guarantee Fee from 0.5% to 0.4% on April 1, 2025, with further reductions to 0.3% on April 1, 2026 and 0.15% on April 1, 2027. While the 2025 provincial budget did not include the 2026 and 2027 reductions, Centra confirmed that those reductions were approved by the provincial Treasury Board.

Effective April 1, 2025, the provincial government also eliminated the Corporations Capital Tax for Crown corporations, providing Manitoba Hydro and Centra with additional savings. The combined effect of the reduction in the guarantee fee and the elimination of the capital tax is to largely offset the anticipated growth in Centra's finance expense, both by reducing the cost of Centra's existing debt and by reducing the amount of new debt required. The resulting savings are illustrated in Figure 4.4, which shows \$163 million of

cumulative savings from the government’s decisions as well as \$72 million in resulting cumulative financing savings.

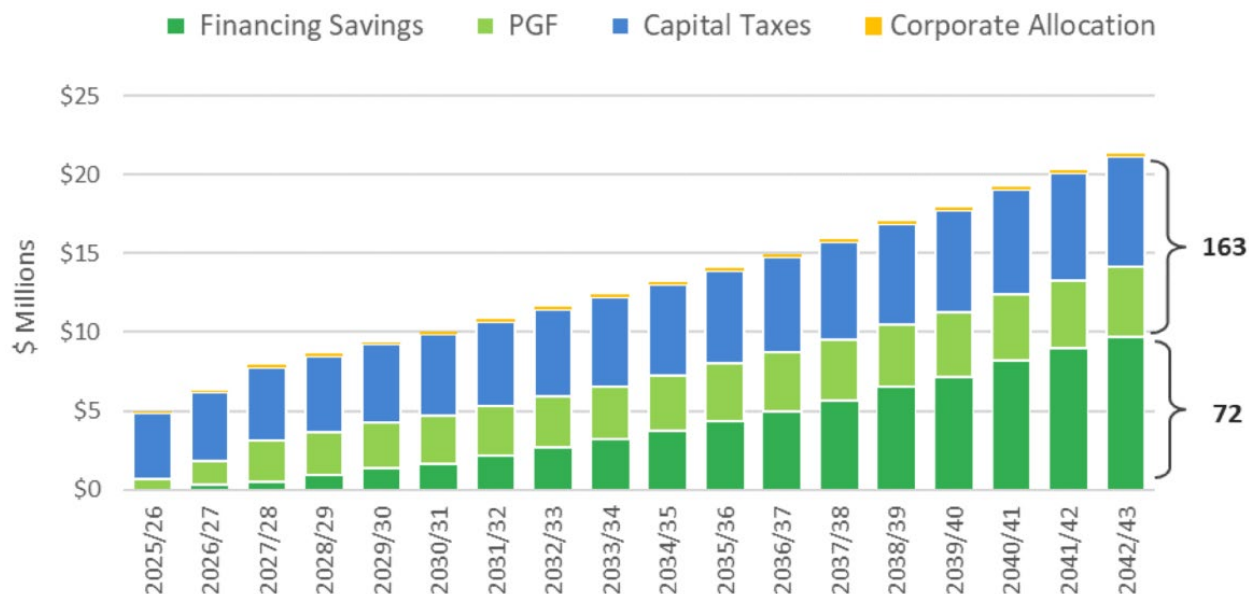


Figure 4.4 — Savings Resulting from Government Relief

Because of the savings, the originally projected growth in Centra’s finance expense is largely offset in the near term, remaining at \$31 million per year or less until the end of the 2026/27 fiscal year. However, in light of Centra’s planned capital investments, this amount is set to increase to \$39 million per year by 2032/33, despite a slight reduction in the projected interest rates since the filing of Centra’s application.

4.2.3 Debt Management Strategy

On average, approximately \$22 million of Centra’s debt matures every year and needs to be refinanced. To manage refinancing risk, Centra currently maintains a weighted average term to maturity for its debt portfolio of over 14 years. To the extent possible, the utility plans to smooth the debt maturity schedule and reduce concentration risk to ensure that no more than 10% of the utility’s debt matures in any 12-month period.

Manitoba Hydro manages its financing requirements on a consolidated basis. This includes maintaining the ratio of floating rate and short-term debt compared to fixed-rate debt within an acceptable range. In 2022, Manitoba Hydro adopted a policy that limits

variable and short-term debt to a range of 0-20% of the utility's overall debt load. In practice, Manitoba Hydro has not issued long-term floating rate debt in several years, but has chosen instead to maintain an increased amount of short-term debt to remain near 15% variable debt. Manitoba Hydro has commissioned an external study to review its interest rate risk policy and guidelines. In this hearing, Centra confirmed that the study will separately assess interest rate risk policies for Centra.

4.2.4 Position of the Parties

Centra

Centra states that its decreased ability to rely on cash from operations has resulted in increased borrowing, increased finance expense, and, because of the overall increase in debt, increased interest rate risk. According to the utility, while Centra's debt is small compared to the consolidated debt of Manitoba Hydro, credit rating agencies may become concerned if Centra's financial health continues to deteriorate.

Consumers' Association of Canada

According to CAC, there is no debate about the diminution of Centra's financial picture since 2020 and the utility's downward financial trajectory. However, CAC submits that credit rating agencies do not discretely consider Centra's net debt in assessing Manitoba Hydro's consolidated credit rating. However, CAC recommends that the Board direct an independent review of Centra's debt management strategy and interest risk policy to assess the appropriate levels of variable and fixed-rate debt, similar to recommendations made by CAC's witness, Mr. Rainkie, in the last Manitoba Hydro general rate application.

4.2.5 Board Findings

The Board accepts, for the purpose of establishing Centra's revenue requirement, the utility's projected finance expense of \$31 million during the 2024/25 test year, \$30 million during the 2025/26 fiscal year, and \$31 million during the 2026/27 fiscal year. The Board notes that the increase in finance expense is largely the result of having operated in a deficit position several years in a row. This highlights the need for regulatory action by the Board beyond the 2024/25 test year to return Centra to a sustainable financial position.

At this time, the Board does not see a need to direct an independent review of Centra's debt management strategy and interest risk policy, in light of Centra's representation that Manitoba Hydro's study will already include Centra-specific recommendations.

4.3 Depreciation and Amortization

4.3.1 Introduction

Utilities recover the capital cost of their investments through depreciation expense recovered through rates during the projected useful life of those investments. The Board must approve those depreciation rates under subsection 78(2) of *The Public Utilities Board Act*.

To determine appropriate depreciation rates, Centra commissions periodic depreciation studies that group assets into different classes depending on the service lives and depreciation criteria of the assets. Centra generally obtains a new study every five years. In the 2019/20 General Rate Application, the Board approved depreciation rates based on the 2014 Depreciation Study. In this application, Centra originally sought approval to establish depreciation rates based on its 2019 Depreciation study. However, Centra subsequently filed its 2024 Depreciation Study during the hearing and proposes to establish depreciation rates based on the new study instead. The utility seeks the approvals described in sections 4.3.2 to 4.3.6 below.

4.3.2 Amortization Period for Loss on Retirement or Disposal of Assets Account

Depreciation studies consider assets by group and depreciate the group as a whole. As such, it is possible for an asset (such as a damaged natural gas main) to be removed from service before it has been fully depreciated. When this happens, Centra accrues the undepreciated capital cost in a deferral account called Loss on Retirement or Disposal of Assets. Centra currently amortizes the amounts in that account over a period of five years. In Order 101/23, the Board approved an amortization period for the Loss on Retirement or Disposal of Assets account for Manitoba Hydro's electric operations based on the weighted average life of the assets contributing to the account. Centra is proposing a similar approach for its natural gas operations and seeks approval to base the

amortization on the weighted average life of the assets contributing to Centra's account. While Centra's original application sought approval to amortize the account over 28 years, Centra subsequently reduced the requested amortization period to 27 years, based on the 2024 Depreciation Study discussed below.

4.3.3 Depreciation Rates Based on 2024 Depreciation Study

While Centra initially filed its application based on its 2019 Depreciation Study, the utility subsequently filed its 2024 Depreciation Study and amended its application to seek approval based on the depreciation rates set out in that study. Under the 2024 Depreciation Study, annual depreciation expense during the test year is \$243,000 lower than under the 2019 study. On a tentative basis, Centra applied this reduction to increase its net income during the 2024/25 test year rather than revising its revenue requirement. Apart from the Special Contract class (for which the Board received information in confidence), the new study does not create any significant impact to customer classes. For the Special Contract class, the study results in a decrease in depreciation expense as a result of the average service life for in-line inspections being extended from 5 years to 10 years.

4.3.4 Amortization of Difference Between 2019 and 2024 Studies

When Centra obtains a new depreciation study, it records the difference in accrued depreciation expense in a deferral account and generally requests approval to amortize that account over a period of five years. Since Centra's last general rate application in 2019/20 was based on the 2014 Depreciation Study, Centra proposes to amortize two deferral accounts — one that captures the difference between the 2014 and 2019 studies and one that captures the difference between the 2019 and 2024 studies.

4.3.5 Four New Depreciation Accounts

Centra's depreciation study is based on Canadian Generally Accepted Accounting Principles ("CGAAP"), not IFRS. However, Centra seeks approval to create two new deferral accounts in the 2024 study for mechanical and electric meters as part of its attempt to make the study IFRS-compliant and to recognize differences in service lives due to technological obsolescence and availability of replacement parts associated with

electric meters. In addition, Centra seeks the Board's approval to establish two accounts to capture and amortize obligations accrued under the Manitoba Metis Federal Revitalization Fund Agreement. The agreement was established to mitigate the adverse effects related to existing development and operations on the Red River Metis and was implemented in 2023/24. While the agreement was signed by Manitoba Hydro rather than Centra, it applies to both electric and natural gas operations. As such, Centra is currently being allocated three percent of the total cost of the Manitoba Metis Federation Revitalization Fund using the %Assets allocator described in section 5.0.

4.3.6 Cloud Computing Deferral Account

Centra seeks approval to establish a Cloud Computing Regulatory Deferral Account related to its small information technology systems and to amortize that account over six years, which reflects the expected service life of these cloud-based solutions.

Centra states that the new account is required because of the shift away from on-premise IT solutions, which are capitalized and depreciated over their expected life, towards cloud-based solutions that need to be expensed under IFRS accounting rules. A regulatory deferral account approved by the Board would allow Centra to treat the expenditures in a similar manner to on-premise IT solutions. This would promote fairness to customers by matching the recognition of expenses to the period in which the associated investments provide benefits. Centra further notes that similar cloud computing deferral accounts have been approved by the British Columbia Utilities Commission and the Ontario Energy Board.

At this time, the proposed cloud computing deferral account would only address the operating and administrative costs allocated to Centra that are related to the setup of its small system solutions. The company's cloud computing arrangement costs related to major shared systems such as SAP or Banner will be addressed in a future regulatory process once the business cases are completed.

4.3.7 Change in Depreciation Method Deferral Account

With the adoption of IFRS, Manitoba Hydro decided to adopt the Equal Life Group (“ELG”) methodology of calculating depreciation, since Manitoba Hydro concluded that the previously used Average Service Life (“ASL”) methodology was not IFRS-compliant. Under the ELG methodology, assets are grouped by lifespan rather than asset type. For successive Manitoba Hydro general rate applications, the Board indicated that it was not prepared to approve ELG for rate-setting purposes until Manitoba Hydro had filed a comparison study contrasting depreciation rates against the previously used ASL methodology. The ASL methodology groups assets by type and then determines the average expected life span of each asset class.

While the issue of the appropriate depreciation methodology was pending, Manitoba Hydro established a Change in Depreciation Method Deferral Account to record the difference between depreciation expense calculated under the ELG and ASL methodologies. Since ELG rates were consistently higher than ASL rates when Manitoba used both methodologies (ELG for financial reporting and ASL for rate-setting), the deferral account accumulated a deferred depreciation expense that Manitoba Hydro sought to amortize and recover over 30 years. In the 2023/24 & 2024/25 Manitoba Hydro General Rate Application, the Board directed Manitoba Hydro to continue using the ASL method for depreciation. The Board, in Order 101/23, also denied the amortization of Manitoba Hydro’s Change in Depreciation Methodology Deferral Account, ruling that:

In light of the Board’s directive to continue to determine depreciation expense for rate-setting purposes through the ASL methodology, the recovery of a deferral account capturing the difference between that methodology and the ELG methodology is denied. To the extent depreciation is determined by the 2019 ASL depreciation rates, the account is notional, as the appropriate amount of depreciation expense is already being recovered through rates.

For Centra, the Board issued a directive in Order 152/19 requiring that utility to keep using the ASL methodology, and to not amortize the difference between ELG and ASL depreciation, until Centra had filed an IFRS-compliant ASL study. In the interim, Centra

kept accruing expenditures in a Change in Depreciation Method deferral account. During the time that Centra operated the account, it accrued a total of \$17.6 million.

In this application, the utility is not formally seeking recovery of the Change in Depreciation Method deferral account. Instead, Centra has adjusted its accrued depreciation and seeks to recover the \$17.6 million through the depreciation rates resulting from the 2024 Depreciation study. However, Manitoba Hydro is currently seeking such approval for its electric operations in that utility's 2026-2028 General Rate Application, and Centra advises that it may seek consistent treatment in the future.

4.3.8 *Position of the Parties*

Centra

Centra notes that that IGU's witness, Mr. Bowman, concluded that the depreciation proposals are appropriately structured and that none of the parties to the proceeding have opposed Centra's depreciation proposals, regulatory deferrals, or proposed amortization periods.

With respect to the proposed Cloud Computing Regulatory Deferral Account, Centra submits that the Board has sufficient information on the record to approve the account, and that there is no need to wait for a ruling in the pending Manitoba Hydro 2026-2028 General Rate Application. Centra emphasizes that the proposal for a regulatory deferral account is limited to small systems and does not include the utility's major systems such as SAP or Banner. The utility plans to work with the Board to determine the best approach to gas operations deferral accounts for those major systems following the Board's decision in the upcoming electric rate application.

Consumers' Association of Canada

CAC did not take a position on Centra's depreciation proposals, except for the proposed Cloud Computing Regulatory Deferral Account. In CAC's view, the request should be denied pending the canvassing of that issue at the upcoming Manitoba Hydro 2026-2028 General Rate Application.

Industrial Gas Users

IGU's witness, Mr. Bowman, concluded that Centra's depreciation proposals are appropriately structured. IGU itself did not make submissions on Centra's depreciation proposals.

4.3.9 Board Findings

The Board approves the change in the amortization period on the loss on retirement or disposal of assets from 5 years to 27 years. The Board notes that this change is consistent with a similar change approved for Manitoba Hydro's electric operations in Order 101/23.

The Board approves depreciation expense during the test year, as well as the 2025/26 and 2026/27 fiscal years, to be determined based on the 2024 depreciation study. In light of the significant projected loss during the 2024/25 test year and the low impact of the \$243,000 reduction in depreciation expense compared to Centra's overall depreciation expense of \$32 million during the test year, the Board approves Centra's proposal to treat the reduction as an increase to net income rather than restating the utility's revenue requirement. The Board further approves Centra's proposal to amortize the deferral accounts that capture the differences between the 2014 and 2019 studies and between the 2019 and 2024 studies, respectively.

The Board finds that Centra's approach to the 2024 depreciation study is consistent with the Board's direction to Manitoba Hydro in Order 101/23, namely to utilize the average service life methodology, with the minimum additional componentization required to make the study IFRS-compliant. To that extent, the Board approves the creation of the two new metering accounts. The Board similarly approves the creation of the two new amortization accounts related to Centra's 3% share of the costs related to the MMF Revitalization Agreement.

The Board also approves the creation of Centra's proposed Cloud Computing Deferral Account for small systems, including the proposed deferral of \$1.3 million into the account during the 2024/25 test year and the amortization of the account over six years. The Board finds it necessary to assess the appropriateness of the account for each regulated utility

and does not see a need to defer the decision to the upcoming Manitoba Hydro General Rate Application.

With Centra having filed an IFRS-compliant average service life depreciation study, the Board considers Directive 4 of Order 152/19 complete.

In the medium term, the Board is concerned about the impact of long depreciation periods and increasing deferral account balances on Centra's financial security, particularly in light of the uncertainty posed by the energy transition. Centra is to address this issue in its business plan.

4.4 Capital and Other Taxes

4.4.1 Introduction

Capital and other taxes consist primarily of payments made to the Province of Manitoba for capital and payroll taxes, as well as business and property taxes paid to various municipalities within Manitoba. These taxes include the corporation capital tax, which is calculated at a rate of 0.5% applied to the taxable capital of the company, municipal property taxes based on the assessed value of Centra's property, payroll tax assessed at 2.15% on Manitoba Hydro's gross payroll (allocated to Centra based on activity charges), and taxes on common assets representing Centra's share of property tax on administrative facilities.

During the 2024/25 test year, Centra expects to pay \$19 million in capital and other taxes. Since the last general rate application, there has been an increase in Centra's municipal taxes because of higher assessment values, as well as an increase in capital taxes because of increased debt levels. Payroll taxes have also increased based on the allocation of those taxes through the %Activity driver discussed in section 5.0, which assigned 8% of those taxes to Centra at the last general rate application but increased to 9% in 2021/22.

On March 20, 2025, the government announced that it would phase out the provincial capital tax payable by Crown corporations on April 1, 2025. As a result, Centra will no longer have to pay capital tax for the 2025/26 and 2026/27 fiscal years and projects the

overall amount of capital and other taxes to decrease to \$15 million and \$16 million for those years.

4.4.2 Board Findings

The Board accepts Centra's projected revenue requirement for capital and other taxes for the 2024/25 test year as well as the 2025/26 and 2026/27 fiscal years.

4.5 Other Expenses

4.5.1 Introduction

Centra's other expenses consist of demand-side management spending, corporate initiatives and restructuring costs, site remediation, regulatory costs and miscellaneous other costs. Demand-side management costs and regulatory costs are currently placed in regulatory deferral accounts and amortized over several years.

4.5.2 Demand-Side Management Deferral Account

Between Efficiency Manitoba's assumption of responsibility for demand-side management in 2020 and the 2024/25 test year, Centra has incurred approximately \$52 million of demand-side management expenditures on a cumulative basis. Under *The Efficiency Manitoba Act*, Centra must pay Efficiency Manitoba for demand-side management initiatives performed under an approved efficiency plan. On average, Centra paid Efficiency Manitoba approximately \$10 million per year during each of the last five years. However, this amount is net of federal funding under the Low Carbon Economy Fund that has been paying approximately half of Efficiency Manitoba's total expenditures for natural gas efficiency measures between 2022/23 and 2024/25. Beginning with the 2025/26 fiscal year, Centra projects demand-side management costs to increase to \$20 million per year, reflecting the end of funding received through the Low Carbon Economy Fund.

Demand-side management expenditures are currently added to a regulatory deferral account and amortized over a period of 10 years. As such, while the increase in Centra's demand-side management expenditures in 2025/26 will not have an immediate effect on

its revenue requirement, it will lead to an increase in the deferral account balance, and to a higher amortization from that account in subsequent years.

4.5.3 Position of the Parties

IGU's witness, Mr. Bowman expressed concern about the projected doubling of the demand-side management deferral account balance by 2032/33 because of the increase in expenditures. He noted that a material growth in the deferral account balance during a period of flat revenue projections could mask Centra's financial situation. However, IGU is not recommending a change to the existing deferral and amortization protocol at this time.

4.5.4 Board Findings

The Board accepts Centra's revenue requirement projection for other expenses for the 2024/25 test year as well as the 2025/26 and 2026/27 fiscal years. This approval includes the continued addition of demand-side management costs to the deferral account and the continued amortization of that account over 10 years. The Board notes that the demand-side management expenditures result from Efficiency Manitoba's approved efficiency plan, which means that Centra is not currently able to reduce those expenditures. Ideally, the appropriate level of natural gas demand-side management should form part of Manitoba Hydro's upcoming integrated resource plan and be considered as part of Centra's business plan.

While the Board approves the deferral for the purposes of this hearing, it does share Mr. Bowman's concern about an increase in the deferral account balance. Demand-side management does not provide a financial benefit to Centra. Deferring expenditures that do not lead to increasing revenues over time entails the risk of being unable to recover those costs. As set out in section 3.0, the Board requires Centra to address the risks related to increasing deferrals in its business plan.

4.6 Corporate Allocation

4.6.1 *History of the Corporate Allocation*

Manitoba Hydro purchased Centra from Westcoast Energy in 1999. At the time, one of the stated objectives was to achieve synergies as a result of Manitoba Hydro owning and operating both the electric and natural gas utilities in the province. Centra largely 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%. All three swaps will mature on September 1, 2029. Collectively, the 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 \$18 million. While the utility 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. As such, the financing costs related to Manitoba Hydro's acquisition of Centra have remained largely the same over the course of the past decade.

During a series of general rate applications in the 2000s, Centra and the Board deliberated how the acquisition costs, as well as the resulting synergies, should be divided between electric and natural gas ratepayers. Beginning with the 2005/06 & 2006/07 General Rate Application, the Board approved a corporate allocation to Centra of \$12 million per year, as a proxy for synergy savings. In Order 135/05, the Board justified the use of a \$12 million proxy as follows:

However, the Board believes that there is no merit in pursuing the elusive issue of estimating realized synergistic benefits and projecting what would have been Centra's operating costs if the former private ownership had continued in future applications.

The passage of time and the continuing full integration of the gas and electric operations make it increasingly difficult if not impossible to track and isolate synergistic benefits from normal productivity gains and other factors.

The corporate allocation forms part of Centra's approved revenue requirement and, together with the previously approved \$3 million in net income, forms part of the utility's authorized return. However, Centra does not consider the corporate allocation to be a return, but rather a recovery of costs related to the acquisition. This is reflected in the fact that Manitoba Hydro has historically also been assigned a corporate allocation of \$7 million per year. Together with the \$12 million allocation to Centra, the two corporate allocations total \$19 million per year and approximate the annual interest cost on the acquisition debt, the depreciation of a capital asset write-up, and the amortization of integration costs.

4.6.2 *Establishment of a \$100 Million Sinking Fund*

On January 9, 2024, Manitoba Hydro invested \$100 million in a sinking fund at an average rate of 3.7% until 2029, when the funds are to be applied against the acquisition debt. The money relates to cash on hand at Manitoba Hydro International (MHI), an unregulated energy consulting subsidiary of Manitoba Hydro, resulting from MHI's sale of its interest in Real Time Digital Solutions Inc. Leading up to the 2029/30 fiscal year, Manitoba Hydro and Centra plan to offset a portion of the annual interest cost on the \$250 million acquisition debt. On maturity of the debt on September 1, 2029, the two utilities plan to discharge \$100 million of the debt while refinancing the remaining \$150 million.

Until the establishment of the sinking fund, the total interest costs on the acquisition debt were approximately \$18 million per year. Of this amount, \$12 million was allocated to Centra through the corporate allocation approved in the 2005/06 & 2006/07 General Rate Application, while the remaining \$6 million were allocated to Manitoba Hydro and formed the majority of the \$7 million corporate allocation embedded in that utility's revenue requirement.

4.6.3 *Proposed Allocation Through the Number of Customers Allocator*

Beginning with the 2022/23 fiscal year, the provincial government halved the debt guarantee fee applicable to Manitoba Hydro's debt, reducing it from 1.0% to 0.5%. The reduction decreased the total corporate allocation by \$1 million, from \$18 million to \$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.

Beginning with the establishment of the sinking fund in the middle of the 2023/24 fiscal year, the total cost of the corporate allocation between the two utilities decreased. During the 2023/24 fiscal year, the sinking fund generated \$1 million in interest income and reduced the total allocation by the same amount. In the 2024/25 test year, and every following year until 2028/29, Centra expects the sinking fund to generate \$4 million per year. Following the retirement of \$100 million of the acquisition debt in 2029/30 and the refinancing of the remaining debt at a lower interest rate, Centra expects the total annual allocation to be even less. The mechanics of the reductions that began in 2023/24 are illustrated in Figure 4.5.

\$ in millions		Without Sinking Fund Investment				With Sinking Fund Investment			Total Cost for Allocation	Total Savings
		Interest on Acquisition Debt	Provincial Guarantee Fee (PGF)	Refinancing Savings	Total Cost for Allocation	\$100M Sinking Fund Investment Interest Income	\$100M Debt Retirement Savings	PGF net of Sinking Fund Investment		
Fiscal Year										
2019/20	Actual	\$16	\$3	\$0	\$18	\$0	\$0	\$0	\$18	\$0
2020/21	Actual	\$16	\$3	\$0	\$18	\$0	\$0	\$0	\$18	\$0
2021/22	Actual	\$16	\$3	\$0	\$18	\$0	\$0	\$0	\$18	\$0
2022/23	Actual	\$16	\$1	\$0	\$17	\$0	\$0	\$0	\$17	\$0
2023/24	Forecast	\$16	\$1	\$0	\$17	(\$1)	\$0	\$0	\$16	(\$1)
2024/25	Forecast	\$16	\$1	\$0	\$17	(\$4)	\$0	(\$0)	\$13	(\$4)
2025/26	Forecast	\$16	\$1	\$0	\$17	(\$4)	\$0	(\$0)	\$13	(\$4)
2026/27	Forecast	\$16	\$1	\$0	\$17	(\$4)	\$0	(\$0)	\$13	(\$4)
2027/28	Forecast	\$16	\$1	\$0	\$17	(\$4)	\$0	(\$0)	\$13	(\$4)
2028/29	Forecast	\$16	\$1	\$0	\$17	(\$4)	\$0	(\$0)	\$13	(\$4)
2029/30	Forecast	\$16	\$1	(\$3)	\$14	(\$2)	(\$3)	(\$0)	\$10	(\$5)
2030/31	Forecast	\$16	\$1	(\$5)	\$12	\$0	(\$5)	(\$1)	\$7	(\$5)
2031/32	Forecast	\$16	\$1	(\$5)	\$12	\$0	(\$5)	(\$1)	\$7	(\$5)
2032/33	Forecast	\$16	\$1	(\$5)	\$12	\$0	(\$5)	(\$1)	\$7	(\$5)
2033/34	Forecast	\$16	\$1	(\$5)	\$12	\$0	(\$5)	(\$1)	\$7	(\$5)
2034/35	Forecast	\$16	\$1	(\$5)	\$12	\$0	(\$5)	(\$1)	\$7	(\$5)
2035/36	Forecast	\$16	\$1	(\$5)	\$12	\$0	(\$5)	(\$1)	\$7	(\$5)
2036/37	Forecast	\$16	\$1	(\$5)	\$12	\$0	(\$5)	(\$1)	\$7	(\$5)
2037/38	Forecast	\$16	\$1	(\$5)	\$12	\$0	(\$5)	(\$1)	\$7	(\$5)
2038/39	Forecast	\$16	\$1	(\$5)	\$12	\$0	(\$5)	(\$1)	\$7	(\$5)
2039/40	Forecast	\$16	\$1	(\$5)	\$12	\$0	(\$5)	(\$1)	\$7	(\$5)
2040/41	Forecast	\$16	\$1	(\$5)	\$12	\$0	(\$5)	(\$1)	\$7	(\$5)
2041/42	Forecast	\$16	\$1	(\$5)	\$12	\$0	(\$5)	(\$1)	\$7	(\$5)
2042/43	Forecast	\$16	\$1	(\$5)	\$12	\$0	(\$5)	(\$1)	\$7	(\$5)
FORECAST TOTAL		\$320	\$25	(\$66)	\$279	(\$21)	(\$62)	(\$9)	\$186	(\$92)

Figure 4.5 — Total Annual Acquisition Debt Financing Costs

Beginning with the 2023/24 fiscal year, Centra proposes to end the fixed allocation of \$12 million to Centra and instead allocate the total financing cost between Manitoba Hydro and Centra using the Number of Customers allocator that forms part of Centra’s integrated cost allocation methodology. Under that allocator, approximately 1/3 of the total acquisition debt financing cost is allocated to Centra, with the remaining 2/3 allocated to

Manitoba Hydro. As a result of that change in allocation, Centra’s total corporate allocation during the 2024/25 test year has been reduced to \$4 million, while Manitoba Hydro’s allocation is higher than it was before the establishment of the sinking fund. The change in the allocation is illustrated in Figure 4.6.

<i>\$ in millions</i>		Total Cost for Allocation	With Sinking Fund Investment	
			Allocation to Gas Operations	Allocation to Electric Operations
Fiscal Year				
2019/20	Actual	\$18	\$12	\$6
2020/21	Actual	\$18	\$12	\$6
2021/22	Actual	\$18	\$12	\$6
2022/23	Actual	\$17	\$12	\$5
2023/24	Forecast	\$16	\$5	\$11
2024/25	Forecast	\$13	\$4	\$9
2025/26	Forecast	\$13	\$4	\$9
2026/27	Forecast	\$13	\$4	\$9
2027/28	Forecast	\$13	\$4	\$9
2028/29	Forecast	\$13	\$4	\$9
2029/30	Forecast	\$10	\$3	\$6
2030/31	Forecast	\$7	\$2	\$5
2031/32	Forecast	\$7	\$2	\$5
2032/33	Forecast	\$7	\$2	\$5
2033/34	Forecast	\$7	\$2	\$5
2034/35	Forecast	\$7	\$2	\$5
2035/36	Forecast	\$7	\$2	\$5
2036/37	Forecast	\$7	\$2	\$5
2037/38	Forecast	\$7	\$2	\$5
2038/39	Forecast	\$7	\$2	\$5
2039/40	Forecast	\$7	\$2	\$5
2040/41	Forecast	\$7	\$2	\$5
2041/42	Forecast	\$7	\$2	\$5
2042/43	Forecast	\$7	\$2	\$5
FORECAST TOTAL		\$186	\$62	\$124

Figure 4.6 — Allocation of Acquisition Financing Costs Between Gas and Electric

The combined effect of the sinking fund and the changed allocation methodology in the 2024/25 test year is to reduce Centra’s corporate allocation from its previous amount of \$12 million per year to \$4 million per year, equal to an \$8 million reduction in Centra’s revenue requirement compared to the existing Board-approved amount.

4.6.4 Position of the Parties

Centra

Centra states that it has used surplus cash from an unregulated subsidiary to invest in a sinking fund that benefits both electric and natural gas customers. According to Centra, it is fully in the purview of Manitoba Hydro to use cash from MHI, an unregulated subsidiary, to manage its consolidated debt obligations, and such treatment falls outside the Board's jurisdiction.

Centra objects to IGU's characterization of the sinking fund as a windfall. The utility observes that electric rates are based on the revenue requirement of Manitoba Hydro's electric operations, which excludes the costs and revenues of unregulated subsidiaries such as MHI. Centra notes that the transfer has been approved by the Manitoba Hydro-Electric Board and that its legal analysis concluded that an Order in Council is not required.

Centra notes that the previous allocation of \$12 million to Centra was based on judgment of the synergistic savings resulting from the acquisition over 25 years ago. According to the utility, Centra is now fully integrated into Manitoba Hydro's consolidated operations, and it is no longer possible to determine such synergies. As such, apportioning the acquisition financing costs based on the number of customers better serves each customer base and mitigates the risk of cross-subsidization.

Consumers' Association of Canada

CAC did not make submissions on the issue of the sinking fund and the adjustment of Centra's corporate allocation. However, CAC's witness, Mr. Rainkie, called it an example of how strategic thinking can be used to moderate the cost pressures faced by Centra.

Industrial Gas Users

IGU submits that the Board should not vary the assumption that Centra is allocated \$12 million per year associated with the perpetual requirement to finance the purchase of the utility in 1999. According to IGU, the existing \$12 million allocation reflects a continuation of the principle that Centra would compensate Manitoba Hydro for the cost of acquiring the assets, albeit at a lower net cost than under the previous private ownership. In IGU's submission, Centra's treatment of both the gifted funds and the reallocation of the acquisition cost is a dubious assumption. IGU notes that Centra previously assumed that it would not discharge any of the acquisition debt.

IGU concludes that a Centra hearing is not the appropriate venue for making a material reallocation at the level of the parent company. Of particular concern to IGU is the fact that the reallocation includes the years 2023/24 and 2024/25, for which the Board has already approved electric rates.

IGU also raises a legal question, namely whether the allocation requires an Order in Council as a result of subsections 15(1.3) and 16(1) of *The Manitoba Hydro Act*, and suggests that these issues be better addressed at the upcoming Manitoba Hydro general rate application. IGU disagrees with Manitoba Hydro's assertion that electric rates do not take into account subsidiaries and submits that electricity rates have been set to be inclusive of the activities, earnings, losses, risks, resource requirements and implications of Manitoba Hydro's subsidiaries. IGU contrasts this with Centra's natural gas rates, which have been set by exclusively looking at the activities of the natural gas subsidiary.

In IGU's view, Centra's natural gas customers have benefitted from the elimination of the return on equity model used under its previous private ownership, and a future allocation of only \$2 million following the planned discharge of a portion of the debt in 2029/30 is an unreasonable assumption given the amount of debt outstanding. The Board should accordingly direct Centra to prepare rate paths on the basis of a continuing \$12 million annual allocation.

4.6.5 Board Findings

The Board approves Centra's proposal to reduce the corporate allocation to \$4 million during the 2024/25 test year and keep it at that level for the 2025/26 and 2026/27 fiscal years. In granting this approval, the Board draws a distinction between the effects of the \$100 million sinking fund and the reallocation of interest costs through the Number of Customers allocator.

With respect to the use of the sinking fund, the Board accepts Centra's evidence that the Manitoba Hydro-Electric Board has approved the use of the funds as proposed by Centra and notes Manitoba Hydro's conclusion that the utility did not require an Order in Council under clause 16(1)(i) of *The Manitoba Hydro Act*. The Board is not making a legal ruling on the latter issue.

With respect to the reallocation of interest costs using Centra's ICAM, the Board observes that 26 years have passed since Manitoba Hydro acquired Centra. As such, the concept of synergies, which was used to justify the \$12 million corporate allocation, may have outlived its usefulness. For the purpose of this hearing, the Board accepts the proposal to reallocate the interest costs based on the Number of Customers allocator, which allocates 1/3 of the costs to Centra and 2/3 of the cost to Manitoba Hydro.

Nonetheless, if synergies are no longer used to justify natural gas ratepayers paying a portion of the acquisition costs, the Board must consider whether, in the long term, retaining a corporate allocation remains justified at all. Ordinarily a company's customers are not responsible for the cost of that company being acquired by a different company. While the Board justified the corporate allocation based on a "hold harmless" principle 20 years ago, the time has come to revisit the concept in its entirety. The Board accordingly directs Centra, to file, with its next general rate application, a plan to eliminate, or transition towards an elimination of, the corporate allocation. Alternatively, Centra is to provide a rationale for retaining the corporate allocation. This directive is independent of the requirement to address the allocation of costs as part of Centra's business plan.

4.7 Rate Base Rate of Return

4.7.1 *Background*

Under *The Public Utilities Board Act*, the Board is required to determine Centra's rates using both a rate base and the rate of return on shareholders' equity through a Rate Base Rate of Return ("RBROR") methodology. While the RBROR methodology was applied during the period when Centra was privately owned, as the Board found in Order 128/09, a cost of service rate-setting methodology is more congruent with the reality of a wholly-owned Crown corporation. As a tax-exempt entity with only one shareholder (the Province of Manitoba), Centra does not seek a return on its investment beyond that necessary to allow Manitoba Hydro to repay the debts incurred in acquiring Centra. However, the legislative requirement to determine rates on an RBROR continues.

The Board employs the RBROR calculation as the upper limit for annual weather-normalized net income under the cost of service determination of revenue requirement. In essence, the Board utilizes the RBROR methodology as a test of an acceptable maximum revenue requirement.

In Order 85/13, the Board determined that the return on equity based on the approved formula did not provide Centra with a fair return. Directive 8 of Order 85/13 instructed Centra to propose an updated return on equity reflective of an appropriate level for use in feasibility tests and rate base determinations. In response, in advance of the 2019/20 General Rate Application, Centra retained Drazen Consulting Group Inc. ("Drazen") to evaluate and recommend an appropriate return on equity and level of annual net earnings beyond the 2019/20 test year. Drazen's evidence recommended a return on equity in the range of 8.3% to 8.5%. In the current application, Centra has used a return of 8.3% for its calculations.

4.7.2 Centra's Rate Base and Return Calculations

Centra's application provides detailed components of its rate base and rate of return for the 2024/25 test year. The rate base is the sum of plant and intangible assets in service, construction work in progress, regulatory deferral balances, and working capital allowance, less accumulated depreciation and contributions in aid of construction. Centra's total rate base for 2024/25 is \$788.6 million. Key assumptions made by Centra are as follows:

- Cost of capital: Comprises cost of equity (8.30% as filed), long-term debt (4.49%), and short-term debt (4.75%).
- Capital structure: Targeted at 77.1% long-term debt, 5.3% short-term debt, and 17.7% equity for 2024/25.
- Overall rate of return: based on the above cost of capital and capital structure of 5.2%.

Centra's capital projects and rate base additions are discussed in more detail in section 7.0.

Using these inputs, an allowable net income of \$7.8 million is determined under RBROR. Centra's filing indicates that a 16.1% general revenue increase would be required to achieve this \$7.8 million net income in accordance with RBROR.

Over the historical period from 2017/18 to 2023/24, Centra's average return on equity was -3.49%. On a weather-normalized basis, incorporating the corporate allocation, the average total return as a percentage of average equity for 2017/18 to 2023/24 was 2.25%.

4.7.3 Board Findings

The Board notes Centra's historical underperformance compared to Drazen's recommended 8.3% – 8.5% return on equity, with average weather-normalized returns (including corporate allocation) of only 2.25% from 2017/18 to 2023/24. Given Centra's current financial position, achieving \$7.8 million in net income would require an unacceptable rate increase, making the RBROR determination effectively moot. However, in the Board's view, the fact that RBROR would lead to a net income significantly higher than \$3 million highlights the need to reassess whether the previously approved net income remains appropriate. It also further reinforces the Board's decision to approve a path of general revenue increases higher than what the utility sought for the 2024/25 to 2026/27 period.

5.0 INTEGRATED COST ALLOCATION METHODOLOGY

5.1 Background

5.1.1 *Centra's Cost Allocators*

Centra is a wholly owned subsidiary of Manitoba Hydro whose assets represent approximately three percent of Manitoba Hydro's consolidated operations, despite representing approximately 1/3 of Manitoba Hydro's total customer base. Centra does not have its own employees. All staff are employed by Manitoba Hydro and provide services, with the cost of those services being assigned or allocated to Centra .

Whenever possible, Manitoba Hydro and Centra directly allocate costs to either the electric or natural gas operations of the utility. However, shared costs are allocated through an Integrated Cost Allocation Methodology ("ICAM"). This includes both operating and administrative costs and finance, depreciation and tax expense.

Integrated cost allocation methodologies involve judgment. Unlike cost of service studies, which are based on specific cost drivers, ICAMs need to allocate those costs for which cost causation cannot easily be determined. This is reflected in the fact that those costs for which clear cost causation exists are directly assigned to Centra, with only shared costs allocated through the ICAM allocators developed by Manitoba Hydro.

In the 2024/25 test year, Centra was allocated \$86.1 million in operating and administrative expenses and \$20.9 million in finance, depreciation and taxes. Approximately 57% of Centra's operating and administrative costs are directly assigned, while the remaining 43% are allocated through ICAM allocators. For finance, depreciation and taxes, 71% of costs are directly assigned, with the remaining 29% allocated through the ICAM allocators.

The ICAM applies four different methods to allocate shared costs to Centra:

- Timecard: The timecard process allocates labour costs by multiplying an employee's hours worked by the employee's activity rate.

- **Overhead:** The overhead process allocates costs that are not directly attributable to specific jobs. There are common overhead costs, such as corporate governance or corporate services. There are also material overhead costs, such as receiving and transportation.
- **Procurement:** The procurement process allocates the cost of materials, supplies and external services incurred using purchase orders, credit card purchases, or the issuance of inventory from Manitoba Hydro’s central stores.
- **System postings:** The system posting process allocates bad debt expense related to natural gas customers, as well as depreciation and taxes on common assets.

To determine the percentage of shared costs to be allocated to electric and gas operations, the utility uses four principal cost drivers, as described in Figure 5.1.

Cost Driver	Fiscal Year														
	2024/25	2023/24	2022/23	2021/22	2020/21	2019/20	2018/19	2017/18	2016/17	2015/16	2014/15	2013/14	2012/13	2011/12	2010/11
% Activity															
Electric	91%	91%	91%	91%	92%	92%	92%	92%	92%	91%	91%	91%	90%	90%	90%
Gas	9%	9%	9%	9%	8%	8%	8%	8%	8%	9%	9%	9%	10%	10%	10%
% Hybrid (Assets & Activity)															
Electric	94%	94%	94%	94%	95%										
Gas	6%	6%	6%	6%	5%										
% Assets															
Electric	97%	97%	97%	97%	97%	96%	96%	96%	96%	96%	96%	96%	96%	95%	95%
Gas	3%	3%	3%	3%	3%	4%	4%	4%	4%	4%	4%	4%	4%	5%	5%
Number of Customers															
Electric	68%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
Gas	32%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%

Figure 5.1 — Manitoba Hydro’s Shared Cost Drivers

The %Activity driver is based on the respective activity charges for Manitoba Hydro and Centra Gas. During the period of Manitoba Hydro’s “decade of investment” from approximately 2014 to 2021, the allocation to Centra Gas decreased from 10% to 9%, and subsequently to 8%. Coinciding with the completion of the Keeyask Generating Station and Manitoba Hydro’s major transmission projects, the driver increased again and has been at 9% since the 2021/22 fiscal year.

The %Hybrid driver was created by Manitoba Hydro during the 2020/21 fiscal year to allocate corporate governance costs. Before that year, Manitoba Hydro allocated governance costs based on the %Assets driver described below. However, with the significant addition of electric assets such as the Wuskwatim Generating Station, the Bipole III transmission line, and the Keeyask Generating Station, Manitoba Hydro

evaluated various alternative drivers to offset a reduction in the allocation of governance costs to Centra. Manitoba Hydro evaluated four approaches before settling on the new %Hybrid driver, including a driver based on total assets and time allocation and a driver based on capital expenditures and time allocation. As a result of the new %Hybrid driver, the percentage of corporate governance costs allocated to Centra increased from 4% (under the %Assets driver) to 5% initially, and to 6% subsequently, as shown in Figure 5.1 above.

The %Assets driver is based on the relative value of assets of Centra and Manitoba Hydro. As of the 2024/25 test year, the three-year average of Centra's assets and regulatory debts totalled \$942 million, compared to \$30.3 billion for Manitoba Hydro. This means Centra's assets represent approximately 3% of total assets and reflected in a %Assets driver of 3%. Since the creation of the %Hybrid driver described above, Centra has only used the %Assets driver as an input into the %Hybrid driver and does not currently use it to assign any costs.

The Number of Customers driver is based on the relative percentage of natural gas customers relative to electric customers. Under this driver, 32% of costs are allocated to Centra.

In addition to the allocators described above, 16% of Centra's total operating and administrative costs are assigned through management estimates during the 2023/24 fiscal year. The main types of management estimates are as follows:

- % of Customers in Arrears: the portion of electric and gas customers in arrears (used to allocate collection fees);
- % Property & Liability Insurance Paid: the portion of property and liability insurance paid for electric and gas operations (used to allocate insurance brokerage fees);
- Comprehensive General Liability Risk Exposures: based on the exposures and risks associated with the insurance requirements of each utility (used to allocate insurance costs);

- Customer Counts: the number of customers per service centre (used to allocate customer disconnection and reconnection costs); and
- Relative % of Time: the relative time estimate required to perform the task (e.g., used to allocate line locates in areas with both natural gas and electric service 50% to gas and 50% to electric).

Manitoba Hydro conducts an annual review of all cost drivers ahead of a new fiscal year to ensure that its common costs are reasonably allocated to the gas and electric lines of business. This is done by updating annual studies, conducting meetings with management to approve the drivers for the upcoming fiscal year, as well as reviewing the cost allocation within all of the work orders that allocate costs to both gas and electric. Depending on the materiality of cost allocations to gas resulting from cost driver changes identified during the annual review, Manitoba Hydro may delay the change until it appears permanent or phase in the change over a three- to five-year period.

5.1.2 Review by Deloitte LLP

The Board last reviewed the ICAM in 2003. Directive 11 of Order 128/09 required a follow-up review, but the Board subsequently deferred the review because of Manitoba Hydro's adoption of IFRS. The Board revisited the issue in the 2019/20 Centra General Rate Application, which culminated in a directive, in Order 152/19, requiring Centra to file a report on its ICAM with its next general rate application. When it became clear to the Board that Centra was not in a position to obtain such a study in time for this proceeding, the Board appointed Deloitte LLP as an independent expert consultant to review the ICAM. Deloitte examined Manitoba Hydro's own approach and compared that approach to several other utilities, including Algonquin Power and Utilities, BC Hydro, Corix, Fortis, ENMAX, and Hydro One. In conducting its review, Deloitte used 2023/24 actual numbers rather than projections for the 2024/25 test year.

Deloitte concluded that Manitoba Hydro's approach to integrated cost allocation remains appropriate and did not recommend any changes to the methodology. However, Deloitte pointed out that to allocate organizational support costs, other utilities often use an FTE (full-time equivalent or staff headcount) driver. Deloitte indicated that an FTE driver could

not be used for Centra because that utility does not have any employees. As discussed in section 5.2 below, the allocation of organizational support costs was a point of contention in this hearing.

As noted above, Deloitte considered the approaches used by several other Canadian utilities. Deloitte concluded that the approaches of those utilities are relatively consistent with the approach taken by Centra. However, Deloitte acknowledged that Centra's %Hybrid allocator, which only includes two factors (assets & activity charges) differs from the commonly used three-factor allocator that uses revenue as a third factor. Deloitte opines that, if Manitoba Hydro were to use a three-factor allocator, export revenue should be included in the revenue component to capture the full extent of the revenues being derived by the costs incurred.

As part of its ICAM review, Deloitte noted that Manitoba Hydro's application of the ICAM framework remains a relatively manual process, subject to potential mismatches on the allocators selected for specific cost entries. In response, Centra indicated that the corporation's existing accounting system is limited but that future upgrades to this system (e.g., SAP S/4HANA) would help minimize the mismatch issues identified by Deloitte.

5.1.3 Head Office Credit

Deloitte also recommended eliminating Centra's head office credit. The head office credit was a credit established by the Board following Centra's move from its previous offices at 444 St. Mary Avenue to Manitoba Hydro's office tower at 360 Portage and was intended to indemnify natural gas ratepayers from Manitoba Hydro's decision to construct a new office tower. The credit arose out of Directive 24 of Order 99/07, which required that no incremental costs associated with 360 Portage should be borne by Centra's ratepayers. Centra established the head office credit in 2008/29 and has continually applied it in each subsequent fiscal year.

In the early years of the head office credit, Centra calculated the credit amount based on assumptions related to the respective leasing costs per square foot between 444 St. Mary Avenue and 360 Portage Avenue. However, in 2017/18, Centra's review of the credit

concluded that the existing methodology would result in the credit increasing at a rate faster than Centra's facility costs, effectively resulting in a subsidy from electric ratepayers. Centra accordingly decreased the head office credit beginning with the 2018/19 fiscal year, initially from \$2.2 million to \$1.6 million. Since the initial adjustment, Centra has been adjusting the credit up or down at the same rate as the overall facility costs allocated to Centra under the ICAM.

According to Deloitte, Centra has become further operationally integrated with Manitoba Hydro and has received the benefit of being an integrated operation. Deloitte also states that it is not possible to ascertain whether Centra's pre-acquisition office costs would have remained stable or consistent more than 20 years after the acquisition. As such, Centra's ratepayers should not expect to receive a benefit from electric ratepayers in perpetuity related to a building from which Centra has derived a benefit since the building was completed.

5.2 Position of the Parties

Centra

In Centra's submission, the utility's existing ICAM methodology is fair and provides a reasonable allocation of costs between electric and natural gas operations. Centra states that gas activity charges have been relatively stable in recent years, while electric activity charges grew during a period of significant construction and have recently decreased again. According to Centra, the recent increase in the %Activity driver from 8% to 9% was caused by a decrease in electric activities. With respect to CAC's recommendation to transition the allocation of all operating and administrative costs to a three-factor composite allocator, Centra points out that such a change would shift costs to electric ratepayers and submits that the change is not warranted at this time. The utility also points out that its electric revenue is subject to significant fluctuations based on changes in export revenue due to water flows and market prices, while gas revenue is susceptible to the impact of weather.

Centra further submits that CAC's proposal to credit ratepayers for an over-allocation of costs between 2020/21 and 2023/24 should be rejected, and that these costs have never

been recovered in customer rates. According to Centra, CAC's suggestion would be equivalent to assigning those amounts to electric ratepayers, but neither electric nor natural gas rates have included these costs.

With respect to the head office credit, Centra adopts Deloitte's recommendation to end the credit and proposes a phase-out over five years, beginning with the 2025/26 fiscal year.

Consumers Association of Canada

In his initial expert evidence, CAC's revenue requirement witness, Mr. Rainkie, recommended that the %Activity driver should be replaced with a "proxy FTE" driver that relies on work hours rather than activity charges. Mr. Rainkie calculated that this would reduce the allocation from the current 9% (through the %Activity driver) to 5%. However, in Centra's rebuttal evidence, the utility advised that this calculation excluded employee-related costs, and that the inclusion of those costs would increase a proxy FTE driver to 10% for the 2023/24 fiscal year, meaning it would allocate more costs to Centra than the %Activity driver. In oral evidence, Mr. Rainkie acknowledged that Centra's approach to the FTE calculation was correct, subject to the caveat that the evidence had not been sufficiently tested. Mr. Rainkie instead recommended that Centra transition to a three-factor allocator consisting of assets, net revenues (net of cost of gas) and activity charges, with a 1/3 weighting to each allocator. Such a three-factor composite allocator would allocate 6% to Centra compared to 9% under the %Activity allocator. Mr. Rainkie proposed this change based on his view that the existing Manitoba Hydro ICAM has an over-reliance on the use of corporate activity charges, which is inconsistent with fair cost causation and with the practices of other Canadian utilities, which more typically use three-factor allocators to address shared corporate costs.

CAC Manitoba adopted Mr. Rainkie's evidence and stated that the allocation of common costs between Centra and Manitoba Hydro through ICAM has become unwieldy, with an inappropriate reliance on one metric (i.e., activity charges) to drive these allocations. According to CAC, a three-factor composite allocator is fair, balanced and simple and should be used to allocate all common operating & administrative costs, not just those

costs that are currently allocated through Centra's two-factor %Hybrid allocator. Further, use of a three-factor composite allocation proactively addresses the expected changes to Manitoba Hydro's major capital investments and is preferable to manual interventions to ICAM allocators as their values change over time.

Based on the FTE proxy calculations as described above, Mr. Rainkie initially concluded that Centra has been over-allocated up to \$10 million per year and recommended that Centra's ratepayers be credited with a lump sum of \$35 million on account of over-allocations between 2020/21 and 2023/24.

When Mr. Rainkie changed his recommendation to instituting a three-factor allocator, he also changed his recommendation regarding the ratepayer credit. Under Mr. Rainkie's revised recommendation, he recommended a total credit of \$21 million, to be credited in three equal increments of \$7 million in 2024/25, 2025/26, and 2026/27. CAC adopted this recommendation in its final argument. CAC also recommends a \$6 million per year reduction in common costs allocated to Centra in the 2024/25 through 2026/27 test years.

5.3 Board Findings

5.3.1 Integrated Cost Allocation Methodology

The Board's starting point in assessing the reasonableness of the ICAM is to assess the different characteristics of Centra and Manitoba Hydro. Centra is largely a local distribution company. As per Centra's own evidence, its projected natural gas sales are basically flat and declining. In the Board's view, the reorganization to decentralize the gas function of Manitoba Hydro into several business units has not fundamentally changed how Centra is operated. Centra is a mature and stable operation. In contrast, Manitoba Hydro is a multi-billion dollar hydroelectric utility with generation, transmission and distribution assets, along with sophisticated export and import arrangements and an aggressive capital expansion plan. This suggests that the benefit of strategic initiatives undertaken by Manitoba Hydro have accrued, and continue to accrue, largely to the benefit of electric ratepayers rather than natural gas ratepayers.

In light of Centra's stable operations and projected flat growth, the Board does not accept the doubling of organizational support costs since the 2019/20 General Rate Application or the utility's consistent above-inflation growth in operating and administrative expenses described in section 4.1. In Order 101/23, the Board noted that Manitoba Hydro's increase in operating and administrative expenses from 2019/20 to 2024/25 was 34.2%. In contrast, as noted above, Centra's operating and administrative expenses have increased 48% over the same time frame. While it may well be that a natural gas utility requires more hands-on work in its day-to-day operations, gas-specific activities are already largely directly assigned. The Board does not see a justification for shared organizational support costs to be increasing at an even faster pace. Taken together, this leads the Board to conclude that the existing ICAM allocates too high of a percentage of Manitoba Hydro's consolidated costs to Centra.

In the Board's view, Centra's shared operating and administrative expenses should be allocated through a three-factor allocator, as should finance, depreciation, and taxes. While Deloitte considered Centra's ICAM to be reasonable, Deloitte also acknowledged that a number of Canadian utilities make use of a three-factor allocator. In that regard, the Board is persuaded by the evidence of Mr. Rainkie that three-factor allocators are already in widespread use.

Nonetheless, the Board shares the concern expressed by Centra in this proceeding that electric revenue is susceptible to large fluctuations in export revenue based on water flows and market prices, while gas revenue is susceptible to the impact of weather. In the Board's view, this can be mitigated by using a rolling three-year average of Manitoba Hydro's net export revenue for electric operations and a similar rolling average of Centra's revenue for natural gas operations, excluding the cost of gas.

The Board anticipates that, consistent with Centra's calculations, the three-factor allocator will reduce the allocation of shared operating and administrative expenses from its currently level of 9% to approximately 6%. As such, the Board anticipates a minimal impact on those costs currently allocated through the %Hybrid driver, which already allocates 6% of the applicable shared costs.

Considering that Centra's asset base is currently only 3% of Manitoba Hydro's consolidated operations, that directly assigned costs are not affected by this directive, and that Centra is a mature and stable operation, the Board sees a three-factor allocator that allocates a lesser amount of shared costs to Centra as just and reasonable. The Board accordingly directs Centra to revise its ICAM to allocate all operating and administrative expenses currently allocated through the %Activity and %Hybrid allocators through a three-factor allocator, effective for the 2024/25 test year. For this purpose, the Board agrees with Centra's submission that activity charges are a more appropriate allocator than an FTE proxy.

In the Board's view, a similar reasoning applies to finance expense, depreciation, and taxes that are currently allocated through the ICAM. These, too, are to be allocated through a three-factor allocator.

The Board accordingly directs Centra to replace the existing %Activity Charges and %Hybrid allocators with a three-factor allocator that equally weights each of the following:

- activity charges as currently determined by Centra, based on a rolling average of the prior three fiscal years;
- assets based on a rolling average of the prior three fiscal years; and
- revenue for electric and natural gas operations based on a rolling average of the prior three fiscal years in a matter that:
 - includes Manitoba Hydro's net export revenue for electric operations; and
 - excludes Centra's gas commodity revenues.

In issuing this directive, the Board is mindful that, for Manitoba Hydro's electric operations, exports form an integral part of that utility's business model. In contrast, for Centra's natural gas operations, gas commodity costs are a simple flow-through cost passed on to ratepayers.

For certainty, the Board's directive does not apply to any costs currently allocated through the Number of Customers driver or to management estimates, including any management

estimates based on activity charges. The directive similarly does not apply to any costs that are currently directly assigned to the utility, whether through activity charges or otherwise.

The Board understands and accepts that the ICAM cost allocation driver values may change from year to year as a result of updates to the data supporting the calculations. However, should Centra or Manitoba Hydro seek changes to the actual ICAM methodology, the Board requires Centra to make an application for approval of the methodology changes before those changes are implemented for rate-setting purposes. In the Board's view, changes to the ICAM can have material impacts on Centra's financial position and rates. Adjustments to the ICAM methodology should not take place without regulatory oversight.

The Board is not persuaded by CAC's argument that Centra ratepayers should be granted a \$21 million refund. Integrated cost allocation methodologies are a matter of judgment. While the Board considers it appropriate to amend the methodology on a prospective basis, the Board sees no justification to retroactively reassign costs between Centra and Manitoba Hydro that were accrued based on the methodology that existed at the time.

In regards to the allocator tagging mismatches identified by Deloitte in this proceeding, the Board expects Centra and Manitoba Hydro to implement adequate internal controls, and to continually seek further process improvements, to ensure the correct application of the ICAM and accurate cost allocation results.

The Board also finds that there exists uncertainty regarding the level of shared services provided to Centra by Manitoba Hydro. In the Board's view, there is a need to clarify such services, and to provide increased accountability, through a service level agreement between Centra and Manitoba Hydro that sets out both the level of service to be provided and the cost to be paid by Centra for that service. The Board directs Centra to file, with its next general rate application, a position paper on the possibility of developing one or more shared service agreements between the two utilities.

In light of the evidence on the ICAM provided in this proceeding, the Board sets aside Directive 3 of Order 152/19 and Directive 3 of Order 6/24.

5.3.2 Head Office Credit

The Board finds that the head office credit is no longer justified and approves Centra's proposal to eliminate the credit. Like the concept of synergies resulting from Centra's acquisition, the concept of a credit for more expensive office space has outlived its usefulness. At this time, Centra's office space has been located in the Manitoba Hydro building for approximately 15 years and costs are more appropriately allocated under the ICAM.

However, with the reduced cost allocation to Centra resulting from the establishment of a three-factor allocator, the Board does not see a need to phase in the elimination of the head office credit over three years. The Board accordingly directs Centra to fully eliminate the credit for the 2025/26 fiscal year.

In light of this finding, the Board sets aside Directive 24 of Order 99/07.

6.0 COST OF GAS AND RELATED APPROVALS

6.1 Background

The cost of gas is the most significant cost that Centra incurs. It include the cost of the molecules of gas, the cost of the pipeline transportation arrangements necessary to bring the purchased gas supplies to Manitoba, and the cost of gas storage facilities, which allow gas purchased in the summer to be injected (i.e., stored) and then withdrawn in the winter for use in Manitoba.

Centra's gas supply, transportation, and storage "portfolio" of arrangements provides the necessary flexibility to serve Manitoban's variable demands for gas, which is primarily driven by weather conditions. Once in Manitoba, gas supplies are delivered to customers via Centra's distribution pipeline system. Costs incurred by Centra for its distribution system form part of the non-gas revenue requirement discussed in section 4.0 above.

The Board regulates the recovery of the cost of gas on a pass-through basis, with the exception of Fixed Rate Gas Commodity Service. This means that gas costs are charged to customers in their rates without any mark-up or profit to Centra. To ensure that only the actual cost of gas is passed on to customers, Centra maintains a number of Purchased Gas Variance Accounts ("PGVA"), which record the differences between the forecast cost of gas embedded in sales rates and the actual cost of gas incurred by Centra. These differences are periodically either refunded to or collected from customers by way of rate riders that either decrease (i.e., refund to customers) or increase (i.e., recover from customers) the base sales rates and form part of the billed rates that are charged to customers.

Centra's gas costs are periodically reviewed by the Board as part of a general rate application, or in the context of a cost of gas application. Centra's cost of gas, including Centra's gas supply, transportation, and storage arrangements, were last reviewed at the 2019/20 general rate application and the related Board decisions are found in Orders 108/19 and 152/19. In Order 131/21, the Board approved a simplified rate structure for Centra as well as the use of the Alberta Energy Company ("AECO") gas

market hub as Centra's primary gas receipt point instead of the Empress market hub. These changes were subsequently implemented in November 2022 per Order 114/22.

6.1.1 Centra's Gas Commodity, Transportation, and Storage Costs

Centra typically contracts separately for natural gas commodity, transportation capacity, and storage capacity with different gas market service providers.

Centra purchases the majority of its gas commodity from Western Canada under contract with ConocoPhillips Canada Resources ("ConocoPhillips). Centra executed contracts with ConocoPhillips following comprehensive Request for Proposal processes conducted in 2018, 2021, and 2023, and the resulting contracts awarded covered various time periods between November 2018 and October 2025. In general, Centra's Request for Proposal and contract award processes related to its Western Canadian gas supply contracts have largely remained the same since the 2019/20 general rate application, although minor changes were incorporated such as the transition of the delivery point to the AECO hub instead of the previous Empress hub. Further, and similar to prior years, the terms of the Western Canada gas supply contracts include volume flexibility and market price index diversity that facilitate reliable gas supplies for Centra's system supply customers. Due to the commercial sensitivities of the contract terms, the details of Centra's Western Canadian gas supply contracts have been filed in confidence with the Board.

In addition to gas supply purchase arrangements, Centra has transportation and storage arrangements in place with a number of inter-jurisdiction pipeline transportation service providers in Canada and the U.S. that also contribute to its gas costs. Since the 2019/20 general rate application, Centra's transportation and storage portfolio has largely remained the same, although Centra cites three main exceptions:

- An increase to Centra's annual transportation capacity on the Nova Gas Transmission Limited system. This change, which was signaled at the last general rate application and relates to Centra's change in its primary supply receipt point from Empress to AECO, fully came into service in November 2022. According to

Centra, the transition to the AECO delivery point allows for significant volume nomination flexibility and mitigates price and supply contracting risks;

- A relatively small increase in Centra’s annual firm transportation capacity on the TransCanada Pipelines Ltd system was implemented in November 2023; and
- A temporary increase in Centra’s gas storage capacity on the ANR system for the August 2019 to March 2020 period.

In each year since the last general rate application, Centra was able to recover some of its gas costs through capacity management activities, under which the utility sells unutilized gas supplies and transportation & storage capacity to other gas market participants. Since the last general rate application, and consistent with prior years, the value of Centra’s capacity management transactions has been dependent on market conditions, which continually fluctuate.

The Board does not approve Centra’s gas supply, transportation, or storage contracts but must approve the cost consequences arising from those contracts. As shown in Figure 6.1 below, Centra is now seeking Board approval of the gas costs incurred for the 2018/19 to 2023/24 gas years. A gas year is the annual period used by the natural gas industry that runs from November 1 to October 31 each year. All references in this section are to a gas year.

Gas Year	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Total Gas Costs (\$ millions)	\$212.0	\$186.4	\$201.9	\$344.3	\$312.6	\$146.6

Figure 6.1 — Requested Gas Cost Approvals

In addition to the impacts of the gas supply, transportation, and storage portfolio changes described above, the actual gas costs incurred since the 2019/20 General Rate Application were affected by both gas market price fluctuations and by weather-related fluctuations in customers’ gas consumption during those years. For example, the gas costs incurred during gas years 2018/19 through 2020/21 were characterized by relatively low and stable natural gas market prices. However, geopolitical and other events (e.g.,

the COVID-19 pandemic, the Russia-Ukraine war, increased demand for liquified natural gas exports, and a colder 2021/22 that led to lower-than-average storage levels at the start 2022/23) led to higher market prices and gas costs in both 2021/22 and 2022/23. In contrast, Centra's total gas costs of \$146.6 million for the 2023/24 gas year were historically low, driven by low commodity costs resulting from various factors such as high North American gas production, robust storage levels, and a generally mild 2023/24 winter season.

6.1.2 Amortization of Prior-Period Non-Commodity PGVA Balances

Centra's rates are approved prospectively based on forecasts. To the extent that actual gas costs differ from forecasts, and to ensure that gas costs are passed to customers without mark-up, the difference between the forecast costs and actual costs accrues in a PGVA deferral account. Per the Board-approved quarterly Gas Commodity rate setting methodology, commodity-related PGVA balances are addressed on a quarterly basis and are finalized as part of cost of gas or general rate applications. However, PGVA balances related to non-commodity gas costs (e.g., for gas transportation or for unaccounted for gas included in delivery rates) accrue over a gas year, and the end-of year PGVA account balances are eventually combined together with other end-of year non-commodity PGVA account balances and dispositioned together as part of cost of gas or general rate applications.

Because of the six-year time frame between general rate applications, multiple annual non-commodity PGVA balances have accrued (including Supplemental Gas PGVA balances prior to November 1, 2022). The cumulative net total of all prior period Supplemental Gas, Transportation, and Distribution PGVA balances for the period of November 1, 2018 to October 31, 2023 is a net gas cost deferral account balance of \$5.1 million owing to customers (inclusive of the associated carrying costs to October 31, 2024). In Order 125/24, the Board granted interim approval to dispose of this net \$5.1 million prior period gas cost PGVA balance and to amortize it to Centra's customer classes over 12 months, beginning on November 1, 2024. The exceptions were the balances affecting the Mainline and Interruptible customer classes, which were instead to be disposed of over a 24-month period to mitigate the bill impacts applicable to those

classes. As part of this proceeding, Centra further requests that the Board now finalize the interim approval of the disposal of the \$5.1 million prior period gas cost deferral account balance starting November 1, 2024.

As part of its May 2, 2025 pre-hearing update submission, Centra advises that the combined variance in the Transportation and Distribution PGVAs for the 2023/24 gas year is a further \$0.1 million. However, Centra advises that it will seek approval of the disposition of 2023/24 gas year gas cost deferral account balances, as well as seek final approval of gas costs associated with the 2024/25 gas year, at a future regulatory process. Such an approach will allow these approvals to occur after the completion of the 2024/25 gas year. Any amounts owing to Centra or to customers will attract carrying costs at Centra's short term borrowing rate.

6.1.3 Non-Commodity Gas Cost Forecasts for Gas Years 2023/24 and 2024/25

In its October 7, 2024 general rate application, Centra proposed interim non-commodity rates effective November 1, 2024 that were, in part, based on its then-current forecast of non-commodity-related gas costs of \$59.6 million for the 2023/24 gas year. In Orders 125/24 and 129/24, the Board approved new non-commodity rates that took effect on November 1, 2024 and any differences between Centra's forecast and actual non-commodity costs flowed to PGVAs for the 2023/24 gas year, as described in section 6.1.2 above.

As part of its subsequent submissions in this proceeding, and because the 2023/24 gas year is now complete, Centra subsequently amended its application to request finalization of the interim non-commodity rates that took effect November 1, 2024 and finalize its actual gas costs incurred in the 2023/24 gas year. Further, Centra also provides a new forecast of its non-commodity related gas costs (\$57.8 million) for the 2024/25 gas year, which is to inform the gas cost portion of non-commodity rates to be approved by the Board at the conclusion of this proceeding.

6.1.4 Alternate Supply Provided to Interruptible Customers

Centra offers alternate supply to interruptible customers when the utility needs to curtail deliveries to protect storage inventory for firm service customers or when demand is forecast to exceed Centra's firm deliverability. During instances of curtailment of interruptible customers, Centra offers alternate supply at its cost (plus the applicable Board-approved distribution rate), with customers having the option to either take the alternate supply or to cease consumption during the curtailment period and instead operate with back-up fuel sources. Under clause 82(1)(b) of *The Public Utilities Board Act*, those rates must be approved by the Board. The Board received evidence, in confidence, on the number of days on which alternate supply was made available and the prices for such supply for the period November 1, 2018 to October 31, 2024.

As further described in Section 10.0 below, Centra's Schedule of Sales and Transportation Services and Rates, more commonly called the Terms and Conditions of Service ("Terms and Conditions"), currently defines Centra's service offerings. Specifically, Section VI of Centra's Terms and Conditions describes the requirements for Interruptible Sales Service and Interruptible Delivery Service. However, Centra agrees that Section VI currently does not define that the sale price of Alternate Supply shall be Centra's purchase price of that supply. For example, paragraph VI.D) 3) of Centra's Terms and Conditions states "*If, on any day, the Customer elects to purchase the Alternate Supply gas, the Customer shall pay the sale price of that gas supply plus the Alternate Supply Service Delivery Rate.*"

6.1.5 Compressed Natural Gas Sale

Centra currently operates a compressed natural gas ("CNG") filling station to provide temporary natural gas supply options for its own utility customers during some scheduled and unscheduled service outages. In 2018, Centra sold 26,284 m³ of CNG to Union Gas under a mutual aid agreement. To bill Union Gas, Centra applied the variable commodity charge associated with the Large General Service customer class effective on August 1, 2018, plus a compressor charge of \$0.1147/m³, which is comparable to a similar charge levied by SaskEnergy during a 2014 emergency where Centra needed to procure CNG

from outside of Manitoba. In addition, Centra billed its technician labour hours at the then-applicable corporate activity rate of \$121/hr. In total, Centra charged Union Gas \$19,539, including GST and PST.

To date, this has been the only time that Centra sold CNG to an external customer, although the utility is investigating the market potential for future CNG sales. In the event of an emergency where Centra is providing CNG as a means of mutual aid to another utility, a similar pricing methodology as the 2018 Union Gas sale would be deemed appropriate. However, at this time, Centra is in the analysis and design stage of considering options for a CNG rate and associated Terms and Conditions. Similar to section 6.1.4 above, clause 82(1)(b) of *The Public Utilities Board Act* requires that Centra's rates be approved by the Board.

6.1.6 Heating Value

The heating value of natural gas is a measure of its energy content per unit of volume. This energy content varies depending on the chemical composition of the gas. Since the early 2000s, Centra has used a reference heating value of 37.8 GJ/10³m³. However, there has been an increase in the actual heating value of gas received in Manitoba since 2008 as a result of gas production in the Western Canadian Sedimentary Basin shifting from conventional, drier, gas toward more liquids-rich gas.

Because Centra charges its customers by volume, and because the amount of energy in a cubic metre of gas supply may vary due to the heating value of the delivered gas on that day, customers will consume less gas volume than they otherwise would have had the heating value on that day been higher than Centra's reference value, and vice versa. In other words, natural gas with a higher than reference heating value will cause customers to require less natural gas to produce the same amount of heat (the reverse is also true). As a result, the heating value of Centra's gas supplies can affect Centra's gross margin.

To address this issue, the Board previously approved a Heating Value Margin deferral account. However, the practice of using such an account was discontinued per

Directive 19 of Order 152/19. Directive 24 of Order 152/19 instead required Centra to file its updated reference heating value in future general rate applications. In response to Directive 24 of Order 152/19, Centra provides historical heating values for the last five years and proposes to use a rolling 12-month average of historical heating values as the method to forecast the reference heating value used for the following fiscal year. Centra plans to update the 12-month rolling average annually and apply it to each new gas volume forecast supporting both quarterly Gas Commodity rate applications and quarterly Fixed Rate Gas Commodity Service offerings.

As a result of Centra's heating value methodology in this proceeding, a reference heating value of 38.5 GJ/10³m³ (based on actual heating value results for the 2020/21 fiscal year) was embedded in Centra's 2021 gas volume forecast, which in turn underpins the interim non-commodity rates approved in Orders 125/24 and 129/24 for November 1, 2024. Similarly, Centra's 2024 gas volume forecast makes use of a heating value of 38.8 GJ/10³m³, based on the 12-month average of actual heating values from April 2023 to March 2024.

6.1.7 Quarterly Rate Setting Methodology — Cost of Gas in Storage and Volume Forecast

Under the existing quarterly Gas Commodity rate-setting methodology, Centra determines a new weighted average for the cost of gas in storage for each November 1 quarterly gas commodity application. This weighted average is then maintained for the remaining three quarterly applications in each year.

In September 2022, Centra requested interim *ex parte* approval of proposed changes to its quarterly rate-setting methodology to provide more timely price signals to customers, including a revised calculation for the cost of gas in storage and a change to Centra's gas volume forecast used to calculate quarterly Gas Commodity rates. In Order 114/22, the Board deferred a ruling on these issues to the next general rate application.

In this 2024/25 General Rate Application, Centra seeks Board approval of two changes to the gas cost forecasting methodology that supports quarterly Gas Commodity rate applications:

- Update the forecast cost of gas in storage each quarter, as part of the quarterly Gas Commodity rate-setting process, rather than only once annually; and
- Routinely use the most recent gas volume forecast in Gas Commodity rate applications.

Regarding the gas volume forecast change, Centra proposes to routinely use its most recent gas volume forecast, instead of the last forecast reviewed by the Board at the previous cost of gas proceeding or general rate application. Whenever the gas volume forecast used for quarterly Gas Commodity rate setting is updated, Centra plans to also provide a summary of the changes relative to the prior forecast. Centra further clarifies that the updated gas volume forecast will use the same underlying methodology as was included in its 2021 gas volume forecast scenario but updated consumption assumptions will be incorporated. In addition, Centra also plans to update the forecast AECO and non-AECO supply mix for the 12-month forecast period in each quarterly rate application.

Similar to its submission in 2022, Centra proposes the above changes to incorporate more current information in the quarterly Gas Commodity rate applications and provide timelier price signals to customers.

6.1.8 2021 and 2024 Natural Gas Volume Forecasts

Centra initially filed the current application based on its 2021 natural gas volume forecast scenario. The interim non-commodity rates approved in Orders 125/24 and 129/24 for November 1, 2024 were based on this forecast. However, Centra subsequently filed an updated financial forecast based on its 2024 natural gas volume forecast, which it now proposes to use when implementing updated non-commodity rates resulting from the Board's decisions in this Order.

While the actual projected gas volumes and customer count details associated with both the 2021 and 2024 natural gas volume forecasts were filed in confidence, the Board had an opportunity to review the projections, along with the underlying assumptions. Most importantly, the forecast assumes that, despite population and customer growth in

Manitoba, the overall volume of gas sold after taking into account demand-side management is flat.

Overall, the forecasting methodology utilized to produce both the 2021 and 2024 volume forecasts is similar to the methodology used for Centra's 2018 volume forecast, which was reviewed by the Board as part of Centra's 2019/20 General Rate Application. However, both the 2021 and 2024 forecasts incorporate various changes in the underlying forecast assumptions. For example, Centra's 2021 and 2024 volume forecasts include the demand-side management savings projected by Efficiency Manitoba, which is legislated to achieve annual savings of 0.75% of the previous years' gas volumes. As well, and as described in section 6.1.6 above, both the 2021 and 2024 gas volume forecasts incorporate updated reference heating values.

6.2 Position of the Parties

6.2.1 Centra

Centra recommends the finalization of its gas costs for gas years 2018/19 through 2023/24. Further, Centra recommends that the existing practice of approving the amortization of non-commodity PGVA deferral balances at cost of gas or general rate application hearings remain, and that there is no benefit to amortizing non-commodity PGVA deferral balances annually as proposed by IGU. The utility notes that, since the revised rate structure approved in Order 131/21 took effect on November 1, 2022, the historically larger impact of Supplemental Gas deferral balances is no longer an issue. To the contrary, the utility notes that a rate rider for a single year may be greater in magnitude in that year than a multi-year rate rider disposing of a new deferral balance accumulated over a longer period.

In regard to the existing Terms and Conditions related to Alternate Supply for Interruptible Sales Service customers, Centra submits that its longstanding practice has been, and will continue to be, to sell Alternate Supply at cost. As such, further amendments to Section VI of its Terms and Conditions are not required. However, should the Board rule that amendments are necessary, Section VI.D), paragraphs 1) through 3) could incorporate "Centra's costs" instead of the words "the sale price".

Centra also submits that its proposed changes to the existing quarterly Gas Commodity rate setting methodology should be approved. Centra states that its proposed methodology changes would not shift away from the ratemaking principles of rate stability or gradualism, as the Gas Commodity cost forecast would still be based on a 12-month forecast. The quarterly update to the cost of gas in storage could also capture shifts in summer market prices sooner.

6.2.2 Interveners

Consumers Coalition of Canada

CAC did not take a position regarding any of the issues set out in this section.

Industrial Gas Users

IGU limited its submissions to the issue of non-commodity PGVA balances and argues that, in the future, the Board should require these deferral balances to be disposed of annually to avoid the accumulation of significant balances and increased rate volatility for some customer classes.

6.3 Board Findings

The Board approves:

- on a final basis, the gas costs incurred by Centra for the 2018/19 to 2023/24 gas years, which include the gas cost consequences of the Western Canadian gas commodity supply contracts covering various time periods between November 2018 and October 2024;
- on an interim basis, the forecast gas costs for the 2024/25 gas year used to set the gas cost portion of rates taking effect November 1, 2025 per this order; and
- on a final basis, the disposal of the prior period gas cost deferral account balances for the period of November 1, 2018 to October 31, 2023 through 12-month or 24-month rate riders per Directive 6 of Order 125/24 and starting November 1, 2024 per Order 129/24.

The Board is not persuaded by IGU's argument that non-commodity PGVA balances should be amortized annually and notes Centra's rebuttal that annual amortizations are

no guarantee of a lower balance. The Board further agrees with Centra that since the rate restructuring implemented on November 1, 2022, the historically large Supplemental Gas PGVA balances are now dispositioned as part of the quarterly Gas Commodity rate setting process. As such, the Board will retain its existing practice of approving prior period non-commodity PGVA amortizations during periodic cost of gas or general rate application hearings.

However, the Board finds that extended time between public reviews of Centra's gas costs, as has been experienced since 2013, is not in the public interest. The Board expects more regular reviews going forward, including both cost of gas hearings and general rate applications.

The Board also approves as final the Alternate Supply rates charged between November 1, 2018 and October 31, 2024. For Section VI.D), paragraphs 1), 2), and 3) of Centra's Terms and Conditions, the words "sale price" shall be replaced with "pass-through cost of acquiring additional gas commodity and transportation to Manitoba". Consequently, Centra shall file a revised version of its Terms and Conditions (along with a red-line version showing the changes) for Board approval as part of the compliance filing required elsewhere in this Order.

Regarding the issue of CNG sales, the Board approves the rates charged for the CNG sale to Union Gas in 2018. The Board expects Centra to complete its ongoing market analysis and rate design studies for CNG sales and to bring its proposals (including proposed changes to Centra's Terms and Conditions) to the Board for approval prior to completing future CNG sales. However, in the case of emergency-related CNG sales to other utilities in support of mutual aid agreements, the Board provisionally accepts the pricing methodology used for the 2018 Union Gas sale. However, the Board expects such sales to be reported shortly (within 60 business days) after they occur for formal approval per the requirements of clause 82(1)(b) of *The Public Utilities Board Act* until such time as CNG rates are approved.

The Board approves Centra's proposal to use a 12-month rolling average to determine the forecast reference heating value of natural gas. In accordance with Directive 24 of

Order 152/19, Centra is to continue to file its reference heating values used for rate-setting in future applications, along with five years of historical heating values.

Regarding Centra's proposed changes to the quarterly Gas Commodity rate-setting methodology, the Board approves the use of the most recent natural gas volume forecast instead of the last volume forecast reviewed by the Board (e.g., at the previous general rate application). For the purposes of the November 1, 2025 Gas Commodity rate change, Centra is to use the 2024 Volume Forecast. If an updated gas volume forecast subsequently becomes available, Centra is to implement the updated volume forecast annually as part of the November 1 Gas Commodity interim rate applications and provide a summary of the changes in assumptions and results associated with this forecast (relative to the previously used forecast). If the volume forecast is not updated from the forecast previously proposed or used, Centra is to explicitly confirm this as part of its November 1 Gas Commodity rate application. However, the Board does not approve Centra's proposal to update the forecast cost of gas in storage each quarter. The Board finds that the existing approach of updating the forecast cost of gas in storage only once a year adequately contributes to Gas Commodity rate stability and gradualism, and therefore remains in the public interest.

The Board accepts Centra's 2021 gas volume forecast for the purposes of setting the interim rates that took effect on November 1, 2024 per Orders 125/24 and 129/24. Similarly, the Board accepts Centra's 2024 gas volume forecast for rate-setting purposes starting November 1, 2025. The Board also notes that the gas volume forecasting methodology remains consistent with the 2018 volume forecast reviewed at the 2019/20 General Rate Application. The Board has examined the substantive changes in assumptions provided to the Board in confidence and considers them to be reasonable. Nonetheless, the Board finds that, while the forecast is reasonable in the short term, there exists significant uncertainty regarding the future of natural gas in the long term. In Order 127/24, the Board indicated that it did not see the current general rate application as the appropriate venue for energy transition-related issues. However, following the anticipated review of Manitoba Hydro's upcoming integrated resource plan, the Board intends to examine the long-term risks to Centra posed by the energy transition. These risks should

also be addressed in the Centra-specific business plan the Board is directing the utility to file as part of this Order.

7.0 CAPITAL EXPENDITURES AND RATE BASE

7.1 Introduction

Sub-section 127(1) of the *Public Utilities Board Act* requires the Board to determine Centra's rate base. Rate base is the sum of Centra's investment in its plant in service, less accumulated depreciation, plus a reasonable amount of working capital, less any contributions made by customers towards the construction of Centra's plant. This means that, effectively, rate base is the remaining undepreciated value of Centra's investment in its assets for which the utility must recover costs from its ratepayers over time.

Historically, gas utilities in Manitoba have been regulated on the basis of a rate base rate of return, meaning a percentage return on their invested equity. When Centra became publicly owned, it stopped being regulated on a rate base rate of return basis and began to be regulated on a cost of service basis. However, as required by the *Public Utilities Board Act*, the Board still determines and approves Centra's rate base.

The last time the Board reviewed and approved additions to Centra's rate base was at the 2019/20 General Rate Application, which included additions up to the 2017/18 fiscal year. The Board also approved the proposed 2019/20 rate base. In this hearing, Centra filed information supporting its rate base, including its historic and forecasted capital expenditures, its working capital, depreciation, and the contributions made by customers. From 2019/20 to the 2024/25 test year, Centra's rate base increased from \$631.2 million to \$788.6 million.

7.2 Historical Additions to Rate Base

Centra distinguishes between capital projects and capital programs. Capital projects are individual capital expenditures with a defined scope and estimated cost greater than \$1 million. In contrast, capital programs represent a collection of expenditures on assets that individually total less than \$1 million and are managed collectively to address specific business needs or risks. Actual plant and intangible additions for Centra's capital programs and projects for 2017/18 through 2022/23, the 2023/24 forecast, and the 2024/25 Test Year are summarized in Figure 7.1.

Figure 1 Plant & Intangible Additions

(\$ Thousands)

	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24 Forecast	2024/25 Test Year
Programs	29,032	30,442	37,315	34,037	41,247	38,258	50,787	44,539
Projects	7,536	5,865	9,897	9,165	2,787	4,088	16,787	15,363
Portfolio Adjustment	-	-	-	-	-	-	(1,759)	(3,589)
Total Plant Additions	36,568	36,307	47,212	43,202	44,034	42,346	65,815	56,313

Figure 7.1 — Plant and Intangible Additions Since the Last General Rate Application

The most significant program-related rate base additions from 2019/20 to 2023/24 are for the following programs:

- New Business involving construction of mains and services to serve new customers (\$107 million);
- Meter Compliance (\$38 million);
- System Betterment – Integrity in order to address degradation of pipeline and station assets (\$11 million);
- System Betterment – Measurement & Regulation Stations in order to upgrade and improve assets used to measure and control the gas system (\$14 million); and
- System Betterment – Gas In-Line Inspections to complete steel pipeline inspections using specialty tools inserted into the pipeline to measure corrosion, dents, and other potential defects (\$6 million).

The significant project-related rate base additions from 2019/20 to 2023/24 are for the following projects:

- St. Pierre Transmission Pressure Line Upgrade, which was \$1 million over its pre-construction budget of \$2 million due to deferred construction from 2018 to 2019 and pipeline routing changes to rectify existing insufficient cover and encroachment issues;
- Brandon Primary Gate Station GS-123 Re-Construction, which was \$1.8 million above its pre-construction budget of \$2.3 million due to higher than anticipated contract bids, as well as increased internal inspection and contract administrator labour hours;

- Natural Gas Transmission Pressure System In-Line Inspection for six transmission pipeline segments (ranging from 6 to 16 inches in diameter), totalling \$7 million;
- Steinbach Natural Gas System Upgrade, which was \$2.1 million above its pre-construction budget estimate of \$4.5 million due to the scope addition of 4km of steel transmission pipeline and more winter construction labour work than was initially anticipated due to limited contractor availability during the summer of 2023;
- Letellier-Red River Transmission Pipeline Upgrade, which Involved the abandonment of one of two parallel, and geotechnically unstable, 4-inch diameter pipeline crossings at a location under the Red River near Letellier, as well as the installation of a new 8-inch diameter transmission pipeline river crossing to provide additional gas supplies across the river and address reliability risks. The project was ultimately \$2.6 million over its pre-construction budget of \$1.6 million. This was primarily due to subcontractors requiring multiple attempts to drill through the geotechnically challenging area and ultimately completing a longer and deeper drill path under the Red River.

Centra states that project cost overruns for projects with horizontal directional drilling are partially related to its decision to drill deeper into the glacial till layer as opposed to the shallower clay layer. While this approach costs more, the pipeline is situated in a more stable geotechnical zone and is less susceptible to erosion and subsidence. Recently, Centra has expanded its reliance on the geotechnical expertise of Manitoba Hydro. Other lessons learned which should improve project cost estimates include:

- Requesting prices from a wider cross-section of contractors;
- Incorporating the increased costs of drilling through glacial till in the project cost estimates; and
- Reflecting the potential costs of failed drilling attempts in the contingency.

Centra's capital expenditures include both Business Operations Capital spending (i.e., for capital programs and projects), and demand-side management expenditures discussed in section 4.5 of this order. Figure 7.2 provides a summary of Centra's overall business operations capital expenditures for the past six years, compared with the forecast from the 2019/20 General Rate Application.

Business Operations Capital (\$ million)	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
2019/20 GRA Forecast (CEF18)	35.4	40.1	38.4	39.0	39.8	40.6
Actual	36.9	43.4	36.6	45.0	45.7	49.8
Variance (overspend is negative)	(1.5)	(3.3)	1.8	(6.0)	(5.9)	(9.2)

Figure 7.2 — Capital Underspend & Overspend Compared to CEF18

7.3 Capital Expenditures During the 2024/25 Test Year

7.3.1 *Centra's Capital Investment Plan*

Centra currently operates approximately 11,000 km of mains and 7,500 km of service pipelines. Centra's 2024-2028 Natural Gas Asset Management Capital Investment Plan forms the basis of the proposed Business Operations Capital expenditures in this general rate application. This plan serves to define and schedule programs and projects to maintain safe and reliable operation and preserve regulatory compliance. The plan sets out the details of known programs and projects to be implemented in the next half decade together with potential future projects. Centra reviews and revises the plan annually as situations change and as new information becomes available.

7.3.2 *Manitoba Hydro's Asset Management System*

The ultimate goal of asset management is to achieve an optimal balance of asset performance, cost, and risk to support business objectives.

Centra's natural gas operations are fully integrated within Manitoba Hydro, such that the approach to asset management is enterprise-wide and incorporates natural gas assets as well as electricity assets. Centra's asset management processes were reviewed at the 2019/20 General Rate Application, with the Board's findings included in Order 152/19. Because the Board reviewed Manitoba Hydro's integrated asset management approach in the 2023/24 and 2024/25 electric general rate application, the Board excluded asset management from the scope of intervenor evidence in this proceeding.

In Order 152/19, the Board issued Directive 8 which required Centra to file its strategic asset management plan with the next general rate application. Since that time, the utility has instituted a corporate Asset Management Policy and a Strategic Asset Management

Plan which it filed in this proceeding. The shared intent of the policy and plan is to mature Centra's asset management system to enable the utility to maximize the value of its assets over their respective lifecycles to the benefit of ratepayers. Good asset management can be described as performing the right work, at the right time, for the right reasons. As such, asset management planning seeks to forecast future asset needs (e.g., maintain, enhance, overhaul, or replace assets) in order to formulate an optimized Business Operations Capital expenditure plan to achieve the utility's asset management objectives. While the forecasting component is largely a factor of asset condition, age, and rate of condition decline, Centra maintains that the capital planning process involves ensuring appropriate resources (both financial and human) are in place to ensure the needs of the assets can be met.

7.3.3 Capital Planning Process

Centra applies a capital optimization process to design a capital project portfolio that maximizes investment value and minimizes risks to the organization, taking into account funding, resource, and timing constraints. The optimization process is a yearly initiative that establishes and communicates the project and program portfolio.

When developing its project and program portfolio, Centra establishes values for the prospective capital projects. Alternatives to the proposed projects are valued through the Corporate Value Framework ("CVF") to determine the alternative offering the most value in terms of reducing risk. Unless the most valuable alternative is to "do nothing", the investment will proceed to internal approval.

Centra submits that its long-term gas portfolio planning efforts have not identified a significant number of potential need projects that would necessitate portfolio optimization. Projects within the gas portfolio have a relatively short turnaround, with a lifecycle from need identification to completion of project execution taking between one to three years. Therefore, Centra states that the capital optimization process has limited applicability or relevance to such projects. Specifically, investments are valued in the CVF as part of the internal approval process to ascertain and communicate their value. However, gas-related projects are not compared to one another as a means of portfolio optimization.

Instead, Centra internally recommends its capital funding requirements based on ongoing projects and programs already in progress. Longer term, potential need assets are identified by technical experts and considered, though not yet evaluated by the CVF. The recommended asset funding is subsequently evaluated by Centra's management along with Centra's long-term financial situation, including revenue requirements, to establish spending targets. Centra further submits that senior management reviews and approves the targets, and the capital expenditure plan proceeds through Centra's governance model, which includes approval by the Manitoba Hydro-Electric Board ("MHEB") and the provincial government, although the Province approves only one year of expenditures at a time.

In terms of the utility's internal capital approval process, Centra shares the same approval level categorization as Manitoba Hydro, meaning capital projects and programs require approval by increasingly senior leadership as the project or program value increases. However, except in rare circumstances, Centra does not have individual capital projects that are of sufficiently high value (e.g., greater than \$25 million) to require approval by the Executive Committee or MHEB. By way of example, even the South Loop Upgrade, which is a major capital investment project for Centra, involves an estimate of \$19 million and falls below the \$25 million threshold.

In this hearing, Centra provided CVF scores for some of its projects. The CVF assigns value points based on specific risks that the project is intended to mitigate. Those risks include reliability benefits, capacity risk, financial risk, safety risk, environmental risk, compliance risk, and stakeholder perception risk.

The Oakbank System Capacity Upgrade project, which involves increasing the pipeline capacity to the growing community of Oakbank, scored the highest of all Centra's projects in its capital plan with a CVF score of 411,175. Further down the list is the Letellier-Red River Transmission Pipeline Upgrade project with a score of 11,775. Centra further normalizes these scores by dividing by the total project cost to determine the CVF value per thousand dollars of capital spending. In this way, projects can be ranked to determine the greatest reduction in risk for a given amount of spending.

7.3.4 2024-2028 Natural Gas Capital Investment Plan

Overall Expenditures

Figure 7.3 sets out the 2024/25 test year capital programs and projects in the 2024-28 Natural Gas Asset Management Capital Investment Plan are highlighted in the following chart:

PROGRAMS (\$000'S)	2023-24	2024-25	2025-26	2026-27	2027-28
Property Land Easements – Gas	72	74	75	76	78
New Business	17,400	17,800	18,200	18,564	18,935
System Betterment- Relocations	900	1,100	1,200	1,224	1,248
System Betterment- Capacity & Other	1,100	1,800	1,800	1,836	1,873
System Betterment- Integrity	3,100	3,100	3,200	3,264	3,329
System Betterment – In-Line Inspection	1,300	600	600	3,720	2,775
System Betterment- Measurement & Regulator Stations	2,480	3,230	3,770	3,800	3,750
Gas Station Upgrades (NGSCM)	600	700	710	724	739
Cathodic Protection	1,200	950	1,200	1,224	1,248
Leak Upgrades & Other (DOM)	1,275	1,300	1,350	1,377	1,405
Service Riser Remediation (DOM)	1,650	1,750	1,800	1,836	1,873
Meter Compliance Program	8,400	8,600	8,800	8,976	9,156
Programs Subtotal	39,477	41,004	42,705	46,622	46,409

PROJECTS (\$000'S)	2023-24	2024-25	2025-26	2026-27	2027-28
Oakbank System Capacity Upgrade	329	0	0	0	0
Transcona Gate Station Upgrade (GS-003)	170	0	0	0	0
Dauphin LNG Regasification Facility	169	3,305	0	0	0
Austin Primary Gate Station Upgrade (GS-195)	947	0	0	0	0
Oak Bluff Primary Gate Station Upgrade (GS-030)	0	530	2,582	0	0
Steinbach Natural Gas System Upgrade	2,410	0	0	0	0
Letellier-Red River Transmission Upgrade	786	0	0	0	0
Virden/Miniota TP System Capacity Upgrade	2,097	2,685	0	0	0
Seine River Transmission Pipeline Replacements	998	0	0	0	0
RM of MacDonald Distribution Upgrade	671	685	0	0	0
South Loop System Upgrade	0	418	6,514	12,000	0
St Norbert-Waverley West Modifications	0	1,140	1,212	0	0
Elie-St Francois Xavier Capacity Upgrade	971	1,703	0	0	0
Gas SCADA Software Upgrade	220	2,119	0	0	0
Projects Subtotal	9,769	12,584	10,308	12,000	0
TOTAL COSTS	49,246	53,588	53,013	58,622	46,409
Portfolio Adjustment	-1,750	-3,580	-2,005	-6,593	6,660
NET TOTAL COSTS	47,496	50,008	51,008	52,028	53,069

Figure 7.2 — Proposed Capital Programs & Projects Spending

Notable capital expenditures over \$2 million planned for 2024/25 Test Year include the following:

- New Business Program (i.e., new mains and services): \$17.8 million - net of third-party contributions in aid of construction and approximately 55% residential and 45% commercial.
- Meter Compliance Program: \$8.6 million – removing meters, testing, repair, calibration, and re-installation, along with new meter purchases.
- System Integrity – Integrity Program: \$3.1 million
- System Integrity – Capacity & Other: \$1.8 million
- Service Riser Remediation: \$1.75 million
- Virden/Miniota Transmission Pressure System Capacity Upgrade: \$2.7 million. This involves the installation of additional pipeline looping sections to address industrial and agricultural load growth projections. The revised project in-service date is October 2025.
- Gas SCADA Software Upgrade: \$2.1 million. This is for an upgrade to the software system used to monitor and control Centra's gas distribution system in real time. The existing software is no longer supported by the vendor and this project is expected to include both the new software as well as the labour required to integrate it into Centra's operations.
- The Oak Bluff Primary Gate Station Upgrade and the South Loop System Upgrade projects have minimal capital spending for 2024/25 (\$0.5 million and \$0.4 million respectively) but have significant spending forecasts in future years (respectively totaling \$2.6 million and \$18.5 million for 2025/26 onwards).

Overall, approximately 36% of Centra's capital budget for 2024/25 is for new mains and service lines needed to connect new customers. This share of the overall Business Operations Capital budget is much higher than for Manitoba Hydro, which budgets the largest share of its Business Operations Capital expenditures on projects to renew and sustain its existing assets. Centra is required to serve customers in its existing service territory if service requests pass the Board-approved feasibility test, which means that the

utility cannot avoid expenditures required to upgrade its gas mains to meet customer demands.

South Loop Project

Centra's South Loop transmission main system serves roughly 10,000 customers in south-central Manitoba, including the communities of Morden, Winkler, Altona, Morris, Dominion City, Emerson, Carman, and Oakville. Because of new residential, commercial, and agricultural customers connecting to the South Loop system, the South Loop is at or approaching its capacity limit. This growth in capacity needs has been exacerbated, at least in part, by significant grain dryer loads energized in 2023-2024. Given the economical advantages of gas for grain drying, Centra does not forecast a decrease in grain drying-related usage.

Centra's evidence in this proceeding further suggests that if TC Energy, who owns and operates the upstream pipeline to Centra's system, were to deliver gas at the minimum pressure specified in its approved tariff, Centra would not have sufficient capacity to serve all current customers on the South Loop. As a result, Centra concludes that its South Loop system requires additional capacity in order to serve the forecast load growth in the area. The South Loop System Upgrade capital project therefore involves the installation of 67 km of new transmission pipelines that parallel two existing transmission pipelines between Dominion City and Winkler. The additional pipeline loop design was selected over other alternatives (such as gas compression or liquefied natural gas peak shaving) due to long-term reliability concerns associated with those alternatives. The current project design requires seven watercourse crossings, four railroad crossings, two TC Energy pipeline crossings, and four highway crossings. In this hearing, Centra explains that it has applied for the required *Environment Act* licence in January 2025 and expects the related process to take 18 months. Geotechnical investigations by Manitoba Hydro's Geotechnical section started in 2024 and will resume in March 2025. Centra further submits that easement-related activities will also start in June 2025. However, no work to tender the project has been completed to date and the project is tentatively due to enter service by the end of the 2027 calendar year. As of February 25, 2025, only \$0.7 million of the \$18.9 million capital cost estimate was spent.

Dauphin Liquefied Natural Gas Regasification Facility

Centra's proposed 2024-2028 capital investment plan also includes the Dauphin Liquefied Natural Gas (LNG) Regasification Facility Project for \$3.3 million in 2024/25. This project was initially planned to support projected load growth in the Dauphin area but during the course of this proceeding, Centra advised that the project has since been cancelled as the chosen solution no longer meets the needs and logistics of the region. Instead, Centra is re-assessing the best option to address the capacity needs on the upstream Minell pipeline, which ultimately serves the Dauphin region. Due to the cancellation of the Dauphin LNG project, Centra acknowledges the 2024/25 capital expenditure forecast is reduced by \$3.3 million.

Centra forecasts \$50.0 million in natural gas-related Business Operations Capital expenditures for 2024/25, not including the \$3.3 million reduction from the now cancelled Dauphin LNG project. Centra further indicates that actual expenditures for 2024/25 were \$47.4 million, a variance of \$2.6 million. If cancellation of the Dauphin LNG project is considered, Centra's capital expenditures exceeded the 2024/25 forecast.

7.3.5 Capital Pacing

Midgard Consulting, an expert witness retained by CAC, recommended that Centra repace its capital expenditure plans. Midgard suggests that Centra continues to build increased capacity under the premise that growth will continue unabated, despite Centra's flat or declining volume forecast. In Midgard's view, Centra is basing its capacity forecasts on the historic consumption trends of its primary gate stations, but that this is no longer aligned with the system volume forecast.

Midgard recommends specific reductions to three of Centra's capital programs: Service Riser Remediation, System Betterment – Integrity, and System Betterment – Capacity & Other. Midgard recommends that the budgets for the System Betterment programs be reduced to the inflation-adjusted average of expenditures made on these programs in the years 2017/18 to 2022/23. Midgard further recommends that, for a three-year period, Centra delay a ramp up of expenditures for the Service Riser Remediation. In aggregate, the recommended reductions in these programs total \$2 million annually. In Midgard's

view, this will reduce the step increase in capital expenditures that Centra implemented in 2023/24.

While Centra claims that reductions to the Service Riser Remediation program would put customers at risk and finds this risk to be unacceptable, Midgard notes that Centra did not undertake any service riser remediations in 2022/23. In Midgard's view, Centra has bypassed its own CVF evaluation framework and applied subjective judgment. This is concerning to Midgard because it implies that Centra is not objectively managing its safety risks and may be overlooking other, more critical risks in favour of the Service Riser Remediation program.

Midgard also recommends that Centra prepare for the energy transition by collecting and sharing with the Board the following information at the next general rate application:

- A reconciliation of different planning outlooks (e.g., normalized annual consumption scenarios and aggregated primary station demand projections) so that they are aligned with the same planning objectives or explain which outlooks are no longer relevant;
- The planning assumptions and assessment of their reasonableness with respect to demand growth variability;
- Rate impacts for its different normalized gas consumption scenarios prepared for the integrated resource plan ("IRP") proceeding;
- Estimates of the stranded capital that is expected to result for each of the different IRP annual consumption scenarios;
- A quantitative analysis of the correlation between historic energy and peak demand, as well as forecast energy and peak demand under the different IRP planning scenarios; and
- A comprehensive list of demand-side initiatives and non-capital alternatives (e.g., fuel switching, interruptible rates, time-of-use rates, and distributed peak shaving) that could either defer, reduce, or eliminate the need for gas capital investments.

According to IGU's witness Mr. Bowman, Centra is operating in a largely static environment of reinvestment and should not be viewed as being in an expansionary phase due to decarbonization concerns. As such, expansion is not the preferred operating mode. This suggests caution regarding excessive reliance on long-term forecasts and on a sustained long-term base on which to recover future costs.

7.3.6 Risk Assessment

Centra maintains that it has established its processes for identifying and quantifying the risks associated with its natural gas assets using enterprise-wide frameworks as well as mandatory requirements. Specifically, Centra's risk management process identifies, assesses, and manages the hazards and associated risks of the lifecycle of the pipeline system.

Centra states that it meets these requirements through its Safety & Loss Management System ("SLMS"), Quality Assessment Process, the Corporate Value Framework, natural gas risk methodologies, the pipeline system integrity management program and, in the future, through increased alignment with the Enterprise Risk Management Program and Framework.

Centra maintains a comprehensive SLMS and related management programs to ensure its natural gas system continues to be operated in a safe and reliable manner. The Oil and Gas Pipeline Systems standard CSA Z662, the latest version of which the Board adopted in Order 112/23, requires companies operating gas pipelines to develop, document, and implement a SLMS with the goal of protecting people (employees, contractors and the public), the environment, and property.

Midgard recommended that Centra implement a Process Safety Management ("PSM") program to enhance its existing SLMS and safety management system, with an implementation plan to be filed in a subsequent application. According to Midgard, a PSM program would focus Centra on preventing and mitigating major accident hazards that occur at a very low annual frequency but pose significant risks to public safety, infrastructure, and the company's reputation when they do occur.

While CSA Z662 provides a foundational compliance baseline, a comprehensive PSM system such as those outlined in CSA Z767 or the Center for Chemical Process Safety guidelines extends significantly further into organizational culture and proactive risk management.

7.3.7 Demand Side Management

In addition to business operations capital spending, Centra funds Efficiency Manitoba to deliver natural gas demand-side management programs. While these are not capital expenditures for Centra, these expenditures are deferred in a regulatory deferral account and form part of Centra's rate base.

Under *The Efficiency Manitoba Act*, Efficiency Manitoba is required to achieve natural gas energy savings of least 0.75% of the consumption of natural gas in the preceding year. While the utility regularly engages with Efficiency Manitoba, Centra does not have direct influence on Efficiency Manitoba's level of forecast gas demand-side management expenditures.

In 2020, the Board reviewed Efficiency Manitoba's 2020/21 to 2022/23 efficiency plan. The Province of Manitoba has since extended this plan beyond the 2022/23 fiscal year.

In Order 128/09, the Board directed Centra to amortize its DSM expenditures over a 10-year period (with the exception of the Furnace Replacement Program, which was to be expensed in the year incurred). Section 4.5.2 of this order provides more information on the amortization of Centra's demand-side management expenditures and the related party positions in this hearing.

7.4 Position of the Parties

7.4.1 *Centra*

Centra maintains that, since the last general rate application, continued investment in the natural gas system was and is essential to maintain safe and reliable service that Manitobans are accustomed to receiving. Therefore, Centra's capital plan is reasonable and necessary for the safe and reliable operation of the natural gas network. While Centra acknowledges the energy landscape is changing in Manitoba, the utility maintains that natural gas will remain an important energy source for Manitobans for the foreseeable future.

While Centra's 2024 Natural Gas Volume Forecast shows that growth in Centra's total sales volumes in Manitoba are projected to remain relatively flat with a slight decline, volume growth rates in specific geographic areas are specific to local development plans and customer requests, which Centra forecasts based on historic trends. Centra's distribution system is designed to deliver the peak hour demand on a design day, which is not comparable to annual volume forecasts. While annual volumes may be projected to plateau or decrease across all customer classes if Efficiency Manitoba targets are met, Centra continues to connect new firm customers each year, which has increased the hourly peak gas usage.

According to Centra, work is prioritized within each specific gas portfolio program, and projects are typically prioritized by hydraulic system need, risk assessment results, integrity activities and customer schedule. This feeds into the multi-year Capital Expenditure Plan. Project execution capacity currently drives the timing of investments.

Centra states that its pacing of System Betterment – Integrity, Capacity & Other, and the Service Riser Remediation programs is appropriate. Using historical averages in a period of underspending is not appropriate as the required integrity and remediation work is beyond the 2% growth over historical spending. As a result, Midgard's proposed decrease in spending would provide insufficient funding and result in increased risk to gas integrity and non-compliance with CSA Z662. Further, defunding the System Betterment Capacity

& Other program that delivers energy to Manitobans is not practical while approximately 2,400-3,100 new customer connections are completed annually.

When planning for a station upgrade, Centra reviews the overall reliability and capacity needs to minimize future rework, system impacts, and cost. If Centra were to only complete a reliability upgrade, it would need to remobilize a few years later to complete a capacity upgrade, resulting in increased overall costs. Executing capacity upgrades at the same time as a reliability project is therefore more cost effective and maintains the resource availability to complete approximately 5 station upgrades per year. Similarly, decreasing funds and re-pacing the Service Riser Remediation program would not allow Centra to keep up with the needed 3,000 service meter set remediations per year.

Centra intends to address problems with directional drilling projects and avoid cost overruns by undertaking additional geotechnical investigations, which may lead to drills that are deeper, longer, and through challenging ground conditions. While undertaking these drills can be riskier and more expensive than Centra's historical drills, they result in infrastructure being placed through significantly more stable ground, protected from landslides such as the one that caused the original Letellier crossing failure. Centra also continues to learn from past projects and incorporates lessons learned into future projects.

In regards to the South Loop System Upgrade, Centra indicates that this project is a needed capacity upgrade on a capacity-constrained part of Centra's gas system that supports residential, commercial, and industrial developments in the region. Connections of grain drying customers also remain strong on the South Loop and work is underway to better understand this type of customer load. Pipeline looping in the South Loop System Upgrade, as opposed to gas compression, provides the long-term capacity and reliability benefits needed to support economic development in this region.

Centra does not consider implementation of Midgard's recommendation for a PSM program necessary. Centra already employs best practice safety measures in the construction, operation, and maintenance of its natural gas network, including compliance with CSA Z662. Low-probability, high-consequence events are also already addressed

by Centra through multiple layers of protection from the Safety and Loss Management System, the Safety Management System, and the Pipeline System Integrity Management System. Further, Centra is not aware of PSM programs being added to gas distribution regulations in Canada or the impending applicability of CSA Z767 to CSA Z662.

Through Centra's canvassing of other Canadian gas utilities, none currently have a PSM program for their gas pipeline system other than Enbridge. Further, it is unclear whether Enbridge's PSM program is in addition to its safety and loss management system and whether or not it applies to their pipeline and conveyance gas business or to the processing side of their business.

Consumers Association of Canada

CAC maintains that Centra's ability to make sound asset management decisions is constrained by poor quality asset data, low risk assessment and review maturity, and weaknesses in asset management decision-making. As a result, Centra continues to rely on budget envelopes. A more mature asset management program would systematically address asset condition and risk issues that develop gradually over the long lifespans of utility infrastructure.

CAC's fundamental concern with Centra's capital investment proposal is the disconnect between Centra's stated planning premise of flat or declining natural gas consumption and its continued reliance on a "business as usual" capital planning approach. Specifically, flat or declining gas demand is not congruent with a projected increase to peak demand at all primary gate stations through 2043. Localized needs, such as specific grain dryer loads or localized population growth, may warrant targeted investment but they do not justify a general capital expansion strategy.

CAC cautions that by continuing to plan as though perpetual growth is assumed, despite Centra's own projections to the contrary, Centra exposes ratepayers to underutilized, or effectively stranded, assets and unnecessary financial risk.

CAC relies on Midgard's representation that increases in annual energy consumption have been, based on historical data, positively correlated with increases in peak demand.

However, the appropriate expectation is a peak demand growth rate that will either be positive, but lower than historical trends, or potentially negative. While some peak demand growth may be expected from new gas furnace additions, the overall growth rate will be lower than historical trends due to peak demand reductions, driven by continued efficiency improvements, full fuel switching as customers abandon their gas service, and partial fuel switching to electric appliances such as electric water heaters.

Accordingly, CAC submits that Centra re-pace its capital investments, which now show a marked step increase (compared to historic trends) starting in 2023/24. Specifically, the System Betterment-Integrity and System Betterment-Capacity & Other programs should be limited to historical average spending until such time as Centra can demonstrate the risks being mitigated and that increasing annual energy demand is not offset by decreases from fuel switching. Further, Centra's service riser remediation program should have a slower ramp-up.

CAC also adopts Midgard's recommendation for additional information filed with the next general rate application to help validate Centra's claim of decoupling of energy and peak demand and to better prepare for the energy transition. This information should include reconciling demand forecasts, quantifying primary station variability, estimating stranded capital under various scenarios, providing rate impact proxies, analyzing the correlation between energy and peak demand, and identifying non-capital alternatives to mitigate investment needs.

CAC recommends that Centra re-pace its capital plans to better align with the expectation of flat or declining annual energy. This would lower the capital expenditure budget by approximately \$2 million annually in 2024/25 to 2027/28, as seen in the table below. The recommended pacing adjustments focus on the following programs: System Betterment – Integrity, System Betterment – Capacity & Other, and Service Riser Remediation. Specifically, CAC recommends that the adjusted pacing for the System Betterment – Integrity program be aligned with historical averages until such time as Centra Gas can demonstrate the risks being mitigated by the proposed 21 percent step-change increase in spending. CAC also recommends aligning capital investment pacing for the System

Betterment – Integrity and System Betterment – Capacity & Growth programs with historical real dollar averages until such time as Centra Gas provides sufficient justification for a departure from past trends.

According to CAC, the justification for the South Loop System Upgrade project hinges on anticipated large grain drying loads that remain unconfirmed and pose a considerable risk of stranded capital to ratepayers. Given the materially higher initial capital cost of the proposed South Loop project compared to the alternatives and the risk of stranded capital if the planned loads do not materialize, it is recommended by CAC that the environmental assessment of the South Loop project continue as planned but that consideration of the South Loop project construction commencement be deferred to the next general rate application when Centra will know the results of the environmental assessment, updated construction costs, greater certainty regarding system growth rates, local growth rates, and grain dryer timings.

Regarding Midgard's recommendation of a PSM program. CAC submits that Centra should be directed to evaluate the adoption of a PSM approach as a complement to its current systems, to align with industry best practices, better manage major accident hazards, and explore potential cost savings for ratepayers.

CAC further argues that due to flammability and potential for explosion, natural gas is classified as a hazardous material and maintaining a range of operating pressures in pipelines is functionally equivalent to storing hazardous material within the system. PSM standards, though originally designed for chemical production, are now widely applied to any operation managing significant quantities of hazardous substances, including pipeline systems which transmit and store natural gas.

The Industrial Gas Users did not take a position regarding Centra's capital projects and capital expenditures.

7.5 Board Findings

7.5.1 *Historical Spending*

The Board finds that Centra's capital expenditures for the 2018/19 to 2022/23 period are used, useful, and were prudently acquired and approves their additions to rate base. The Board will evaluate capital expenditures completed in 2023/24 in a future proceeding and consider their addition to rate base at that time. The Board approves, on an interim basis, the proposed rate base for 2024/25 of \$788.6 million, including the regulatory deferral accounts proposed by Centra. The Board intends to finalize this approval at the next general rate application, based on actual capital additions.

While the Board approves the addition of these capital expenditures to rate base, it notes that Centra's project budgeting processes need improvement. Several projects, including the Letellier-Red River Transmission Pipeline Upgrade, the St. Pierre Transmission Pressure Line Upgrade, and the Brandon Primary Gate Station GS-123 Re-Construction, all experienced significant cost overruns.

Centra shares the same capital authorization levels as Manitoba Hydro. The Board does not believe that the approval authority levels for Manitoba Hydro are appropriate for Centra, whose asset base is 3% of Manitoba Hydro's consolidated operations. Projects costing less than \$2 million require approval by a director for either Manitoba Hydro or Centra, but \$2 million is approximately 0.3% of Manitoba Hydro's annual capital budget while it is 4% of Centra's budget. In the Board's view, Centra needs a capital authorization guideline specifically developed for that utility and that is tied into Centra's business plan. Centra should also investigate other improvements to its budgeting processes, including industry best practices in order to avoid the substantial cost overruns experienced on certain projects, either through better cost estimating or better project execution. This is especially important during the current period of uncertainty regarding the energy transition.

7.5.2 Capital Budgets Beyond 2024/25

While the Board is not disallowing any of the historical capital expenditures, it sees a need to adjust the prospective expenditures in light of Centra's current financial situation. Centra's overall level of capital expenditures, which has increased by approximately 20% to 30% since the 2019/20 General Rate Application, cannot continue to escalate in the face of a utility that has eroded its retained earnings and accrued multi-million dollar losses.

In the Board's view, the risk related to Centra's overall capital spending is exacerbated by the potential for cost overruns. The potential of significant cost overruns related to the \$19 million South Loop Capacity Upgrade project is especially concerning, given Centra's growing debt levels and gross margin forecasts in this proceeding.

While the Board continues to treat gas safety as a priority, the Board notes that Centra's forecast includes capacity assumptions that may not be borne out by the natural gas volume forecast. In particular, there is an apparent disconnect between the 2024 Volume Forecast projection of flat or declining volumes for Centra's overall system and the individual projections of increasing peak demand for each subsystem Centra serves through its primary gate stations. Centra explained this dichotomy by the increasing number of new customers that continue to connect to Centra's system who use gas for space heating but not for water heating, along with existing customers who replace their gas water heaters with electric ones. However, Centra's assumption is a simple approximation that is not tied to actual local demand forecasts.

In consideration of the Board's findings regarding Centra's planned capital expenditures, the Board directs Centra to reduce its capital expenditure forecast for 2025/26 and 2026/27 and find \$2 million of savings in overall capital budgets for each of these years. This is in line with the magnitude of spending reductions recommended by Midgard. However, the Board does not direct Centra to specifically reduce spending in the programs that Midgard identified in its evidence. Instead, Centra may conduct its own risk assessment to eliminate the lowest-risk projects if necessary.

Because the Board is approving a general revenue increase for two years beyond the 2024/25 test year, the Board directs Centra to file its 2025-2029 and 2026-2030 Natural Gas Asset Management Capital Investment Plans with its compliance filing resulting from this order. The Board expects that the 2025-2029 and 2026-2030 Natural Gas Asset Management Capital Investment Plans have already been prepared, so Centra is to reflect the reduced capital budgets in its compliance filing and may show them in separate schedules if necessary.

7.5.3 Corporate Value Framework

The Board understands that the CVF is a tool to be used to inform the capital budgeting process, and it recognizes that not all projects are evaluated with the CVF, as some projects are required to connect new customers or are mandatory because of legal or regulatory requirements. However, the Board observes that the CVF appears to have minimal impact on Centra's capital decisions, which limits its utility. Centra was unable to articulate why certain projects scored higher than others, leaving the impression that the CVF scoring methodology was overly subjective, incomplete, or inaccurate. For example, the Oakbank System Capacity Upgrade scored 34 times higher than the Letellier-Red River Transmission Pipeline Upgrade, even before normalizing for the total project expenditures.

Decision making driven by the CVF is a hallmark of a mature asset management system, as it allows a utility to prioritize limited budgets in the most cost-effective manner. If capital funding is constrained, projects can be compared using their CVF scores to identify the portfolio of expenditures that deliver the greatest reduction in risk for the available capital funding. However, this approach only works if the CVF scores can be relied upon to be a valid measure of the amount of risk reduction per dollar of spending. The Board directs Centra to file a report with its next general rate application on how it intends to use the CVF to prioritize and approve capital expenditures in future test years to better manage limited capital budgets.

The Board finds Order 152/19 Directive 8, which directed Centra to file a strategic asset management plan, to be complete.

7.5.4 Energy Transition and South Loop System Upgrade

The energy transition, which is the expected reduction in natural gas usage as customers seek to decarbonize their energy use, was ruled out of scope of this proceeding in Order 127/24 as, at the time, the Board only expected to review and approve rate increases for a single test year. This means that questions about the long-term usage and viability of Centra's gas system and the potential for stranded assets were not canvassed in this proceeding. The Board's intention is for these questions to be brought forth in upcoming proceedings, such as the review of Manitoba Hydro's integrated resource plan which is scheduled for 2026.

That said, it is clear that gas for space heating is the most viable and economic option for space and water heating at this time. Without direction from the government that gas is to be restricted to any degree, the Board expects continued growth in the gas system. Also, the Board has not reviewed any of Efficiency Manitoba's Efficiency Plans since the inaugural plan submitted to the Board in 2019. The Board is waiting for more information and policy direction from government. In the interim, the Board set the scope of this proceeding to exclude the energy transition, but is now reviewing capital expenditures for a three-year period including a major expenditure such as the proposed South Loop System Upgrade.

The issues around the energy transition and the future use of gas have taken on added significance when considering the South Loop System Upgrade project, which is a \$19 million project to enhance the capacity serving Morden, Winkler, Morris, and other communities in the area.

At present, Centra has an obligation to serve when customers request service, if economic to do so. The Board's economic feasibility test determines whether it is economic; if the discounted cashflow analysis shows that it is not, customers must make a contribution toward construction. In the absence of government policy restricting or precluding the expansion of the gas system, the Board finds that Centra's obligation to serve if economically justified supports the construction of the South Loop System Upgrade.

That said, Centra is in the preliminary stages of developing the South Loop System Upgrade, and is currently in the process of obtaining a licence under the *Environment Act*. The Board questions whether the primary drivers articulated by Centra for this project, specifically grain drying loads, are certain enough to justify the \$19 million South Loop System Upgrade. Furthermore, even if these loads ultimately materialize, there is the question of whether the revenues from these grain drying loads are sufficient to justify this capacity expansion. The Board therefore recommends that the Manitoba Hydro-Electric Board review this project before a final expenditure decision is made, even if it falls below the \$25 million threshold of the current policy.

The Board has not historically applied the approved feasibility test to system-level expansions (which would potentially require customers to contribute to the construction costs if forecasted revenues are insufficient). Costs to increase capacity at the system level have typically been considered “system betterment” and have been excluded from the feasibility test. However, it does not mean that the merits of an expansion that may not fully recover its costs cannot be considered by the Board. The Board understands that, individually, these grain drying loads pass the feasibility test because they make use of unutilized capacity on their local gas systems, and therefore require only a minimal contribution in aid of construction, or no contribution at all. However, in aggregate, these grain drying loads are contributing to the need for a \$19 million expansion at the system level and their annual revenues may not justify such an expansion.

The Board notes that these grain drying loads typically are in the Large General Service customer class, because their annual volumes are less than 680,000 m³ per year. However, their peak hourly demands may be more in line with the loads typically found in the High Volume Firm class. Customers in the High Volume Firm class have demand meters which measure peak daily demand and they pay a demand charge in addition to their Basic Monthly Charge and commodity charges. The demand charge is specifically to recover the demand-related costs of serving these customers. Grain dryers in the Large General Service class do not pay a demand charge. They therefore only pay \$77 per month as their Basic Monthly Charge (which Centra proposes to increase to \$85 in this proceeding), with the bulk of their revenues coming from their commodity charges.

However, because grain dryers operate for only limited periods of the year in the fall and early winter, their overall annual revenues may not provide a material contribution toward the fixed costs of the South Loop System Upgrade.

The Board directs Centra to study these and other seasonal, low annual load factor customers to determine whether it is appropriate to modify the rate design and apply a demand charge. Metering their daily demand and charging a demand charge may help contribute to recovery of system expansion costs such as the South Loop System Upgrade. This study should also consider whether changes to the demand charge winter ratchet are warranted for these customers, or whether a special service offering, such as the previously approved Modified Large General Service offering discussed further in section 10.3 that requires grain dryers to cease service between December 1 and March 31, is a suitable option.

With respect to the estimated capital cost of the South Loop System Upgrade, the Board notes that Centra has underestimated the capital cost of several large projects in recent years. With a project as large as the South Loop System Upgrade and which has several water, road, and other pipeline crossings, similar proportional cost overruns would have a significant negative impact on ratepayers. The Board recommends that this project and its budget be given appropriate scrutiny, including by the Manitoba Hydro-Electric Board. The current approval process, including the regulatory process to obtain an *Environment Act* licence, provides the opportunity for stage gate approvals where cost forecasts can be refined prior to the final decision to proceed.

7.5.5 Process Safety Management

The Board finds that Centra's safety and risk management of its pipeline system is completed through its safety and loss management system. This is consistent with Order 90/16 and the requirements of CSA Z662, the latest version of which was adopted in Order 112/23. Order 90/16 also directs Centra to continue its Quality Assessment Process, which is primarily used to verify Centra's compliance with its documented procedures, standards, safe work practices, and work instructions. Centra's Quality

Assessment Process also contributes to the continual improvement of Centra's operations and documented systems.

As such, the Board does not require Centra to adopt the Process Safety Management system approach. However, as there are likely elements of the PSM methodology that could be of use to Centra to manage low probability, high consequence events, the Board encourages Centra to review the PSM methodology and, if warranted, adopt relevant beneficial approaches from this methodology.

8.0 COST OF SERVICE STUDY

Once Centra's revenue requirement has been determined, the next step in the rate-setting process is to determine which customers or groups of customers should be responsible for paying which portions of the revenue requirement. This is accomplished largely by means of a cost of service study, which is used to allocate costs to customer classes based on how each group contributes to the costs being incurred. 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 considers other factors, such as fairness and equity, in the final rate design.

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

1. Step One: Functionalize or categorize the total annual costs into one of six gas utility functions (Production, Pipeline, Storage, Transmission, Distribution, Onsite).
2. Step Two: Classify the functionalized cost into one of three categories (Energy, Demand, Customer) based on the system design and operating characteristics that cause the costs to be incurred.
3. Step Three: Allocate the functionalized and classified costs among Centra's customer classes. 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 Board completed a major review of Centra's cost of service methodology in 2022 and approved various changes in Order 109/22 that are summarized and explained in detail in that order. While Centra's cost of service methodology was not fully reviewed again in this proceeding, Centra and interveners raised several cost of service related issues that are addressed in this section.

8.1 Changes Resulting from Order 109/22

8.1.1 *Background*

With Order 109/22, the Board approved several changes to Centra's cost of service study methodology that were to be implemented for the next general rate application. For example, Directive 1 of Order 109/22 approved the following:

- Directive 1.a): Use a design day coincident peak methodology (instead of peak and average) to allocate the Demand cost component of Centra's Transmission and Distribution functions;
- Directive 1.b): Directly assign dedicated transmission mains and related assets supplying unodourized gas to the Special Contract and Power Station classes.
- Directive 1.c): Use a minimum system study, which uses system cost data indexed to inflation, to inform the classification of Centra's Distribution mains.
- Directive 1.d): Use a design day coincident peak methodology that excludes Interruptible customers (instead of peak and average) to allocate the Demand component of Centra's Pipeline function.
- Directive 1.e): Use a winter season demand in excess of summer season demand methodology that includes Interruptible customers (instead of peak and average) to allocate the Demand component of Centra's Storage function.

Directive 2 of Order 109/22 required Centra to update its service line study and meter study using cost data indexed for inflation. Directives 5 and 6 of Order 109/22 required various updates stemming from the Order 131/21 rate restructuring decision, along with the elimination of the Co-op customer class within the cost of service study.

In Order 6/24, the Board ruled that Centra's revised cost of service model was to be reviewed by an independent expert consultant for compliance with various directives from Order 109/22. Accordingly, the Board engaged Elenchus Research Associates ("Elenchus") as an independent expert consultant to analyse Centra's cost of service

model and file a compliance report in this hearing. Elenchus concluded that Centra's cost of service model fully complies with the Board's directives set out in Order 109/22. None of the parties took issue with that overall conclusion.

Centra's minimum system study (Directive 1.c of Order 109/22) is separately addressed in section 8.4 below. Similarly, issues related to the franchise expansion adjustment (Directive 3 of Order 109/22) and to the unaccounted-for gas study (Directive 4 of Order 109/22) are separately addressed in sections 8.2.1 and 8.3 below.

In this hearing, Centra submits that it has updated its cost of service methodology to reflect the changes approved in Order 109/22, which results in updated allocators included in Centra's cost of service study for the 2024/25 test year.

IGU's witness, Mr. Bowman, criticized Centra's development of its design day ("DDAY") allocators by observing that Centra's proposed allocators may not be appropriately paralleling the loads used for determining rates, resulting in greater than expected allocations to the High Volume Firm and Mainline customer classes. As a result, Mr. Bowman recommends that the Board should direct Centra to complete a more detailed assessment of its implemented approach to the new design day allocators to determine whether the allocator is adequately representing the test year.

In response, Centra submits that its design day allocators are based on the degree day coefficients from the 2021 and 2024 volume forecasts, excluding the Special Contract and Power Station class loads. Further, Centra submits that the DDAY methodology differences noted by Mr. Bowman are because the peak day allocations discussed at the 2021/22 Cost of Service Methodology Review proceeding were based on the peak portion of the previous peak and average methodology and not the new DDAY methodology now developed and implemented as a result of Order 109/22.

In regards to the direct assignments applied to the Special Contract and Power Station classes pursuant to Order 109/22, CAC's witness, Ms. Derksen, submits that Centra has not provided a reasonability assessment to evaluate those direct assignments of costs.

Concerns therefore remain about their appropriateness, including whether more costs should be directly assigned to those classes.

8.1.2 Position of the Parties

Centra

Centra submits that the results of the 2024/25 Cost of Service Study comply with Order 109/22 and that this was confirmed by Elenchus in this proceeding. Centra also disagrees with Ms. Derksen's assertion that the direct assignments made to the Special Contract and Power Station classes are unreasonable as these were based on the accounting records applicable to the portion of assets used to service these customers.

Consumers Association of Canada

CAC did not make specific submissions regarding the above issues.

Industrial Gas Users

IGU submits that, subject to its submissions discussed in the sub-sections outlined below, Centra has properly and accurately implemented the methods and directives from Order 109/22. However, Centra's design day parameters should reflect the results of the 2024 load forecast, which was filed later in this proceeding, with the updated allocators incorporated in an updated 2024/25 cost of service study to be used for setting rates in this proceeding.

8.1.3 Board Findings

The Board accepts the report filed by Elenchus and finds that Centra's cost of service study and methodology, as filed in this proceeding, complies with the directives set out in Order 109/22. While the Board notes Mr. Bowman's concerns regarding the design allocators, and expects Centra to periodically refresh its allocators, the Board does not see the need to issue a specific directive on the issue at this time.

For the purposes of this section, Directives, 1.a), 1.b), 1.d), 1.e), 2, 5, and 6 of Order 109/22 are deemed complete. The Board's findings for Directive 1.c) of Order 109/22 are addressed in section 8.4 of this order.

8.2 Additional Methodology Changes Proposed by Centra

In addition to the changes implemented as a result of the Board's directives from Order 109/22, Centra proposes to make four additional changes to its cost of service methodology. In Orders 125/24 and 129/24, the Board approved interim rates effective November 1, 2024 that were based on Centra's 2024/25 cost of service study results at that time, which incorporated these additional methodology changes.

8.2.1 Elimination of Franchise Expansion Adjustment

In Order 118/99, the Board approved a Franchise Expansion Adjustment to reflect that significant rural expansion in the 1990s resulted in allocation of costs to several customer classes that were not benefitting from the expansion. Under the Franchise Expansion Adjustment, the costs attributed to each customer class were permanently adjusted so that each higher volume class did not pay more than it would have paid without the expansion project.

At the 2021/22 Cost of Service Methodology Review proceeding, Centra proposed to eliminate the Franchise Expansion Adjustment from its cost of service study. While the Board accepted Centra's rationale to eliminate the adjustment for the Special Contract and Power Station classes, Directive 3 of Order 109/22 required Centra to file additional information before the Board would consider approving its full elimination.

In this hearing, Centra continues to propose the full elimination of the Franchise Expansion Adjustment. Centra submits that given the change to directly assign costs to the Special Contract and Power Station classes, as well as the change to a peak day allocation methodology for demand-related costs, which affects the remaining larger volume customer classes, the adjustment is no longer appropriate. Centra's proposed cost of service results for 2024/25 therefore reflect the full elimination of the Franchise Expansion Adjustment. However, pursuant to Directive 3 of Order 109/22, Centra filed alternate cost of service study results incorporating the elimination of the Franchise Expansion Adjustment for only the Special Contract and Power Station classes.

CAC's witness, Ms. Derksen, as well as IGU's witness, Mr. Bowman, both supported the full elimination of the Franchise Expansion Adjustment.

8.2.2 *Allocating the Cost of Demand-Side Management*

Centra previously allocated the cost of demand-side management ("DSM") on the basis of forecast class participation in DSM programs. In this hearing, Centra proposes to change this allocation methodology to instead allocate DSM costs based on historic class participation (i.e., the last ten years) rather than forecast participation. Centra submits that this methodology change is more reflective of cost causation as DSM expenditures are capitalized and subsequently amortized over a period of ten years. It is these amortized costs that form part of the revenue requirement and which are allocated to and recovered from customers.

CAC's witness, Ms. Derksen, ultimately supported the proposed change to the allocation of DSM costs for the reasons outlined by Centra. While also supporting, this change, IGU's witness, Mr. Bowman noted concerns regarding the long amortization period of DSM and a disconnect between participating customers reducing their consumption and those costs increasingly being allocated to the remaining customers within the same class who were unable to similarly reduce their consumption. Given the cost allocation impacts of this change to the High Volume Firm and Mainline customer classes, Mr. Bowman suggests that it may be appropriate to implement this change in stages while the matter of DSM deferral is further considered.

8.2.3 *Allocating the Cost of Working Capital Related to Gas in Storage*

As discussed in section 6.0 of this order, Centra makes use of gas storage in order to levelize and smooth out its annual gas purchases and minimize its overall gas costs. Effectively, Centra pre-purchases gas supplies during the summer period, transports those supplies to contracted gas storage facilities in the U.S., and then withdraws them from storage for use during the subsequent winter heating season. As a result, Centra includes costs related to its gas storage inventory in the working capital requirements included in its rate base calculations. While rate base does not ultimately form part of the rates to be paid by customers, the results of its allocation are used to drive the class

allocations of certain revenue requirement items such as finance expense, capital taxes, corporate allocation, and, previously, net income.

For the purposes of its cost of service study, Centra functionalizes the gas in storage as Storage and classifies it as Energy. In this hearing, Centra is not proposing to change this approach. However, the utility proposes to use winter volumes rather than annual volumes for the allocation of gas in storage included as working capital in Centra's rate base. Centra's rationale for this proposal is based on the fact that the costs associated with gas storage are driven by Centra's need to meet winter demands, which it can do more economically by using storage instead of holding excessive firm pipeline capacity which goes unutilized for much of the year. In addition, storage also reduces Centra's gas purchases during the winter period, when demand for gas is higher and market prices tend to be higher.

IGU's expert, Mr. Bowman, supported this change for the reasons cited by Centra. However, CAC's expert, Ms. Derksen, opposed the change. According to Ms. Derksen, the intent and purpose of storage is to take advantage of excess summer capacity made available by low load factor classes such as the Small General Service class, in order to purchase lower cost commodity in low demand periods. The result is that all sales customers benefit through commodity costs that would otherwise be higher.

8.2.4 Allocating Net Financial Losses

Centra has historically functionalized, classified, and allocated net income based on its rate base. Allocating net income on this basis effectively treats it as a return on investment, a cost most reasonably viewed as driven by the net investment of the utility.

As described in section 3.0 of this order, Centra has experienced an annual net loss for several years, including a net loss during the 2024/25 test year (even with the proposed general revenue increase). In this proceeding, Centra is proposing to allocate the net loss in proportion to the utility's non-gas revenue requirement instead of the class share of Centra's rate base. According to Centra, this treatment recognizes that it is not Centra's assets that are causing the negative financial position, but rather the cumulative effect of

the changes in all components of the non-gas revenue requirement. In particular, Centra notes that increases in expenses related to operation and administration, finance, and depreciation, are driving the forecast net loss, rather than changes to rate base.

However, Centra is not proposing this change to be a permanent cost of service study methodology change. Rather, Centra's intention is to allocate future levels of positive net income according to rate base, as was historically done.

8.2.5 *Position of the Parties*

Centra

With respect to the Franchise Expansion Adjustment, Centra states that, with the direct assignment of transmission plant to the Special Contract and Power Station classes approved in Order 109/22, it is no longer reasonable to include an offset to such costs, since the costs are no longer being allocated to those classes. Similarly, with the elimination of the Peak and Average methodology approved in Order 109/22, the High Volume Firm and Mainline classes now receive a lower allocation of demand costs. As a result, maintaining the Franchise Expansion Adjustment to these classes would over-compensate them for costs that are no longer being allocated to them.

Regarding the use of historic participation to allocate the cost of demand-side management costs, Centra states that the proposal is an improvement in cost causation as it better matches the capitalization and subsequent amortization of DSM costs. Further, Centra submits that the allocation of DSM costs will be updated for each cost of service study so that the allocation remains consistent with costs being recovered through rates.

Regarding the allocation of the working capital related to cost of gas in storage, Centra explains that its proposal recognizes that it is the increased needs of customer classes through the winter period that drive the need for holding winter storage in the first place. The utility therefore notes that, without winter volumes being higher than summer volumes, the extra costs associated with storage would not be required.

According to Centra, its proposal to use non-gas revenue requirement for the purposes of allocating its net loss in the test year represents a level of fairness between how classes are allocated the net loss. Absent the change, some classes would receive less of a benefit of phasing in overall revenue requirement increases.

Consumers Association of Canada

In its final argument submission, CAC did not specifically address Centra's proposal to eliminate the Franchise Expansion Adjustment, the methodology used to allocate the costs of DSM, or the costs of gas in storage included as working capital in rate base. However, CAC argues that, consistent with Order 109/22, Centra's proposed net loss allocation change embeds fairness and equity considerations that should be removed from the cost of service study and instead embedded in a Zone of Reasonableness (with revenue to cost coverage ratio adjustments).

Industrial Gas Users

IGU supports the elimination of the Franchise Expansion Adjustment, the proposed allocation for the cost of gas in storage included in working capital, and the temporary change proposal regarding the allocation of net losses.

Regarding the issue of the allocation of DSM costs, IGU notes that, in isolation, the change results in a material 10% increase (\$0.2 million) in allocated costs to the Mainline class and a 1.6% increase (\$0.2 million) for the High Volume Firm class. Nonetheless, IGU considers Centra's proposal to allocate DSM costs based on historical class participation as reasonable in the short-term (i.e., the next 1-2 years) if the Board is imposing a requirement for timely updates to Centra's cost of service studies. However, IGU expresses concern that Centra has not demonstrated a pattern of timely updates and that, in the absence of a clear and present direction that requires Centra to return to the Board in a timely way, the approach should be based on a blended weighting (e.g., 50:50) of past and future DSM participation activities.

8.2.6 Board Findings

The Board approves the elimination of the Franchise Expansion Adjustment as proposed by Centra and supported by the interveners. In the Board's view, the benefits of the adjustment are greatly diminished since Order 109/22 changes affecting the direct assignment of certain transmission-related costs and the elimination of the Peak and Average methodology for demand-related costs. Like the Head Office credit addressed in section 5.0 of this Order, the Franchise Expansion Adjustment is an artifact of an earlier time in Centra's history that is no longer justified. In light of the above, and as a result of Centra's filing of alternative cost of service study results incorporating the elimination of this adjustment for only the Special Contract and Power Station classes, Directive 3 of Order 109/22 is also considered complete.

The Board approves Centra's proposal to allocate the cost of DSM based on historical class participation in DSM programs rather than forecast class participation. While the Board is mindful of IGU's argument that this increases the need for timely updates to the cost of service study, the Board finds that Centra's proposed approach is simpler and more cost-causal than the existing approach. Further, phasing in this change (i.e., blending past and future participation) over the next few years would be an unnecessary complication.

The Board approves Centra's approach to allocate the cost of gas in storage included in the working capital requirement of rate base based on winter volumes rather than annual volumes. The Board finds that this approach is more cost-causal than the existing approach, for the reasons outlined by Centra.

The Board also approves, on a temporary basis, Centra's proposal to allocate the net loss portion of its revenue requirement based on each class's share of the non-gas revenue requirement. However, the Board notes that Centra's rationale for this treatment does not apply in years when the utility has a positive net income. Based on the revenue requirement increases over three years approved in this order and the overall adjustments directed in this order, the Board expects Centra's net income to be positive in 2025/26 and 2026/27. As such, the Board approves Centra's proposed treatment of

the net losses only for the 2024/25 test year, and not for the subsequent two years. For added clarity, Centra is to revert to allocating future levels of net income according to the class share of rate base for fiscal years 2025/26 and 2026/27, and the Board's one-year approval should not be construed as approval for similar treatment in future test years.

8.3 Unaccounted-for Gas

8.3.1 Background

In simplified terms, unaccounted-for gas ("UFG") is the difference between the measured volume of gas entering Centra's system (i.e., total gas purchases) and the total volumes delivered and metered to customers (i.e., total gas sales). It effectively is "missing" gas that is unaccounted for as a result of leakage, measurement errors, accounting errors, or other issues. Centra's UFG loss percentage typically varies from year to year due to a number of factors. Historically, Centra assumed UFG amounts of 0.9% of total system receipts but for 2024/25, the UFG assumption is 0.6% based on a trend of lower actual UFG.

In Order 131/04, the Board approved the allocation of UFG to Centra's customer classes based on a modification to the results of the utility's 2004 UFG study. For cost allocation purposes, Centra has been using these modified UFG study results since that time.

With Directive 4 of Order 109/22, the Board directed Centra to update its 2004 UFG study as soon as practicable but allowed the utility to keep using the existing results of the historical UFG study for cost allocation purposes if the updated UFG study was not available by the next general rate application.

In this hearing, Centra submits that an updated UFG study is not available. As such, Centra is not proposing updates to the existing method for allocating UFG costs to the customer classes. However, Centra states that updating the UFG study is a complicated exercise that also requires a review of what other jurisdictions are doing. At this time, Centra has completed some preliminary research of the UFG approaches used in other jurisdictions and alternative approaches to UFG rate design have been identified for further analysis regarding feasibility and impacts to Centra's customers.

IGU's witness, Mr. Bowman, was critical of Centra's continued use of the results of the 2004 UFG study. Specifically, Mr. Bowman submits that Centra's continued use of its 2004 UFG study is problematic given the marked decline in the amount of UFG present on Centra's system and a clear shift in the relative balance of loads and customers since 2004. Consequently, the Board should revise Directive 4 of Order 109/22 in order to establish a hard deadline for Centra to prepare its new UFG study.

8.3.2 Position of the Parties

Centra

Centra submits that while its updated UFG study is not complete, the utility remains committed to bringing forward an updated proposal on the treatment of UFG.

Industrial Gas Users

IGU adopted Mr. Bowman's recommendation for the establishment of a specific deadline for the filing of Centra's updated UFG study. Specifically, IGU recommends that the results of the updated UFG study should be incorporated in a proposed 2026/27 cost of service study filed pursuant to a conditional November 1, 2026 rate change filing.

8.3.3 Board Findings

The Board agrees with IGU's submission that using the results of a 21-year old UFG study for cost allocation purposes is not ideal. While there is no evidence that Centra's reduction in assumed UFG to 0.6% for 2024/25 is unreasonable, there continues to be a need to update the existing UFG study to confirm the underlying cost allocation assumptions. The Board accordingly sets aside Directive 4 of Order 109/22 and replaces it with a directive for Centra to file an updated UFG study together with its next general rate application or earlier.

8.4 Minimum System Study

8.4.1 Background

Distribution mains are lower-pressure pipelines used to distribute gas to Centra's customers, usually along the streets and alleys of urban areas and along road allowances in rural areas. They generally branch off a transmission line at a point known as a town border station or gate station. From the gate station, gas flows through a branched network of pipes until it arrives at the end user's service line.

For cost of service purposes, all of Centra's distribution mains are functionalized to the Distribution function and classified partially as Demand and partially as Customer. This is because the cost of constructing distribution mains can vary as a function of the peak demand that the main must serve as well as the number of customers connecting to the main. The number of customers is a proxy for the length of the mains, which is a driver of the cost of construction.

There are three common methods for determining the classification proportions related to a utility's distribution mains:

- Diameter-Length Method: This methodology estimates the total capacity of the distribution mains by multiplying the length of pipe by its diameter. The minimum capacity of the system (deemed as the Customer component) is then determined by multiplying the same length of distribution main by the minimum pipe size in the system. The percentage in excess of the minimum demand is classified as Demand, while the remainder is classified as Customer.
- Minimum System Method: This methodology is similar to the diameter-length method but incorporates unit cost data for each size of pipe used in the utility's system. As such, it is based on cost data rather than pipe size alone, and estimates the cost of connecting existing customers to the nearby gate station or town border station using the smallest diameter of pipe.
- Zero-Intercept Method: This is a more complicated version of the minimum system method that estimates the cost of connecting existing customers to the nearby gate station or town border station using a hypothetical zero diameter pipe, which would

carry no capacity and therefore would estimate the purely customer-related cost of distribution mains.

Since at least 1996, Centra has classified its distribution mains as 67% Demand-related and 33% Customer-related. This classification result was based on Centra's historical diameter-length study.

At the 2021/22 Cost of Service Methodology Review, the methodology used for the classification of Centra's distribution mains was revisited. In that proceeding, the Board received submissions that suggested that the historical 67:33 classification split falls within a reasonable range based on jurisdictional research previously completed by both Christensen Associates Energy Consulting and Atrium. However, the Board ultimately found that the minimum system method is a more accurate manner of classifying Centra's distribution mains than the historical diameter length method. Directive 1.c) of Order 109/22 therefore directed Centra to prepare such a minimum system study. However, if this study was not available by the next general rate application, Centra was directed to retain the existing 67% Demand and 33% Customer classification for its distribution mains and provide an update on the preparation of the study at the general rate application.

Atrium Economics LLC ("Atrium"), on behalf of Centra, completed a minimum system study that resulted in an updated classification of distribution mains of 79% Demand and 21% Customer. To derive these results, Atrium calculated unit costs for each pipe material type and main diameter using replacement cost, quantities, and installation method information obtained by Centra. Atrium also used a 60.3 mm plastic main as Centra's minimum-sized main, since it is the most commonly installed size of main within Centra's distribution system. Further, Atrium adjusted for the load carrying capacity of a 60.3 mm main, which it considered to be a best-practice adjustment used in a number of U.S. jurisdictions, as well as by one Canadian utility. As a means of comparison, Atrium's study also included the results of a zero-intercept study that suggests a 65% Demand and 35% Customer classification is appropriate.

Centra submits that the methods used by Atrium to complete the minimum system study are industry-standard and are consistent with studies completed in other jurisdictions.

Further, the minimum system study was prepared using the available replacement cost data since Centra does not have data on original cost or net book value by either pipe type (i.e., plastic versus steel) or by pipe size.

IGU's expert, Mr. Bowman took issue with the Atrium minimum system study and the application of the results in Centra's proposed cost of service study. Mr. Bowman points out that Atrium made the assumption that the minimum system consisted of 60 mm plastic pipe at a unit cost of \$44.20 per metre, and attributed any cost above this to be demand-related, including for steel pipes, which have materially higher unit costs even at the same 60 mm size. Mr. Bowman suggests that, rather than being installed for incremental demand requirements, the installation of steel pipe instead of plastic pipe was simply the result of the technology available at the time. Mr. Bowman supports this assertion by pointing to the fact that Centra mostly installed steel pipe until the mid-1980s, while new installations have since primarily been plastic pipe.

By using modern replacement costs for each and every unit of pipe still in service, Mr. Bowman submits that Atrium is weighting historic steel pipe with a significant cost disadvantage that was of no meaning at the time the cost was actually incurred by Centra, much less reflecting that the same pipe is now heavily depreciated.

As a result, Mr. Bowman rejects Atrium's minimum system study for the purposes of Centra's cost of service study. Instead, Mr. Bowman suggests three alternatives. The first is to revert to the historical, and previously accepted, 67% Demand and 33% Customer split, with the option to direct Centra to update the diameter-length study for the next general rate application. A second option would be to repeat the Atrium analysis and simply compare the incremental plastic replacement costs for each diameter versus 60 mm plastic costs, regardless of the material type. However, Mr. Bowman's third, and preferred, alternative would be to repeat the same analysis but develop ratios independently for each of steel and plastic, which would be consistent with the approach used by FortisBC Energy Inc. for their 2023 minimum system study.

In response to Mr. Bowman's criticisms, Centra states that Mr. Bowman's option to return to the historical 67% Demand and 33% Customer split is a reasonable option as it has

previously produced reasonable rates. Further, Centra's evidence on capital expenditures suggests that the system is built to account for the capacity needs of customers. Further, while Mr. Bowman's third recommended method is conceptually acceptable, it produces results that would push Centra's Customer classification component to 81-87%, which is well beyond the jurisdictional scan previously completed by Atrium. Consequently, Atrium's zero-intercept study methodology is now the utility's preferred method for classifying distribution mains.

In regards to Atrium's zero-intercept results, Mr. Bowman submits that the Board should not put any weight on this approach as Atrium applied a linear regression to pipe installation costs that do not follow a linear trend at the smaller pipe diameters given the crew mobilization costs to install the system.

Figure 8.1 provides a summary of the results of various studies advanced in this hearing for the classification of Centra's distribution mains:

Study Description	Demand %	Customer %
Atrium Minimum System	79%	21%
Historical Diameter-Length	67%	33%
Atrium Zero Intercept	65%	35%
Bowman Alternative #3	24%	76%

Figure 8.1 – Results of Different Methods for Classifying Distribution Mains

8.4.2 Position of the Parties

Centra

Centra reiterates that in Order 109/22, the Board directed it to complete a minimum system study, using cost data indexed to inflation, to inform the classification of Centra's distribution mains. This study was completed by Atrium, consistent with industry standard approaches and compared both plastic and steel pipes to the minimum sized system consisting entirely of plastic pipes.

Centra acknowledges that Mr. Bowman's proposal to prepare separate studies appears reasonable and that FortisBC has adopted a similar methodology. However, Centra points out that adopting this approach has the potential for significant bill impacts. For

example, Mr. Bowman's proposal could allocate an additional \$8 million to the Residential class (a subset within the Small General Service customer class) while reducing the allocation to the Large General Service class by \$6 million and the High Volume Firm class by \$2 million. Centra therefore states that it is not comfortable accepting a novel methodology that will transpose the relative proportions of the Demand and Customer classifications compared to the long-standing ratio previously employed.

Consequently, Centra's preferred alternative is Atrium's zero-intercept study, which uses regression analysis to determine the cost of a zero capacity pipe. Centra submits that the zero-intercept study is a classification method used with some regularity by other jurisdictions and Atrium's 65% Demand and 35% Customer results are consistent with Centra's previous diameter-length study. It also avoids the significant cost shifts that would occur with IGU's recommended approach.

Consumers Association of Canada

CAC submits that the Board should reject Mr. Bowman's approach and approve Atrium's minimum system study as filed, with an 80% Demand and 20% Customer classification. If the Board views that the movement from 67% Demand and 33% Customer to 80% Demand and 20% Customer classification is too large a shift in classification, CAC submits that Centra's recommendation to adopt the zero-intercept study by Atrium is a reasonable compromise, as it weights Demand as the dominant driver of the distribution main costs.

Additionally, CAC submits that, in Order 109/22, the Board found that the minimum system approach is the best manner of classifying Centra's distribution mains, in part because it is the most frequently used distribution classification method for North American utilities. On this basis, the Board should approve the Atrium minimum system study. CAC notes that the high demand classification factor for Centra's distribution mains is not inconsistent with Order 164/16 regarding Manitoba Hydro's cost of service methodology, where electricity distribution poles and wires are classified as 100% demand and allocated based on non-coincident peak. CAC states there is no difference between distribution poles and wires and natural gas distribution in mains.

CAC submits that Mr. Bowman's approach is extreme, given existing industry practice. It notes that Centra's Transmission plant is classified as 100% demand, as are Manitoba Hydro's distribution poles and wires. In CAC's submission, the gas distribution system is built to address demand.

Industrial Gas Users

While IGU supports the use of a minimum system study to classify distribution mains, it submits that the classification of distribution mains should be based on 76% Customer and 24% Demand weightings. This weighting reflects the minimum system study separately benchmarking the minimum size to 2 inches for plastic pipe and 2 inches for steel pipe.

IGU states that Centra's application of the minimum system study approach, as performed by Atrium, is conceptually aligned with regulatory precedent, responsive to the Board's direction in Order 109/22, and is valid as the preferred approach for classifying plastic distribution mains. However, IGU points out that Atrium calculates that the plastic distribution mains, on their own, should be classified as 87.6% Customer (before applying the well-accepted 10.23% peak load carrying capacity adjustment). Since plastic mains have predominantly been installed since 1996 and 85% of Centra's current rate base investment in distribution mains dates from 1996 or later, steel pipe may be the minority of investment on the Centra system, but it dominates the Atrium analysis. IGU therefore argues that Atrium's minimum system is flawed in that it overly-weights the importance of steel mains in Centra's system. Further, Centra already overemphasizes the distribution demand allocation as compared to peers by classifying multiple aspects of the distribution plant as 100% Demand before applying the minimum system study to only a subset of the assets (i.e. distribution mains). In light of this, IGU submits that a more appropriate methodology would benchmark steel infrastructure separately from plastic, as done in FortisBC's 2023 study.

IGU also submits that the Board should not place weight on the zero-intercept method. According to IGU, this method is highly theoretical, unsupported by practical cost data,

and has already been dismissed by the Board in Order 109/22 with the direction to use the minimum system methodology.

8.4.3 Board Findings

The Board approves the use of Centra's historical diameter-length study to classify the costs of distribution mains as 67% Demand and 33% Customer.

While the parties in this hearing presented several different options, the Board is not satisfied that the evidence justifies deviating from the long-accepted results of Centra's historical diameter-length study. None of the parties provided compelling evidence as to the best option for distribution mains cost allocation, or that there is a single, determinative, methodology. On the one hand, the Board agrees with IGU that the concept of a zero-intercept study is unsupported by cost data. On the other hand, the Board notes that Mr. Bowman's approach of separate studies for plastic and metal is still based on replacement cost rather than embedded costs, which Centra indicated are not currently available.

The Board is persuaded that the reversal of the classification ratio under Mr. Bowman's approach would be unusual when compared to other utilities. In summary, the Board is unable to conclude that there is a clearly better approach than the one previously used by Centra for decades. However, because the 2024/25 test year is already complete, and the interim rates implemented on November 1, 2024 were based on a 79:21 classification split for distribution mains, the Board approves the use of Atrium's minimum system study for that year on a one-time basis.

The Board further notes distribution mains have been classified as 67% Demand and 33% Customer since at least 1996, and therefore helped inform just and reasonable rates over that time. As outlined in Order 109/22, the Board accepts Atrium's position at the 2021/22 Cost of Service Study Methodology Review proceeding that the historical 67:33 classification split is reasonable based on Atrium's experience. As a result, the Board accepts Centra's long-standing diameter-length study and the resulting historical 67% Demand and 33% Customer split for the classification of costs related to distribution

mains. The Board does not require Centra to update its historical diameter-length study at this time.

8.5 Other Cost of Service Study Matters

8.5.1 Relief For Customer Classes Resulting from a Revised Cost of Service Methodology

As part of its 2021/22 Cost of Service Methodology Review Application, Centra proposed various changes to its cost of service methodology, including the elimination of the previous Peak and Average methodology for costs classified as Demand, as well as the direct assignment of specific transmission assets to the Special Contract and Power Station classes. As part of that Application, Centra also provided indicative class allocation results, showing how the different customer classes could be affected by Centra's proposals. These indicative results were based on the Board-approved 2019/20 revenue requirement, the 2018 volume forecast and the assumption that all of Centra's requested methodology changes would be approved. Centra's indicative results suggested that Centra's proposed methodology changes could result in large cost allocation changes for Centra's customer classes. In the specific case of the Special Contract class, the indicative results of the proposed methodology changes could decrease the amount of costs allocated to the Special Contract class by \$1.2 million, mainly as a result of the impacts of the design day coincident peak and direct assignment methodology changes.

In Order 109/22, the Board approved several changes to the cost of service methodology. The changes approved in Order 109/22 were not expected to be implemented until Centra filed a new cost of service study as part of its next general rate application. However, with Directive 7 of Order 109/22, the Board also approved an interim rate measure for the Special Contract class to provide interim rate relief based on the indicative impacts of the design day coincident peak and direct assignment methodology changes approved at the same time. Per Order 114/22, the Special Contract class interim rate measure was implemented on November 1, 2022 and reduced the annual costs assigned to the Special Contract class by approximately \$838,000, with the resulting Centra revenue deficiency absorbed by the Power Station class. The Board's approval for the Special Contract

interim rate measure was for one year (as a general rate application was expected to be filed within that time frame) but the measure was subsequently extended through Directive 1 of Order 106/23.

Section 0 of this Order provides a summary of the procedural history leading up to the filing for Centra's 2024/25 General Rate Application on October 7, 2024. Order 125/24 also provides a summary of these events.

In this hearing, IGU's witness, Mr. Friesen, submits that the delays in Centra filing its 2021/22 Cost of Service Methodology Review Application and its 2024/25 General Rate Application resulted in high volume customers, specifically those in the High Volume Firm, Mainline, and Special Contract customer classes, incurring excess costs since the 2019/20 General Rate Application. According to Mr. Friesen, this outcome does not appear aligned with the basic principle of cost-based rates that are fair and reasonable.

Accordingly, Mr. Friesen submits that the Board should provide retroactive relief for excess costs incurred by high-volume customers in the High Volume Firm, Mainline, and Special Contract classes when setting final rates for 2024/25. At minimum, such relief should consider the costs arising from the two-year delay in Centra filing its General Rate Application after the completion of the 2021/22 Cost of Service Methodology Review, which disproportionately harmed high volume classes and benefited General Service rate classes.

8.5.2 Program Cost Rate for Centra's Fixed Rate Gas Commodity Service

Centra's Fixed Rate Gas Commodity Service (previously known as Fixed Rate Primary Gas Service) was created in 2008 and allows Small General Service and Large General Service customers to fix their gas commodity rate for a one to five year term. Per the approved rate setting methodology, quarterly Fixed Rate Gas Commodity Service offerings are based on a forecast weighted average cost of gas commodity (one, three, or five year strip), an 8% self-insurance risk premium, as well as a Program Cost Rate that seeks to recover the fixed costs associated with administering Centra's fixed rate program.

The Program Cost Rate has typically been revised at every general rate application based on the results of Centra's updated cost of service study, which incorporates volume forecasts for Fixed Rate Gas Commodity Service customers.

While the cost of service study results originally filed in this Application indicated that the Fixed Rate Gas Commodity Service Program Cost Rate should increase, Centra proposes to maintain the Program Cost rate at \$0.02428/m³. Centra submits that its proposal strikes a balance of rate stability and considers the material impact to prospective Fixed Rate Gas Commodity Service customers, especially as a result of additional customers enrollments in the rate offering since the 2021 gas volume forecast was developed. Centra's request to maintain the Fixed Rate Gas Commodity Service Program Cost Rate at \$0.02428/m³ was approved on an interim basis in Orders 125/24 and 129/24.

As part of its pre-hearing update submission on May 2, 2025, Centra filed an updated version of its 2024/25 cost of service study, which was based on its updated 2024/25 revenue requirement, its 2024 gas volume forecast, 2024 depreciation study, and the same proposed changes to its cost of service methodology. In this case, the results of this updated 2024/25 cost of service study indicated that the Fixed Rate Gas Commodity Service Program Cost Rate should decrease from the approved \$0.02428/m³ level. This was due to an increase in program participation as incorporated in the 2024 gas volume forecast. Given the recent volatility in customer participation in the Fixed Rate Gas Commodity Service program between the 2021 and 2024 volume forecasts, and the resulting material swings in the Program Cost Rate, Centra continues to propose that the Program Cost Rate should be maintained at \$0.02428/m³.

8.5.3 Gas Commodity Overhead Rate

In procuring and managing its gas commodity supplies, Centra incurs non-gas related (i.e., overhead) costs, which are allocated to customers through a discrete Gas Commodity class. These non-gas related costs are then recovered through an overhead rate applied to the commodity charge.

Similar to the Fixed Rate Gas Commodity Service Program Cost Rate described in the previous sub-section, Centra's Gas Commodity Overhead Rate is updated based on the results of a cost of service study filed at periodic cost of gas or general rate applications. Prior to November 1, 2024, the Gas Commodity Overhead rate was \$0.00095/m³, which was approved at the 2019/20 General Rate Application and further maintained in Order 114/22.

Based on the October 7, 2024 version of its 2024/25 cost of service study, Centra requested that the new Gas Commodity Overhead Rate increase to \$0.00093/m³. In Orders 125/24 and 129/24, the Board approved, on an interim basis, a Gas Commodity Overhead rate of \$0.00093/m³ effective November 1, 2024.

On May 2, 2025, Centra filed an updated version of its 2024/25 cost of service study. Since this update maintained the same non-gas revenue requirement and cost of service methodology changes as the initial October 7, 2024 filing, the updated study results continued to show a Gas Commodity overhead rate of \$0.00093/m³.

8.5.4 Position of the Parties

Centra

Centra argues that Mr. Friesen's recommendation for further relief for excess costs incurred by high volume customers as a result of delays in generating a new cost of service study is tantamount to retroactive ratemaking and should be rejected. Further, the utility maintains that Mr. Friesen's relief estimates were also based on approximations and assumptions. Centra further states that the timing of its application on October 7, 2024 was influenced by a number of factors both within and outside its control.

Centra's position is that the current Fixed Rate Gas Commodity Service Program Cost Rate of \$0.02428/m³ should be maintained at this time. In Centra's view, when considering the potential for market price volatility (as seen recently). Program Cost Rate volatility does not align with the rationale of a fixed rate program and introduces the prospect of rate variability for program participants solely based on the timing of the Program Cost Rate change.

Consumers Association of Canada

CAC submits that Mr. Friesen's relief sought for the High Volume Firm and Mainline customer classes is inappropriate and should be rejected. Interim relief was already considered and delivered in Order 109/22 and if the Board had intended interim relief to any other classes it would have done so at that time.

Industrial Gas Users

IGU submits that the Board should approve rate riders for all classes to address the impacts of delays in the implementation of the updated cost of service methodology. These rate riders should be revenue-neutral to Centra. This is to provide retroactive relief to affected classes from the three-year period November 1, 2021 to October 31, 2024 and should be designed to dispose of the balances accrued during this period over a 12- or 24-month term. Further, the Special Contract interim rate measure approved in Directive 7 of Order 109/22 and extended in Order 106/23 should be approved as final along with the provision for full recovery of relief owing for the period November 1, 2022 to October 31, 2024.

In response to submissions labelling Mr. Friesen's proposal as retroactive ratemaking, IGU points out that Section 127(3) of *The Public Utilities Board Act* provides the Board with the authority to implement retroactive relief and submits that given the current special circumstances, it is appropriate to exercise that discretion in this case. The consequence of Centra's filing delays resulted in material over-charges for the High Volume Firm, Mainline, and Special Contract classes for the three-year period extending November 2021 to October 2024, and that it is neither fair nor reasonable for these classes to bear the brunt of Centra's inaction in filing Board-directed applications.

8.5.5 Board Findings

The Board approves as final the interim rate measure for the Special Contract class, which affected the Power Station class between November 1, 2022 and October 31, 2024. As such, Directive 7 of Order 109/22 and Directive 1 of Order 106/23 are deemed complete. However, the Board does not approve further relief to customers

for delays in implementing the cost of service study changes approved in Order 109/22 (or those approved in this Order).

The Board finds that customer impacts will always result from changes to a utility's revenue requirement or cost allocation changes and the rate implications of these impacts are an issue of timing. Centra's delays in filing its 2024/25 General Rate Application, and the resulting impacts on the utility and its ratepayers, are well documented in other sections of this Order. Despite this, the Board finds it challenging to accept any specific retroactive relief to certain customer classes (beyond the interim rate measure for the Special Contract class initially approved in Order 109/22) based on illustrative cost of service results that were grounded on a now very out of date 2019/20 revenue requirement, 2018 volume forecast, methodology changes that were not fully approved, and additional methodology changes proposed in this proceeding. Consequently, the Board is not convinced that additional relief should be afforded to certain customer classes, particularly with respect to a single aspect of the cost of service study.

The Board also approves as final Centra's proposal to maintain the Fixed Rate Gas Commodity Service Program Cost rate at \$0.02428/m³. The Board expects to review this rate at a future general rate application in order to assess whether the recent volatility in customer participation in the Fixed Rate Gas Commodity Service program, which affects the calculated Program Cost Rate, continues based on the cost of service study results filed at that time.

In regards to the Gas Commodity Overhead rate, the Board approves as final the \$0.00093/m³ rate approved in Order 125/24 and implemented on November 1, 2024 per Order 129/24. As part of the compliance filing required in this Order, the Board expects Centra to re-compute the rate in accordance with the new cost of service study and confirm, or otherwise propose to change, the Gas Commodity Overhead rate to be used for the November 1, 2025 Gas Commodity rate application.

9.0 RATE DESIGN AND RATE DIFFERENTIATION

Consistent with other jurisdictions in North America, the Board's process for fixing Centra's natural gas rates follows three sequential steps:

1. Determination of Centra's approved revenue requirement;
2. Completion of a cost of service study based on a cost of service methodology approved by the Board; and
3. Determination of a Board-approved rate design and setting of rates.

While the cost of service study step discussed in section 8.0 determines how costs are to be allocated among the various customer classes, the rate design step establishes how the costs allocated to a class will be recovered from the customers within those classes. For example, the target revenue allocated to a particular class may be recovered through a gas commodity charge, a delivery charge, a basic monthly charge, and, in some cases, a demand charge. Changes to rate design may result in changes to the way costs are recovered and by whom, but do not change the overall amount of revenue that needs to be recovered.

Centra's rate designs are generally reviewed as part of general rate application proceedings. Currently, 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 this hearing, Centra proposes various changes to its class rate designs. Intervening parties also raised additional rate design issues for the Board to consider in this proceeding. Each of those issues is discussed below.

9.1 Zone of Reasonableness

9.1.1 *Background*

The ratio of revenue recovered from a class of customers to the costs allocated to that class is known as the revenue-to-cost coverage (“RCC”) ratio. A ratio above 100% (i.e., unity) indicates that a class is paying more than the costs allocated to that class. Conversely, a ratio below 100% indicates that the class is not paying all of its allocated costs.

A zone of reasonableness is an established tolerance range of RCC values within which a class is deemed to satisfactorily recover its allocated revenue requirement. For example, if a utility’s zone of reasonableness is established at a range of 95% to 105%, any class with an RCC ratio within this range is deemed to represent full cost recovery without further adjustments to their existing rates.

A zone of reasonableness can be established for a number of different reasons, including to recognize that there is a range of judgment that applies when conducting cost of service studies, and to accommodate various ratemaking objectives such as fairness, equity, rate stability and gradualism.

Before 1997, Centra had a zone of reasonableness of 97-103% but it was eliminated in Order 8/97 following the Board’s review of Centra’s cost of service methodology in 1996. At the time, the Board ruled that the implementation of the peak and average methodology for the allocation of costs classified as Demand eliminated the need for a zone of reasonableness at the rate design stage. Since that time, Centra has set its class rates so that the RCC ratios for each class are exactly equal to unity (i.e., $RCC = 1$). In contrast, Manitoba Hydro has historically utilized a zone of reasonableness of 95% to 105%, although Manitoba Hydro has not always proposed rates such that all class RCC ratios were within (or moved toward) this range.

At the 2019/20 Centra General Rate Application, some interveners proposed the introduction of a zone of reasonableness as a way to mitigate high bill impacts that some customer classes were forecast to experience as a result of Centra’s requests in that

proceeding. However, in Orders 152/19 and 161/19, the Board continued to set Centra's rates such that the forecast class revenues exactly recovered the class's allocated revenue requirement.

In Order 36/22, the Board found that matters of rate design and the introduction of a zone of reasonableness were not in scope for the 2021/22 Cost of Service Methodology Review proceeding. Specifically, the Board stated that:

The Board expects Centra to address rate design matters, including the issue of a Zone of Reasonableness and other possible rate impact mitigation measures, stemming from the Board's decisions in this proceeding, to be addressed at Centra's next General Rate Application.

In Order 109/22, the Board approved a number of cost of service methodology changes, including the elimination of the peak and average method and the use of the coincident peak allocation methodology based on Centra's design day. As described in section 8.0 of this order, Centra's proposed 2024/25 cost of service study in this hearing is compliant with the Order 109/22 methodology changes.

For the purposes of rate design, Centra is proposing to continue to set rates at unity and not establish a zone of reasonableness to guide its rate designs. In support of this proposal, Centra submits that the rate principles of gradualism and affordability were already given significant consideration when deciding on the appropriate level and pace of the overall general revenue increase sought in this Application. Additionally, Centra's cost of service methodology recently underwent a substantial review and the approved changes resulted in a methodology that appropriately allocates costs to the classes based on the design and operational considerations of Centra's system. The utility further states that given these changes, setting rates at unity provides the greatest likelihood that revenues are reasonable compared to costs.

However, if at some point in the future there were additional policy considerations or non-cost causal factors that should be factored into determining customer class rates, then Centra opines that these are best dealt with at that time rather than on a predetermined tolerance level of a zone of reasonableness.

In support of its current proposal, Centra explains that the introduction of an explicit zone of reasonableness for its ratepayers would also be of limited efficacy given the fact that the Small General Service class is responsible for two-thirds of Centra's non-gas costs and any variation from unity for the class will have twice the impact on the remaining classes. For example, if Small General Service non-gas rates were set to recover 97% of the non-gas costs allocated to the class, all other classes would need to recover 106.4% of their allocated non-gas costs.

CAC's expert, Ms. Derksen testified that the results of a cost of service study are generally an indicator, not a dictator, of each class's cost to serve. As such a zone of reasonableness is a tool that provides flexibility in addressing fairness and equity ratemaking objectives. In Ms. Derksen's view, Centra's proposal to set rates at unity without a zone of reasonableness ignores the fundamental changes flowing from Order 109/22, ignores Centra's own evidence at the 2019/20 General Rate Application (e.g., difficult to smooth rate changes and minimize bill impacts), and amounts to discarding all ratemaking objectives other than cost causation.

Ms. Derksen testified that various Canadian gas utilities (e.g., FortisBC Energy and SaskEnergy) commonly use a zone of reasonableness with a range of 95%-105% and the relative size of their residential classes is consistent with that of Centra. As such, Centra's statements regarding the size of this class as a limiting the efficacy of a zone of reasonableness is not credible. Ms. Derksen suggested that the removal of ratemaking objectives such as fairness and equity from Centra's cost of service methodology raises the importance of addressing rate rebalancing through a zone of reasonableness. In her view, such considerations should not be made at the revenue requirement stage, since some classes are affected more than others by cost allocation judgments, while revenue requirement increases affect all customers.

To address issues of fairness and equity, Ms. Derksen proposes a zone of reasonableness of 95% to 105% be implemented, with the Small General Service class's RCC ratio set between 95% and 97% for this application. In Ms. Derksen's view, setting the Small General Service class RCC ratio in the range of 95% to 97% would reduce their

allocated costs by approximately \$3.3 million to \$7.0 million. In turn, this adjustment would reflect the fact that the Small General Service class, which includes low-income residential customers, has been the most affected (on a dollar basis) by the Order 109/22 decisions. This change would also recognize the fact that Small General Service customers are captive to Centra's system, while commercial and industrial customers can pass along their energy costs to their own customers.

In establishing the recommended zone of reasonableness, Ms. Derksen opines that class RCC ratios should be calculated based on total costs (including gas costs and non-gas costs), which would be consistent with FortisBC Energy's existing practice and also reflect the fact that there is no evidence to suggest that Centra's gas costs are more accurately forecast than its non-gas costs.

9.1.2 Position of the Parties

Centra

Centra maintains that its proposal to set rates at unity is fair and results in rates that are just and reasonable for all classes. Despite this, Centra's proposal for this Application does not mean that Centra generally disagrees with the use of a zone of reasonableness or that its proposed cost allocation methodology produces results with total 100% accuracy. Indeed, Centra agrees that professional judgement, use of forecasts, estimates, extrapolations, and simplifying assumptions have always been, and will continue to be, a fundamental aspect of Centra's cost of service study. In the utility's view setting Centra's rates and RCC ratios at unity provides the greatest likelihood that revenues are reasonable compared to costs and are fair for all classes.

Centra further argues that Ms. Derksen's position on fairness, equity, and the zone of reasonableness is focused on exclusively accommodating perceived issues that impact the Small General Service class. Centra therefore concludes that Ms. Derksen's vision for implementing fairness and equity is simply to systematically unwind the cost allocation methodology changes approved in Order 109/22.

Nevertheless, should the Board determine that a zone of reasonableness is required, Centra strongly recommends that the calculation of class RCC ratios only consider non-gas costs. This is because changes in non-commodity related gas costs are not necessarily directionally consistent with changes in non-gas costs. As such, the impacts to customer classes will be different and the potential of over- or under-recovery of the distinct pools of costs is masked when looked at on a consolidated basis.

Consumers Association of Canada

CAC points out that there is no single acceptable cost of service methodology, and that a range of reasonableness is intended to capture the range of possible cost of service results. In CAC's view, it also reflects considerations of fairness and equity, rate stability and gradualism. Further, CAC submits that the use of a zone of reasonableness is the leading utility ratemaking best practice, is consistent with Manitoba Hydro's rate design approach, and has been supported by Atrium, Christensen, RJ Rudden, Collins (Koch), and IGU in previous Board proceedings.

CAC also argues that a zone of reasonableness should exist because the design peak day is a theoretical calculation that is subject to debate, and the direct assignments to the Special Contract and Power Station classes are based on approximations and judgements. Further, Centra's proposed net loss allocation change embeds fairness and equity considerations that should be removed from the cost of service study and instead embedded in a zone of reasonableness (with RCC adjustments), consistent with Order 109/22. CAC further points out that in this proceeding, Centra filed five different analyses of the impacts associated with the classification of distribution mains, suggesting a \$7 million cost allocation differential for the Small General Service class. This is therefore one example that illustrates a vast range of possible class cost responsibilities, further justifying the need for a zone of reasonableness.

Given the above, CAC recommends a zone of reasonableness of 95% to 105%, which is a range that is widely accepted in Canada and is consistent with Manitoba Hydro's zone of reasonableness. CAC further points out that the residential RCC ratios for those other utilities tend to be at the lower end of the zone. Further, CAC argues that placing Small

General Service customers at the lower end of a zone of reasonableness does not equal under-recovery of costs given the uncertainty in cost allocations and the recognition of other objectives and cost considerations in setting class RCC ratios. As such, it is not an attempt to unwind the changes resulting from Order 109/22.

Industrial Gas Users

In IGU's submission, there is no basis at this time to intentionally set the rates of any Centra customer class at a level other than 100% RCC. IGU also expresses concern regarding the Large General Service class having already received an increased cost allocation as a result of Order 109/22, and that Ms. Derksen's proposal to set the residential RCC ratio at 97% would increase those costs further. IGU therefore questions why Small General Service ratepayers should be entitled to such an adjustment but other classes such as Large General Service customers should not.

IGU also points to Mr. Bowman's testimony in this hearing that fair and equitable rates are those that are cost-based and that a zone of reasonableness may result in sustained cross-subsidization between, and among, customer classes.

9.1.3 Board Findings

The Board finds that rates should continue to be set at unity and that a zone of reasonableness is not warranted at this time.

A zone of reasonableness can be a useful tool in some circumstances, for example to deal with cost of service fluctuations or to smooth in larger changes to a cost of service allocation. However, for the 2024/25 test year, all customer classes are already paying less than what their total allocated costs would have been if Centra's revenue requirement was set to avoid a net loss. The Board's decision to approve a revenue requirement increase that still results in a deficit for the 2024/25 test year is an equitable decision that integrates gradualism into all of Centra's rates in a more direct manner than a zone of reasonableness that may purposely set the RCC ratio of one or more classes below 1.0.

While occasionally contributing to more pronounced bill impacts (either higher or lower) for some classes, the Board finds that setting rates at unity generally provides the greatest

likelihood that revenues are reasonable compared to the underlying costs. However, the Board remains open to the possibility of implementing a zone of reasonableness in the future if the specific evidence at the time justifies such a decision.

9.2 Increase in the Basic Monthly Charges for the Small General Service and Large General Service Customer Classes

9.2.1 *Background*

Centra's Small General Service and Large General Service customer classes pay a gas commodity charge, a delivery charge, and a basic monthly charge ("BMC"). The BMC is intended to recover costs classified in the cost of service study as customer-related, such as the costs incurred for meter reading, billing, service lines, and meters.

Before November 1, 2024, the BMC approved for Small General Service customers was \$14.00 per month, while the BMC for Large General Service customer was \$77.00 per month. These amounts have remained the same since 2010.

In this hearing, Centra proposes to increase the BMC for the Small General Service and Large General Service classes to \$14.75 and \$85.00, respectively, effective November 1, 2024. In Orders 125/24 and 129/24, the Board approved these BMC increases on an interim basis and pending final approval in this order.

9.2.2 *Position of the Parties*

Centra submits that the utility's approach to the BMC has always been about balancing cost of service, fairness and equity, stability, and practicality. Despite the proposed BMC increases in its Application, Centra is not proposing to increase these BMCs such that they fully recover the allocated downstream customer costs from the 2024/25 cost of service study results. In fact, the proposed BMCs of \$14.75 and \$85.00 seek to recover approximately 66% and 61% of customer-related costs allocated to the respective classes through the 2024/25 cost of service study. As in previous years, the remaining portion of the allocated customer-related costs are included in the delivery charges.

In the utility's submission, increasing the Small General Service and Large General Service BMCs provides a better alignment with cost causation and results in less bill

variability for customers. Further, Centra's proposed \$14.75 BMC for Small General Service customers remains one of the lowest monthly fixed charges for residential gas distribution customers in Canada.

None of the interveners have taken a position on this issue.

9.2.3 Board Findings

The Board approves, on a final basis, the increases to the Small General Service BMC from \$14.00 to \$14.75 per month, and to the Large General Service BMC from \$77.00 to \$85.00 per month. The Board finds that these increases contribute to an improvement in the balancing of cost causation, equity, and gradualism ratemaking principles, while also contributing to reduce variability in customer bills, and greater stability in Centra's revenues. For the next general rate application, the Board expects Centra to once again review the level of the Small General Service and Large General Service BMCs and determine whether these should recover an even greater portion of the allocated downstream customer-related costs.

9.3 Two-Part Rate for the Power Station Class

9.3.1 Background

Before November 1, 2024, Centra used a three-part rate structure for the Power Station class, consisting of a BMC, a demand charge, and a volumetric charge. In this hearing, Centra is proposing to eliminate the monthly demand charge for the Power Station class and transition to a two-part rate structure that includes a basic monthly charge (to recover all of the class's non-gas costs) and a variable volumetric charge (to recover the class costs of unaccounted for gas). In Orders 125/24 and 129/24, the Board approved, on an interim basis and pending final approval in this order, Centra's proposed rate design change for the Power Station class.

9.3.2 Position of the Parties

Centra notes that, following the approval of the direct assignment of certain costs to the Power Station class in Order 109/22, the utility's cost of serving this customer class is now predominantly fixed. Further, Centra submits that eliminating the demand charge and

recovering the fixed costs entirely through a BMC holds other customers harmless regardless of whether actual Power Station class usage is below forecast. Similarly, the class will not over-contribute to system costs if actual class usage exceeds Centra's forecast.

None of the interveners took a position on this issue.

9.3.3 Board Findings

The Board approves, on a final basis, Centra's request to transition the Power Station class to a two-part rate structure and eliminate the demand charge. The Board notes that this rate design is similar to the existing rate structure for the Special Contract class.

9.4 Demand Charge Recovery Percentage for the High Volume Firm and Interruptible Customer Classes

9.4.1 Background

Centra's existing rate design for the High Volume Firm ("HVF") and the Interruptible customer classes currently sets the demand charge to recover 65% of the demand costs allocated to those classes. The remaining 35% of allocated demand costs are added to the allocated commodity costs and recovered through volumetric changes. In contrast, the demand charge for the Mainline class recovers 100% of the allocated demand-related cost.

In Order 118/03, the Board increased the HVF and Interruptible demand charge recovery percentage from 50% to 65% but refrained from moving to 100% at that time in order to mitigate bill impacts on lower load factor HVF and Interruptible customers. However, Order 118/03 stated:

The Board encourages Centra to continue with this initiative until 100% of the demand costs are recovered by the demand rate, but being mindful of the individual customer impacts, so that all classes will be treated consistently.

Despite this direction, Centra continues to propose setting the monthly demand charge for the HVF and Interruptible classes to recover the historical 65% of the allocated

demand-related costs from the 2024/25 cost of service study. Consequently, the interim rates approved in Orders 125/24 and 129/24, and which took effect November 1, 2024, incorporated demand charges for the HVF and Interruptible customer classes that recovered 65% of allocated demand costs.

9.4.2 Position of the Parties

Centra

Centra indicates that there are several seasonal customers within the Interruptible class that do not pay demand rates (because demand charges are levied on winter-only demand). There are also customers within the HVF class that exhibit seasonal usage characteristics. As a result, having 35% of demand costs recovered in the commodity rate is an equity consideration that ensures that all customers in these classes pay some portion of capacity costs allocated to that class. If Centra moves to recovering all the demand costs in the demand rate for this class, these seasonal (or seasonal-like) customers will not contribute to any fixed capacity costs. As a result, the current rate design reflects a reasonable balance between the nature of the costs and their recovery given the practical realities of Centra's system.

Centra notes that, if the HVF and Interruptible demand charge recovery percentage were changed such that the most negatively affected customer received a maximum bill impact of 5% greater than the class average bill impact from its 2024/25 Application, the new demand charge recovery percentage would be 87.4% for the HVF class and 91.0% for the Interruptible class. Centra did not want to create an additional bill impact for these customers given the already significant changes in class allocations resulting from its 2024/25 General Rate Application.

In response to IGU's witnesses' proposals on this matter, the utility indicates that it is not opposed to a greater recovery of demand-related costs through the demand charge for the HVF class. However, Centra would prefer to leave the Interruptible class rate design unchanged, given the seasonal customers served in that class. Centra further submits that it is not opposed to a seasonal rate offering or a seasonal class, but that these are separate issues from this billing demand recovery issue. However, Centra maintains that

it will be further exploring whether seasonal customers are covering enough costs based on their existing volumetric rates as part of future rate reviews.

Industrial Gas Users

IGU adopts the evidence of both of its witnesses (Mr. Bowman and Mr. Friesen) and maintains that the longstanding 65% demand cost recovery level is outdated and no longer reflects the cost causation principles or usage patterns of the HVF customer class. IGU suggests a phased transition toward 100% of demand related costs being recovered through HVF demand charges, which would improve fairness, enhance price signals, and align Centra's rate design with industry best practices for cost recovery. Specifically, IGU recommends that the HVF demand charge be adjusted such it recovers 85% of allocated demand-costs in 2024/25, with a further increase from 85% to 100% effective November 1, 2025.

In IGU's submission, increasing the recovery of demand costs through the demand charge will also reduce cross-subsidization between high load factor and low load factor customers within the HVF class and more fairly represent the impact that these customers have on the class's peak demand.

The issue of the demand charge recovery percentage for the Interruptible class was not addressed in IGU's final submission but IGU's witness, Mr. Friesen, filed evidence in this hearing recommending that the Board direct Centra to consider implementing an alternate rate structure for seasonal customers in the Interruptible rate class that do not pay demand charges.

9.4.3 Board Findings

For the purposes of the November 1, 2024 interim rates, the Board finds that continuing the longstanding 65% demand cost recovery level through the HVF demand charge is acceptable. However, the Board finds that the demand charge recovery percentage should gradually increase for the HVF class. The Board accordingly directs Centra to increase the HVF demand charge recovery percentage to 70% effective November 1, 2025, and to 75% effective November 1, 2026. The Board intends to revisit

this issue at the next general rate application, with a view to eventually migrating the HVF rate design toward 100% demand recovery through the demand charge.

In regards to the Interruptible class, the Board accepts demand charges for that class based on the historical recovery of 65% of allocated demand costs. As set out in section 10.3.2 of this order, the Board is requiring Centra to develop the concept of a seasonal rate. The Board therefore expects Centra to revisit the demand charge recovery percentage for the Interruptible class and file its related proposals in future rate applications if, at that time, the Interruptible class no longer includes seasonal customers.

9.5 Power Station Minimum Margin Guarantee

9.5.1 Background

During the 2003/04 General Rate Application, which resulted in Order 118/03, the Board reviewed the original Centra contracts with Manitoba Hydro for the Power Station class customers. Given the unusual operating characteristics expected for these customers, Centra determined that an annual minimum gross margin guarantee would be appropriate to support the initial assumptions in the stations' feasibility tests. Essentially, the minimum margin guarantee for the Power Station class would ensure that customers in this class paid their share of the capital costs for the pipelines and facilities required to serve them despite their expected variable usage and, therefore, uncertain revenue stream for Centra. At the time, the minimum margin guarantee was not a cost allocation consideration but rather a top-up to Centra's revenues during years when Power Station customers contributed insufficient revenues to meet the minimum gross margin required to fund the capital investments.

Per the terms of the 2003 contracts, the minimum gross annual margin amount applied to the initial 10-year term of the contracts. For that period, the amount for the Brandon Combustion Turbine station was \$572,600 and the amount for the Selkirk Generation station was \$374,500. The last year that Manitoba Hydro paid these amounts was for the period from August 2012 to July 2013.

At the 2019/20 General Rate Application, CAC questioned the utility's removal of the Power Station minimum margin guarantee following the 2013 feasibility test true-up period which, according to Centra, confirmed that this class's contributions in aid of construction were sufficient to pass the Board-approved feasibility test. In Order 152/19, the Board found that based on the language of Order 118/03, the Board had previously intended to maintain the Power Station minimum margin guarantee beyond the initial 10-year term but that there was insufficient evidence at that point to reinstate the charges.

To resolve the issue, Directive 28 of Order 152/19 required Centra to file all contracts with Power Station customers, as well as feasibility tests and any true-ups associated with the extension of service to these customers, including any information supporting the determination of the minimum margin guarantee. While the Board expected the issue of the Power Station minimum margin guarantee to be reviewed at the 2021/22 cost of service methodology review, the matter was subsequently deferred to the next general rate application per Order 36/22.

In this hearing, Centra filed the original Power Station contracts and related feasibility tests, which included both the initial tests and the subsequent true-ups.

9.5.2 *Position of the Parties*

Centra

According to Centra, a new true-up of the Brandon generating station feasibility test as of July 2024 shows that all parameters of the feasibility test are satisfied and that no additional contributions would now be required.

In contrast, Manitoba Hydro made a total contribution of \$8.2 million for the Selkirk generating station. A new true-up of the Selkirk generating station feasibility test as of July 2024 shows that an additional \$0.37 million should now be paid. However, the Selkirk station was retired in March 2021.

Centra submits that the Power Station minimum margin guarantee should not be re-instated, given that the Brandon generating station no longer requires a contribution in aid of construction and that the Selkirk generation station is no longer in service.

Consumers Association of Canada

While CAC did not address this issue in its final argument, its witness, Ms. Derksen, opined that the decision to include the minimum margin guarantee in the original Power Station contracts has proven to be reasonable as it helped generate sufficient revenues to pass the feasibility test. Ms. Derksen acknowledges that the switch to the direct assignment of costs for the Power Station class has moderated the volatility in allocated costs to this class (and hence all other classes) due to variable class usage forecasts. On this basis, Ms. Derksen is satisfied that the minimum margin guarantee is no longer required.

9.5.3 Board Findings

The Board finds that the most recent Brandon generating station feasibility test demonstrates that the parameters of the feasibility test have been satisfied and that no additional contributions are required. While the Board does not arrive at the same conclusion for the most recent Selkirk generating station feasibility test, the Board acknowledges that the station is no longer in operation. As a result, the Board finds that no minimum margin guarantee should be re-instated. The Board further finds that Directive 28 of Order 152/19 is complete.

10.0 TERMS AND CONDITIONS OF SERVICE

Centra's service and rate offerings are subject to Board-approved terms and conditions of service set out in the utility's Schedule of Sales and Transportation Services and Rates, also known as Centra's Terms and Conditions. In this hearing, Centra proposed only minor amendments to its Terms and Conditions related to an increase in hourly billing rates for chargeable services. However, during the hearing, interveners identified several other issues related to Centra's Terms and Conditions. As a result, the Board is addressing submissions on the following issues in this section:

- Transportation Service balancing fees;
- external billing rates; and
- Centra's Modified Large General Service offering.

10.1 Transportation Service Balancing Fees

10.1.1 *Background*

Since there are no alternative natural gas transmission pipelines serving Manitoba, all natural gas consumed in Manitoba is transported via the TransCanada Pipelines Limited ("TCPL") Mainline pipeline, which is regulated by the Canada Energy Regulator. Gas supplies needed in Manitoba are transported on the TCPL Mainline to the Manitoba Delivery Area and Southern Saskatchewan Delivery Area, where Centra then takes possession of the gas and delivers it to its customers using its own downstream distribution pipeline system.

Centra's Terms and Conditions currently outline different customer service options. Under Centra's Sales Service offerings (i.e., system supply, Fixed Rate Gas Commodity Service, or Western Transportation Service), customers purchase their gas supplies from either Centra or a third-party gas marketer and rely on Centra to arrange for the transportation of those gas supplies to Manitoba.

Customers can instead choose to arrange their own transportation of gas supplies to Manitoba. Centra's Transportation Service ("T-Service") was originally introduced in Manitoba in 1988 to allow customers, typically those with high daily consumption requirements, to use this option. As a result, T-Service customers do not make use of Centra's gas supply, transportation, and storage arrangements nor contribute to their cost.

T-Service customers do not form a separate customer class. Rather, T-Service is a service offering that is available to customers in the High Volume Firm, Mainline, and Interruptible customer classes, and is the only service offering for customers in the Special Contract and Power Station customer classes.

To ensure adequate operation of the TCPL Mainline, the Canada Energy Regulator has approved a gas nomination balancing framework applicable to all shippers utilizing the TCPL Mainline. As such, TCPL requires Centra to ensure that the daily quantities of gas nominated for transportation to these delivery areas are balanced with the daily quantities Centra actually takes off the TCPL system on behalf of its customers. The nominations and deliveries for Centra's T-Service customers are included in the pipeline balancing requirements imposed on Centra by TCPL. If there are imbalances, Centra must pay balancing fees to TCPL, regardless of whether the imbalances were caused by Centra or by T-Service customers, by extreme weather variations, or downstream operational issues. Accordingly, Section V.D) of Centra's Terms and Conditions outlines the requirements for T-Service customers to balance their daily nominations with their daily gas consumption.

In Order 152/19, the Board approved a new balancing fee structure for T-Service customers to further incent T-Service customers to improve their balancing performance. The new balancing fee structure was based on the fee structure imposed on Centra by TCPL but the resulting fees were set at 50% of the TCPL charges for balancing fees. Appendix C of Centra's Terms and Conditions currently outlines the approved T-Service balancing fee structure, which is reproduced in Figure 10.1.

Daily Fee	Level of Imbalance	Balancing Fee
	Less than 2%	0
Tier 1	2% up to 4%	0.2 times FTD, times 50%
Tier 2	4% up to 8%	0.5 times FTD, times 50%
Tier 3	8% up to 10%	0.75 times FTD, times 50%
Tier 4	10% or greater	1.0 times FTD, times 50%
Cumulative Fee		
	Less than 4%	0
Tier 1	4% up to 6%	0.15 times FTD, times 50%
Tier 2	6% or greater	0.25 times FTD, times 50%

FTD (Firm Transportation daily demand charge) is the approved Canada Energy Regulator reference toll for calculating all TCPL Mainline balancing fees

Figure 10.1 — Centra T-Service Balancing Fees Structure per Order 152/19

While TCPL requires Centra to balance its delivery areas to the greater of $\pm 2\%$ of confirmed nominations or $\pm 2,111$ GJ, the new T-Service balancing fee structure approved in Order 152/19 included a wider tolerance level than the 2% requirement applicable to Centra. Figure 10.2 sets out the approved T-Service balancing tolerances approved in Order 152/19, which represents, on average, a 14% daily tolerance based on average daily consumption.

Average Daily Consumption	Absolute Daily Tolerance	Absolute Cumulative Tolerance
Less than 1,000 GJ/d	± 100 GJ	± 200 GJ
1,000 to less than 1,700 GJ/d	± 200 GJ	± 400 GJ
1,700 to less than 2,500 GJ/d	± 300 GJ	± 600 GJ
2,500 to less than 5,000 GJ/d	± 500 GJ	$\pm 1,000$ GJ
5,000 GJ/d or more	$\pm 1,000$ GJ	$\pm 2,000$ GJ

Figure 10.2 — Centra's T-Service Balancing Tolerance Levels per Order 152/19

At the 2019/20 General Rate Application, the Board reviewed evidence associated with the potential for T-Service balancing fee revenue to exceed the overall system balancing fees paid by Centra to TCPL. At the time, Centra had submitted that the estimated exceedance would still not offset all the indirect costs incurred by Centra to continually address T-Service load imbalances. Further, Centra stated that it expected T-Service

customers to respond to the new balancing fee structure and improve their balancing performance, thereby minimizing their balancing fees.

The balancing fees approved in Order 152/19 represented a measure intended to improve balancing compliance by T-Service customers and to help mitigate issues of cross-subsidization by Sales Service customers. In December 2020, Centra filed a report with the Board that concluded that the new balancing fee structure was working as intended. Since that time, Centra submits that the balancing performance of T-Service customers, along with the amount of balancing fees incurred by Centra and by T-Service customers, has remained stable.

10.1.2 *Position of the Parties*

Centra

Centra is strongly opposed to the recommendations of IGU and its consultant, Mr. Friesen, to change the balancing fee structure approved in Order 152/19. According to Centra, the balancing fees recovered from T-Service customers remain reasonable and appropriate for incenting improved balancing performance while also mitigating the cross-subsidization of T-Service customers by Sales Service customers. According to Centra, the balancing fees are not punitive, considering Centra charges only half of the rate levied by TCPL and provides its customers with seven times the tolerance level that is afforded to Centra by TCPL. Centra notes that overall, T-Service customer balancing behaviour has not improved since the first year the current fees were in effect, and that the current 50% charge is arguably not enough to improve balancing behaviour by T-Service customers.

Centra maintains that despite incurring lower direct balancing fees from TCPL than recovered from T-Service customers, Centra continues to incur costs (which are paid by Sales Service customers) though the use of an operational capacity buffer, as well as foregone capacity management revenues and higher commodity costs associated with delayed transactions needed to address T-Service. As such, comparing balancing fees paid by T-Service customers with those paid by Centra is not appropriate. Further, the

utility points out that balancing fees are not designed to be cost-based, but rather to incent behaviour.

Centra also opposes the recommendation of Mr. Friesen to increase the T-Service balancing daily tolerance band. The utility points out that there are only 14 T-Service customers in total, so an increased number of tolerance bands would still not achieve exact tolerance parity. The utility notes that the tolerance bands approved in Order 152/19 were intended to average 14% and that, apart from the smallest and largest customers, the average performance of T-Service customers is approximately 14%. Centra also concludes that further engagement with T-Service customers would be unproductive and unnecessary, since balancing fees were extensively reviewed during the 2019/20 General Rate Application, that circumstances have not materially changed since that time, and that Centra is already in regular contact with all T-Service customers regarding their nominations. Centra further submits that if the T-Service customer obligation to balance or the incurrence of balancing fees is too onerous, Centra continues to offer services, such as Sales Service, that may better align with customer business needs and risk profile.

In opposing IGU's proposed balancing tolerance structure, Centra also points out that calculating tolerances based on daily consumption would not be practical as the change would add undue complexity and would require Centra to incur costs to develop software systems to report daily tolerances. However, Centra acknowledges that it could, with minimal administrative effort, accommodate modification to the determination of daily tolerances so that all T-Service customers are provided with a fixed 14% tolerance based on their average daily consumption for the prior 12 months. Should this change be approved, Centra would still maintain the existing minimum tolerance of ± 100 GJ and maximum tolerance of $\pm 1,000$ GJ.

In response to IGU's recommendation that Centra be directed to file additional information at the next general rate application regarding daily Centra and T-Service customer imbalances, Centra submits that the information requested by IGU can either not be provided or would be unduly burdensome. Additionally, the requested information

mistakenly assumes that actual imbalances relate to Centra's estimate of opportunity costs, which they do not, and would distract from the fact that T-Service customers are contractually obligated to balance their nominations with their own gas consumption.

Industrial Gas Users

IGU is critical of Centra's current balancing fee regime and argues that the current 50% level is disproportionate when compared to the relatively small imbalance as a percentage of Centra's average daily load. While IGU accepts that balancing fees are unavoidable, it argues that T-Service customers, as individual entities, are more vulnerable to unplanned events such as equipment or power outages, which can cause large consumption variances that are difficult to manage. In contrast, Centra benefits from netting the aggregate volumes of its customers, which attenuates fluctuations. IGU suggests that a reduction in balancing fees to 25-30% of the TCPL level would therefore be prudent.

IGU is also critical of the tiered balancing fee tolerance structure described in Figure 10.2 above and points out that, for the largest customers, that structure results in a tolerance level of less than the 2% afforded to Centra. By way of example, IGU cites that a consumption level of 60,000-75,000 GJ per day would require a large T-Service customer to balance to between 1.3 and 1.7%. IGU notes that one particular T-Service customer consistently achieved a 2% balancing performance from 2019/20 to 2022/23 and 1% in 2023/24, demonstrating effective use of available balancing tools. Nonetheless, the customer continues to be assessed balancing fees, suggesting that those fees are punitive.

IGU suggests that Centra move away from the tiered balancing tolerance structure currently approved for T-Service customers and instead implement a 15% tolerance level for each T-Service customer based on their individual daily consumption (as opposed to annual average consumption). However, IGU recommends maintaining the existing maximum and minimum thresholds of ± 100 GJ and $\pm 1,000$ GJ, respectively. IGU's witness, Mr. Friesen, is of the view that retaining the absolute maximum daily tolerance at $\pm 1,000$ GJ will limit the likelihood of Centra exceeding the maximum daily tolerance of 2,111 GJ for the Manitoba Delivery Area as a result of T-Service customer imbalances.

IGU also recommends that Centra should collect and report data on days in which it incurs balancing fees, days when imbalances are caused by Centra's own Sales Service customers, and days when T-Service customers exceed their assigned imbalance thresholds.

10.1.3 Board Findings

The Board accepts the premise of Centra's argument that T-Service balancing fees are not a cost recovery mechanism, but rather an incentive tool. In light of Centra's evidence that balancing performance has not materially improved since the first year the current fees came into effect, the Board is not persuaded by IGU's argument that fees should be set at a level lower than the existing 50%.

Due to the complexity of continually recalculating T-Service balancing tolerances based on daily T-Service customer consumption levels, and continually communicating these adjusted values to each T-Service customer in a timely fashion, the Board does not accept IGU's recommendation to determine balancing tolerances based on actual daily consumption rather than annual averages. Accordingly, Centra is to continue to determine the daily tolerance level based on average daily consumption.

Similarly, the Board is not persuaded that the fixed balancing tolerance level should be increased from 14% to 15%. As noted by Centra, the existing 14% tolerance level contrasts with a 2% tolerance level afforded to Centra by TCPL. The Board accepts that Centra incurs an opportunity cost through T-Service nomination imbalances and does not, at this time, see a need to broaden the tolerance band further.

Despite the above, the Board agrees with IGU's recommendation to move away from the existing tiered balancing tolerance structure and replace it with a structure based on a fixed 14% tolerance level. However, the existing ± 100 GJ minimum and $\pm 1,000$ GJ maximum daily tolerance levels are to be maintained.

With only 14 T-Service customers in total, a five-level tolerance band is an imperfect tool to assess balancing charges, with the largest customers, as well as any customers at the top of a particular tolerance band, disproportionately affected. The Board accordingly

directs Centra to revise (and file for approval as part of the compliance filing required elsewhere in this Order) its Terms and Conditions to implement a fixed 14% daily tolerance based on individual customers' average daily consumption over the prior 12 months, which the utility indicated it could do with minimal administrative burden.

At this time, the Board does not see a need to direct Centra to collect and report the data requested by IGU.

10.2 External Billing Rates

10.2.1 Background

Centra's Terms and Conditions include external billing rates for chargeable services such as third-party damage repairs or appliance relights. The Board periodically approves those rates.

In Order 152/19, the Board approved updates to Centra's external billing rates based on a five-year moving average of internal activity rates, plus a third-party billing surcharge based on a percentage of the annual internal corporate activity rates. The third-party billing surcharge includes cost components that has previously been removed from activity rates and common overhead as a result of Centra's transition to IFRS.

In this application, Centra proposes new external billing rates based on the annual internal activity rate, rather than a five-year average, plus a third-party billing surcharge. In Centra's view, this better reflects Centra's current costs. Given the recent changes to the Consumer Price Index and other issues related to internal activity rates, Centra submits that it will continue to evaluate whether additional external billing rate calculation changes are required and bring any proposed updates in future applications.

Given the above changes, the proposed changes to Centra's external billing rates are set out in Figure 10.3.

	Approved Rates		Proposed New Rates		Proposed Increase	
	Regular	Overtime	Regular	Overtime	Regular	Overtime
Service Line Alterations	\$128	\$179	\$152	\$212	\$24	\$33
Damage Repairs	\$128	\$179	\$152	\$212	\$24	\$33
Damage Investigations	\$153	\$215	\$171	\$240	\$18	\$25
Appliance Relights	\$128	\$179	\$152	\$212	\$24	\$33
Metering Services	\$143	\$200	\$160	\$225	\$17	\$25
"As Built" Plans	\$137	\$192	\$144	\$202	\$7	\$10

Figure 10.3 — Proposed External Billing Rates

None of the parties, including Centra, specifically addressed this request in their final submissions.

10.2.2 Board Findings

The Board considers the proposed increases to be reasonable and approves Centra's proposed increases to its billing rates for external services and the resulting new rates, effective November 1, 2025.

10.3 Modified Large General Service Offering

10.3.1 Background

As a natural gas utility operating in a cold-weather climate, and since most natural gas consumed in Manitoba is burned for space and water heating purposes, Centra must plan its operations to meet peak winter capacity needs. Per Centra's Terms and Conditions, firm service customers have a right to consume natural gas at any time, including during the winter peak. As more customers connect to Centra's natural gas distribution system, or as customer loads change over time, certain segments of Centra's system may become capacity limited. In such instances, Centra may not be able to accept new customers who wish to connect to the system on a firm, year-round service basis, unless Centra first makes capacity upgrades.

In 2022, Centra filed an application with the Board to introduce a Modified Large General Service ("Modified LGS") offering. The new service offering proposal was in response to

agricultural customers, who are often located near capacity-constrained portions of Centra's distribution system, increasingly approaching Centra for natural gas service to support their grain drying operations due to the economics of that fuel source over propane-based systems. Such grain drying operations would be deemed examples of high-capacity seasonal customers due to the characteristics of the expected gas deliveries to these customers (e.g., high gas consumption during the fall season with minimal gas usage at other times of the year).

In Order 2/23, the Board approved Centra's request for authorization to offer Modified LGS contracts to high-capacity seasonal customers connecting to capacity-constrained areas of Centra's system. Under the terms of the new offering, Centra may physically lock off the gas supply to these seasonal customers such that gas service will not be available during the peak winter heating season months of December through March. The intent of the new offering was to allow prospective customers to connect to capacity-constrained areas of Centra's system sooner and assist in deferring capacity upgrades that would normally have been required had the incremental capacity needed to be provided during Centra's winter peak period. Under the approved Terms and Conditions, Modified LGS customers pay basic monthly charges on a year-round basis in the same manner as regular LGS customers but do not get charged for seasonal disconnections and reconnections.

To further assess issues related to the overall adoption of the Modified LGS service option, as well as to further review cost of service and rate design considerations associated with the new offering, Directive 3 of Order 2/23 required Centra to file additional information regarding the Modified LGS at the next general rate application.

In response to Directive 3 of Order 2/23, Centra submits that the Modified LGS offering has enabled Centra to connect several seasonal agricultural grain-drying operations to its system where otherwise, they would not have been eligible for regular LGS service based on system capacity constraints. Further, Centra advises that a total of 17 agricultural customers contracted for Modified LGS service, of which four are already connected and the remaining 13 are in the process of being connected.

However, in the two years since the Board approved Modified LGS service, Centra has determined that a clustering of high-capacity seasonal loads has the potential for shifting the local system peak from a winter peak to a fall peak, creating a fall capacity issue, which then requires capacity upgrades and eliminates the intended benefits of Modified LGS. To address this challenge, the utility has decided to pause the Modified LGS offering, although it has committed to honouring the 17 existing contracts executed to date.

Centra states that it does not propose grouping the Modified LGS customers into their own customer class. The utility notes that, given the small number of customers to date and the lack of usage history, it would be difficult to develop rates that accurately reflect the costs imposed by such customers. However, Centra commits to monitor the number of customer requests and enrollments into the Modified LGS contract to determine the most appropriate treatment in the long term.

None of the parties, including Centra, specifically addressed this request in their final submissions.

10.3.2 Board Findings

The Board accepts Centra's decision to pause the Modified LGS offering pending further investigation of the impact of seasonal customers on Centra's infrastructure. However, the Board sees a need for the utility to investigate the possibility of a separate seasonal rate offering. As evidenced by the need for capital projects such as the South Loop System Upgrade, there appears to be a significant interest by the agricultural community on converting grain-drying operations from propane to natural gas. As a result, Centra is including such load in its local capacity forecasts used for system planning, which, in turn, is advancing the need for capital upgrades to various portions of Centra's transmission and distribution systems. This raises the issue of how such seasonal operations affect Centra's peak loads and how those should be addressed.

The Board therefore directs Centra to investigate the potential for a separate seasonal rate offering. As part of the next general rate application, Centra is to either file a proposal

for such a rate offering or to provide a report that sets out why a separate seasonal rate offering is not feasible.

The Board deems Directive 3 of Order 2/23 to be complete.

11.0 OTHER MATTERS

This section deals with the following other matters:

- the finalization of interim gas commodity rate approvals and other interim non-gas commodity rate approvals;
- the finalization of interim franchise approvals;
- the finalization of an interim approval of a change to Centra's Terms and Conditions relating to the Customer Equipment Problem Program;
- Centra's liability insurance;
- Other completed, closed, and set-aside directives; and
- Centra's outstanding requests for confidential treatment of commercially sensitive information.

11.1 Compliance Filing

The Board directs Centra to file a compliance filing based on the directives set out in this order by October 15, 2025. The compliance filing is to include the following:

- revised calculations and schedules for rate base, revenue requirement, rates, and customer class bill impacts that reflect all of the directives of this order, as well as Centra's proposed Gas Commodity rate for November 1, 2025.
- a revised financial forecast based on the approvals and adjustment directed in this order;
- revised breakdowns of the integrated cost allocation methodology results for 2024/25, 2025/26, and 2026/27 reflecting the changes approved in this order; and
- revised 2025-2029 and 2026-2030 Natural Gas Asset Management Capital Investment Plans reflecting the reduced capital budgets approved in this order.

In addition, Centra is to file a revised Schedule of Sales and Transportation Services and Rates.

If Centra is not in a position file all documents by October 15, 2025, it may delay the filing of the updated financial forecast and the revised Schedule of Sales and Transportation Services and Rates to December 31, 2025.

11.2 Finalization of Interim Gas Commodity Rate Approvals

11.2.1 Background

As part of the current proceeding, the Board completed its review of Centra's non-gas costs and also reviewed Centra's historical gas costs incurred since the 2019/20 General Rate Application. Any interim *ex parte* orders relating to the approval of quarterly gas commodity (previously Primary Gas) rate changes or interim non-commodity rate changes that were approved between the 2019/20 General Rate Application and November 1, 2024 have been subject to public review and were available for comments from the public and interveners. None of the parties expressed any concerns regarding the finalization of these interim orders, although IGU's submissions regarding the interim rate measure for the Special Contract class is addressed in section 8.5.

11.2.2 Board Findings

The Board approves the finalization of the interim rates included in the following interim *ex parte* orders:

- 2019 Orders: 161/19
- 2020 Orders: 10/20, 62/20, 96/20, 128/20
- 2021 Orders: 14/21, 47/21, 83/21, 117/21
- 2022 Orders: 6/22, 44/22, 79/22, 114/22
- 2023 Orders: 10/23, 52/23, 85/23, 121/23
- 2024 Orders: 16/24, 49/24, 91/24

11.3 Finalization of Interim Franchise Approvals

11.3.1 *Background*

The *Public Utilities Board Act* enables municipalities that would like Centra to provide natural gas to residents and businesses within their boundaries to enter into a franchise agreement with Centra. A franchise agreement grants Centra a monopoly on the supply of natural gas in the municipality for the duration of the agreement. Franchise agreements are reviewed and, if approved, are granted by the Board on an interim *ex parte* basis, subject to passing of a Board-approved financial feasibility test.

Crossing agreements between a municipality and Centra are also granted by the Board on an interim *ex parte* basis. The Board has not finalized any franchise or crossing agreements since the issuance of Order 152/19. Any franchise or crossing agreements approved in interim *ex parte* orders issued since the 2019/20 General Rate Application have now been subject to public review and were available for comments from the public and interveners. No party expressed any concerns regarding the finalization of these interim orders.

11.3.2 *Board Findings*

The Board is satisfied that all interim *ex parte* orders with respect to municipal franchise or crossing agreements approved since the 2019/20 General Rate Application are in order. The Board therefore finalizes the following prior interim Orders.

- 2019 Orders: 133/19, 134/19
- 2022 Orders: 89/22, 90/22
- 2023 Orders: 92/23, 93/23, 94/23
- 2024 Orders: 58/24, 88/24, 89/24
- 2025 Orders: 32/25, 36/25

11.4 Terms and Conditions for the Customer Equipment Problem Program

11.4.1 Background

Centra requests final approval of the changes to its Terms and Conditions that were approved in Order 53/20.

In Order 53/20, the Board set aside the Order 49/96 Customer Equipment Problem Program component list and amended, on an interim *ex parte* basis, section IV.E.c) of Centra's Schedule of Sales and Transportation Services and Rates. Section IV.E.c) now reads:

*Provide safety inspections, safety related adjustments and/or repairs to the natural gas burning portion of stoves, ranges, and all primary space and water heating residential and commercial appliances under 400,000 Btu/h (422 MJ/h). This includes, but is not limited to, repair of minor gas leaks, and the adjustment and replacement of controls and control parts, **performed by the Company where reasonably possible.** The Small General Class Customer will be responsible for the cost of parts. All other Customers will be responsible for the cost of parts and labour. (emphasis added)*

No Intervener made submissions on this matter.

11.4.2 Board Findings

The Board approves the changes to the Terms and Conditions for the Customer Equipment Problem Program as final. The Board notes that changes required in Order 53/20 have already been included in Centra's existing Terms and Conditions.

11.5 Liability Insurance

11.5.1 Background

Under to section 11 of *The Gas Pipe Line Act*, the Board must approve the amount of liability insurance held by Centra. The Board last reviewed and approved Centra's liability insurance as part of Order 152/19.

To facilitate the regular review of Centra's liability insurance coverage amount, Directive 42 of Order 152/19 requires Centra to file the following insurance-related information as part of future general rate applications:

- evidence as to Centra's existing liability insurance coverage and any planned changes to such coverage;
- evidence as to the cost of the liability insurance coverage;
- a summary of the rationale for the coverage limit, and, if external reports were obtained to arrive at the coverage limit, a copy of such reports; and
- a list of all pending claims, if any, that together exceeds a threshold of \$20 million.

In this hearing, Centra filed information on its insurance coverage and premiums paid but requested that the Board receive the information in confidence, as in prior proceedings.

Centra advises that, since 2006, Manitoba Hydro's commercial general liability ("CGL") insurance policy has included both gas and electric operations. The combined value of the CGL policy premium costs was historically allocated 55% to gas operations and 45% to electric operations, which was representative of the individual premium costs for the two separate operations before they came under one combined policy. However, Centra notes that, following a 2018 wildfire in California, the casualty market for electric utility wildfire insurance began to harden, resulting in an adjustment of premium costs based on wildfire insurance. Consequently, the allocation of the CGL policy premium costs was adjusted such that CGL policy premiums are now allocated 45% to gas and 55% to electric operations to reflect the change in insurer focus upon wildfire exposure to electric utilities having transmission and distribution infrastructure.

Centra further notes that in order to achieve the most competitive premium cost rates from insurers, the utility and its broker present to both the domestic and London markets, that there are no changes planned for the existing CGL insurance policy, and that there are no current claims that exceed \$20 million.

None of the interveners made submission on this issue.

11.5.2 Board Findings

The Board approves the amount of Centra's existing liability insurance. The Board will maintain Directive 42 of Order 152/19 for future liability insurance coverage approvals. However, the Board notes that, with increasing wildfire and climate change risk, as well as Manitoba Hydro's increasing asset base, it is an appropriate time to revisit the level of insurance coverage available. The Board accordingly directs Centra to consider the appropriate level of coverage for the utility as part of the Centra-specific business plan required under this order, as well as the appropriate allocation of costs between Centra and Manitoba Hydro.

11.6 Other Completed, Closed, and Set Aside Directives

11.6.1 Centra's Electronic Cost of Service Model (Directive 11 of Order 109/22)

In Directive 11 of Order 109/22, the Board required Centra to file a proposal with the Board on how an electronic version of its cost of service model may be shared with interveners and what confidentiality protections should be put in place to enable the sharing of such a model. While Centra filed an initial response on March 24, 2024, the Board subsequently extended of the deadline for the directive to receive further input from both Centra and interveners. As part of Order 6/24, Directives 1 and 2 now outline the Board's subsequent decisions regarding access to Centa's COSS model. These subsequent Directives superseded Directive 11 of Order 109/22, and are discussed below. The Board accordingly sets aside Directive 11 of Order 109/22.

11.6.2 Cost of Service Methodology (Directive 12 of Order 109/22)

In Directive 12 of Order 109/22, the Board required Centra to file, with its next general rate application, confirmation that it has implemented the changes to its cost of service methodology approved in that order and that its cost of service study filed in the general rate application conforms to the directives set out in that order. Centra provided the requested confirmation in Tab 11 of its general rate application. Appendix 10.1 of Centra's application and the Elenchus report also confirm Centra's compliance with Order 109/22. The Board accordingly confirms that Directive 12 of Order 109/22 has been completed.

**11.6.3 Requested Rates Based on the Methodology in Order 109/22
(Directive 13 of Order 109/22)**

In Directive 13 of Order 109/22, the Board required that the rates requested by Centra in the next general rate application be based on the methodology approved in that Order. Centra was required to file, with its next general rate application, the results of a new cost of service study prepared using the methodology approved in that Order. In Appendix 10.1 of its application, Centra has filed the results of its 2024/25 Cost of Service Study prepared in accordance with the methodology approved in Order 109/22. This is confirmed by the Elenchus report filed as part of this general rate application. The Board accordingly confirms that Directive 13 of Order 109/22 has been completed.

11.6.4 Electronic Cost of Service Model to Elenchus (Directive 1 of Order 6/24)

In Directive 1 of Order 6/24, the Board ordered Centra to make its electronic cost of service model available for review by Elenchus Research Associates Inc. and to collaborate with that firm in a review of the model.

In Tab 11 of Centra's application, Centra states that it has provided its electronic cost of service model to Elenchus Research Associates Inc. for review and will continue to collaborate as required in accordance with the scope of work. The Board has also received Elenchus's report regarding Centra's cost of service model. The Board accordingly confirms that Directive 1 of Order 6/24 has been completed.

11.6.5 Electronic Cost of Service Model to Interveners (Directive 2 of Order 6/24)

In Directive 2 of Order 6/24, the Board ordered Centra to make an Excel version of its cost of service model available to those interveners at the upcoming general rate application who are entitled to receive commercially sensitive information. Centra was further directed to make a redacted proxy model available to other interveners. The models may lock the embedded formulas but must allow for inputs to be changed.

In Tab 11 of its general rate application, Centra stated that access to the model would be provided to CAC and IGU once agreements/undertakings to finalize the commercially

sensitive information were finalized. Accordingly, a redacted proxy was not provided as it was no longer necessary.

During the hearing, Elenchus, acting as an independent expert consultant, reviewed Centra's electronic cost of service model. Interveners were also able to request different cost of service results to assess the impacts of Centra's change proposals or different underlying model assumptions. As it was agreed that Elenchus would receive and review the cost of service model, the Board sets aside Directive 2 of Order 6/24.

11.6.6 Filing of Centra's 2024/25 Fiscal Year General Rate Application (Directive 1 of Order 92/24, Directive 1 of Order 96/24, and Directive 2 of Order 111/24)

In Directive 1 of Order 92/24, the Board required Centra to file its 2024/25 General Rate Application with the Board on or before August 30, 2024.

On August 13, 2024, the Board issued Directive 1 of Order 96/24, which varied Directive 1 of Order 92/24 to extend the GRA filing date to September 30, 2024. As a result, the Board confirms that Directive 1 of Order 92/24 was superseded and set aside by Order 96/24.

On September 27, 2024, the Board issued Order 111/24 Directive 2, which varied Order 96/24 Directive 1 to extend the GRA filing date to October 7, 2024. As a result, the Board confirms that Directive 1 of Order 96/24 was superseded and set aside by Order 111/24.

On October 7, 2024, Centra filed its 2024/25 fiscal year General Rate Application. The Board accordingly confirms that Directive 2 of Order 111/24 has been completed.

11.6.7 Confirmation of the 4.5% Interim General Revenue Increase (Directive 2 of Order 125/24)

In Directive 2 of Order 125/24, the Board ordered that Directive 1 of that Order would expire on October 31, 2025, unless confirmed or varied by the Board that day. Under Directive 1, Centra's request for approval of a general revenue increase of 4.5% effective November 1, 2024 was approved on an interim basis. If Directive 1 expired, on

November 1, 2025 the non-gas components of rates approved under Directive 1 would revert back to the rates in effect immediately before November 1, 2024.

The resulting interim rates stemming from Order 125/24 were approved in Order 129/24. Following the completion of the current general rate application and the Board's adjudication of the issues, the Board has released its decision regarding the Order 125/24 interim decision as part of the current order. As this order has been released before October 31, 2025, the Board sets aside Directive 2 of Order 125/24.

11.6.8 Filing of Revised Rate Schedules (Directive 8 of Order 125/24)

In Directive 8 of Order 125/24, the Board required Centra to file, within two weeks of the issuance of that order, revised rate schedules that reflected the directives set out in that order.

On November 1, 2024, Centra filed its revised rates under Directive 8 of Order 125/24. This revised rate schedule was subsequently approved in Order 129/24. The Board accordingly confirms that Directive 8 of Order 125/24 has been completed.

11.6.9 Provision of Redacted Information to Mr. Friesen (Directive 2 of Order 140/24)

In Directive 2 of Order 140/24, the Board directed Centra to provide Mr. Friesen, IGU's expert consultant, with access to redacted commercially sensitive information in Centra's 2024/25 General Rate Application following the mutual execution of a non-disclosure agreement. Mr. Friesen received access to the material. The Board accordingly confirms that Directive 2 of Order 140/24 has been completed.

11.7 Remaining Requests for Confidentiality

11.7.1 *Background*

Since Centra filed its application, the Board has received several requests from Centra seeking permission to file information in confidence in accordance with Rule 13 of the Board's *Rules of Practice and Procedure*. 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 significantly harm 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 57/25, the Board adjudicated Centra's requests in relation to Centra's initial application filed on October 7, 2024 and Centra's response to the Round 1 information requests filed on January 27, 2025. This Order addresses all remaining requests for confidentiality, including those relating to Centra's response to the Round 2 information requests, evidence submitted by the interveners, responses to information requests by the interveners, Centra's pre-hearing update and rebuttal, submissions made by the parties during the oral hearing, the parties' final written submissions, and specific portions of the hearing transcript.

Consistent with earlier proceedings, Centra used a list of redaction codes in support of its request. A copy of the codes was filed as Appendix 1.1 of Centra's application.

The Board reviewed each of the requests and the corresponding unredacted versions of the evidence. The Board asked Centra for clarification on several requests for confidentiality. In response, Centra agreed that some additional evidence no longer needed to be redacted and filed updated documents with the Board to reflect the revised or lifted redactions. This Order deals only with the redactions that Centra would like to remain in place and that remain as of the date this order is issued.

11.7.2 Board Findings

The Board considers Centra's request 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, as the public interest would likely be harmed if there was disclosure of Centra's confidential information. Accordingly, the Board orders that this information be held confidential.

12.0 IT IS THEREFORE ORDERED THAT:

1. Centra's request for a general revenue increase of 4.5% effective November 1, 2024 that was approved, on an interim basis, in Directive 1 of Order 125/24 **BE AND HEREBY IS APPROVED AS FINAL.**
2. For the two fiscal years beyond 2024/25, Centra's application **BE AND HEREBY IS VARIED** as follows:
 - a) an additional general revenue increase of 4.5% effective November 1, 2025 is **APPROVED AS FINAL**; and
 - b) an additional general revenue increase of 4.0% effective November 1, 2026 is **APPROVED AS FINAL.**
3. For the purposes of determining Centra's 2025/26 and 2026/27 non-gas revenue requirement, and in addition to other requirements in this order, the utility is directed to:
 - a) reduce its forecast operating and administrative expenses by \$2 million in both 2025/26 and 2026/27; and
 - b) reduce its forecast capital expenditures by \$2 million in both 2025/26 and 2026/27.
4. Centra is directed to file a three-year 2027/28 to 2029/30 General Rate Application with the Board on or before April 1, 2027.
5. Centra's application of updated depreciation rates for rate setting purposes and regulatory deferral accounts and the proposed amortization periods of those accounts, **BE AND HEREBY IS VARIED AS FOLLOWS:**
 - a) The Board approves a change to the amortization period on the loss on retirement or disposal of assets from 5 to 27 years.
 - b) The Board approves the use of Centra's 2024 Depreciation Study (based on the Average Service Life methodology) to reflect updates to depreciation and amortization expense for the 2024/25 fiscal year, as well as the 2025/26 and 2026/27 fiscal years.

- c) The Board approves the amortization of the regulatory deferrals for the differences between the 2014 and 2019 depreciation studies and between the 2019 and 2024 depreciation studies over five years.
 - d) The Board approves the commencement of the use of four new depreciation accounts as set out in the body of this order.
 - e) The Board approves the establishment of a cloud computing deferral account for small information technology systems beginning with the 2024/25 test year and the amortization of amounts deferred into that account over six years.
 - f) Centra is authorized to apply the \$243,000 reduction in depreciation expense for the 2024/25 test year that results from using the 2024 Depreciation Study instead of the 2019 Depreciation study as an increase to net income for that year.
6. Centra's proposal to reduce the corporate allocation from \$12 million to \$4 million for each of the 2024/25, 2025/26 and 2026/27 fiscal years **BE AND HEREBY IS APPROVED.**
7. Centra is directed to permanently eliminate the head office credit for the 2025/26 fiscal year.
8. Centra is directed to revise its integrated cost allocation methodology, beginning with the 2024/25 test year, by replacing the %Activity and %Hybrid allocators with a three-factor allocator that equally weights all of the following:
- a) activity charges as currently determined by Centra, based on a rolling average of the prior three fiscal years;
 - b) assets based on a rolling average of the prior three fiscal years; and
 - c) revenue for electric and natural gas operations based on a rolling average of the prior three fiscal years in a matter that:
 - i. includes Manitoba Hydro's net export revenue for electric operations; and
 - ii. excludes Centra's gas commodity costs for natural gas operations.
9. Following the changes required by Directive 8 of this order, Centra is directed not to change the integrated cost allocation methodology without the prior approval of

the Board. For certainty, this directive does not require the Board's approval to change the allocator driver values based on year-to-year updates to the data supporting the calculations.

10. Centra is directed to file with the Board, on or before April 1, 2027, a Centra-specific business plan. The plan is to include, at minimum, the following:

- a) Centra's strategy for satisfying existing and future service requirements, including whether the utility will continue to expand its service territory and customer base or plans to restrict its operations in light of the provincial government's intention to transition towards a carbon-neutral economy;
- b) a management structure with a clear chain of accountability for administrative and regulatory decisions affecting natural gas operations and management approval levels that are tailored to the relative size of Centra and the materiality of decisions to Centra;
- c) a financial strategy that includes, among other things:
 - i. a proposed approach to setting an annual net income level appropriate for Centra that will be included in the utility's revenue requirement, and
 - ii. a regulatory strategy for returning Centra to a sustainable rate path and regular rate applications;
- d) the appropriate cost allocation methodology in light of Manitoba Hydro's future major initiatives needing to be contrasted against Centra's mature and relatively stable operations;
- e) business risks posed by the energy transition, including the following:
 - i. the risk of stranded assets and the impact, if any, on appropriate depreciation rates and amortization periods, and
 - ii. the risk posed by increasing the number of regulatory deferral accounts, and the balances in those accounts, at a time of flattening or decreasing natural gas volumes;
- f) appropriate financial metrics and financial targets for the utility, including the role, if any, of retained earnings in natural gas operations; and

- g) the appropriate amount of insurance coverage for Centra and allocation of insurance costs to Centra.
11. Centra is directed to file, with the next general rate application, a plan to eliminate, or transition towards an elimination of, the corporate allocation. Alternatively, Centra is to provide a rationale for retaining the corporate allocation.
12. Centra is directed to file, with its next general rate application, a position paper on the possibility of one or more shared service agreements between Centra and Manitoba Hydro. The paper is to address the potential benefits of such agreements in achieving increased certainty regarding
- a) the services to be provided to Centra; and
 - b) the amounts to be charged to Centra for those services.
13. Centra's application for final approval of actual gas costs from November 1, 2018 to October 31, 2019 of \$212.0 million **BE AND HEREBY IS APPROVED AS FINAL.**
14. Centra's application for final approval of actual gas costs from November 1, 2019 to October 31, 2020 of \$186.4 million **BE AND HEREBY IS APPROVED AS FINAL.**
15. Centra's application for final approval of actual gas costs from November 1, 2020 to October 31, 2021 of \$201.9 million **BE AND HEREBY IS APPROVED AS FINAL.**
16. Centra's application for final approval of actual gas costs from November 1, 2021 to October 31, 2022 of \$344.4 million **BE AND HEREBY IS APPROVED AS FINAL.**
17. Centra's application for final approval of actual gas costs from November 1, 2022 to October 31, 2023 of \$312.6 million **BE AND HEREBY IS APPROVED AS FINAL.**
18. Centra's application for final approval of actual gas costs from November 1, 2023 to October 31, 2024 of \$146.6 million **BE AND HEREBY IS APPROVED AS FINAL.**

19. Centra's request for approval of the Transportation (to Centra), Distribution (to Customers), and corresponding Delivery Rates, and the Gas Commodity Overhead rate, as approved on an interim basis, effective November 1, 2024, in Order 129/24, **BE AND HEREBY ARE APPROVED AS FINAL.**
20. Centra's request to maintain the Fixed Rate Gas Commodity Service Program Cost Rate at \$0.02428/m³, effective November 1, 2024 and approved on an interim basis in Directive 2 of Order 129/24, **BE AND HEREBY IS APPROVED AS FINAL.**
21. Centra's forecast of gas costs for the 2024/25 gas year of \$159.1 million **BE AND HEREBY IS APPROVED.**
22. Centra's Alternate Service rates charged to Interruptible customers during periods of potential curtailment between November 1, 2018 and October 31, 2024 **BE AND HEREBY ARE APPROVED AS FINAL.**
23. Centra's rates applied to a sale of Compressed Natural Gas to an external party in 2018 for utility mutual aid purposes **BE AND HEREBY ARE APPROVED AS FINAL.**
24. Centra's application to replace the historical reference heating value with a calculation methodology that uses a 12-month rolling average of actual heating values experienced over the previously completed fiscal year **BE AND HEREBY IS APPROVED.**
25. Centra's application for endorsement of a change to the quarterly Gas Commodity rate setting methodology such that the most recent natural gas volume forecast is used **BE AND HEREBY IS APPROVED.** Centra is to incorporate its updated gas volume forecasts per the requirements outlined in this order.
26. Centra's application for endorsement of a change to the quarterly Gas Commodity rate setting methodology such that the forecast cost of gas in storage is updated quarterly rather than annual **BE AND HEREBY IS DENIED.**
27. Centra is directed to file with the Board, together with its next general rate application, a report on how the Corporate Value Framework can be used to prioritize Centra's capital expenditures.

28. The following changes to Centra's cost of service methodology **BE AND HEREBY ARE APPROVED**:
- a) the permanent elimination of the Franchise Expansion Adjustment;
 - b) use of historic class participation rather than forecast class participation for the purpose of allocating demand-side management costs;
 - c) use of winter volumes rather than annual volumes for the allocation of gas in storage included as working capital in rate base; and
 - d) the temporary allocation of net losses during the 2024/25 test year based on each customer class's share of Centra's non-gas revenue requirement. Centra is to revert to the allocation of net income based on class share of rate base for 2025/26 and 2026/27.
29. Centra is directed to file, together with its next general rate application, a new unaccounted-for gas study.
30. Centra's proposal, for cost of service purposes, to classify the costs related to the distribution mains using the results of the minimum system study prepared by Atrium and filed in Centra's application **BE AND HEREBY IS VARIED AS FOLLOWS**:
- a) for the 2024/25 test year, the costs related to Centra's distribution mains are to be classified in accordance with the Atrium study; and
 - b) for any subsequent years, and until the Board determines otherwise, Centra is to revert to classifying distribution mains as 67% demand and 33% customer as per the results of Centra's historical diameter-length study used in fiscal years before 2024/25.
31. The interim rate measure, approved in Directive 7 of Order 109/22 and extended in Order 106/23, affecting the Special Contract and Power Station classes between November 1, 2022 and October 31, 2024, **BE AND HEREBY IS APPROVED AS FINAL**.
32. Centra's proposal to increase the basic monthly charge for the small general service and large general service classes to \$14.75 and \$85.00, respectively, effective November 1, 2024, **BE AND HEREBY IS APPROVED AS FINAL**.

33. Centra's proposal to eliminate, effective November 1, 2024, the demand charge for the Power Station class, **BE AND HEREBY IS APPROVED AS FINAL.**
34. Centra is directed to revise the rate design for the High Volume Firm customer class as follows:
- a) effective November 1, 2025, the percentage of demand-related costs recovered through the demand charge is to be increased from 65% to 70%; and
 - b) effective November 1, 2026, the percentage of demand-related costs recovered through the demand charge is to be increased from 70% to 75%.
35. Centra is directed to file, together with the next general rate application, a seasonal rate proposal or a report that sets out why a separate seasonal rate offering is not feasible.
36. Centra's proposed increases to its billing rates for external services, **BE AND HEREBY ARE APPROVED**, effective November 1, 2025.
37. Interim orders 161/19, 10/20, 62/20, 96/20, 128/20, 14/21, 47/21, 83/21, 117/21, 6/22, 44/22, 79/22, 114/22, 10/23, 52/23, 85/23, 121/23, 16/24, 49/24, and 91/24, relating to the approval of Primary Gas, Gas Commodity rates, and non-commodity rate changes, **BE AND HEREBY ARE APPROVED AS FINAL.**
38. Interim orders 133/19, 134/19, 89/22, 90/22, 92/23, 93/23, 94/23, 58/24, 88/24, 89/24, 32/25, and 36/25 relating to the approval of municipal franchise and crossing agreements **BE AND HEREBY ARE APPROVED AS FINAL.**
39. Centra's existing liability insurance amount **BE AND HEREBY IS APPROVED.**
40. The following directives are set aside:
- a) Directive 24 of order 99/07;
 - b) Directives 3 and 31 of Order 152/19;
 - c) Directive 1 of Order 72/22;
 - d) Directives 4 and 11 of Order 109/22;

- e) Directives 2 and 3 of Order 6/24;
- f) Directive 1 of Order 92/24;
- g) Directive 1 of Order 96/24;
- h) Directive 2 of Order 125/24.

41. Subject to Directive 43, Centra is directed to file, by no later than October 15, 2025, a compliance filing that includes the items listed below:

- a) revised calculations and schedules for rate base, revenue requirement, rates, and customer class bill impacts that reflect all of the directives of this order, as well as Centra's proposed Gas Commodity rate for November 1, 2025.
- b) a revised financial forecast based on the approvals and adjustment directed in this order;
- c) revised breakdowns of the integrated cost allocation methodology results for 2024/25, 2025/26, and 2026/27 reflecting the changes approved in this order; and
- d) revised 2025-2029 and 2026-2030 Natural Gas Asset Management Capital Investment Plans reflecting the reduced capital budgets approved in this order.

42. Subject to Directive 43, Centra is directed to file, together with the compliance filing required by this Order, a revised Schedule of Sales and Transportation Services and Rates for Board approval that reflects the following items:

- a) For Section VI.D), paragraphs 1), 2), and 3) of the existing terms and conditions for Interruptible Sales Service, the words "sale price" are to be replaced with "pass-through cost of acquiring additional gas commodity and transportation to Manitoba";
- b) For Appendix B, the rate table is to reflect the increased billing rates for external services approved in this Order; and
- c) For Appendix C regarding Transportation Service balancing fees, the existing balancing tolerances section is to be updated to reflect a 14% daily tolerance band for all Transportation Service customers that's based on the average of the individual customer's absolute daily consumption over the prior 12 months

while still maintaining the existing ± 100 GJ minimum and $\pm 1,000$ GJ maximum absolute daily tolerance levels.

For the purposes of the Board review of the above changes, two versions of the above changes are to be provided, one showing the individual text changes and one public-facing (“clean”) copy that fully integrates all changes.

43. If Centra is unable to comply with Directives 41 and 42 in their entirety by October 15, 2025, Centra may defer the following until December 31, 2025:

- a) the filing of the revised financial forecast required by clause (b) of Directive 41; and
- b) the filing of the revised Schedule of Sales and Transportation Services and Rates required by Directive 42.

44. Centra’s residual claims for confidentiality and requests to file redacted information are accepted insofar as they relate to redactions remaining on the day this order or issued. The Board’s ruling on this issue does not affect any prior rulings of the Board on access to confidential information by any of the parties or their witnesses.

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.

THE PUBLIC UTILITIES BOARD

“Marilyn Kapitany, B.Sc.(Hon), M.Sc.”
Panel Chair

“Rachel McMillin, B.Sc., MPA”
Associate Secretary

Certified a true copy of Order No. 120/25
issued by The Public Utilities Board


Associate Secretary

APPENDIX A – GLOSSARY

Term	Acronym	Description
Applicant		A party who makes an application to the Public Utilities Board. Generally, this is a utility seeking an approval from the Board.
Atrium Economics LLC	Atrium	A consultant retained by Centra to prepare a minimum system study for submission in the current general rate application.
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.
Business Operations Capital		Capital expenditures to renew existing assets and facilities, extend the natural gas system to new customers, and address both load growth and requirements for new capacity.
Canadian Generally Accepted Accounting Principles	CGAAP	Accounting standards that applied to Centra and Manitoba Hydro before the adoption of International Financial Reporting Standards (IFRS) in 2015.
TCPL Mainline		An interprovincial gas transmission pipeline that is regulated by the Canada Energy Regulator. The Canadian Mainline is owned by TransCanada Pipelines Limited, which is a subsidiary of TC Energy. Also known as the TCPL Mainline, the Canadian Mainline is used to transport natural gas between the Alberta-Saskatchewan border, across to Manitoba, into the eastern provinces, as well as to the U.S., including to the south at Emerson in Manitoba.
Centra Gas Manitoba Inc.	Centra	Manitoba's only natural gas distributor. Centra is a wholly owned subsidiary of Manitoba Hydro, a Crown corporation.
Consumer Price Index	CPI	An index published by Statistics Canada to measure inflation.
Consumers' Association of Canada (Manitoba) Inc.	CAC	An intervener to this hearing who represents the interests of consumers across Manitoba and, in particular, the interests of Centra's residential natural gas customers.
Classification		Step 2 in the cost of service process. Costs are classified into one of three categories: (1) Demand, (2) Energy, or (3) Customer.
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. Centra's cost of service studies are prepared on a forward-looking basis and named based on the test year for which they are prepared.
Customer Class		Centra Gas's customers are grouped into customer classes based on their service characteristics. All customers within the same class pay the same rates. The customers classes discussed in this Order include the following: (1) Small General

		Service, (2) Large General Service, (3) High Volume Firm, (4) Mainline, (5) Interruptible, (6) Special Contract, and (7) Power Station.
Customer (Classification)		For cost of service purposes, the classification used for costs that are directly affected by the number of customers attached to the system.
Deloitte LLP	Deloitte	The independent Integrated Cost Allocation Methodology (ICAM) expert selected by Centra for this general rate application.
Demand (Classification)		For cost of service purposes, the classification used for costs that vary based on peak usage rather than the volume of natural gas 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 natural gas DSM in Manitoba.
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.
Distribution (Function)		For cost of service purposes, the function used for the capital and operating costs of Centra's high-, medium- and low-pressure distribution systems.
Elenchus Research Associates Inc.	Elenchus	The independent expert consultant appointed by the Board to review Centra's cost of service methodology for compliance with the Board's directives issued in 2022.
Energy (Classification)		For cost of service purposes, the classification used for costs that are directly affected by the amount of natural gas purchased or consumed.
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 intervenor 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. Such orders are typically approved on an interim basis and subsequently finalized during the public reviews of cost of gas or general rate applications.
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 six Functions: (1) Production, (2) Pipeline, (3) Storage, (4) Transportation, (5) Distribution, and (6) Onsite.
General Rate Application	GRA	A Public Utilities Board process to review Centra's proposed changes to rates and their impact on various customer classes.

High Volume Firm (Customer Class)	HVF	Commercial and industrial customers with an annual consumption of more than 680,000 m ³ .
Integrated Cost Allocation Methodology	ICAM	Used allocate common costs between Manitoba Hydro and Centra. As such, a portion of Manitoba Hydro's operating and administrative expenses, together with costs associated with finance, depreciation and taxes on common assets, are allocated to Centra's income statement based on various allocation factors). However, if costs are deemed 100% related to Centra, these costs will be fully allocated to Centra's income statement.
Industrial Gas Users	IGU	An Intervener to this hearing that represents a coalition of high-consumption natural gas users.
International Financial Reporting Standards	IFRS	Accounting standards adopted by Manitoba Hydro in April 2015 which replace Canadian Generally Accepted Accounting Principles (CGAAP).
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.
Interruptible (Customer Class)	INT	Commercial and industrial customers with an annual consumption of more than 680,000 m ³ whose service may be interrupted from time to time by Centra if there is inadequate capacity to serve them.
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.
Koch Fertilizer Canada, ULC	Koch	An Intervener to this hearing. Koch is a large fertilizer manufacturer and customer within the Special Contract class.
Large General Service (Customer Class)	LGS	Medium-sized commercial and industrial customers with an annual consumption of less than 680,000 m ³ .
Load Factor		The ratio of average demand to peak demand. A high load factor indicates that demand is fairly constant. A low load factor indicates that peak demand is much higher than average demand.
Mainline (Customer Class)	ML	Commercial and industrial customers with an annual consumption of more than 680,000 m ³ and who are served directly from Centra's transmission system or through dedicated high-pressure distribution systems.
Operating & Administrative Expense	O&A	Expenditures to support Centra Gas's day-to-day operations, including labour costs and external service providers.
Peak Demand		The instantaneous maximum amount of natural gas required by a customer or group of customers.
Power Station (Customer Class)	PS	Electrical generating stations that use natural gas to produce electricity. Manitoba Hydro is the only customer in this class.
Purchased Gas Variance Account	PGVA	A regulatory deferral account used to ensure that the "exact" totals of Centra's gas costs are passed on to customers. These

		accounts record differences between the cost of gas embedded in rates, which are based on forecasts, and the costs that Centra actually incurs, which are typically market rates. Positive PGVA balances represent sums owing to Centra, indicating that existing billed rates have under-recovered Centra's actual gas costs. Conversely, negative PGVA balances represent sums owing to customers, indicating that existing billed rates have over-recovered Centra's actual gas costs.
Rate Base		The amount of investments based on which a utility is entitled to earn a reasonable rate of return. Rate base consists of the sum of a utility's plant-in-service, plus a reasonable amount for working capital, minus accumulated depreciation and customer contributions. The annual depreciation applied to a utility's rate base is one of the costs that must be included in a cost of service study.
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.
Rate Rider		A temporary credit or charge on a utility bill that is separate from the regular monthly rate.
Revenue to Cost Coverage	RCC	The ratio of the revenues recovered from a customer class divided by the costs allocated to that class. Since 1997, Centra's rates have been set to achieve an RCC ratio of 1.0.
Small General Service (Customer Class)	SGS	Residential and small commercial customers with an annual consumption of less than 680,000 m ³ .
Special Contract (Customer Class)	SC	Customers to whom service is provided under a written agreement between the customer and Centra that governs Centra's service to that customer.
Storage (Function)		The function used for the fixed and variable costs of Centra's U.S. transportation and storage portfolio. This function includes all U.S. pipeline charges.
System Load Factor		The Load Factor of a utility's overall system, determined by the collective average and peak demand.
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 year is 2024/25.
Transportation Service	T-Service	A Centra service offering where customers, typically those with high daily consumption requirements, arrange for their own gas supplies and the transportation of those supplies to Centra's service territory. As a result, T-service customers do not pay Gas Commodity rates and also pay reduced Delivery rates (i.e., only contribute to Centra's distribution costs as they do not contribute to Centra's transportation costs). In addition, T-service customers pay basic monthly charges according to their customer class (e.g. High Volume Firm, Mainline, Interruptible, Special Contract, and Power Station).

Unaccounted-for Gas	UFG	Gas that is purchased by Centra but not available for sale, whether as a result of leakage, measurement errors, accounting errors, or other issues measurement errors, accounting errors, or other issues.
Upstream Costs		Costs incurred before Centra's transmission and distribution system. The first 3 functions, being production, pipeline and storage, relate to upstream costs.
Zone of Reasonableness	ZOR	An established tolerance zone around the COSS RCC target of 100% for each class. Centra Gas is currently set at unity, meaning that a Zone of Reasonableness has not been set.

APPENDIX B – SUMMARY OF PRESENTER EVIDENCE

In addition to receiving evidence from Centra and intervener witnesses, the Board also received written and oral public presentations from two interested parties. A summary of the public presentations made in this proceeding is provided below.

Manitoba Eco-Network

Kent Elson, James Beddome, and Stephanie Grout presented on behalf of the Manitoba Eco-Network. The Manitoba Eco-Network was founded as a non-profit charity that seeks to strengthen Manitoba's environmental community with the goal of protecting the environment for the benefit of current and future generations. It has strong connections with approximately 122 member organizations across Manitoba. The Manitoba Eco-Network's presentation focused on energy transition impacts on the gas system.

Mr. Elson described that the energy transition will have a number of impacts on the gas system, including major declines in gas consumption and resulting major declines in Centra's revenue. Without proactive planning and actions, this could result in a runaway rate base, unaffordable rates, stranded assets, and a "death spiral" in which customers leave the system, requiring the same fixed costs to be spread over a smaller base of customers. This impacts low income and vulnerable customers in particular because these customers often have the most difficulty leaving the system. This also has a significant impact on industrial customers who also have difficulty leaving the system, particularly when they have high heat processes that are difficult to decarbonize.

Manitoba Eco-Network stated that the decline in gas demand overtime is certain for five reasons. First, natural gas is a potent fossil fuel that must be virtually eliminated by 2050 as part of the energy transition. Second, current policy, such as Manitoba's Affordable Energy Plan and the Federal 2030 Emissions Reduction Plan, supports electrification. Third, heat pumps have become more efficient and effective, while also creating jobs and growth within the province. Fourth, electrification has been shown to be the cheapest pathway to decarbonization. Finally, renewable natural gas and hydrogen can only replace around 5% of the throughput of natural gas.

Environmental Defence

Kent Elson, James Beddome, and Stephanie Grout also presented on behalf of Environmental Defence. Environmental Defence is a leading Canadian environmental advocacy organization. The organization and its representatives have been involved in a variety of energy regulation matters both in Manitoba and other parts of Canada, including before the Board. Environmental Defence's presentation focused on the actions that need to be taken now to protect customers in the face of the potential energy transition impacts outlined by Manitoba Eco-Network. Environmental Defence provided a list of five actions that it argues need to take place to prevent the possible negative impacts of the energy transition.

First, subsidies from the electricity ratepayers to natural gas ratepayers should be ruled out as they allow for the "unsustainable status quo" to continue, while being unfair to electricity customers by making electricity and electrification less affordable. Environmental Defence asked that the Board ensure fair payment to Manitoba Hydro from Centra for centralized services to warrant against a subsidy from the electric system to the gas system.

Second, Environmental Defence recommends that Centra cut costs. This could be through the use of non-pipe alternatives, system pruning, repairing pipelines rather than replacing them, and undertaking proactive maintenance.

Third, Centra needs to ensure a downward rate base trajectory to avoid stranded assets and a rate spiral, as well as protect affordability in the medium and long-term. This could be done by cutting capital spending and accelerating depreciation if necessary.

Fourth, Environmental Defence recommends that Centra amend its connection policy. New customer growth is highly risky. This is because it increases the rate base, creates new assets that are most vulnerable to stranding, and creates a lost opportunity for electrification. As the Canadian Climate Institute has stated that continued growth of the gas network is inconsistent with cost-effectively reaching net zero. Instead, Environmental

Defence suggests that Centra offer utility-scale geothermal via heating-as-a-service as an alternative.

Finally, Environmental Defence recommends that the Board ensure Centra's next general rate application is filed as soon as possible. In its view, a filing deadline is needed to avoid maintaining the status quo. With Centra's rate base increasing, proactive changes are needed now to prepare for the energy transition before natural gas customer counts start dropping. Any delayed action will create more cost and more risks.

APPENDIX C – APPEARANCES

PARTY

LEGAL COUNSEL

The Public Utilities Board

Bob Peters, Sven Hombach, Avril Brown

Centra Gas

Brent Czarnecki, Gwen Muirhead

Consumers' Association of Canada

Brian Meronek

Industrial Gas Users

Antoine Hacault, Erin Lawlor Forsyth

Koch Fertilizer Canada

Antoine Hacault, Erin Lawlor Forsyth

APPENDIX D – PARTIES OF RECORD AND WITNESSES

PARTY

Centra Gas

WITNESSES

Revenue Requirement Panel

Alastair Fogg, Vice-President & Chief Financial Officer
Sandra Amorim-Dew, Corporate Controller
Greg Epp, Manager, Financial Planning
Susan Stephen, Director Treasurer
Tom Tonner, Director, Construction

Policy Panel

Allan Danroth, President & Chief Executive Officer
Alastair Fogg, Vice-President & Chief Financial Officer

Cost of Service and Rate Design Panel

Marnie Van Hussen, Department Manager,
Rate Analysis & Design
Jonathon Trenchard, Department Manager, Gas Supply
Neil Kostick, Department Manager, Gas Supply Planning
Tanis Brako, Director, Energy Service Advice & Products

Independent Expert Consultants

Deloitte LLP (written evidence only)
Elenchus Research Associates Inc.
(written evidence only)

Consumers' Association of Canada

Darren Rainkie, Darren Rainkie Consulting
Kelly Derksen, Kelly Derksen Consulting
Midgard Consulting (written evidence only)

Industrial Gas Users

Patrick Bowman, Bowman Economic Consulting
Dale Friesen, Intergroup Consultants

Koch Canada Fertilizer

Patrick Bowman, Bowman Economic Consulting