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DECISION AND ORDER

EB-2022-0200

ENBRIDGE GAS INC.

Enbridge Gas Inc. Application for 2024 Rates – Phase 1

BEFORE: **Patrick Moran**
 Presiding Commissioner

Emad Elsayed
Commissioner

Allison Duff
Commissioner

December 21, 2023

TABLE OF CONTENTS

1	INTRODUCTION AND SUMMARY OF FINDINGS.....	1
2	THE PROCESS	5
3	ENERGY TRANSITION RELATED ISSUES	9
3.1	ENERGY TRANSITION.....	9
3.2	CAPITAL EXPENDITURES.....	23
3.2.2	<i>System Renewal</i>	<i>50</i>
3.2.3	<i>Overall Capital Budget</i>	<i>52</i>
3.3	EQUITY THICKNESS	61
4	AMALGAMATION AND HARMONIZATION ISSUES	69
4.1	BENEFITS OF AMALGAMATION REALIZED IN CONTEXT OF A FIVE-YEAR DEFERRED REBASING TERM.....	69
4.2	RECOVERY OF INTEGRATION-RELATED CAPITAL COSTS	71
4.3	TAX VARIANCE DEFERRAL ACCOUNT	76
4.4	DEPRECIATION POLICY & OVERHEAD CAPITALIZATION.....	77
4.4.1	<i>Depreciation</i>	<i>77</i>
4.5.2	<i>Overhead Capitalization</i>	<i>95</i>
4.5	ACCOUNTING POLICY CHANGES DEFERRAL ACCOUNT.....	101
5	OTHER ISSUES	108
5.1	RESPONSE TO RELEVANT OEB DIRECTIONS AND COMMITMENTS FROM PREVIOUS PROCEEDINGS	108
5.2	OTHER REVENUES	108
5.2.1	<i>Disposition of Property</i>	<i>109</i>
5.2.2	<i>Natural Gas Vehicle Program.....</i>	<i>111</i>
5.3	HISTORIC PARKWAY DELIVERY OBLIGATION COSTS	115
5.4	DAWN PARKWAY CAPACITY TURNBACK.....	118
5.5	DEFERRAL AND VARIANCE ACCOUNTS	120
5.5.1	<i>Volume Variance Account.....</i>	<i>121</i>
5.5.2	<i>Panhandle Regional Expansion Project Variance Account.....</i>	<i>124</i>
5.5.3	<i>Short-term Storage and Other Balancing Services Deferral Account</i>	<i>125</i>
5.5.4	<i>Change to IFRS Deferral Account.....</i>	<i>125</i>
5.5.5	<i>OEB Directive Deferral Account.....</i>	<i>126</i>
5.6	EARNINGS SHARING MECHANISM FOR 2024.....	126
5.7	EXEMPTIONS FROM CERTAIN PERFORMANCE METRICS	128
6	IMPLEMENTATION ISSUES.....	136
7	ORDER	139
8	DISSENT IN PART - COMMISSIONER DUFF.....	143

1 INTRODUCTION AND SUMMARY OF FINDINGS

Enbridge Gas Inc. (Enbridge Gas) filed an application with the Ontario Energy Board (OEB) under section 36 of the *Ontario Energy Board Act, 1998* (OEB Act) seeking approval for changes to the rates that Enbridge Gas charges for natural gas distribution, transportation and storage, beginning January 1, 2024. Enbridge Gas also applied for approval of an incentive rate-making mechanism for the years 2025 to 2028.

This is the first cost of service rate application for Enbridge Gas since the OEB approved the amalgamation of Enbridge Gas Distribution Inc. and Union Gas Limited, effective January 1, 2019.¹

In its application, Enbridge Gas proposed that the application be reviewed in phases. Accordingly, in Procedural Order No. 2, the OEB set out the issues list for the proceeding, dividing the review of the application into Phase 1 and Phase 2.

A settlement conference was held from May 29, 2023 to June 9, 2023 regarding the Phase 1 issues. Enbridge Gas filed a partial settlement proposal with the OEB on June 28, 2023. The OEB approved an updated settlement proposal filed on July 14, 2023 in a written decision issued on August 17, 2023.

An oral hearing on most of the remaining Phase 1 issues was held between July 13, 2023, and August 11, 2023, with the other unsettled issues going directly to written submissions. Enbridge Gas filed its argument-in-chief on August 18, 2023. OEB staff filed its submission on September 12, 2023, followed by intervenor submissions which were filed by September 22, 2023. Enbridge Gas filed its reply argument on October 11, 2023. This Decision and Order addresses the Phase 1 issues that went to oral hearing as well as those that were addressed in writing.

This Decision and Order is organized into three main sections: the energy transition, amalgamation and harmonization issues, and other issues. For reasons that follow, the OEB makes the following key determinations, for the purpose of establishing just and reasonable rates.

Energy Transition

The intersection of the energy transition and the approvals sought by Enbridge Gas was a major focus of this proceeding. The OEB makes the following key findings:

¹ EB-2017-0306 and EB-2017-0307.

1. The energy transition poses a risk that assets used to serve existing and new Enbridge Gas customers will become stranded because of the energy transition. Enbridge Gas has not provided an adequate assessment of this risk to demonstrate that its capital spending plan is prudent. The stranded asset risk affects all aspects of Enbridge Gas's system and its proposals for capital spending on system expansion and system renewal.
2. The OEB is reducing the overall proposed capital budget for 2024 by \$250 million. Enbridge Gas is expected to utilize its project prioritization process to accommodate this envelope reduction. The current Asset Management Plan is not accepted as a basis to support the proposed capital investments.
3. For the proposed system expansion capital spending plan, the OEB has determined that for small volume customer connections, the revenue horizon that Enbridge Gas uses to determine the economic feasibility of new connections is to be reduced to zero, thus reducing stranded asset risk to zero, effective January 1, 2025. Projects under the current phase of the Natural Gas Expansion Program are excluded from this requirement.
4. For the proposed system renewal capital spending plan, the OEB has determined that Enbridge Gas needs to put more emphasis on monitoring, repairing and life extension of its system so that replacement projects are only implemented where absolutely necessary in order to address the stranded asset risk in that context.
5. To address the issue of stranded asset risk further, the OEB requires Enbridge Gas to carry out a risk assessment and to consider a range of risk mitigation measures, including:
 - a. How Enbridge Gas would prune its existing system to avoid the replacement of assets
 - b. What role Enbridge Gas's depreciation policy should play in reducing the stranded asset risk
 - c. How Enbridge Gas will identify maintenance, repair and life extension alternatives to extend the life of existing assets instead of long-lived replacements that increase the stranded asset risk
6. Given the increased risk for Enbridge Gas's business due to the energy transition, partially offset by other factors resulting from amalgamation, the OEB approves an increase in Enbridge Gas's equity thickness from 36% to 38%.

Amalgamation and Harmonization Issues

Amalgamation issues were another major focus of this proceeding. It has been ten years since the legacy utilities, Union Gas and Enbridge Gas Distribution, last applied for cost of service rates. Approval of harmonization ratemaking proposals, accounting policies and recovery of integration costs was sought by Enbridge Gas. The OEB makes the following key findings:

7. The OEB is satisfied that the amalgamation produced savings that will be reflected in 2024 rates. Since Enbridge Gas was able to achieve and retain savings that exceeded its integration capital investments, the OEB denies Enbridge Gas's proposal to add \$119 million of integration capital to its 2024 rate base.
8. The OEB denies Enbridge Gas's proposed recovery of \$156 million of Pension and Other Post Employment Benefit expenses recorded in the Accounting Policy Changes Deferral Account related to the pre-2017 Union Gas unamortized actuarial gains/losses.
9. The OEB approves the proposed harmonized depreciation methodology, except for the capitalization of indirect overheads.
10. The OEB approves the Average Life Group depreciation procedure, the Traditional Method for net salvage calculations and updated asset life parameters to calculate depreciation expense.
11. The OEB approves the proposed overhead harmonization methodology, except for the capitalization of indirect overheads. The OEB does not approve the proposal to capitalize \$292 million in 2024. Recognizing that a requirement to expense the entire \$292 million in 2024 would have a large impact on 2024 rates, the OEB directs Enbridge Gas to expense \$50 million of the indirect overhead amount in 2024, and capitalize the remainder. In subsequent years during the IRM term, Enbridge Gas shall reduce the capitalized amount by expensing a further \$50 million in each year.

Other Issues

There were other issues in the proceeding, in addition to the energy transition and amalgamation and harmonization issues, as detailed in the approved Issues List. The OEB makes the following key findings:

12. The OEB approves the proposed levelized treatment for the Panhandle Regional Expansion Project and the establishment of the proposed deferral account.

13. The OEB accepts Enbridge Gas's proposed changes to the Natural Gas Vehicle program provided that it operates as an ancillary business activity on a fully allocated cost basis, and any losses are at Enbridge Gas's risk.
14. The OEB is not making any base rate adjustment related to Parkway Delivery Obligation costs for the 2019 to 2023 period, as some intervenors had proposed.
15. The OEB denies Enbridge Gas's proposed Volume Variance Account. The OEB approves a harmonized average use variance account based on the average use forecast methodology approved as part of the settlement proposal.
16. The OEB is not establishing an International Financial Reporting Standards Deferral Account at this time.
17. The OEB does not require an Earnings Sharing Mechanism for the 2024 Test Year.
18. The OEB approves the requested partial exemption to the Performance Measurement target metric for the Time to Reschedule a Missed Appointment from 100% to 98%. The OEB denies the requested partial exemption to the target metrics for the Call Answering Service Level and the Meter Reading Performance Measurement.
19. The OEB approves January 1, 2024 as the effective date for 2024 rates.

2 THE PROCESS

Enbridge Gas filed its rate application in two parts. Most of the evidence in support of the application was filed on October 31, 2022, and included evidence on the revenue requirement elements of the application and the incentive rate-making mechanism (IRM) proposal. The balance of the application was filed on November 30, 2022, and included evidence on cost allocation and rate design.

In its application, Enbridge Gas proposed that the case be heard in phases. The issues that needed to be determined to support January 1, 2024 rates could be determined in the first phase, and the remaining issues could be determined in a second phase of the same proceeding.

The OEB issued its Notice of Hearing on November 14, 2022. The deadline for applying for intervenor status was December 2, 2022. The following parties applied for intervenor status:

1. AnnaMaria Valastro
2. Association of Power Producers of Ontario (APPrO)
3. Atura Power
4. Building Owners and Managers Association (BOMA)
5. Canadian Biogas Association (CBA)
6. City of Kitchener
7. Canadian Manufacturers & Exporters (CME)
8. Coalition for Renewable Natural Gas (RNG Coalition)
9. Consumers Council of Canada (CCC)
10. Enercare Home and Commercial Services Limited Partnership
11. Energy Probe Research Foundation (Energy Probe)
12. Environmental Defence
13. Farhan Shah (Withdrew request on July 21/23)
14. Federation of Rental-housing Providers of Ontario (FRPO)
15. Ginoogaming First Nation (GFN)
16. Green Energy Coalition (GEC)
17. Independent Electricity System Operator (IESO)
18. Industrial Gas Users Association (IGUA)
19. Koch Canada Energy Services, LP
20. London Property Management Association (LPMA)
21. Marshall Garnick
22. Ontario Association of Physical Plant Administrators (OAPPA)
23. Ontario Greenhouse Vegetable Growers (OGVG)
24. Otter Creek Co-operative Homes Inc. (Otter Creek)

25. Pollution Probe
26. Quinte Manufacturers Association (QMA)
27. Russ Houldin
28. School Energy Coalition (SEC)
29. Six Nations Natural Gas Company Limited (SNNG)
30. Three Fires Group Inc. (Three Fires Group)
31. TransCanada PipeLines Limited
32. Unifor
33. Vulnerable Energy Consumers Coalition (VECC)

In Procedural Order No. 1 issued on December 16, 2022, the OEB approved a list of intervenors and granted cost eligibility to APPRO, BOMA, CBA, CME, CCC, Energy Probe, Environmental Defence, FRPO, GFN, GEC, IGUA, LPMA, OAPPA, OGVG, Otter Creek, Pollution Probe, QMA, SEC, Three Fires Group and VECC.

The OEB further determined that it was appropriate to hear the application in phases and developed a revised draft issues list based on a two-phase hearing. The OEB made provision for an issues conference to consider the draft issues list, the assignment of issues to each phase, as well as the timing to consider Phase 2 issues. The OEB also provided a procedural schedule for discovery of the evidence and a settlement conference.

An issues conference was held on January 9, 2023, with the objective of discussing the draft issues list and agreeing to a proposed issues list for the OEB's consideration. Enbridge Gas and intervenors agreed to most of the issues and the assignment of the issues to each phase of this proceeding. There were two proposed storage-related issues and a proposed issue related to the quality of data and methodologies for which consensus was not achieved.

In its Decision on Issues List & Expert Evidence and Procedural Order No. 2, the OEB approved a revised Issues List pushing some of the agreed Phase 1 issues to Phase 2 of this proceeding.² The OEB also approved specific intervenor requests to file evidence in the proceeding.

After Enbridge Gas responded to interrogatories, and an eight-day technical conference, a settlement conference was held from May 29, 2023 to June 9, 2023

² The approved Issues List is set out in the OEB's [Decision on Issues List & Expert Evidence and Procedural Order No. 2](#), January 27, 2023.

regarding the Phase 1 issues. Enbridge Gas and 23 intervenors participated in the settlement conference.³ The Parties reached a partial settlement on the Phase 1 issues.

Enbridge Gas filed a settlement proposal with the OEB on June 28, 2023 (updated on July 14, 2023). The Parties reached complete agreement on the following Phase 1 issues:

Issues List Category	Completely Settled Issues ⁴
Overall	4
Volumes & Revenues	9-11
Operating Costs	19
Cost Allocation	24*
Rate Design	25-28*, 30
Deferral & Variance Accounts	31
Other	35-36, 39*

*The Parties agreed that issue 24 (cost allocation) and some / all of issues 25-28 (rate design) and issue 39 (storage space/deliverability methodology) should be deferred to a subsequent phase of the proceeding.

The Parties also reached partial agreement on the following Phase 1 issues:

Issues List Category	Partially Settled Issues
Rate Base	6
Operating Costs	12-14, 17-18
Cost of Capital	21
Rate Design	29
Deferral & Variance Accounts	32-33

No party objected to the issues or portions of issues identified as settled. As part of the settlement proposal, the parties agreed to address certain storage related issues, cost allocation and rate harmonization in a new Phase 3 of the proceeding.

OEB staff filed a submission on July 5, 2023 supporting the settlement proposal, subject to clarification regarding the dispute resolution process within the settlement reached for Issue 4.⁵ In response to OEB staff's submission, Enbridge Gas filed an updated settlement proposal on July 14, 2023.

On the first day of the oral hearing, July 13, 2023, the hearing panel accepted the partial settlement proposal in principle and noted that a formal decision would be issued in due

³ The full list of intervenors that participated in the settlement conference can be found in the [Settlement Proposal](#), June 28, 2023 (Updated July 14, 2023), pp. 5-6.

⁴ The issue numbers correspond with the approved Issues List.

⁵ Issue 4 states, "Has Enbridge Gas appropriately considered the unique rights and concerns of Indigenous customers and rights holders in its application?"

course.⁶ In a decision issued on August 17, 2023, the OEB approved the updated settlement proposal, and accepted the proposal to add a third phase to the proceeding.

An oral hearing on some of the unsettled issues in Phase 1 was held over 18 hearing days, between July 13, 2023, and August 11, 2023. At the oral hearing, the OEB amended the dates for the filing of Enbridge Gas's argument-in-chief, final arguments from intervenors and OEB staff and Enbridge Gas's reply.

Enbridge Gas filed its argument-in-chief on August 18, 2023. OEB staff filed its submission on September 12, 2023, followed by intervenor submissions filed by September 22, 2023. APPrO, BOMA, CCC, CME, City of Kitchener, Energy Probe, Environmental Defence, FRPO, GEC, GFN, IGUA, LPMA, OGVG, Pollution Probe, QMA, Russ Houldin, RNG Coalition, SEC, Three Fires Group and VECC filed written arguments for Phase 1 of this proceeding. Enbridge Gas filed its reply argument on October 11, 2023.

The OEB also considered approximately 385 letters of comment that expressed a range of concerns regarding the application and the OEB's process including:

- The OEB should not approve the proposed rate increase
- The proposed rate increase is unaffordable
- Inflation has increased the cost of living, specifically for those on fixed income
- Enbridge Gas should optimize costs and not request a rate increase
- Customers will have to reduce gas consumption in order to afford the bills
- Poor customer service – problems with reading meters and receiving e-bills on time
- Customers should not pay carbon charges
- Carbon charges should be explained clearly
- The OEB should review Enbridge Gas's spending strategies and the benefits that customers receive
- Require clarity from Enbridge Gas regarding rate increases
- Make the hearing and decision-making process accessible and inclusive
- Stop using fossil fuels – promote sustainable and clean energy sources
- Uncertainty regarding additional rate increases due to incentive rate-making mechanisms and other applications, along with uncertainty about Canada's future regarding greenhouse gas emissions reduction

⁶ Oral Hearing Transcript, Vol. 1, July 13, 2023, p.1.

3 ENERGY TRANSITION RELATED ISSUES

3.1 Energy Transition

It has been ten years since the legacy utilities, Union Gas and Enbridge Gas Distribution, last applied for cost of service rates. This is the first cost of service proceeding for the amalgamated utility, Enbridge Gas, and the first OEB proceeding to consider a gas rates application in the context of the energy transition. The energy transition and how it impacts the future of the gas system was a major focus of this proceeding.

The exploration of the energy transition in the proceeding encompassed the impacts and changes to the energy system and the energy supply mix that result from efforts to reduce greenhouse gas emissions by reducing dependence on fossil fuels, along with the use of renewable natural gas, hydrogen, and carbon capture technologies, to combat climate change.

Enbridge Gas's Evidence – Energy Transition

Enbridge Gas filed evidence detailing its perspective and approach to energy transition,⁷ including an Energy Transition Plan and a description of how the energy transition has been integrated into Enbridge Gas's business and planning processes. Enbridge Gas did not seek specific OEB approval of its Energy Transition Plan, clarifying that its approach to the energy transition informed proposals in several areas of its application.

Enbridge Gas identified key actions in relation to its energy transition planning:

- Conducting two energy transition studies to examine potential scenarios to reduce greenhouse gas emissions to net zero⁸
- Filing an Energy Transition Plan
- Identifying actions called “safe bets” to advance during the rebasing term⁹

⁷ Exhibit 1, Tab 10.

⁸ Net zero greenhouse gas emissions means that the net amount of greenhouse gas emissions emitted to the atmosphere must equal zero. This can be achieved through a combination of emissions reduction and emissions removal from the atmosphere (e.g., through carbon sequestration).

⁹ Exhibit 1, Tab 10, Schedule 6.

- Incorporating energy transition assumptions into customer, volume, and demand forecasts¹⁰
- Bringing Integrated Resource Planning (IRP) into Enbridge Gas's asset management planning process
- Requesting an increase to Enbridge Gas's deemed equity ratio to address increased business risk associated with the energy transition
- Requesting approval for a change to the depreciation methodology which, in part, would mitigate energy transition-related stranded asset risk
- Potential changes to Enbridge Gas's customer connection policy due to the energy transition. These potential changes were not part of Enbridge Gas's filed Energy Transition Plan or evidence but were discussed during the oral hearing and addressed by Enbridge Gas in its Reply Argument.

Intervenor Evidence – Energy Transition

Evidence focused on energy transition related matters was filed by the following:

- Chris Neme of Energy Futures Group, commissioned by Environmental Defence and GEC, covering the following aspects of energy transition:
 - Technical options for decarbonizing fossil gas use
 - Approach to electrification in other independent decarbonization pathway studies
 - Practical reasons to expect electrification to dominate
 - Customer economics of electrification
 - Flaws in Enbridge Gas's vision of a hydrogen future
 - Protecting customers in the context of future decarbonization
- Dr. Asa Hopkins of Synapse Energy Economics Inc., commissioned by IGUA, focused primarily on energy transition-related business risk and capital structure.

¹⁰ Exhibit 1, Tab 10, Schedule 4.

- Ian Jarvis and Gillian Henderson of Enerlife Consulting Inc., commissioned by BOMA, focused on considerations for energy transition related to the commercial buildings sector.
- Dr. Robert W. Howarth, Professor of Ecology and Environmental Biology at Cornell University, and Dr. Mark Jacobson, Professor of Civil and Environmental Engineering at Stanford University, commissioned by Environmental Defence, focused on blue hydrogen and its greenhouse gas emissions impact.

Provincial and Federal Greenhouse Gas Policy Considerations

The pace and shape of the energy transition is guided to a large degree by relevant provincial and federal policy, including greenhouse gas emissions reductions targets and available alternatives for customers.

The Government of Canada has committed to reducing greenhouse gas emissions by 40% below 2005 levels by 2030, and to net-zero emissions by 2050 through the *Canadian Net-Zero Emissions Accountability Act*. To reduce greenhouse gas emissions, the Government of Canada has implemented an escalating carbon price, increasing annually from \$10/ tonne CO₂e (carbon dioxide equivalent) in 2018 and reaching \$170/tonne CO₂e by 2030.¹¹ Canada has also established the Greener Homes Grant program that provides financial incentives for measures that reduce emissions, including insulation and window upgrades and cold climate heat pumps. This program is delivered in Ontario by Enbridge Gas with enhanced incentives under their OEB approved demand side management program.¹²

The Government of Ontario has committed to reducing greenhouse gas emissions by 30% below 2005 levels by 2030.^{13,14} Ontario has identified several initiatives to achieve its target, including the continuation of demand side management programming for natural gas customers through 2030.¹⁵ In 2022, Ontario implemented its Emissions Performance Standards program, replacing the federal Output Based Pricing System. The Ontario program is aligned with the minimum federal carbon price for the period

¹¹ *Greenhouse Gas Pollution Pricing Act*, S.C. 2018, c.12, s. 186, Schedule 4.

¹² EB-2021-0002, Schedule B.

¹³ [Cap and Trade Cancellation Act, 2018, S.O. 2018, c. 13](#), s. 3

¹⁴ Ministry of the Environment, Conservation and Parks, [Preserving and Protecting our Environment for Future Generations A Made-in-Ontario Environment Plan, November 29, 2018, ERO 013-4208, Environmental Registry of Ontario](#), at pp. 21-24.

¹⁵ [Ontario Emissions Scenario as of March 25, 2022](#) (Ministry of the Environment, Conservation and Parks, [Ontario's responsible and balanced approach to meeting the federal benchmark for the Emissions Performance Standards industrial emissions program for 2023-2030, April 11, 2022, ERO 019-5316, Environmental Registry of Ontario](#)).

2023-2030.¹⁶ Ontario established the Electrification and Energy Transition Panel (EETP) to provide advice on helping Ontario's economy prepare for electrification and the energy transition, and has also commissioned an independent study on cost-effective energy pathways.¹⁷

Energy Transition Pathways Studies and Routes to Net Zero

Enbridge Gas filed two energy transition studies, the Energy Transition Scenario Analysis by Posterity Group, and the Pathways to Net Zero Emissions for Ontario by Guidehouse (Guidehouse Pathways Study). Enbridge Gas indicated that it undertook these studies to understand the impact of energy transition and associated climate policies on Ontario's natural gas demand and Enbridge Gas's transmission, distribution, and storage system. These studies informed Enbridge Gas's demand forecast, vision of Ontario's energy sector, and energy transition plan.

The Energy Transition Scenario Analysis study modeled four future scenarios to understand the impacts of energy transition and the associated climate policies on natural gas demand in Enbridge Gas's distribution system.

The Guidehouse Pathways Study built upon the Energy Transition Scenario Analysis study, by taking the two scenarios most likely to achieve net zero by 2050, and comparing the cost of the two scenarios:

- A "Diversified Scenario" in which total energy provided by gaseous fuels increases between 2020 and 2050. Low and zero carbon gases and the gas delivery infrastructure are used in combination with end-use electrification to reduce greenhouse gas emissions in all sectors. Conventional natural gas is replaced by hydrogen, renewable natural gas and natural gas paired with carbon capture.
- An "Electrification Scenario" that focuses on electrification of all sectors, with low and zero carbon gas use limited to cases where no reasonable alternative energy source exists.

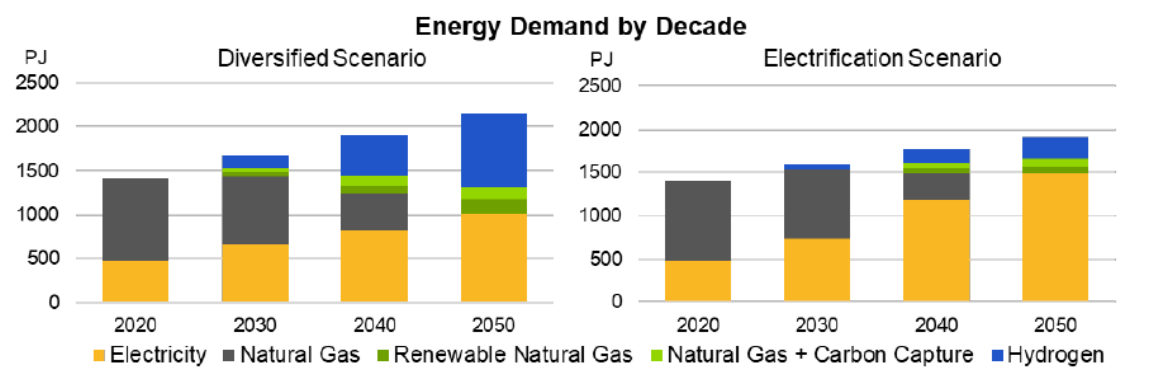
The Guidehouse Pathways Study filed with Enbridge Gas's application concluded that the Diversified Scenario is more cost-effective in terms of overall energy system costs between 2020 and 2050. The inputs in the Guidehouse Pathways Study were tested and discussed extensively in the interrogatory and technical conference phases of this proceeding. Guidehouse identified the need for corrections and other changes and subsequently filed an updated version of its study prior to the oral hearing phase. The

¹⁶ Ministry of the Environment, Conservation and Parks, Emissions Performance Standards (EPS) program regulatory amendments for the 2023-2030 period, ERO-019-5769, .

¹⁷ Exhibit J8.1, Attachment 1.

updated study forecasted a \$41 billion cost advantage or a 6% cost difference between the Diversified and Electrification Scenarios, compared to the original version which forecasted a cost advantage of \$181 billion.

Figure 1 – Comparison of the Two Scenarios¹⁸



Enbridge Gas indicated that the energy transition pathways studies were used to develop Enbridge Gas’s vision for energy transition in Ontario, along with other inputs such as its own experience, a review of federal, provincial, and municipal climate policies, and stakeholder engagement.

Enbridge Gas noted that, based on the updated study, it “continues to believe and assert that the Guidehouse Pathways Study provides support for showing that a diversified approach to achieving greenhouse gas emission reductions targets is as plausible as electrification” and that the Guidehouse Pathways Study is “only one support for the OEB to be comfortable that there can be an important role for Enbridge Gas and its distribution system in a resilient, cost-effective, low-carbon energy future.”¹⁹

Despite the updates, OEB staff, Environmental Defence, GEC, Pollution Probe and SEC continued to have concerns with the Guidehouse Pathways Study, and the degree to which its conclusions should be used as a basis for energy transition planning. BOMA, Three Fires Group and GFN raised concerns around the study’s lack of granularity regarding the commercial sector, and northern and remote communities, respectively. GEC and SEC also expressed concern that Enbridge Gas was seeking to use the conclusions of the Guidehouse Pathways Study and Energy Transition Scenario Analysis to influence provincial policy in forums outside of this proceeding and asked the OEB to make a statement in its decision regarding the limitations of these studies.

¹⁸ Exhibit KT 9.2, Figure ES-2.

¹⁹ Enbridge Gas, Letter Re: *Update Re Guidehouse Pathways to Net Zero Emissions for Ontario report*, April 4, 2023,

Some parties continued to have methodological concerns following the Guidehouse Pathways Study update, specifically the study's use of a higher carbon price in the Electrification Scenario compared to the Diversified Scenario. Parties submitted that the use of common assumptions in both scenarios would affect the Guidehouse Pathways Study's key conclusion and make the Electrification scenario's cost lower than the Diversified scenario.²⁰

Mr. Neme's evidence²¹ questioned why a pathway to net zero would include a large role for low carbon gaseous fuels. Submissions from Environmental Defence, GEC, Pollution Probe and SEC raised the following concerns:

- Supply limitations that would prevent Enbridge Gas from sourcing large volumes of renewable natural gas
- Technical and economic challenges with using the gas distribution network to deliver 100% hydrogen or a high blend ratio, due to hydrogen's much lower energy density and different chemical and physical properties
- Technical performance, economic viability and market readiness of more efficient gas-fired space heating alternatives contrasted with cold climate electric heat pumps
- Concerns about lifecycle emissions associated with blue hydrogen²²

Enbridge Gas, APPrO, CME and Energy Probe submitted that there are also significant concerns and uncertainties about a high-electrification future. Submissions questioned the ability of the electricity sector to build sufficient generation in the time needed to meet the significant increase in demand without compromising reliability, and the associated costs of generation, transmission, and distribution. GEC and SEC submitted that these concerns were overstated and were not comparable in magnitude to the challenges associated with a diversified pathway to net zero that included a large role for hydrogen and renewable natural gas.

Mr. Neme's evidence discussed how other independent decarbonization pathways studies forecasted higher levels of electrification than the Diversified Scenario in the Guidehouse Pathways Study. Another scenario analysis discussed in the proceeding was the recently released energy futures scenario analysis of the Canada Energy Regulator, *Canada's Energy Future 2023*. It was noted that in the net-zero scenarios

²⁰ Exhibit M9-GEC-ED, pp. 27-28.

²¹ Exhibit M9-GEC-ED, chapter 6.

²² Blue hydrogen is produced from methane and makes use of carbon capture to reduce emissions, as opposed to green hydrogen, which is produced directly from zero-carbon electricity.

used in that analysis, electric heat pumps were assumed to become the building heating technology of choice, with the scenarios showing a lower level of renewable natural gas and hydrogen use than in the Diversified Scenario in the Guidehouse Pathways Study.²³

Enbridge Gas's Energy Transition Plan and Safe Bets

The Energy Transition Plan proposed specific actions for Enbridge Gas to move forward with during the rebasing term,²⁴ with the following objectives:

- Support an orderly energy transition in Ontario
- Provide cost-effective, secure, reliable, and resilient energy for customers during the transition to a low-carbon economy and once net-zero is achieved
- Maintain alignment with Ontario's energy objectives and with provincial and federal energy transition and climate change targets and policies

Enbridge Gas's vision was for a diversified pathway towards net zero for Ontario, but recognized alternate views on how the energy transition will occur. Given this uncertainty, Enbridge Gas proposed a list of safe bet actions:

- Maximizing energy efficiency through demand side management programs²⁵
- Increasing the amount of renewable natural gas in the gas supply through a Low-Carbon Voluntary Program and supporting renewable natural gas upgrading
- Reducing greenhouse gas emissions from the industrial and transportation sectors via fuel switching and carbon capture and sequestration, including expansion of the Natural Gas Vehicle Program
- Integrating gas and electric system planning
- Supporting consumer choice and the energy transition journey, including:
 - Conducting a Hydrogen Blending Grid Study

²³ Exhibit K3.1, p. 49; Oral Hearing Transcript, Vol. 3, pp. 86-88.

²⁴ Exhibit 1, Tab 10, Schedule 6.

²⁵ Enbridge Gas's current approved DSM Plan runs through December 31, 2025. The OEB's Decision and Order on the DSM Plan (EB-2021-0002) requires Enbridge Gas to file an application seeking approval of a new multi-year DSM Plan from 2026 to 2030. The OEB expects that Enbridge Gas will have a decision on its next multi-year DSM plan prior to December 31, 2025.

- Implementing Phase 2 of Enbridge Gas's Low Carbon Energy Project (hydrogen blending)
- Establishing an Energy Transition Technology Fund
- Maintaining the gas system via Integrated Resource Planning and scope 1 & 2 emissions reductions²⁶

Enbridge Gas also submitted that these safe bets (and Enbridge Gas's Energy Transition Plan as a whole) align with the Ontario Ministry of Energy's recent *Powering Ontario's Growth* report, although the Energy Transition Plan was developed prior to the release of this report.²⁷ Enbridge Gas indicated that the Ministry's report focused on consumer choice, affordability, coordinated energy planning, hybrid heating, energy efficiency, industrial decarbonization, and the use of low carbon fuels in the gas system.²⁸

The only safe bet proposal for which approval is specifically requested in Phase 1 of this proceeding is the proposed expansion of the Natural Gas Vehicle Program.

Enbridge Gas is seeking approval for the Energy Transition Technology Fund and the Low-Carbon Voluntary Renewable Natural Gas Program in Phase 2. Spending for several additional safe bet proposals is included in Enbridge Gas's capital expenditures over the rebasing term, although approval of these individual projects is not specifically requested. These will also be examined in Phase 2.

Parties generally agreed that the safe bets proposed by Enbridge Gas as part of its Energy Transition Plan were modest in scope.

Parties noted that some of the safe bets are actions Enbridge Gas is already doing or required to do (energy efficiency, renewable natural gas injection, Integrated Resource Planning, scope 1 and 2 emissions reductions)

Some parties (APPrO, Energy Probe, LPMA, OGVG, QMA and VECC) were generally of the view that, given the uncertainty about future provincial policy direction and the role the gas system will play in the energy transition, Enbridge Gas's safe bets and level of activity on energy transition were appropriate at this time, at least for the purposes of

²⁶ Scope 1 & 2 emissions reductions involve reducing Enbridge Gas's direct and indirect emissions arising from its utility operations (e.g., reducing leaks, improving the efficiency of Enbridge Gas equipment), as distinct from emissions from Enbridge Gas's customers due to their natural gas use.

²⁷ Exhibit K1.5, [Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future](#)

²⁸ Enbridge Gas, Argument-in-Chief, August 18, 2023, p. 41.

setting rates in this application. These parties indicated that the implications of the energy transition are likely to be modest during the rebasing term.

Some parties (particularly Environmental Defence, IGUA, SEC and Three Fires Group) suggested that there was a gap in Enbridge Gas's Energy Transition Plan due to the lack of a risk assessment associated with possible energy transition futures, including an analysis of the possible implications for Enbridge Gas's business and for its customers, and options to mitigate risks. For example, SEC submitted that "what the OEB should have seen in this application is a detailed review of the risks associated with the Energy Transition, and the possible responses of the utility to each of those risks, both to protect the shareholders and the ratepayers."²⁹ A risk assessment of the nature proposed by SEC would also consider whether Enbridge Gas's traditional business activities can be considered safe bets in light of the energy transition. For example, Environmental Defence submitted that "Enbridge has missed the most important safe bet – avoiding and deferring capital spending where possible."³⁰

The energy transition evidence of Dr. Hopkins included an illustrative model assessing the financial implications for a gas distribution utility undergoing a strategic downsizing,³¹ and recommended that Enbridge Gas be required to conduct a detailed business analysis along the lines of this model, to inform its capital and operational plans. Several parties (CCC, CME, Environmental Defence, IGUA, City of Kitchener, SEC, Three Fires Group and VECC) supported this recommendation from Dr. Hopkins as a basis for improving energy transition planning that would incorporate an assessment of energy transition risks. For example, IGUA submitted that Enbridge Gas should be directed to complete an analysis, such as that recommended by Dr. Hopkins, of how its operations can or should change in response to the energy transition, which would consider:³²

- which customers are more likely to leave the system sooner rather than later, when, where and in what numbers
- which of Enbridge Gas's assets are more likely to be underutilized or stranded sooner rather than later and at what potential cost
- where should capital and operating costs be deployed to most effectively meet the demand for gas delivery services and take advantage of energy transition opportunities into the future

²⁹ SEC Submission, p.12.

³⁰ Environmental Defence Submission, p. 24.

³¹ Exhibit M8, Attachment 4.

³² IGUA Submission, p. 4.

- what regulatory mitigation tools may be most useful to address shareholder and customer risks

Three Fires Group and GFN submitted that the Energy Transition Plan had not adequately considered the impacts of the energy transition on remote and northern communities or on lower-income ratepayers.

In reply, Enbridge Gas indicated that it would target a revised Energy Transition Plan for its next rebasing application that it believed would be largely consistent with the recommendations of several intervenors and IGUA's expert, Dr. Hopkins. This would consist of a business analysis that informs Enbridge Gas's capital and operational plans, subject to available information, including:

- Creation of regional profiles (with analysis of customer data, alternative fuels, utility system and municipal plans)
- Development of regional pathways to net zero
- Modeling of different pathway scenarios by region and identifying risks and opportunities
- Considering impacts on the Asset Management Plan and other aspects of system planning

While Enbridge Gas agreed with the need to continue evolving its Energy Transition Plan, Enbridge Gas indicated that its specific proposals within this rebasing application, which were informed by energy transition considerations (e.g., capital expenditures, equity thickness and depreciation), are appropriate based on its current Energy Transition Plan. Many parties linked their submissions regarding Enbridge Gas's energy transition planning to Enbridge Gas's 2024 capital budget request and its proposal to increase equity thickness due to the energy transition.

Subsequent Procedural Steps on the Energy Transition

There was no consensus on the timing or appropriate procedural format of next steps on the energy transition. Enbridge Gas indicated that the appropriate time for review of an evolved Energy Transition Plan would be as part of its next rebasing application.

Some parties (APPrO, CCC³³, Energy Probe and LPMA) indicated that the energy transition issues should be re-examined once additional provincial policy direction, such as the Ontario government's response to the EETP report, on the energy transition has been provided. SEC noted that government policies will change many times over the lives of the assets that Enbridge Gas is investing in today, and submitted that if there is no government-mandated path to net zero, that does not mean that the status quo is the appropriate planning assumption.³⁴

Procedurally, some parties (APPrO, GFN, LPMA and Three Fires Group) expressed a preference for considering the energy transition issues in the context of a generic hearing, likely involving the electricity sector as well, and potentially others with an interest in the energy transition issues, such as providers of other energy services, municipalities, and Indigenous communities.

Several other parties were of the view that the energy transition can be further considered in future Enbridge Gas applications, not a generic hearing, but that the next major Energy Transition Plan update (and review by the OEB) should likely not wait five years until Enbridge Gas's next scheduled rebasing. While recognizing that the rate term is intended to be addressed in Phase 2 of this proceeding, CCC, GEC and IGUA submitted that due to energy transition considerations, a shorter rate term may be more appropriate. SEC expressed a preference for a "planning pause" where timing of future steps on the energy transition is at Enbridge Gas's discretion. Under this proposed approach, rate base would be held steady at its current level for the time being (capital in-service additions equal to depreciation), but Enbridge Gas could apply to rebase at any time, once it has filed a more detailed Energy Transition Plan including an options analysis.

Enbridge Gas did not support the OEB convening a generic proceeding on the energy transition in advance of the next rebasing application, stating that this would likely not be as efficient or effective as a more business-led planning process.

Findings

The OEB concludes that Enbridge Gas's proposal is not responsive to the energy transition and increases the risk of stranded or underutilized assets, a risk that must be mitigated. In particular, Enbridge Gas has not met the onus to demonstrate that its

³³ CCC submitted that Enbridge Gas should be required to start analysis along the lines of that proposed by Dr. Hopkins and Energy Futures Group now, but that the ability to complete this analysis would be enhanced once the Government of Ontario's policy objectives were clearer.

³⁴ SEC Submission, p.11.

proposed capital spending plan, reflected in its Asset Management Plan, is prudent, and that it has accounted appropriately for the risk arising from the energy transition.

Two important themes emerged during this proceeding:

- climate change policy is driving an energy transition that gives rise to a stranded asset risk, and
- the usual way of doing business is not sustainable.

Enbridge Gas identified the energy transition as a source of increased business risk. Despite this, Enbridge Gas has proposed approximately \$14 billion in capital expenditures for the 2023 to 2032 period (an average of \$1.4 billion per year), based on a forecast that shows continued growth in natural gas peak demand, extending the historic trendline, with a very small impact from the energy transition. The actual capital spend for the prior five years (2018 to 2022) was \$5.7 billion (average of \$1.1 billion year). As OEB staff put it,

Enbridge Gas expects to continue to add new customers and expand its rate base in what appears to be “business as usual.”³⁵

Enbridge Gas is entitled to recover through rates the reasonably incurred cost of operating and maintaining the gas distribution and transmission system and prudently incurred capital investments in that system, along with a fair return on that investment.

An essential component of prudent investment is the identification, management, and mitigation of risk. This includes the risk arising from the energy transition, the very risk that Enbridge Gas relies upon to justify an increase in its deemed equity thickness, which, if approved, would increase Enbridge Gas’s return on its investment.

The energy transition is underway, underpinned by the totality of current government policy. The reality of the energy transition provides context for the OEB to understand the risks, mitigation of those risks, and potential cost consequences posed by Enbridge Gas’s application.

The risk that arises from the energy transition results from gas customers leaving the gas system as they transition to electricity to meet energy needs previously met by natural gas. This departure gives rise to assets that are not fully depreciated but are no longer used and useful. This results in stranded asset costs that Enbridge Gas would seek to recover from the remaining gas customers. This in turn would increase rates for those gas customers, leading more customers to leave the gas system, potentially

³⁵ OEB staff Submission, p. 59.

leading to a continuing financial decline for the utility, often referred to as the utility death spiral.

In the face of the energy transition, Enbridge Gas bears the onus to demonstrate that its proposed capital spending plan, reflected in its Asset Management Plan, is prudent, having accounted appropriately for the risk arising from the energy transition.

The record is clear that Enbridge Gas has failed to do so. Enbridge Gas has taken the position that there is no stranded asset risk for the purposes of setting rates for 2024. This is not logical. The capital expansion proposed by Enbridge Gas for 2024 amounts to \$1.47 billion and forms the basis for its proposed five-year rate term, with 2024 rates being adjusted annually for inflation, which would include a continuation of capital at a similar pace beyond 2024. This five-year period is part of the ten-year period covered by Enbridge Gas's Asset Management Plan, which contemplates a total capital expenditure of \$14 billion over ten years. Based on Enbridge Gas's proposal, the depreciation expense for these assets would be recovered over 40 years or more,³⁶ with no meaningful consideration of:

- Ontario's policy objective to reduce greenhouse gas emissions by 30% below 2005 levels by 2030, which is seven years away;
- Canada's policy objective to achieve net zero carbon emissions by 2050, which is 27 years away, and
- The risk of assets becoming stranded or underutilized.

In light of this, the position taken by Enbridge Gas that there is no stranded asset risk in 2024 cannot stand. The assets Enbridge Gas proposes to add to rate base in 2024 would be depreciated over the next 40 years or more,³⁷ based on the physical asset life. The same would apply to the assets that Enbridge Gas plans to add in each of the following four years, as proposed in its application, and over the next ten years, as proposed in its Asset Management Plan. It is the 40-year horizon against which the stranded asset risk must be examined, not the five-year horizon of the requested rate term that Enbridge Gas urges the OEB to use.³⁸ When looked at through the 40-year lens, what Enbridge Gas proposes looks very much like business as usual and it is not sustainable.

³⁶ Exhibit J13.6.

³⁷ Exhibit J13.6.

³⁸ Enbridge Gas, Argument-in-Chief, p. 166.

Enbridge Gas's application engages the objectives the OEB is required to consider, in particular:

- Protecting the interests of consumers with respect to the price, reliability, and quality of gas service
- Facilitating the rational expansion of the gas system
- Facilitating the maintenance of a financially viable gas system industry

In the absence of:

- a meaningful assessment of the risk of stranded assets resulting from the proposed capital expansion, premised on the possibility of replacing natural gas with renewable natural gas, hydrogen and carbon capture abated natural gas,
- meaningful information about the associated system cost to implement those alternatives, let alone the commodity cost of those alternatives, and
- information as to the likelihood of any of the alternatives happening,

there is a completely insufficient evidentiary basis on which to:

- Ensure the interests of consumers regarding pricing are protected.
- Determine whether the proposed system expansion is rational.
- Determine whether Enbridge Gas will continue to be financially viable.

On the one hand, Enbridge Gas describes an increase in risk to justify an increase in the revenue it earns from its investment. On the other hand, it does not adjust its proposed capital spending to account for this risk. Enbridge Gas cannot have it both ways. It is this dissonance that leads the OEB to conclude that the proposed system expansion is not rational, and that Enbridge Gas has not established the prudence of its proposal. There is no ability to determine how the reliance on speculative long-term proposals relating to renewable natural gas, hydrogen and carbon capture will impact the cost of energy for ratepayers, let alone determine if such cost impacts would be reasonable. The OEB is left with the clear conclusion that the energy transition is underway, it creates a risk of stranded asset costs, and that Enbridge Gas has not addressed this in any meaningful way. The OEB is not satisfied that Enbridge Gas's proposal will not lead to an overbuilt, underutilized gas system in the face of the energy transition.

There are three important areas where the risk of stranded assets needs to be mitigated:

- system access or expansion capital spending
- system renewal capital spending
- depreciation policy

Enbridge Gas's system access and system renewal proposals give rise to similar risks of stranded assets since they both involve the addition of new assets to rate base. In the case of system access or expansion, new assets are used to connect new customers. In the case of system renewal, new assets are used to replace existing assets that are at their end of life, or in a condition that requires their replacement, to continue serving existing customers. If these assets are depreciated over an average of 40 years, and a material number of current customers leave the gas system as part of the energy transition, there is a risk that the remaining undepreciated assets will become a stranded cost on Enbridge Gas's regulatory accounting books.

Enbridge Gas's proposed depreciation policy determines how depreciation expense is recovered. Typically, depreciation expense should be recovered based on an asset's physical life, or its used and useful life, whichever is shorter.

If the depreciation expense was expected to be recovered over a period that ends up being longer than the asset is used and useful, this will give rise to stranded asset costs. In the context of the energy transition, the question is how this risk should be mitigated or avoided, and if the risk is realized, who should bear the stranded asset costs.

Each of these three areas (system access or expansion, system renewal, depreciation policy) are addressed separately.

3.2 Capital Expenditures

3.2.1 System Access or Expansion

Enbridge Gas requested approval of its harmonized customer connection policy, to replace the separate previous OEB-approved policies for the Enbridge Gas Distribution and Union rate zones.³⁹ Enbridge Gas's original proposal to harmonize the previous OEB-approved policies did not include significant changes from its previous customer

³⁹ Exhibit 1, Tab 15, Schedule 1.

connection policies, with the exception of a significantly higher Extra Length Charge (ELC) for Residential Infill Service Connections.⁴⁰

The customer connection policy describes the approach Enbridge Gas uses to ensure that projects to connect new customers meet all financial compliance requirements and do not result in undue cross-subsidization between new and existing customers. The policy addresses connections for new customers that connect to Enbridge Gas's system from both system expansions where Enbridge Gas must build new mains (e.g., new subdivisions), and infills, where buildings along the line of an existing gas main that do not have gas service are connected.

The primary focus in this proceeding was on a specific aspect of Enbridge Gas's customer connection policy – the revenue horizon that Enbridge Gas uses to determine whether the cost of connecting a new customer will be financially feasible, and whether the new customer will need to pay a contribution toward the connection cost.

In the context of the energy transition, questions were raised as to whether the current 40-year revenue horizon for residential and small commercial customers in Enbridge Gas's customer connection policy remains appropriate, given the increasing likelihood over time that customers may leave the gas system prior to the end of that 40-year period, as greenhouse gas emission reduction policies continue to become more stringent to meet emissions reductions objectives, and as alternatives to natural gas service such as electric heat pumps become more prevalent. This raised the concern that continued use of the 40-year revenue horizon for new customer connections could result in a revenue shortfall posing a stranded asset risk. After the assets are constructed and the money is spent, the only remaining issue is who pays the cost. If this stranded asset risk materializes, the associated cost would either be recovered from remaining customers through rates or borne by Enbridge Gas. The OEB identified this as a matter of particular interest in this proceeding.⁴¹

Assessing Economic Feasibility of New Customer Connections

Enbridge Gas's customer connection policy is subject to the OEB's Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, which were created in a Report of the Board issued in 1998 (E.B.O. 188). E.B.O. 188 provides for a common analysis and reporting framework.

⁴⁰ Exhibit 8, Tab 3, Schedule 1. Other minor changes proposed by Enbridge Gas for the purpose of harmonizing differences in the previous policies for the Enbridge Gas Distribution rate zone and Union rate zones are listed in VECC Submission, p. 14. No party objected to these other minor changes.

⁴¹ Procedural Order No. 6, June 23, 2023.

E.B.O. 188 sets an objective for rate-regulated natural gas distributors, including Enbridge Gas, that the Investment Portfolio of all a distributor's new distribution projects (both system expansion projects and infill customers attaching to existing mains) in each year shall be designed to achieve a Profitability Index (PI) greater than 1.0. In other words, the distribution revenues from new customers over a specified revenue horizon should exceed the costs of adding those new customers to the system, assuming that the customers remain connected to the system.

Enbridge Gas designs its customer connection policies to achieve this objective. Depending on the cost to Enbridge Gas to connect a customer, this may in some cases require customers to make an additional payment to bring a project PI up to 1.0. This can take several forms, such as:

- An upfront Contribution in Aid of Construction (CIAC);
- A temporary rate surcharge (Temporary Connection Surcharge/System Expansion Surcharge) on customer bills (for up to 40 years); or
- The ELC, applied to connections that are longer than the free service length, for infill customers only.

The upfront costs incurred by Enbridge Gas to connect new customers are substantial. Enbridge Gas estimated the average cost to connect a home in the Enbridge Gas Distribution rate zone to be \$4,412 (weighted average of new construction and existing homes) which would take approximately 31 years to recover through distribution rates.⁴² Connection costs for new construction system expansion projects are generally lower than for infill projects, due to economies of scale. The initial cost to Enbridge Gas for a 20 metre connection for an infill project is approximately \$6,000.⁴³

Connection costs have escalated sharply for Enbridge Gas in recent years, due to rising construction costs and additional costs related to municipal permit and restoration requirements.⁴⁴ The increase in costs resulted in the overall Investment Portfolio of Enbridge Gas (based on the customer connection policies in place at the time) failing to achieve a PI of 1.0 in the years 2021 to 2023; i.e., the cost of adding those customers is higher than the revenues that will be received in rates over the 40-year revenue horizon.⁴⁵

⁴² Exhibit JT 3.11 (updated).

⁴³ Exhibit 8, Tab 3, Schedule 1, p. 13, Figure 2.

⁴⁴ Exhibit 8, Tab 3, Schedule 1, pp. 12-13.

⁴⁵ Exhibit I.2.6-SEC-118.

Appropriate Revenue Horizon for Customer Connections

For both infill and system expansion projects, the economic analysis Enbridge Gas uses to assess the economic feasibility of projects is based on a maximum 40-year revenue horizon for residential and small commercial customers. For large volume customers, the revenue horizon is based on the distribution services contract term, up to a maximum of 20 years.

Enbridge Gas's customer connection policy also provides for a project specific revenue horizon when the project life cycle is determined to be shorter than the prescribed time horizons.

Enbridge Gas's costs to connect new customers are largely upfront costs, related to the initial work to physically connect the customer to the gas system. Revenues, on the other hand, are expected to be collected over the full revenue horizon through rates. If customers do not remain Enbridge Gas customers for the full revenue horizon, as a result of moving away from natural gas to electricity, there would be a revenue shortfall that would either be recovered from remaining customers or borne by the utility's shareholders. In other words, there is a risk of stranded asset costs which have not been fully paid for in rates.

All parties that made a specific submission on the appropriate revenue horizon for new customer connections expressed a preference for a shorter revenue horizon than the current 40-year horizon. Some parties submitted that this issue might be best addressed as part of a future generic proceeding.

Proposals for the appropriate revenue horizon ranged from zero years, i.e., a connecting customer would be responsible for the connection cost in its entirety upfront, to 30 years.

Parties favouring a very short or zero revenue horizon (GEC and Environmental Defence) noted the need to address the problem of split incentives between developers and final customers. GEC noted that new subdivisions account for approximately 80% of connections, and the choice to connect to gas is largely made by developers. GEC submitted that because most or all of the connection cost is currently borne in rates and not up front, developers are incented to connect to gas, even if the long-run costs to the connecting customer or other ratepayers, taking into account both energy costs and connection costs, end up being higher than if the customer had used electricity for heating.

GEC and Environmental Defence also commented on the approach to cost allocation between new and existing customers. Environmental Defence submitted that new

customers should pay for a share of existing Enbridge Gas assets in rate base that they benefit from (e.g., pre-existing upstream pipelines), not just the connection costs and system reinforcement costs associated with their connection, as is currently required under E.B.O. 188. Enbridge Gas and OEB staff both disagreed, submitting that the existing approach in E.B.O. 188 is intended to ensure that existing customers are made better off by new connections, and the associated cost should not be considered a cross-subsidy. Enbridge Gas further submitted that this is an enduring principle of E.B.O. 188 and a fundamental change to this principle would be better considered in a generic proceeding. OGVG noted that, in trying to avoid a cross-subsidy from existing customers to new customers, the OEB should be careful not to create a cross-subsidy in the opposite direction (from new customers to existing customers), which OGVG submitted would be the case if new customers were required to pay 100% of their connection costs.

Environmental Defence also noted that safely disconnecting the service line for a customer leaving the system has an approximate cost to Enbridge of \$3,700 and that this cost needs to be taken into account in determining the appropriate revenue horizon.

Most other parties proposed a revenue horizon that was linked, to some extent, to the average length of time a customer is likely to remain on the system (which, if forecast perfectly, would result in a PI of 1.0, although, as noted by Environmental Defence, disconnection costs are not currently captured in this calculation). Due to the energy transition, parties were generally of the view that the average length of time a customer will remain on the system is likely less than 40 years and continued use of the 40-year revenue horizon would therefore result in stranded assets or cross-subsidization.

The expert evidence of Mr. Neme recommended using a revenue horizon of 15 years, as a way to reduce an upfront subsidy from existing customers to new customers, noting that the typical life of a new gas furnace is roughly 18 years, and suggesting that it is more likely that a customer will electrify at the time that they need to replace their heating system.⁴⁶ In his testimony, Mr. Neme also said that there is a reasonable case for reducing the revenue horizon to zero, which would eliminate the risk altogether.⁴⁷ SEC, FRPO and Pollution Probe supported a 15-year horizon on this basis in their submissions. CCC supported a 20-year horizon, while OEB staff submitted that

⁴⁶ Exhibit M9.GEC-Environmental Defence, p. 43.

⁴⁷ Oral Hearing Transcript, Vol. 6, p. 48.

choosing a revenue horizon close to, but slightly longer than, the initial life of space heating equipment (i.e., 20 years instead of 18) is appropriate.⁴⁸

LPMA supported a reduction to the revenue horizon from 40 to 30 years. LPMA submitted that a larger reduction in the revenue horizon could not be justified at this time given the high connection costs it would impose on new customers and the lack of concrete government policy with respect to the energy transition.

In reply, Enbridge Gas indicated that it was willing to update its overall proposal for its customer connection policy, having considered the submissions of OEB staff and intervenors. Enbridge Gas proposed using a 30-year revenue horizon (as opposed to a 40-year revenue horizon), on an interim basis, effective January 1, 2025, applicable to both system expansions and infill customers. Enbridge Gas proposed a “blended revenue horizon” of 30 years, basing this on the assumption that perhaps half of new customers might leave the gas system at the end of life of their initial heating equipment, while the other half might remain.⁴⁹ Enbridge Gas also noted that this is close to the 31 years that it currently takes, on average, to recover the capital cost associated with connecting a typical residential customer to the distribution system.

Enbridge Gas also submitted that the OEB should initiate a generic proceeding (or rulemaking process) to complete a fuller review of whether further changes to gas distributor customer connection policies are appropriate, taking into account the energy transition, to be held in the next year or two.

For electricity distributors, the revenue horizon used for the economic feasibility analysis for customer connections is 25 years.⁵⁰ In addition, the customer connection horizon⁵¹ (i.e., the time period the distributor uses to determine the expected number of customer connections that would be served by a system expansion) is five years for electricity system expansions, compared to ten years for the gas system expansions.

Some parties noted that it may be appropriate for the revenue horizon to be different for the gas and electricity distribution systems, as there may be differences between the systems that are relevant to setting the appropriate revenue horizon (e.g., stranded

⁴⁸ OEB staff noted that some customers will likely remain on the system after the initial life of their space heating equipment, while other customers may exit the system prior to the end of life of space heating equipment, particularly if these customers were not responsible for making the original request to connect to the gas system. OEB staff noted its belief that the first result is likely slightly more probable than the second. OEB staff Submission, p. 26.

⁴⁹ Enbridge Gas Reply Argument, p. 114.

⁵⁰ Parameters for the customer revenue horizon and customer connection horizon for the electricity system are specified in [Appendix B to the Distribution System Code: Methodology and Assumptions for An Offer to Connect Economic Evaluation](#).

⁵¹ Referred to as the customer attachment horizon in E.B.O. 188.

asset risk, technical life of new infrastructure). However, SEC submitted that there did not appear to be any reason why the customer connection horizon should differ between electricity and gas, and that a five-year connection horizon should also be used by Enbridge Gas in its customer connection policies. Enbridge Gas disagreed, noting that a longer period is necessary in some cases, as conversions to natural gas occur over time often based on the replacement of the customer's space heating equipment. Enbridge Gas also noted that the policy for electricity customer connections allows distributors to use a connection horizon longer than five years, if supported by an explanation to the OEB.

E.B.O. 188 Parameters and Appropriateness of Modification in this Proceeding

Distinct from the question of the appropriate length of the revenue horizon is the procedural question of whether the OEB should modify the revenue horizon (or other aspects of the customer connection policy that are derived from E.B.O. 188), in this rebasing proceeding, or whether this is best considered in a separate OEB initiative, perhaps through a generic proceeding. Parties reached different conclusions on this question.

In its argument-in-chief, Enbridge Gas noted that changes to the revenue horizon were not considered in Enbridge Gas's original application. Enbridge Gas raised concerns around process and the potential need to make related changes to the Gas Distribution Access Rule (GDAR),⁵² which applies to all gas distributors regulated by the OEB, specifically:

- Whether there is a full and sufficient record in this proceeding to make changes to the long-standing principles and directions determined in E.B.O. 188.
- Whether changes to the customer attachment policy, which effectively amend E.B.O. 188, can be made without also changing GDAR. Section 2.2.2 of GDAR specifically directs gas utilities to follow the E.B.O. 188 guidelines in attaching customers.⁵³

In reply, Enbridge Gas also submitted that, in its view, the OEB had the authority to change the revenue horizon in this proceeding, but that the OEB should not make a fundamental and permanent change to the revenue horizon (or other aspects of E.B.O. 188 and the GDAR) at this time. Therefore, Enbridge Gas proposed the adoption of a 30-year revenue horizon on an interim basis, until this issue (and other potential changes to E.B.O. 188) could be considered in a generic proceeding.

⁵² Enbridge Gas, Argument-in-Chief, pp. 105-108.

⁵³ Section 2.2.2 of GDAR: "A rate-regulated gas distributor shall assess and report on expansion to its gas distribution system in accordance with the guidelines contained in the E.B.O. 188 Report".

Some parties (CCC, Energy Probe, LPMA and VECC) also expressed a preference for a separate generic proceeding that would review E.B.O. 188 and the relevant sections of GDAR, possibly combined with a review of the equivalent policies for the electricity system that are referenced in the electricity Distribution System Code. These parties noted that this would allow the OEB to consider all aspects of the policies regarding system expansion set out in E.B.O. 188, rather than addressing one component in isolation, and would provide an opportunity for stakeholders not participating in this rebasing proceeding that would be impacted by any change to E.B.O. 188 to participate. Enbridge Gas supported these submissions.

VECC further submitted that creating a new maximum revenue horizon would be a change to the policies of E.B.O. 188, and because E.B.O. 188 is incorporated into GDAR by reference, this would be a rule change, which has its own procedural requirements and must be made under the authority of the OEB's Chief Executive Officer.⁵⁴ Therefore, in VECC's view, the OEB cannot change the revenue horizon in this proceeding.

Other parties commenting on this procedural question did not specifically oppose the idea of a generic hearing but did conclude that the OEB had the authority to modify aspects of Enbridge Gas's customer connection policy including the revenue horizon in this proceeding. OEB staff submitted that Enbridge Gas's existing customer connection policies already include methodological approaches not described in E.B.O. 188 that reflect subsequent OEB decisions, that these changes were not accompanied by any amendments to GDAR, and that the requirement in GDAR should be read to include any subsequent updates to the methodologies approved in E.B.O. 188. Environmental Defence, GEC, and SEC submitted that the 40-year revenue horizon described in E.B.O. 188 (taking into account the language in both the full OEB decision on E.B.O. 188 as well as the appendix) should be interpreted as a maximum value, and therefore there is no conflict with E.B.O. 188 if the OEB mandates the use of a shorter revenue horizon. OEB staff and SEC also submitted that, should the OEB believe there is an inconsistency between any changes made to Enbridge Gas's customer connections policy and the relevant section (2.2.2) of GDAR, the OEB also has the authority to exempt Enbridge Gas from this section of GDAR. Enbridge Gas agreed with this submission.

Applicability of a Revenue Horizon Change to the Natural Gas Expansion Program

The Natural Gas Expansion Program (NGEP) is an Ontario government initiative that provides funding to Ontario natural gas distributors to support the expansion of natural gas to communities that are not currently connected to the gas system. NGEP funding

⁵⁴ VECC Submission, pp. 9-14.

acts in a manner similar to a CIAC and the amount of funding is designed to bring projects that would otherwise be uneconomic to a profitability index of 1.0 (i.e., make them economic under the OEB's test under E.B.O. 188), assuming a 40-year revenue horizon.⁵⁵ The eligible projects, and the amount of funding, are specifically set out in regulation.⁵⁶

Enbridge Gas and OEB staff submitted that natural gas expansion projects already selected for government funding in Phase 2 of the NGEF should be subject to the existing 40-year revenue horizon, as those projects were selected and their eligibility for funding was determined on this basis. Enbridge Gas and OEB staff were in agreement that, should future phases of the NGEF be undertaken, then (absent direction from the Government of Ontario), these projects could be assessed using any revenue horizon that might be determined by the OEB in this rebasing proceeding. Environmental Defence agreed that any use of the previous revenue horizon should be limited to the specific projects already selected and named in regulation, but argued that Enbridge Gas should still be required to maintain an overall Investment Portfolio designed to achieve a PI of greater than 1.0 for all projects including the NGEF projects, as calculated with the new revenue horizon (e.g., by balancing out the NGEF projects with more profitable projects).⁵⁷ Enbridge Gas opposed this proposal, indicating that it penalizes Enbridge Gas for complying with the terms of the Government's NGEF.

Surcharge Mechanisms for New Construction

As noted earlier, Enbridge Gas's customer connection policy allows for several approaches to improve the economic feasibility of a project by requiring an additional customer contribution, if a project cannot achieve a PI of 1.0 without this contribution.

Enbridge Gas indicated that its unofficial approach has been to use the upfront CIAC instead of a rate surcharge (System Expansion Surcharge or Temporary Connection Surcharge) for system expansion projects that are for new developments, to ensure that these costs are paid by developers, and not passed onto customers through rates.⁵⁸ However, this is not part of Enbridge Gas's written customer connection policy.

Environmental Defence, GEC, and OEB staff submitted that Enbridge Gas should be required to use the CIAC approach for system expansion projects for new

⁵⁵ A System Expansion Surcharge is also used to bring the economic feasibility of these projects up to 1.0.

⁵⁶ O. Reg. 24/19: Expansion of Natural Gas Distribution Systems.

⁵⁷ Environmental Defence Submission, pp. 35-36.

⁵⁸ Technical Conference Transcript, Vol. 3, pp. 42-46.

developments,⁵⁹ as opposed to other methods such as the System Expansion Surcharge/Temporary Connection Surcharge. The primary rationale for these submissions was to partially address the split incentive problem between developers and final customers, such that the cost of connecting to the gas system would be borne initially by developers and brought into their economic decision-making process in their initial building design choices. OEB staff noted that this approach also reduces stranded asset risk (should a customer leave the system before the end of the revenue horizon) by recovering a higher share of costs upfront.

In reply, Enbridge Gas indicated that, if the OEB agrees with its proposal for interim implementation of a 30-year customer connection revenue horizon, Enbridge Gas could agree to refrain, on a similar interim basis, from offering the Temporary Connection Surcharge to developers of eligible new residential subdivisions. However, if the OEB requires a shorter revenue horizon, Enbridge Gas noted that it could not make that commitment, and that it may be appropriate to use the Temporary Connection Surcharge in some circumstances. Enbridge Gas submitted that there is insufficient evidence or basis for the OEB to effectively overrule, or at least rewrite, the relatively recent OEB decision⁶⁰ that set out the terms under which the Temporary Connection Surcharge can be offered.

Does the OEB have Jurisdiction to Change the Revenue Horizon?

Findings

While Enbridge Gas and some intervenors suggested that the question of the length of the revenue horizon should be deferred to a generic proceeding, no party other than VECC argued that the OEB lacked the jurisdiction to change the revenue horizon in this case.

The OEB does not agree with VECC. Although GDAR says in section 2.2.2 that “A rate-regulated gas distributor shall assess and report on expansion to its gas distribution system in accordance with the guidelines contained in the E.B.O. 188 Report,” it does not follow that shortening the revenue horizon requires an amendment to GDAR.

Changing the revenue horizon applied by Enbridge Gas does not conflict with E.B.O. 188. The OEB agrees with OEB staff, who argued that doing so would in fact be consistent with the fundamental principles of the economic feasibility approach used in

⁵⁹ This would not apply to NGEF-funded projects, which use a rate surcharge. These projects primarily serve existing buildings that would be converting to natural gas, but new developments within the project areas would also be subject to the rate surcharge.

⁶⁰ EB-2020-0094, Decision and Order, November 5, 2020; Decision and Order, December 4, 2020; Rate Order, January 7, 2021.

E.B.O. 188, which is designed to ensure that expansions are economically feasible and, in the words of one of the OEB's statutory objectives, "rational". As OEB staff pointed out, Enbridge Gas's current customer connection policies already include methodological approaches not described in E.B.O. 188, such as the System Expansion Surcharge, which were approved without an amendment to GDAR. And as some intervenors noted, while E.B.O. 188 itself establishes maximum revenue horizons (20 years for large volume customers and 40 years for others), shorter horizons are not proscribed.

For these reasons, the OEB finds that it has the jurisdiction to change the revenue horizon for Enbridge Gas in this proceeding. In any case, no party disputed that the OEB could exempt Enbridge Gas from GDAR.⁶¹ For greater certainty on the jurisdictional question, the OEB exempts Enbridge Gas from section 2.2.2 of GDAR, but only to the extent required to give effect to the findings below on the revenue horizon.

That still leaves the question of whether this is the best proceeding to address the revenue horizon issue as it pertains to Enbridge Gas. The OEB finds that it is. There was extensive evidence and argument on this issue. Indeed, it became one of the focal points of Phase 1. Many parties pointed to the revenue horizon as a crucial tool for mitigating the risk of stranded assets and stranded costs – a risk that is increasing with the energy transition. Moreover, as elaborated below, the revenue horizon is inextricably linked to other ratemaking questions. It only makes sense to address these together, in this proceeding.

Should the Revenue Horizon for Small Volume Customers be Reduced?

Findings

The OEB finds that the revenue horizon should be reduced to address the risk of stranded assets resulting from the energy transition.

The Report of the Board in the E.B.O 188 proceeding, issued in 1998, established a requirement for gas utilities to carry out an economic assessment of new customer connections. For most customer connections, primarily connections for residential and small commercial customers, the economic assessment compares the capital cost of the connection facilities against the revenue that would be collected over a maximum of 40 years, based on the rates in effect at the time of the assessment. The 40-year period is referred to as the revenue horizon. If there is a revenue shortfall, the amount of the shortfall will be charged to the connecting customer, usually as a contribution in aid of

⁶¹ Section 1.5.1 of GDAR provides that "The Board may grant an exemption to any provision of this Rule. An exemption may be made in whole or in part and may be subject to conditions or restrictions."

construction or CIAC. A similar economic assessment is carried out for large volume customers based on a maximum revenue horizon of 20 years.

Enbridge Gas has typically used the maximum 40-year revenue horizon for proposed new residential and small commercial connections. Despite Enbridge Gas's assertion that business as usual is not sustainable, Enbridge Gas's initial proposal to continue using a 40-year revenue horizon for residential and small commercial projects is very much business as usual and does not take into account the risk of stranded assets. Based on the assumption that new connection assets will be used and useful for at least 40 years, there is an implicit assumption that the new customers will remain connected to the gas system for that same period. In other words, it is assumed that none of these new customers will leave over the next 40 years. This is not a reasonable assumption.

The OEB is of the view that the revenue horizon needs to be shortened to address the risk of stranded assets resulting from the energy transition, to protect the interests of ratepayers and the utility in relation to prices, rational expansion of the gas system, and energy conservation and efficiency.

Under the current process, with a 40-year revenue horizon, developers generally do not have to contribute to the capital cost of gas service for the development, and where they do, it is generally small. For example, Enbridge Gas estimated the average cost to connect a home in the Enbridge Gas Distribution rate zone to be \$4,412, based on the weighted average connection cost for new construction and existing homes, which would take approximately 31 years to recover through distribution rates.⁶² For this example, using a 40-year revenue horizon would not result in a requirement for a developer to pay a contribution for an average connection, since it only takes 31 years to recover the cost. Enbridge Gas's proposal for a 30-year revenue horizon would simply amount to reflecting the current average time needed to recover connection costs and therefore, does not materially mitigate the stranded asset risk.

As a result of using the 40-year revenue horizon, virtually all developments end up including gas servicing, since the developer bears little or no cost to include gas servicing, has no responsibility for the energy bills to be paid by subsequent property owners, no exposure to the future stranded asset cost risk resulting from the energy transition, and therefore, no incentive to consider any of those impacts or alternatives that would avoid or reduce those impacts. Enbridge Gas's application implicitly assumes that this pattern will continue. This is the split incentive problem identified by Mr. Neme and by OEB staff and intervenors in their submissions. The developer makes the decision on how to service the development and the purchasers pay the energy bills.

⁶² Exhibit JT 3.11 (updated).

In effect, the developer is making a choice that does not require the developer to consider the cost consequences that will be faced by the buyers of the properties sold by the developer. Enbridge Gas's forecast of new customer attachments is consistent with this default approach, assuming as it does that virtually every new housing development will include gas servicing. This approach increases investments by Enbridge Gas to be included in rate base and earn a return. However, it does not address the risk of stranding the cost of those investments, arising from the energy transition. Enbridge Gas takes the position that in the event of stranded asset costs, ratepayers should bear the risk. What Enbridge Gas means by this is that when ratepayers leave the gas system, and assets become underutilized, or no longer used or useful, it would still be entitled to recover any remaining undepreciated value for those assets and a return on the remaining undepreciated value from remaining ratepayers until those assets are fully depreciated. This is not an acceptable position in the face of Enbridge Gas's clear acknowledgement of the risk resulting from the energy transition, namely the risk of stranded assets and the associated cost. It is inconsistent with the rational development of the gas system and does not sufficiently protect gas customers. Acknowledging the existence of a risk and failing to take steps to avoid or mitigate that risk does not meet the prudence requirement that must be met for infrastructure investments if ratepayers are expected to pay for those investments through a depreciation expense, along with a return on those investments.

New construction offers a clear opportunity to reduce the risk of stranded asset costs.

The challenge is to establish the circumstances that will facilitate the ability of developers to make a more informed decision on how to proceed in the face of the energy transition and the associated risk of stranded asset costs that arises from the choice to include gas infrastructure to meet the energy requirements of new developments. The ability to make informed choices acts to protect the interests of the buyers of the developed properties.

Reducing the current 40-year revenue horizon means that developers are more likely to be required to pay a CIAC if they choose to include gas servicing in their development. When faced with this, a developer now has the opportunity to make an informed choice that will facilitate the rational expansion of the gas system and protect the interests of customers. This also serves to reduce the market distortion problem identified by Mr. Neme, during his testimony, and addressed by other intervenors and OEB staff in their submissions:

MS. DUFF: I was hoping that you could perhaps elaborate on that and maybe identify the distortion or distortions that you were referring to.

MR. NEME: Sure. Sure. I think this relates to the issue I was just talking about with Mr. Shepherd. If you are a builder building a new house or a new subdivision of houses, you are going to connect every single one of those houses to the electric grid. That is pretty much a given. You have a choice then of whether you are going to put a gas furnace with a central air conditioner into that home for heating and cooling purposes or whether you will a cold-climate air-source heat pump into that home for heating and cooling purposes. You have that choice.

From a societal perspective, if you offer – there is a cost to society to connect that customer, if they go the gas route, to the gas system. If you offer a subsidy from existing gas ratepayers for some period of time to facilitate that gas connection or to reduce the cost to the builder of making the gas connection, you have distorted the decision, from an overall societal economics perspective, that the builder would otherwise have made between electricity and gas for heating or for other end uses. That is the point that I was trying to make.⁶³

The smaller the revenue horizon that is used, the larger the required CIAC will be. The larger the CIAC is, the smaller the stranded asset cost risk will be.

Ontario has established a target to achieve at least 1.5 million new homes constructed by 2031 with a focus on affordable housing.⁶⁴ Affordable housing has two components – the cost to buy the home and the cost to operate the home. Both are important. A home may have what appears to be an affordable purchase price, but that price advantage is diminished if the cost to operate the home, including the home's energy costs, are higher than they need to be. The revenue horizon plays an important role in ensuring that both the purchase price and the energy costs to operate the home are as affordable as possible. Reducing the revenue horizon provides a developer with the opportunity to make an informed decision that takes into account both aspects of affordability. Every home requires space heating and cooling. This can be achieved with a gas furnace and an air conditioner which will require both gas and electricity service, or alternatively with a heat pump, which only requires electricity service. Similarly, domestic hot water can be provided through gas water heaters or electric solutions, which include electric resistance water heaters and electric heat pump water heaters.

When faced with a requirement to pay a CIAC, one choice is to pay the CIAC and include gas servicing along with electric servicing in the development. The payment of a CIAC will reduce the amount of capital that is added to rate base and therefore, reduce

⁶³ Oral Hearing Transcript Vol. 6, p. 167.

⁶⁴ [More Homes, Built Faster: Ontario's Housing Supply Action Plan 2022–2023](#)

the risk of stranded asset costs quantitatively. The CIAC will be a cost that the developer will seek to pass on in the price of the property. Those buyers would then be gas customers. The amount of investment by Enbridge Gas that would go into rate base would be reduced by the amount of the CIAC.

Since some of the capital cost of the gas infrastructure will have been covered by the CIAC paid by the developer and recovered by the developer through the purchase price of the property, standard postage stamp rates (which include a revenue requirement to recover the costs of previous customer connections that did not have to pay a CIAC based on the current 40-year revenue horizon) would result in cross-subsidization from new to existing customers. An approach would need to be adopted to avoid this (as discussed later) to ensure that these new gas customers would pay rates that reflect the fact that a CIAC had been paid.

The effect of choosing to include gas servicing and pay a CIAC would be to potentially increase the cost of housing by the amount of the CIAC while reducing the operating cost of the house through lower gas rates – largely a wash for homebuyers. Those homes would continue to emit greenhouse gases and would not be contributing to the achievement of government decarbonization goals. Finally, while there would be a reduction in the stranded asset cost risk as a result of the payment of the CIAC, some risk would still remain since the homeowners would still be able to transition to electric solutions for space heating and domestic water heating before the end of the useful life of the gas infrastructure built to serve them.

The other choice is to decide against gas servicing and avoid having to pay any CIAC, and only include electricity servicing in the development. In this scenario, the people who buy from the developer would not be gas customers. The effect of this choice would be to lower the cost of housing, depending on the capital cost differential between gas and electric equipment, by avoiding paying a CIAC for gas servicing, and lower the operating energy cost of the house⁶⁵ – a win for homebuyers and an outcome for developers that keeps them competitive on price in the housing market.

Enbridge Gas would not need to make any investment, and the stranded asset cost risk in this scenario would be zero.

In laying out its energy strategy, Ontario has identified a need for reliable electricity “especially as households increase their consumption to heat and cool their homes and power their vehicles.”⁶⁶ This recognizes that households will be moving from natural gas to electricity to heat and cool their homes as the energy transition progresses, and the

⁶⁵ Exhibit M9-GEC-ED, pp. 22-24.

⁶⁶ Exhibit K1.5, *Powering Ontario's Growth*, p. 39.

need to factor this into electricity planning. This is important because it addresses the concern that electricity resources will be insufficient to meet growing demand. The reality is that there is a strategy and planning process to address this, which is described in detail in the Government of Ontario's *Powering Ontario's Growth* report, released on July 10, 2023.⁶⁷ The IESO has engaged in, and will continue to engage in, electricity demand forecasting and electricity procurement, all with the objective of ensuring that growing electricity demand for electric vehicles and home heating and cooling will be met. Similarly, electricity distributors will continue to forecast demand and plan for how to meet that demand,

Government policy at the federal, provincial and municipal level is focused on reducing reliance on fossil fuels, including gas, thereby decarbonizing the economy to address the existential threat posed by climate change. This policy direction includes support for electric heat pumps as an alternative to gas heating equipment. Examples are Canada's Greener Homes Grant retrofit program which is being delivered by Enbridge Gas in Ontario, and Enbridge Gas's own demand side management program, which provides enhancements to the retrofit incentives under the Greener Homes Grant program.⁶⁸ Enbridge Gas delivers these combined incentives in its Home Efficiency Rebate Plus (HER+) program. An Enbridge Gas customer can qualify for an incentive of up to \$6500 for installing a heat pump under the HER+ program. There are also incentives for domestic hot water heat pumps. Ontario has implemented a Clean Home Heating Initiative that also provides retrofit support for homeowners in four communities to add an electric heat pump to their home to reduce greenhouse gas emissions.⁶⁹

The retrofit cost to move from gas equipment to electric equipment is higher than installing electric equipment for both heating and cooling at the time a home is built, due to the possible need to address technical limitations related to the sizing of ductwork,⁷⁰ in addition to the sunk cost of gas equipment. Furthermore, the operating cost of a new all-electric house using a cold climate air source heat pump for space heating, is lower than a new gas and electricity serviced house.⁷¹ While Enbridge Gas submitted that Mr. Neme's evidence regarding the customer economics of electrification relied on various assumptions, Enbridge Gas did not establish that these assumptions were unreasonable. To the contrary, Enbridge Gas relied on the unreasonable assumption that virtually all new homes would connect to the gas system and those new customers would remain connected to the gas system for at least 40 years, despite the energy transition.

⁶⁷ Exhibit K1.5, *Powering Ontario's Growth*, pp. 60-70.

⁶⁸ EB-2021-0002, Decision and Order, Schedule B.

⁶⁹ Exhibit K1.5, *Powering Ontario's Growth*, p. 27.

⁷⁰ Exhibit J11.5.

⁷¹ Exhibit M9-GEC-Environmental Defence, pp. 22-24.

A reduced revenue horizon will allow a developer to make an informed decision on whether to include gas service in the development. While there is a logic to providing retrofit incentives for existing customers, the logic is less clear for new construction. Adding new customers to the gas system and then offering those same customers an incentive to replace their gas equipment works against the goal of reducing the risk of stranded assets. While Enbridge Gas has not provided a risk assessment of the impact of the energy transition, it did provide evidence for a scenario that assumes that 100,000 existing residential customers exit the gas system over a three-year period. The need to recover the stranded costs of these assets from remaining ratepayers (through accelerated depreciation) would result in an increase in the annual revenue requirement of \$34 million.⁷²

Enbridge Gas has not demonstrated that the 40-year revenue horizon is appropriate in light of the energy transition underway. Enbridge Gas acknowledges this in its reply argument. It proposes a 30-year revenue horizon on an interim basis, pending a separate proceeding to determine what the revenue horizon should be. The OEB is of the view that the record before it is more than sufficient to determine this issue and there is no benefit to deferring the issue to a subsequent proceeding.

Having considered the evidence and the objectives of protecting the interests of ratepayers and the utility in relation to prices, facilitating the rational expansion of the gas system, and promoting energy conservation and efficiency⁷³, the OEB finds that the revenue horizon needs to be shortened to address the risk of stranded assets resulting from the energy transition.

How much should the revenue horizon for small volume customers be shortened?

Findings

The OEB finds that zero is the optimal revenue horizon because this fully addresses the risk of stranded assets resulting from the energy transition for new connection projects as described below.

The parties and OEB staff have proposed a range of revenue horizons, from the 30 years proposed by Enbridge Gas, through the 20 years proposed by OEB staff, all the way to zero years proposed by GEC and Environmental Defence. The following considerations apply:

⁷² Exhibit J18.5.

⁷³ OEB Act, s.2.

- The shorter the revenue horizon, the smaller the risk of stranded asset cost is, since part or all of the cost is being paid up front, or alternatively, is being avoided entirely by going with all electric servicing.
- The shorter the revenue horizon, the more likely it is that a developer will choose not to include gas service since the size of the CIAC is larger and will lead the developer to choose the most cost-effective servicing solution.
- If developments proceed without gas service, government decarbonization policy objectives are being met efficiently because new housing development is being optimized to meet energy supply needs through electricity solutions.
- If developments proceed with gas servicing, despite having to pay a CIAC, government decarbonization objectives will be met less efficiently since decarbonization measures would then require retrofit measures that typically cost more than including those measures as part of the original construction process. For example, a house that is initially optimized for gas heating may need further optimization to accommodate a switch to an electric heat pump, such as ductwork or electrical panel upgrades.⁷⁴
- Retrofits frequently need incentive payments. Enbridge Gas's HER+ is an example. The HER+ incentive payments are funded by a combination of tax dollars and money collected through gas rates. These payments are not necessary when the decarbonization measures are part of the initial construction process because it avoids the need for a retrofit.

These considerations all militate in favour of a shorter revenue horizon.

The expert evidence of Mr. Neme, in his written report, recommended using a revenue horizon of 15 years, as a way to reduce an upfront subsidy from existing customers to new customers.⁷⁵ In his testimony, Mr. Neme also said that there is a reasonable case for reducing the revenue horizon to zero, which would eliminate the risk altogether.⁷⁶

While parties provided various reasons to support their various proposals for changing the revenue horizon, it is clear that there is not a mathematical approach upon which to determine the issue. As Mr. Neme said in his evidence:

MR. NEME: No, I disagree with that. I don't think there is a mathematical formula that will give you the answer of what is the right number of years. It is a question of two things: One, how do you judge the risk that

⁷⁴ Exhibit J11.5.

⁷⁵ Exhibit M9.GEC-ED, p. 43.

⁷⁶ Oral Hearing Transcript, Vol. 6, p. 48.

customers may not be there for the entire duration of the revenue horizon time frame.

Secondly – actually maybe three things. Secondly, what expectations from a policy perspective do you have about whether customers over and above paying for their cost of connection should have in terms of contributing to the cost of the rest of the system and, thirdly, to what extent as policymakers – I am now thinking of regulators-- do they think it is appropriate to essentially create a market distortion that influences builders on which type of fuel that should be used for a customer's space heating.

Those are conceptual policy concepts – sorry for the redundancy of the word “conceptual” there – that are not something that can be resolved with a mathematical formula or a calculation.⁷⁷

Mr. Neme’s evidence on what factors the OEB should consider is important, since these factors underpin to varying degrees the various revenue horizon options that were proposed. The primary consideration throughout this proceeding has been the risk of stranded assets resulting from the energy transition. The OEB’s finding of a zero revenue horizon fully addresses that risk for new connection projects. When a developer is faced with the full cost of including gas service in a development, that developer will be fully incented to choose the most cost effective, energy efficient choice in a manner that not only achieves efficiency in the cost of housing in a competitive market and lowers the operating cost of that housing, but also maximizes the contribution to achieving government decarbonization policy goals. It also eliminates the split incentive problem.

This issue does not lend itself well to an incremental approach. The various proposed reductions to the revenue horizon, other than the zero option, all include the split incentive problem to varying degrees, while the zero option avoids it completely.

The zero revenue horizon is the only option that provides the opportunity to make a fully informed decision on whether to include gas servicing. All the other proposals mute the price signal to varying degrees, while the zero option uses the full cost of the connection facilities. For example, a 20-year revenue horizon would generate a requirement for a CIAC of \$1,774, less than one third of the connection cost.⁷⁸ The zero option provides

⁷⁷ Oral Hearing Transcript, Vol. 6, p. 46.

⁷⁸ Exhibit J11.1.

the full cost of the connection facilities, allowing for a fully informed decision to be made on whether to include gas servicing.

Finally, all the other proposals retain a residual stranded asset cost risk that increases as the length of the revenue horizon increases toward the 40 years currently used by Enbridge Gas. In the 20-year example, over two thirds of the connection cost would still have to be recovered over a period of 20 years, and all new customers would need to remain connected to the gas system for at least 20 years to avoid any stranded asset costs. Using a zero revenue horizon reduces the stranded asset cost risk to zero.

The OEB makes no determination of what choice a developer may actually make, if the revenue horizon is shortened to zero. It is not necessary to predict what choice a developer might make, since the objective in shortening the revenue horizon is to facilitate an informed choice, and the stranded asset cost risk is reduced to zero regardless of the actual choice made.

This change will apply to all new small commercial and residential developments, including infill projects. The OEB agrees with the submissions by Enbridge Gas and OEB staff that the new revenue horizon should not apply to the projects in the current phase of the NGEF under O. Reg. 24/19. The current approach for large volume customers was not an issue in the proceeding and remains unchanged.

In making this change, the OEB acknowledges the submission by Enbridge Gas that it has an informal practice of using the E.B.O. 188 analysis to avoid reliance on the System Expansion Surcharge and the Temporary Connection Surcharge when addressing the economic feasibility of a connection project. The OEB is of the view that this is the right approach to take and it will be mandatory with the new revenue horizon.

There were submissions from parties regarding the connection horizon under E.B.O. 188, which is currently ten years, compared to five years for electricity connection projects under the Distribution System Code. The connection horizon is the period used to establish the number of customers that will be connected in a project. Given that the OEB has determined that the revenue horizon will be reduced to zero, and requiring the full cost of new connections to be recovered if a developer chooses to include gas servicing, there is no need to address the connection horizon. Regardless of the length of the connection horizon, Enbridge Gas is required to provide the developer with the full cost of the connection facilities that may be required, so that the developer can make an informed decision about whether to proceed with gas servicing.

When Should the New Revenue Horizon be Implemented?

Enbridge Gas requested that the change take effect on January 1, 2025. Enbridge Gas noted that it requires substantial lead time to update systems and processes.⁷⁹

OEB staff, GEC, and Environmental Defence submitted that any changes to the customer connection policy should take effect sooner (immediately following the OEB's decision or as of January 1, 2024, with the possible exception of changes related to infill customers).⁸⁰ OEB staff and GEC were concerned that any delay in implementation may lead to a large number of requests seeking connection agreements to be grandfathered under the old customer connection policy. Environmental Defence also noted the high connections related capital costs that would be put into rate base if changes to the policy are delayed until 2025.

Enbridge Gas submitted that more rapid implementation was not possible due to the complexity of the required system and process changes, and also indicated that it would need to provide notice to customers about changes to the customer connection policy, and that some of the changes that may be required will have to be reflected in Enbridge Gas's Conditions of Service. Enbridge Gas argued that it is required under GDAR⁸¹ to provide advance public notice of any revisions to Customer Service Policies related to residential customers, and noted that in previous changes to GDAR, the OEB has set out a range of notice periods from four months to one year.

Enbridge Gas also proposed that customers who have requested service in writing, received commitments, and have been advised of whether there will be a requirement for a CIAC based on the current revenue horizon, for new connections prior to the date of any change to the customer connection policy should be subject to the existing rules. OEB staff agreed with this, but Environmental Defence argued that the proposed language around grandfathering was excessively broad, and should be limited to customers who had received a binding commitment as of September 1, 2023.

Findings

The OEB finds that January 1, 2025, is an appropriate implementation date. This would allow sufficient time for Enbridge Gas to adjust its processes and give a full year's notice to the development industry regarding the change to the revenue horizon to be used by Enbridge Gas.

⁷⁹ Exhibit J10.13.

⁸⁰ Environmental Defence Submission, p. 35, GEC Submission, pp. 32-33; OEB staff Submission, pp. 31-32.

⁸¹ Section 8.5.1.

For new connections where a CIAC has been paid, there is an issue about whether those new customers will end up overpaying and cross-subsidizing existing customers, if they also pay the same postage stamp rates as everyone else.⁸² This is an issue regardless of what revenue horizon is used but becomes more important the more the revenue horizon is reduced. This needs to be addressed to ensure rates are just and reasonable. Enbridge Gas, in its reply argument, expressed concern about the complexity of establishing a separate rate class for those customers for whom a CIAC has been paid.

A simpler approach, which is currently utilized by Enbridge Gas in other contexts, may be to establish a negative rate rider, reflecting the fact that a CIAC had been paid.⁸³ This allows Enbridge Gas to continue with postage stamp rates while ensuring that where the full connection cost has been paid through a CIAC, the purchasers of the new homes do not end up overpaying and cross-subsidizing existing customers. This will be addressed as part of the process to establish rates for 2025 in Phase 2 of this proceeding. To further avoid complexity, a postage stamp rate rider using the then current average connection cost to represent the CIAC paid could also be considered.

Enbridge Gas shall file a proposal for Phase 2 of this proceeding that will address the need to ensure that where the CIAC has been paid, the new connecting customers do not end up paying for the connection facilities a second time through postage stamp rates. Enbridge Gas may consider a rate class option or a rate rider option. Under the rate class option, the new customers would pay a lower rate that recognizes the payment of the CIAC. Under the rate rider option, the new customers would have a rate rider that, over time, refunds the amount of the CIAC that was paid, against the postage stamp rate.

The January 1, 2025 implementation date is not intended to allow an opportunity for introducing new projects that would not normally come forward in 2024 for a connection assessment to avoid the application of the new revenue horizon. Projects that are connecting to the gas system in 2024 will not be affected by the change to the revenue horizon. The new revenue horizon will apply to any proposed project that will be connecting to the gas system after December 31, 2024.

For projects connecting to the gas system in 2024 only, the OEB approves Enbridge Gas's harmonized customer connection policy as filed. For Phase 2 of this proceeding, Enbridge Gas is directed to file an updated customer connection policy, applicable to

⁸² For example, Oral Hearing Transcript Vol. 6, pp. 117-119.

⁸³ For example, the OEB's Quarterly Rate Adjustment Mechanism process, and the Markham Hydrogen Pilot Project utilize rate riders.

projects connecting to the gas system after December 31, 2024, that is consistent with the OEB's findings.

The OEB will provide an opportunity to the development industry to make submissions on the implementation, as part of Phase 2 of this proceeding. This will allow the OEB to consider whether any changes to implementation are necessary. Enbridge Gas will be required to give appropriate notice of this. Direction regarding the form and service of the notice will be provided in due course.

Is There a Role for Exit Fees?

An exit fee (to be paid by customers if they leave the gas system prior to the full cost of their connection being recovered) could potentially reduce stranded asset risk. An exit fee policy could potentially include requiring new customers to provide financial assurance in support of the forecast revenue (as Enbridge Gas has indicated it uses on occasion for larger customers).⁸⁴

Enbridge Gas did not make a proposal related to exit fees, and no party supported the use of exit fees as the primary tool (i.e., as opposed to modifying the revenue horizon) to address concerns about cross-subsidization and stranded asset risk. Mr. Neme noted that exit fees may reduce stranded asset risk, but are potentially problematic from an energy transition perspective, as they may introduce new barriers to customers exiting the gas system and electrifying, even if that turns out to be the least cost solution to meeting greenhouse gas reduction goals.⁸⁵

OEB staff indicated that it sees merit in Enbridge Gas considering expanding the use of exit fees and recommended that Enbridge Gas be required to make a proposal on exit fees (including how exits from the distribution system could be tracked) in its next rebasing application.

In reply, Enbridge Gas indicated that it would make a proposal on exit fees (including how exits from the distribution system could be tracked) in its next rebasing application, noting that its proposal may not endorse exit fees, in which case an explanation for that position would be provided.

⁸⁴ Exhibit I.1.15-ED-84.

⁸⁵ Exhibit N.M9.Staff-1.

Findings

Since the revenue horizon will be reduced to zero, exit fees are unnecessary for new construction, since there will be no stranded asset cost risk for any connection facilities that have been fully paid for through a CIAC.

For existing customers who leave the gas system where their connection facilities are not fully depreciated, Enbridge Gas may wish to consider in Phase 3 of this proceeding what role, if any, might be played by exit fees, along with other regulatory options that could also address the risk of stranded assets.

Customer Information

Environmental Defence, OEB staff, Pollution Probe, and SEC all made submissions that would require Enbridge Gas to provide customers with factual or unbiased information regarding gas and non-gas options to meet their energy needs. The supporting rationale for these proposals was to facilitate more informed customer choice and reduce stranded asset risk (on the basis that customers who choose to connect to the gas system with a full understanding of other options are less likely to prematurely exit the system), and to support the OEB's objectives regarding consumer protection. These submissions noted examples where the information currently provided by Enbridge Gas to its customers on energy choices may be selective or incomplete.

OEB staff submitted that a new provision should be added to Enbridge Gas's customer connection policy, requiring Enbridge Gas to provide, upon receipt of customer connection requests (or in response to any contact regarding a new connection prior to a formal customer connection request), information to prospective customers on energy options in a manner and form approved (at least initially) by the OEB, as part of this proceeding. OEB staff provided additional suggestions as to what types of information could be required. Environmental Defence supported OEB staff's proposals, and also noted the need for Enbridge Gas to provide unbiased information in all of its communications with customers, recommending changes to Enbridge Gas's current online comparison calculator, and its bill inserts for existing customers. Pollution Probe made several additional proposals the OEB could consider to achieve the objective of ensuring that Ontario energy consumers receive objective, unbiased, best available information to support their energy choices.

In reply, Enbridge Gas indicated that it believes that the information it currently provides to customers meets the intent of OEB staff's recommendations while avoiding duplication with existing and better sources for such information. Enbridge Gas proposed making one minor modification (adding a statement to its marketing materials directing customers to consult an HVAC service provider regarding specific energy

options, building considerations and cost estimates that will be appropriate for their specific needs, and about electric-related costs). Enbridge Gas submitted that it would be extraordinary for the OEB to require Enbridge Gas to provide information about alternative technologies and programs it does not administer, at the cost of gas ratepayers, and noted a previous OEB decision,⁸⁶ where the OEB determined that Enbridge Gas would not be required to provide detailed assessments of alternative technologies such as solar and geothermal as part of its community expansion (NGEP) applications.

Findings

Since the new revenue horizon will not be implemented until January 1, 2025, this important question is best addressed as part of Phase 2. This will allow the OEB to consider any input that may be provided by representatives of the development industry that choose to participate along with the views of the other intervenors and Enbridge Gas.

There was discussion about the information that Enbridge Gas currently provides in its informational and marketing materials, including its website, about the cost of heating with other energy sources relative to gas and concerns were raised about its accuracy. It is important that customers are provided with accurate information by Enbridge Gas. A comparison between the cost of electric baseboard heating and the cost of using a high efficiency gas furnace is not helpful if that comparison is not clearly described. It is also not helpful for a customer who wants to understand how a cold climate air source heat pump or a geothermal heat pump compares to a gas furnace.

The OEB directs Enbridge Gas to review the energy comparison information currently on its website and printed materials to determine whether it fully discloses what is being compared and on what basis, and what assumptions are being used for the comparison. Enbridge Gas shall either update the information to correct any deficiencies or remove the information. As part of its updated evidence for Phase 2, Enbridge Gas shall provide a report on the review it undertook and the actions it took as a result of the review.

Cost Impacts of the New Revenue Horizon and Impacts to Capital Budget

The primary impact of using a shortened revenue horizon would be higher costs paid directly by many newly connecting customers and correspondingly lower capital costs to be included in rate base to support new customer connections, if the developer chooses to proceed with gas servicing. Enbridge Gas estimated the average CIAC that new

⁸⁶ EB 2016-0004, Decision and Order, November 17, 2016.

customers would need to pay under different revenue horizons, and the corresponding reduction in Enbridge Gas's customer connections capital budget (Table 1). Relative to a 40-year revenue horizon, the impact would range from an average CIAC of \$645 and five-year capital budget reduction of \$124 million using a 30-year revenue horizon, to an average CIAC of \$4,428 and a five-year capital budget reduction of \$853 million using a ten-year revenue horizon.

Table 1
Customer Connections Capital Expenditure Supported by
Different Revenue Horizons⁸⁷

Line No.	Revenue Horizon	2024	2025	2026	2027	2028	Total	Reduction vs. 40 Year Revenue Horizon	CIAC per Customer
	(Years)	(\$ millions)	(\$ millions)	(\$ millions)	(\$ millions)	(\$ millions)	(\$ millions)	(\$ millions)	
1	40	304	248	258	254	250	1,314		
2	30	229	227	239	241	253	1,190	124	645
3	25	210	208	219	221	235	1,094	220	1,140
4	20	188	185	196	198	205	972	342	1,774
5	15	146	144	153	154	159	757	557	2,890
6	10	89	88	93	95	96	460	853	4,428

Findings

Given that the new revenue horizon only applies to projects connecting on or after January 1, 2025, there is no impact to the 2024 capital budget. However, there will be an impact in 2025 and subsequent years that needs to be considered. The OEB is of the view that this is best addressed in Phase 2 of this proceeding, which will also consider the issue of incentive ratemaking mechanisms in the context of the energy transition.

Under the new revenue horizon, any developer that wants to include gas servicing will need to pay the full connection cost upfront. Regardless of whether a developer chooses to proceed with gas service and make the CIAC payment or chooses to avoid the cost and go with all electric servicing, there will be an impact to the capital budget in 2025. As part of the updated evidence that Enbridge Gas plans to file for Phase 2, the OEB directs Enbridge Gas to address how the reduction will be implemented during the proposed IRM term.

⁸⁷ Exhibit J11.1, Table 1. Connection costs associated with the Natural Gas Expansion Program projects are not included in this table.

Enbridge Gas has suggested that the new revenue horizon could have an impact on the Province's housing strategy. As discussed earlier, the extent to which there will be an impact and the extent to which that impact is positive or negative, will depend on the choices made by developers now that the split incentive problem has been addressed. The change to the revenue horizon facilitates the ability to make an informed choice about how to service a new development, including consideration of the affordability of new housing, not only from a capital cost perspective, but also from an operating cost perspective.

What is the Appropriate Extra Length Charge (ELC)?

Enbridge Gas proposed a harmonized service length threshold of 20 metres that would be provided free of charge for infill service connections, and an updated ELC of \$159 per additional metre across all franchise areas, and requested approval of this charge. Enbridge Gas noted that the existing rates for the ELC had remained constant for many years, despite increases in construction costs, and required updating.⁸⁸ Enbridge Gas's proposal for the length of free service connection and the ELC was based on updated cost data. This analysis demonstrated that the distribution revenue from a typical residential customer can support the average cost of services below 20 metres, and that 75% of residential services are less than or equal to 20 metres, and thus would not need to pay an ELC.

Parties generally agreed that any change to the revenue horizon should also be used to determine the appropriate cost recovery charge for new infill connections. Enbridge Gas indicated that, should the revenue horizon be changed, it would examine whether to use a modified version of the ELC (likely with a higher per metre charge), or a different approach (such as a straight fixed charge, or a per metre charge that would apply to the entire service length).

Enbridge Gas indicated that it was open to providing an updated proposal for infill customers in a future phase of this proceeding, which could be implemented along with any other changes to the customer connection policy as of January 1, 2025. OEB staff and FRPO submitted that the OEB should approve Enbridge Gas's requested charge for the ELC (\$159 per metre, beyond 20 metres) as of January 1, 2024, until an updated approach for infill customers is approved by the OEB. Enbridge Gas agreed.

VECC submitted that the requested charge for the ELC, being a significant increase over the previous charge, should not be approved without a full review of customer

⁸⁸ The current approved ELC is \$32 per additional metre for the Enbridge Gas Distribution rate zone and \$45 per additional metre for the Union rate zones. The Union rate zones also use a different service length threshold (30 m instead of 20 m). Exhibit 8, Tab 3, Schedule 1, p. 10.

connection policies. VECC proposed that the ELC be set at \$100 per metre (beyond 20 metres), which Enbridge Gas disagreed with.

Findings

The OEB approves the proposed ELC of \$159 per metre beyond the first 20 meters for use in 2024. In keeping with the new revenue horizon to be implemented in 2025, it is necessary for Enbridge Gas to propose a modified approach to infill connections, to be filed as part of its updated Phase 2 evidence.

The OEB accepts that Enbridge Gas did not meet a PI of 1.0 for the Investment Portfolio during certain years of the deferred rebasing term, for the reasons submitted by Enbridge Gas. Some parties argued that the 2023 customer connections capital proposed to be added to the 2024 rate base should be reduced by the forecast revenue shortfall. In reply, Enbridge Gas noted that apart from inflation and other related factors, the OEB's direction in the 2019 rates proceeding⁸⁹ that Enbridge Gas could not change its charges to connect infill customers was a significant contributor to the customer attachment portfolio being lower than 1.0 in 2023. The OEB recognizes that the inability to increase customer connection charges impacted the PI in 2023. Nothing further needs to be done to address this. The requirement to meet a PI of 1.0 remains in place going forward.

3.2.2 System Renewal

System renewal investments involve replacing or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the system to provide customers with natural gas services. System renewal assets include compressor stations, distribution pipelines, distribution stations and utilization assets that regulate system pressure.

System renewal is the highest asset investment category at \$2.9 billion for the 2024 to 2028 period in terms of in-service additions. Forecast capital expenditures for 2024 on system renewal projects is \$530.6 million.⁹⁰

Enbridge Gas did not identify any adequate steps in its application to mitigate the stranded asset risk for system renewal investments resulting from the energy transition.

Mr. Neme's evidence recommended that the OEB should require Enbridge Gas to explicitly assess the potential for repairing rather than replacing aging pipelines. Further, the OEB should direct Enbridge Gas to conduct an assessment of the risk that a new

⁸⁹ EB-2018-0305, Decision and Order, September 12, 2019, pp. 34-36.

⁹⁰ Exhibit I.2.6-SEC-113, p. 3, Updated July 6, 2023.

pipeline will be underutilized or stranded before the end of its physical life. The repair option to extend the life of an asset would offer the potential to prune the gas system so that the pipeline is no longer required in the context of future decarbonization pathways.

OEB staff submitted that Enbridge Gas should document how infrastructure repair options are considered in meeting system needs, and how the consideration of repair options relates to the IRP assessment process. In light of the energy transition and the goal to reduce the risk of stranded assets, OEB staff stressed the need to consider repair options. SEC supported Mr. Neme's evidence and OEB staff's submission.

FRPO submitted that asset management would be improved with incentives for Enbridge Gas tied to service life extension. In reply, Enbridge Gas indicated that it could share information on the utility's inspection and maintenance programs and viable infrastructure repair options (along with associated limitations), as part of project applications. Enbridge Gas did not specifically comment on how this would be connected to its IRP assessment. Enbridge Gas submitted that incentives associated with service life extension were premature and could have unintended consequences.

Enbridge Gas regarded the repair of assets to extend the useful life of the asset as the equivalent to a "run to failure" approach.

Findings

System renewal is comprised of all the activities required to maintain the reliability and safety of the existing gas system. These activities include monitoring the system, making necessary repairs to the system, and replacing sections of the system that are nearing the end of their physical life.

The stranded asset risk for replacement assets is the same as for system access assets. For example, the replacement of the connection assets in an existing residential subdivision is the same as installing connection facilities in a new subdivision, in terms of the risk of stranded asset costs. If the cost of those assets is recovered over an average of 40 years, there is a risk that customers in each of those subdivisions will leave the gas system because of the energy transition, before the cost of those assets has been completely recovered.

In section 3.2.1 of this Decision and Order, the stranded asset risk for new connections to the gas system was addressed by reducing the revenue horizon to be assumed for the economic feasibility analysis under E.B.O. 188. However, for existing assets, system renewal decisions are made on a safety and reliability basis and have not been subject to the economic feasibility requirements in E.B.O. 188.

The option of imposing a requirement for an E.B.O. 188 analysis with a reduced revenue horizon for system renewal assets was not the subject of evidence or submissions in Phase 1 of this proceeding.

System pruning, for example, converting a subdivision from gas to electricity for space and water heating, is another option. Under this option, existing gas customers would replace their gas equipment with electric equipment. This could be supported by an IRP solution, which would consider various alternatives to avoid the need to replace the facilities. The IRP process could offer alternatives through pilot projects for the OEB to consider, including incentives to be paid to the customers to defray the cost of replacing their gas equipment, or investment by the utility to cover the cost of the electric equipment to be recovered over time, with a return on that investment. This has been the subject of some discussion in Phase 1 of this proceeding.

A comprehensive IRP approach to renewal projects would include measuring the cost of the renewal project against the cost of the alternative of replacing gas equipment with electric equipment and to implement alternatives that defer or eliminate the need for the replacement project when they are economically feasible.

In Phase 2 of this proceeding, a key issue regarding Enbridge Gas's incentive ratemaking mechanism proposal is to determine how performance-based incentives could be used in the face of the energy transition. Phase 2 will provide an opportunity to examine ways in which Enbridge Gas could be provided with an incentive to implement economic alternatives to gas infrastructure replacement projects, including asset life extensions and system pruning, including replacing gas equipment with electric equipment. For the recovery of the cost of economic alternatives to gas infrastructure, how should the expense be treated for rate making purposes – expensed or capitalized? How should the cost be recovered – from all remaining ratepayers, or from the benefiting ratepayers who are exiting the gas system, or some combination? What form should incentives take – a ratepayer funded incentive payment or a return on the expenditure? An examination of these questions in Phase 2 will also assist the OEB in developing direction prior to the next rebasing application.

3.2.3 Overall Capital Budget

Enbridge Gas's updated proposed capital expenditure for the 2024 to 2028 period is \$7.2 billion and \$13.8 billion from 2023 to 2032. The projected annual spend ranges between \$1.2 billion to \$1.6 billion from 2023 to 2032. System Renewal and System

Access are Enbridge Gas's highest asset investment categories at \$2.9 billion and \$2.5 billion from 2024 to 2028, respectively.⁹¹

CCC and CME noted that in ten years from 2013, Enbridge Gas's capital budget has increased by 84% and rate base has increased by 105%.

Although Enbridge Gas referred to the energy transition risks in its Asset Management Plan, OEB staff submitted that the proposed expenditures do not reflect the risks related to the energy transition. OEB staff referenced the oral testimony of Enbridge Gas where it confirmed that it had not directly addressed energy transition risk and the related stranded asset risk in the Asset Management Plan.

APPrO was generally supportive of Enbridge Gas's proposed capital spending plan. However, APPrO suggested that some portion of the spending could be smoothed over a longer period. APPrO and CCC noted that Enbridge Gas's capital budget is "front-loaded" with the highest spending in the first two years (2024 and 2025). APPrO recommended that the OEB could use the average spending for the proposed rate term (2024 to 2028) to set the spending for 2024.

In reply, Enbridge Gas agreed that, to a certain extent, an optimized Asset Management Plan should strive for a levelized spend profile. However, Enbridge Gas noted that in reality, 2024 has been significantly impacted by the deferral of and cost increases to the Panhandle Regional Expansion project (PREP), deferral of the St. Laurent projects, increased renewable natural gas projects, timing of major real estate projects and Technology and Information Services (TIS) investments required to support rate harmonization. For these reasons, Enbridge Gas submitted that it cannot support a proposal to levelize capital expenditures over the five-year period.

OGVG submitted that Enbridge Gas's proposed updated capital budget of \$1.47 billion for 2024 is consistent with historical spending over the 2013 to 2023 period, accounting for inflation and the fact that all materially large expansion and reinforcement projects have been subject to review by the OEB through leave to construct applications. OGVG further noted that a material increase in "other" spending is related to renewable natural gas and compressed natural gas stations that is new relative to historical years and directly recovered from customers requesting the service.

SEC and VECC submitted that the proposed spending has consistently increased over successive Asset Management Plans. In 2019, Enbridge Gas forecasted spending of \$5 billion over the 2021 to 2025 period. The Asset Management Plan filed two years later saw the spending increase by more than \$1.3 billion to \$6.3 billion. In this application,

⁹¹ Exhibit 2, Tab 6, Schedule 1, p. 37.

the forecast spending for the same period has increased to \$6.9 billion.⁹² SEC argued that Enbridge Gas had not demonstrated that there were any fundamental flaws in its previous Asset Management Plans that would require such a significant increase in spending over the same period in each subsequent version. It further noted that inflation alone is not an appropriate justification for the proposed increase in capital spending. SEC recommended that the OEB approve an in-service additions budget that maintains the rate base at existing levels each year, essentially in-service additions that equal the depreciation expense. Based on Enbridge Gas's proposed depreciation methodology, SEC noted that the 2024 in-service additions budget would be \$878 million (excluding PREP).

In reply, Enbridge Gas argued that SEC's suggestion to cut capital additions to match depreciation expense is without merit and shows a flawed understanding of Enbridge Gas's core business. Enbridge Gas noted that the company has an obligation to maintain the safety and reliability of the distribution system. If SEC's proposed cuts were implemented, Enbridge Gas submitted that it would have to curtail all investments in gas infrastructure – growth, emission reduction, energy transition, as well as proactive replacements targeting future resource balancing and cost-effectiveness in the long run.

Environmental Defence noted that Enbridge Gas has proposed to spend over \$7 billion in capital over the next five years and the level of spending far outstrips the amounts that customers will be paying through depreciation. Environmental Defence submitted that the spending plan will add \$2 billion to the rate base which is in addition to the doubling of rate base over the past ten years. Environmental Defence considered the trend to be unsustainable and far too risky in light of the potential impacts of the energy transition on demand and revenue. Environmental Defence submitted that at a high level, the capital envelope should be reduced in a manner that achieves a declining rate base. However, Environmental Defence noted that the capital envelope should be large enough to ensure safety and reliability and if there is a funding gap, it could be addressed through accelerated depreciation.

Pollution Probe submitted that the Asset Management Plan process is largely arbitrary and based on Enbridge Gas staff and management decisions. Pollution Probe argued that Enbridge Gas had not credibly considered the non-gas options that are more cost effective than attaching to the gas system. Pollution Probe recommended that Enbridge Gas's proposed 2024 capital expenditures should be reduced from \$1.47 billion to \$1.1 billion.

⁹² Updated forecasted spending is \$7.2 billion as referred to in the findings.

CCC submitted that Enbridge Gas's base capital spending for 2023 and 2024 should not exceed its average historical base capital spend for the years 2018 to 2022 of \$940 million. CCC proposed reductions of \$39 million for 2023 and \$254 million for 2024. This results in total capital expenditures of \$1.39 billion in 2023 and \$1.22 billion in 2024 (excluding PREP). CCC noted that approximately 40% of the investments in the updated capital plan are Value-Driven as opposed to Mandatory or Compliance (must-do capital projects).

In reply, Enbridge Gas submitted that customer connection costs during 2019 to 2021 averaged \$209.9 million compared to \$302.3 million forecast for 2024 due to cost pressures from higher inflation, supply chain issues and permitting challenges/costs. In addition, the meter exchange program needs to be accelerated to compensate for lower replacements during COVID-19. Enbridge Gas submitted that when these differences are factored in and added to the average spend of \$1.2 billion across 2019 to 2021, the total is \$1.46 billion which is in line with the 2024 Test Year forecast exclusive of PREP.

CME noted that many projects that were deemed necessary in the pre-filed evidence have been moved out of the capital spending plan in the Capital Update. CME submitted that the value framework is not transparent or robust enough to justify Enbridge Gas's capital spending plan. CME suggested that the capital spending for 2024 should be reduced by \$400 million to \$1.265 billion.⁹³ CME noted that the proposed amount would still give Enbridge Gas a higher capital budget than the actual spend for 2020 to 2022.

OEB staff also made submissions on specific capital expenditures and proposed reductions to certain items. OEB staff recommended reductions to customer connection costs for 2024 related to its proposed 20-year revenue horizon, reductions to system reinforcement costs, adjustments to the Selwyn Community Expansion project, reductions to spending related to compressor stations and integrity digs, and a levelized treatment for the St. Laurent projects. Overall, OEB staff proposed a total reduction of \$271.5 million, from \$1.47 billion to \$1.2 billion.

LPMA made a similar submission focusing on specific expenditures and recommended that the forecasted capital expenditures for the 2024 Test Year should be reduced from \$1.47 billion to \$1.32 billion (a reduction of \$143.7 million).

⁹³ CME has included PREP in its calculation: \$1,470.3 million + \$194.9 million = \$1,665.2 million (as per Undertaking J13.14). Reducing \$400 million from this number gives the recommended amount of \$1.265 billion.

Information in Future Asset Management Plans

SEC noted that Enbridge Gas currently forecasts demand only out to ten years in its Asset Management Plan. Considering that some assets have physical lifespans of over 60 years, CCC and SEC submitted that Enbridge Gas should consider future underutilization risk due to the energy transition, just like other risks that are currently considered as part of its value framework.

Environmental Defence noted that Enbridge Gas uses a single ten-year demand forecast based on a single future demand scenario. Environmental Defence submitted that Enbridge Gas should be required to assess capital projects with at least three demand forecast scenarios reflecting a range of potential energy transition futures. Environmental Defence believed that neglecting to consider the possibility of a high electrification scenario through a demand sensitivity analysis could result in bad investment decisions and major cost/risk implications for ratepayers.

OEB staff recommended that Enbridge Gas review its energy transition assumptions in its load forecast on an annual basis and document how, if at all, these changes have impacted Enbridge Gas's Asset Management Plan. In reply, Enbridge Gas agreed that in future iterations of the Asset Management Plan and addendum, it could capture updated customer connection forecasts based on updated energy transition assumptions and present these as forecasted adjustments to capital requirements for customer connections. However, Enbridge Gas disagreed with Environmental Defence's suggestion to conduct multiple demand scenarios for every project. Enbridge Gas submitted that it does not have the information to identify revenue streams for certain segments of its system nor information to assess the probability analysis of revenue generation.

OEB staff further submitted that at the next rebasing, Enbridge Gas should be required to file an Asset Management Plan that establishes clear linkages between the energy transition and capital spending in all operating areas including a discussion on scenarios and probabilities of stranded assets.

In reply, Enbridge Gas acknowledged the concerns of OEB staff and intervenors about the financial risks tied to stranded assets. Enbridge Gas submitted that it will continue to monitor for clear, discrete, geographically based disconnection or demand reduction signals to help support asset level decision making and ensure that the approach taken is clearly documented in the Asset Management Plan filed with the next rebasing application.

Findings

As discussed previously, Enbridge Gas has not undertaken any meaningful assessment of the risk of stranded assets in relation to its Asset Management Plan supporting its 2024 capital spending proposal. As a result, Enbridge Gas has not identified any adequate steps it would take to mitigate the risk of stranded asset costs arising from system renewal.

Enbridge Gas has not established that its current approach to system renewal maximizes system monitoring for the purpose of repair and asset life extension over asset replacement, as contemplated in the St. Laurent Ottawa North Replacement Project decision.⁹⁴ The OEB's decision to deny the St. Laurent leave to construct application set an important precedent. In that decision, the OEB directed Enbridge Gas to assess other alternatives such as in-line inspection, repair and life extension. In that decision, the OEB also suggested that Enbridge Gas work collaboratively with stakeholders to proactively plan a course of action if and when pipeline replacement is required, including the pursuit of IRP alternatives.

Enbridge Gas's approach continues to favour asset age over asset condition for replacement decisions and does not satisfactorily address the OEB's concerns as identified in the St. Laurent decision.

Enbridge Gas needs to implement an approach that assesses asset condition and has as its objective the maximization of asset life. This does not constitute a "run to failure" policy but instead maximizes the value of an asset in providing service to ratepayers. Maximizing the life of existing assets is a prudent practice in general, but in this case, it also increases the ability to avoid capital investments that may not be needed because of the continuing energy transition, thereby reducing the risk of stranded asset costs.

Safe and reliable life extension delivers more value to ratepayers than premature asset replacement.

The OEB finds that the 2024 capital budget proposed by Enbridge Gas has not been justified and shall be reduced from the updated \$1,470.3 million to \$1,220.3 million, a reduction of \$250 million or 17.0%.⁹⁵ The reasons for the reduction are summarized below.

⁹⁴ EB-2020-0293.

⁹⁵ Enbridge Gas Reply Argument, p. 167. This reduction is inclusive of Enbridge Gas's agreed to reduction of \$1.5 million related to the Selwyn Community Expansion Project to reflect the revised (lower) net capital cost estimate for the project.

- The proposed capital expenditures for 2024 do not reflect the risk associated with the energy transition, more specifically the longer-term risk of under-utilized or stranded assets. The energy transition risk is not even explicitly mentioned in Enbridge Gas's corporate risk register.
- The proposed 2024 capital expenditure represents a significant increase compared to average historical spending. The average annual spending during the 2018 to 2022 period is \$1,148.2 million. The proposed updated 2024 spending (\$1,470.3 million) is \$322.1 million (28%) higher than the 2018 to 2022 average actual spending. The approved 2024 capital expenditure in this proceeding (\$1,220.3 million) is still higher than the average actual spending for the 2018 to 2022 period. In its evidence, Enbridge Gas considered \$1.2 billion as a minimum constraint to safely operate and maintain the natural gas system, respond to demand growth, invest in low-carbon solutions and ensure on-going reliability and service to customers.⁹⁶
- Enbridge Gas's Asset Management Plan projection for the period 2021 to 2025 in the current application (\$7,235.1 million)⁹⁷ is significantly higher than the previous Asset Management Plan projection for the same period in the 2021 rate application (\$6,297.2 million); an increase of \$937.9 million or 14.9%.

The OEB's reduction of \$250 million is an envelope reduction to the 2024 capital program and does not specify which projects are to be deferred or reduced to achieve that envelope reduction. Enbridge Gas has sufficient flexibility to re-prioritize its capital projects within its Asset Management Plan based on risk to accommodate the 2024 reduction and flatten the level of expenditure for future years. The OEB is reducing the system renewal budget envelope to motivate Enbridge Gas to improve its approach to integrity management, repair and life extension, so that only truly necessary replacement projects proceed.

Enbridge Gas is directed, in its next rebasing application, to file an Asset Management Plan that provides clear linkages between capital spending and the energy transition risk. The Asset Management Plan should address scenarios associated with the risk of under-utilized or stranded assets and possible mitigating measures. As discussed later in this Decision and Order, Enbridge Gas will also be required to determine whether to propose changes to its approach to depreciation to account for the impact of the energy transition, recognizing that a failure to act prudently in relation to the risk of stranded assets will have an impact on the ability to keep those assets in rate base.

⁹⁶ Exhibit 2, Tab 5, Schedule 1, p. 6.

⁹⁷ As per Exhibits J13.14 and J14.5.

Panhandle Regional Expansion Project (PREP)

Enbridge Gas proposed a levelized treatment for PREP and excluded the associated capital expenditures from the 2024 rate base. PREP is a significant project (forecasted in-service capital of \$252 million for 2024).⁹⁸ Since the project has yet to receive leave to construct from the OEB, Enbridge Gas proposed to exclude the costs and incremental revenues that are attributable to the project's forecast 2024 in-service component from the 2024 revenue requirement. The treatment is similar to Incremental Capital Module (ICM) projects that were considered by the OEB during Enbridge Gas's deferred rebasing term (2019 to 2023).

Enbridge Gas proposed to calculate a separate unit rate based on the average of the five-year net revenue requirement. In the event that the OEB does not grant leave to construct, no adjustment to base rates will be required and Enbridge Gas will not implement the rate rider. Enbridge Gas proposed to establish an associated variance account, the PREP variance account, that would capture any variance between the project's actual net revenue requirement and the actual revenues collected through the average unit rate that would be in place over the IRM term.

OEB staff supported the proposed approach.

LPMA, SEC and CCC opposed the exclusion of PREP costs from the 2024 revenue requirement. LPMA submitted that if the proposed approach was approved, it would cost ratepayers in excess of \$100 million over the 2024 to 2028 period. LPMA argued that Enbridge Gas is seeking to treat PREP as an ICM project in a cost of service proceeding, which is contrary to OEB policy. These intervenors stated that the reason that Enbridge Gas wants to exclude the PREP costs in 2024 rate base is that it results in a reduction to the 2024 revenue requirement of \$14.4 million⁹⁹ and this reduced revenue requirement would persist for the remainder of the IRM term. CCC and SEC also noted that there are several other large projects forecasted to go into service in 2023 and 2024 and Enbridge Gas has not proposed a levelized treatment for these projects. CCC and SEC submitted that the appropriate rate treatment for PREP is to include the project in 2024 rate base with a variance account to capture the outcome in the scenario that the project is denied leave to construct or to track actual costs against forecast.

⁹⁸ Exhibit 2, Tab 5, Schedule 4, p. 10 – PREP capital expenditures of \$34.3 million in 2022, \$22.7 million in 2023 and \$194.9 million in 2024.

⁹⁹ PREP has a negative revenue requirement in the first year (2024) due to tax benefits and the application of the half-year rule.

In reply, Enbridge Gas submitted that if the project is included in base rates and subsequently denied leave to construct, then it will cause \$14 million in revenue sufficiency for 2024 (growing to about \$75 million over the proposed IRM term), and this would unfairly benefit ratepayers.

Findings

The OEB accepts Enbridge Gas's proposed approach. PREP is one of the largest growth-driven investments ever undertaken by Enbridge Gas. In addition, Enbridge Gas has identified that there is uncertainty regarding the approval and timing of the project, referring to the contentious nature of the project and the risk that the OEB may not approve the project.¹⁰⁰

The OEB considered two other options: the usual approach of including it in rate base or excluding it from rate base and subjecting it to a future ICM application. Considering the risk and uncertainty, it would be premature to determine rate treatment by including it in rate base. Given the materiality of the project cost, scope and timing, the OEB finds that Enbridge Gas's proposed approach is reasonable.

St. Laurent Phase 3 and Phase 4 Projects

The 2024 capital budget includes spending on the St. Laurent Phase 3 (NPS12/16), St. Laurent Phase 3 (Coventry/Cummings/St. Laurent) and St. Laurent Phase 4 (East/West) replacement projects (St. Laurent project). Total spending on the St. Laurent project is \$223.4 million over the 2024 to 2026 period with \$75.7 million of spending to be added to rate base in 2024 (Phase 3 in-service addition of \$23.9 million + Phase 4 in-service addition of \$51.8 million).¹⁰¹

In a previous OEB Decision on phases 3 and 4 of the St. Laurent project, the OEB denied Enbridge Gas's leave to construct application. The OEB determined that Enbridge Gas had not demonstrated that pipeline integrity was compromised, nor that pipeline replacement was required at that time.¹⁰² OEB staff submitted that the OEB's denial of the St. Laurent leave to construct application creates some uncertainty with respect to the likelihood and timing of any future approval of the St. Laurent project. Accordingly, OEB staff recommended a levelized treatment for the St. Laurent project similar to PREP.

¹⁰⁰ Enbridge Gas Reply Argument, p. 192.

¹⁰¹ Exhibit J13.21.

¹⁰² EB-2020-0293, Decision and Order, May 3, 2022, p. 3.

LPMA opposed OEB staff's proposed treatment of the St. Laurent project. LPMA submitted that OEB staff's recommendation would result in ratepayers paying more, not only for 2024, but for all the incentive regulation years that follow. LPMA noted that including the St. Laurent project in 2024 rate base reduces the 2024 revenue requirement because the project has a sufficiency of \$2 million in 2024. SEC opposed the proposed levelized rate treatment for the same reasons that apply to PREP.

In reply, Enbridge Gas agreed to the proposed levelized approach and to exclude \$75.7 million in direct capital and overhead from the 2024 capital budget and removing the associated in-service additions from 2024 rate base. Enbridge Gas also agreed to establish an associated project variance account to capture any variance between the project's actual net revenue requirement and the revenues collected through the rate rider during the proposed IRM term.

Findings

The St. Laurent project is like most other capital projects and does not share the characteristics of PREP in terms of cost, scope and risk. The OEB accepts Enbridge Gas's original proposal of including it in rate base. No compelling basis has been established to justify deviation from the usual treatment of capital projects that are proposed to go into service in the Test Year.

3.3 Equity Thickness

Enbridge Gas's current deemed capital structure for the purposes of ratemaking is a ratio of 64% debt to 36% equity. In this Decision and Order, the equity component is referred to as the equity thickness.

In the OEB-approved settlement proposal, parties agreed to the as-filed debt rates and the use of the OEB's formula to determine the return on equity (ROE). The 2024 ROE was approved by the OEB and communicated through a letter issued October 31, 2023.¹⁰³ There was no settlement with respect to the deemed equity thickness for ratemaking purposes in this proceeding.

Enbridge Gas currently has a deemed equity thickness of 36% for ratemaking purposes, established on the basis that, at the time of the amalgamation between Enbridge Gas Distribution and Union Gas, the two predecessor utilities both had an approved deemed

¹⁰³ OEB Letter Re 2024 Cost of Capital Parameters, October 31, 2023.

equity thickness of 36%.¹⁰⁴ The equity thickness of 36% was originally established for the two predecessor utilities over ten years ago in their respective rebasing applications.¹⁰⁵

Enbridge Gas's Evidence

Enbridge Gas proposed to increase its deemed equity thickness from 36% to 42%. This was supported by the evidence of its expert, Concentric.¹⁰⁶ Concentric concluded that the energy transition is the most important factor impacting Enbridge Gas's business risk since the cost of capital and business risk were last formally reviewed in 2012. For its quantitative analysis, Concentric relied primarily on an analysis of four comparator groups. Through a comparison of statistics of comparator groups of Canadian and U.S. holding companies and operating companies, Concentric concluded that Enbridge Gas's current deemed equity thickness is below that of the comparator groups and recommended a minimum equity thickness of 42%.

Enbridge Gas proposed to implement the increased equity thickness in steps starting with an increase to 38% effective January 1, 2024. Enbridge Gas proposed a further one percentage point increase in the equity thickness for each year from 2025 to 2028 to reach 42% deemed equity thickness in 2028.¹⁰⁷ If accepted, an increase to 38% in 2024 would increase the revenue requirement by \$26.1 million and by approximately \$80.6 million once the equity thickness reaches 42% in 2028. The total increase in revenue requirement over the proposed rate term (2024-2028) related to Enbridge Gas's proposed increase to equity thickness is \$266.5 million.¹⁰⁸

Intervenor and OEB staff Evidence

Evidence related to equity thickness and business risk was filed by the following:

- London Economics International LLC (LEI), on behalf of OEB staff, filed an independent analysis of Enbridge Gas's application and provide an independent opinion on the appropriateness of its capital structure proposal¹⁰⁹

¹⁰⁴ EB-2017-0306, which was considered jointly by the OEB for the multi-year price cap plan proposed for the amalgamated entity ("Amalco", now known as Enbridge Gas Inc. (Enbridge Gas)). The plan was proposed for 2019-2028, but the OEB ultimately approved a five-year plan for 2019-2023.

¹⁰⁵ EB-2011-0354 for Enbridge Gas Distribution and EB-2011-0210 for Union Gas.

¹⁰⁶ Exhibit 5, Tab 3, Schedule 1, Attachment 1 (the Concentric Report).

¹⁰⁷ Enbridge Gas, Argument-in-Chief, pp. 212-233.

¹⁰⁸ Exhibit J9.1, 2024 amount of \$26.1 million + \$13.6 million annual increase to 2028.

¹⁰⁹ Exhibit M2, Recommendation for Appropriate Capital Structure for Enbridge Gas in its application for 2024 Rebasing and 2025-2028 Price Cap Plan.

- Dr. Sean Cleary, Professor of Finance at the Smith School of Business at Queen's University, on behalf of IGUA, filed an analysis of Enbridge Gas's evidence regarding the allowed equity ratio¹¹⁰
- Dr. Asa Hopkins of Synapse Energy Economics, on behalf of IGUA, filed an independent analysis of Enbridge Gas's business risk and capital structure¹¹¹

LEI recommended an increase in the deemed equity thickness to 38% for 2024-2028 based on its analysis. LEI considered changes in Enbridge Gas's business risk since the amalgamation in 2019 as well as changes since the last cost of capital reviews for the predecessor utilities in 2012. LEI stated that the energy transition has increased Enbridge Gas's business risk, but the amalgamation operates to partially offset that increased risk when compared to 2012.

Dr. Cleary concluded that there was no increase in Enbridge Gas's business risk and recommended that there be no change from the current deemed equity thickness of 36%. Dr. Cleary's analysis considered the historical financial performance of Enbridge Gas and its predecessor utilities.

Dr. Hopkins concluded that Enbridge Gas's operational business risk had not changed appreciably between 2012 and the present given his assessment of the impacts of the energy transition on Enbridge Gas's financial metrics and business risk.¹¹² Dr. Hopkins further concluded that Enbridge Gas and Concentric had not adequately analyzed the energy transition impacts on Enbridge Gas's business.¹¹³

VECC recommended an increase in equity thickness to 37%. OEB staff, APPrO, Energy Probe, QMA and SEC recommended an increase of the deemed equity thickness to 38%. Other intervenors (CCC, CME, GEC, IGUA, City of Kitchener, LPMA, Pollution Probe, Russ Houldin, and Three Fires Group) submitted that Enbridge Gas's deemed equity thickness of 36% should remain unchanged.

VECC observed that none of the evidence in the proceeding used well-established cost of capital estimation methodologies, and the proceeding did not adequately consider countervailing risk factors that might mitigate risk. For example, VECC submitted that the proposed fixed rate structure, although mentioned in the expert reports, was not appropriately analyzed. Pending a full review of all aspects of Enbridge Gas's cost of

¹¹⁰ Exhibit M6, Evidence of Dr. Sean Cleary.

¹¹¹ Exhibit M8, Evidence of Dr. Asa S. Hopkins on the Topic of Business Risk and Capital Structure.

¹¹² Dr. Hopkins was specifically qualified as an expert "on the future of electric and gas utility regulatory and business models and associated business risk in the context of deep building decarbonization objectives", not as an expert on cost of capital: Oral Hearing Transcript, Vol. 4, p. 152.

¹¹³ Exhibit M8, On the Topic of Business Risk and Capital Structure, May 11, 2023, p. 5.

capital, VECC suggested that in the interim, the OEB could approve an increase to 37% equity thickness.

OEB staff and Energy Probe submitted that Enbridge Gas's deemed equity thickness should be increased from 36% to 38% for 2024, as recommended by LEI. QMA suggested a range between 38% and 42% with a gradual increase to manage the impact on rates.

OEB staff noted that LEI considered the 2019 amalgamation as the relevant starting point for assessing a change in Enbridge Gas's business risk, but also considered changes back to 2012 the last time the OEB formally reviewed and made determinations on the predecessor utilities' business risk and the commensurate equity thickness to ensure that the fair return standard was met. OEB staff noted that with amalgamation in 2019, Enbridge Gas became one of the largest natural gas distributors in North America and could avail itself of economies of scale and other productivity opportunities resulting from the larger and more contiguous service area post-amalgamation.

OEB staff accepted that the energy transition brings new pressures and risks. However, OEB staff submitted that it is not just the presence of these energy transition-related pressures but also the firm's ability to react to and prudently manage the risks that determines whether there has been a non-manageable increase in risk.

OEB staff submitted that Concentric's evidence was overly qualitative in nature. OEB staff submitted that the Canadian comparator groups were not good comparators due to size and other operational characteristics. OEB staff also criticized Concentric's use of simple unweighted averages. OEB staff argued that the evidence of LEI and Dr. Cleary was based on a better balance of qualitative and quantitative analyses.

APPPrO submitted that until the province and the EETP provide clear guidance on the most cost-effective manner of implementing the energy transition, it is not clear that there is a material risk to Enbridge Gas's business. However, based on LEI's analysis, APPPrO was willing to accept an equity thickness of 38% by 2028.

SEC acknowledged that there are clear risks related to the energy transition. SEC submitted that compensation in terms of a higher equity thickness is only appropriate if Enbridge Gas takes reasonable steps to mitigate those risks. However, SEC did support a 38% equity thickness if there is a substantial reduction in capital spending over the next five years.

LPMA and OGVG referenced Enbridge Gas's testimony that the energy transition is not expected to have a large material impact during the proposed rate term. LPMA

concluded that Enbridge Gas's business risk had not increased and recommended that the equity thickness should remain unchanged at 36%. However, if the OEB were to determine that Enbridge Gas's risk had increased, LPMA suggested an equity thickness of no more than 38%.

LPMA agreed with OEB staff's position that the amalgamation of Enbridge Gas Distribution and Union Gas had reduced the risk of Enbridge Gas since the last time the cost of capital was reviewed for the legacy utilities.

GEC and the City of Kitchener submitted that unless a comprehensive mitigation plan is implemented, Enbridge Gas's proposal to increase the equity thickness would be inappropriate.

CME and IGUA submitted that Enbridge Gas and Concentric have not demonstrated that the company is facing any near-term increase in its operational risks due to the energy transition. CME and IGUA noted that the credit rating agencies (DBRS and S&P) have given Enbridge Gas a stable outlook and have raised no specific concerns. Further, Enbridge Gas had no trouble attracting capital at a similar rate for "like risk" companies and meets the capital attraction standard.

IGUA argued that LEI's report examines only external factors and provides no Enbridge Gas specific analysis that could support a determination that Enbridge Gas's business risk has changed significantly beyond the ability of Enbridge Gas to manage it prudently.

IGUA submitted that pending Enbridge Gas completing additional analysis on identifying risks emerging from the energy transition and developing specific mitigation strategies to prudently respond to the risks, it would not be reasonable to allow Enbridge Gas to increase its equity thickness and increase customer costs by \$260 million (over the proposed rate term).¹¹⁴

IGUA noted that increasing the equity thickness to 42% was tantamount to customers paying once to cover those unmitigated risks and then paying again when those unmitigated risks and associated costs crystallize. IGUA submitted that there should be no change made to the equity thickness.

Three Fires Group suggested that the OEB could issue a provisional approval concerning equity thickness pending the outcome of a generic OEB proceeding to review risks emerging from the energy transition.

¹¹⁴ The correct amount is \$266.5 million as noted earlier in this section.

In reply, Enbridge Gas argued that LEI's Canadian comparator peer group is "outdated" in light of a British Columbia Utilities Commission (BCUC) decision in its Generic Cost of Capital proceeding issued on September 5, 2023. In its decision, the BCUC increased the deemed equity thickness of FortisBC Energy Inc.'s (FEI) from 38.5% (set in 2016) to 45%.¹¹⁵ Enbridge Gas documented that the updated data for FEI would increase the average for LEI's Canadian peer group to 40.5%.¹¹⁶

Enbridge Gas submitted that a detailed study of the energy transition impacts on Enbridge Gas, as recommended by Dr. Hopkins, is not required in order to determine whether the criteria of the fair return standard are satisfied.

Enbridge Gas argued that the quantitative analysis undertaken by both LEI and Dr. Cleary was flawed and incomplete; both reports lacked the depth and breadth of the work completed by Concentric. Enbridge Gas disagreed with intervenors that submitted that Enbridge Gas has no problems attracting capital. Enbridge Gas noted that the data shows that Enbridge Gas has borrowed at higher rates than many of its utility peers. Enbridge Gas further argued that the rating agencies, specifically S&P, have expressed concerns with Enbridge Gas's equity thickness and the evidence shows that the company's financial metrics have weakened over time.

Enbridge Gas submitted that Dr. Cleary's approach to measuring risk is overly narrow, focusing solely on Enbridge Gas's ability to earn its allowed return, the company's current and historic credit ratings, and historic and near-term projected credit metrics. Enbridge Gas argued that none of these measures are indicative of an equity investor's required return, which is forward looking and considers both near-term and long-term risks.

Enbridge Gas also dismissed the report and oral testimony of Dr. Hopkins. Enbridge Gas submitted that the BCUC decision regarding FEI, wherein the BCUC concluded that FEI's business risk increased as a result of the energy transition, was inconsistent with Dr. Hopkins's views that government policy and emission reduction targets do not present business and capital risks to Enbridge Gas.¹¹⁷

Enbridge Gas noted that LEI acknowledged that the OEB did not undertake a review of comparable investment standards including considering US comparators for the predecessor utilities in the 2012 proceedings. It was therefore incorrect, according to Enbridge Gas, to assume that the difference between equity thickness and ROE between Canadian and US companies was considered at all by the OEB. Enbridge Gas

¹¹⁵ BCUC Decision and Order, G-236-23, Generic Cost of Capital Proceeding (Stage 1), September 5, 2023.

¹¹⁶ Enbridge Gas Reply Argument, pp. 272-273.

¹¹⁷ Enbridge Gas Reply Argument, p. 291.

submitted that LEI should have undertaken a more thorough analysis of comparable investment standards including analyzing reasons for differences in equity thickness. Enbridge Gas argued that had LEI given any consideration to the US comparators, it would have caused LEI to conclude that the increase in equity thickness should be materially higher than 38%. Furthermore, Enbridge Gas submitted that LEI did not give any reasons as to why the equity thickness of Ontario electric distribution utilities at 40% is or is not relevant to determine the equity thickness of Enbridge Gas. Enbridge Gas submitted that using LEI's approach (even with its flaws) and the revised customer weighted average for Canadian utilities, Enbridge Gas's equity thickness should be no less than 40.5%.

Findings

The OEB approves an increase in Enbridge Gas's equity thickness to 38%.

Enbridge Gas seeks to increase its deemed equity thickness from 36% to 42% based on the assertion that the energy transition has increased its business risk. The difficulty is that Enbridge Gas also took the position that the impact of the energy transition is very small over the same five-year period. Enbridge Gas provided no assessment of the risk from the energy transition, something that the Concentric witness agreed has been underway for some time.¹¹⁸

The energy transition is only one change in business risk since the legacy utility rates were last rebased. When these legacy utilities amalgamated, one of the largest natural gas distribution utilities in North America was created – the largest in Canada. The OEB finds the amalgamation in 2019 is a significant factor in assessing the change in business risk since then.

The OEB concludes that amalgamation has decreased business risk, as described by LEI, and will result in operational efficiencies and economies of scale, enabling Enbridge Gas to leverage its sheer size as a business and combined franchise area covering 98% of natural gas distribution in Ontario.

Enbridge Gas and other parties referred to regulatory decisions from other jurisdictions. As a general proposition, those decisions are of limited value given that they address the business risk of utilities in the context in those jurisdictions, including in relation to how the energy transition is seen to be playing out in those jurisdictions.

The OEB has also considered the evidence and resulting business risk associated with the energy transition. The OEB has also concluded that there is a risk of stranded

¹¹⁸ Oral Hearing Transcript, Vol. 9, pp. 38-40.

assets arising from the energy transition and has taken some steps in this Decision and Order to mitigate that risk in relation to the system access capital expenditures and new connections. The OEB is also directing Enbridge Gas to carry out a risk assessment and to develop an approach to reducing the stranded asset risk in the context of system renewal, to be provided in its next rebasing application.

Considering both a decrease in business risk due to amalgamation, and an increase in business risk due to the energy transition, which is partially mitigated by this Decision and Order, the OEB concludes that there is a net increase in business risk that justifies a modest increase in the deemed equity thickness. The OEB is persuaded by the analysis of LEI and its recommended 38% equity thickness. Enbridge Gas has not met the onus to establish that its ultimate requested increase to 42% is reasonable. In the absence of the risk assessment evidence that Enbridge Gas is directed to develop for its next rebasing application, the OEB denies Enbridge Gas's request. The OEB approves an increase to the deemed equity thickness to 38% at this time. The approved increase in equity thickness will be applied to 2024 rates and will not be phased in.

4 AMALGAMATION AND HARMONIZATION ISSUES

In 2017, Enbridge Gas Distribution's corporate parent, Enbridge Inc., merged with Union Gas's corporate parent, Spectra Energy Corp. Both companies (Enbridge Gas Distribution and Union Gas) had been expected to file rebasing applications for 2019 rates.

Enbridge Gas Distribution and Union Gas filed an application with the OEB to amalgamate in November 2017 (MAADs application).¹¹⁹ The applicants proposed a deferred rebasing period of ten years, pointing to a similar option available to electricity distributors in the OEB's *Handbook for Electricity Distributor and Transmitter Consolidations* (MAADs Handbook).¹²⁰

The current rates application addresses some of the issues that emerged as a result of the amalgamation. This section deals with amalgamation issues, specifically:

- a) whether ratepayers received benefits as a result of the amalgamation
- b) whether ratepayers are responsible for integration costs incurred during the deferred rebasing period
- c) how the balance in the Tax Variance Deferral Account (TVDA) that recorded the tax impacts of integration costs should be disposed of
- d) the proposed harmonized depreciation methodology
- e) the proposed capitalized overheads methodology
- f) how to address overhead capitalization and Union Gas's pre-2017 Actuarial Losses in the Accounting Policy Changes Deferral Account (APCDA)

4.1 Benefits of amalgamation realized in context of a five-year deferred rebasing term

In the MAADs application, the capital investment required for the integration of systems and technology to support the amalgamation was estimated to be between \$50 million and \$250 million to deliver potential cost synergies of between \$350 million and \$750 million over ten years. In its decision, the OEB approved the amalgamation of the two

¹¹⁹ Mergers, acquisitions, amalgamations and divestitures (MAADs).

¹²⁰ EB-2017-0306/0307.

legacy utilities effective January 1, 2019 with a deferred rebasing term of five years, not ten years as proposed.¹²¹

OEB staff noted that capital expenditures related to integration during the five-year deferred rebasing term were \$252 million, at the top end of the range of the estimated investment identified in the MAADs application. The total cumulative savings over the deferred rebasing term is expected to be \$327.6 million. The net savings were retained by Enbridge Gas during the five-year deferral period. Enbridge Gas submitted that annual integration synergies of \$86 million demonstrate that amalgamation will provide ongoing benefits to customers. Beginning in 2024, these annual savings of \$86 million would be reflected in rates.

However, OEB staff noted that operating and maintenance (O&M) costs have consistently increased from 2018 to 2024 as COVID-19 had a substantial impact on operations and costs during this period.

In its submission, QMA recognized the seamless switch to the amalgamated utility with the same level and quality of service as the legacy utilities.

Pollution Probe claimed that the customer benefits produced over the five-year deferral period were lower than expected. Although Enbridge Gas emphasized the \$86 million of sustained efficiencies, Pollution Probe noted that O&M costs have consistently increased from 2018 to 2024, and finding small efficiencies in one area and then proposing higher costs elsewhere defeats the overall purpose of incentive regulation and recognizing amalgamation benefits.

VECC submitted that the claimed amalgamation savings are based on speculation of what costs would have been in the absence of certain initiatives. VECC questioned whether the claimed reductions could be attributed to amalgamation. VECC submitted that the savings are less than \$18 million, not \$86 million per year. Nevertheless, VECC agreed that customers do not appear to be worse off. VECC urged the OEB to ensure that Enbridge Gas does not receive significant consolidation benefits as a result of other proposals in this proceeding.

Findings

The evidence demonstrates that the amalgamation delivered benefits to Enbridge Gas during the deferred rebasing term which are being passed on to ratepayers in 2024. Although some intervenors argued that Enbridge Gas has overstated the savings due to amalgamation, no party submitted that ratepayers are worse off.

¹²¹ EB-2017-0306/0307, Decision and Order, August 30, 2018, p. 22.

4.2 Recovery of Integration-Related Capital Costs

Enbridge Gas spent \$189 million on integration capital projects during the deferred rebasing term, of which \$70 million has already been depreciated. Enbridge Gas requested that the undepreciated net book value of \$119 million be included in the opening 2024 rate base.

Enbridge Gas referenced the OEB's general principle of "benefits follow costs" and submitted that customers should pay the ongoing integration capital costs that will continue to benefit them after rebasing in 2024.

APPrO supported Enbridge Gas's proposal and submitted that the approved five-year deferred rebasing term was insufficient to recover integration related capital costs.

In its submission, OEB staff recommended an alternative to Enbridge Gas's proposal for the OEB's consideration. OEB staff referenced the OEB's MAADs policy which provides the opportunity for electricity distributors to defer rebasing for a period up to ten years following the closing of a consolidation transaction. This deferred rebasing period was intended to enable distributors to fully realize anticipated efficiency gains and retain achieved savings to help offset the costs of the consolidation.¹²²

Since Enbridge Gas received only a five-year deferred rebasing period instead of ten years, OEB staff submitted that Enbridge Gas should be able to include 50% of the net book value of integration capital in the 2024 rate base. Accordingly, OEB staff recommended that Enbridge Gas should be permitted to include \$59.5 million (50% of \$119 million) in the 2024 rate base. Energy Probe, LPMA, and Pollution Probe supported OEB staff's recommendation.

While Energy Probe agreed that the MAADs Decision was clear that O&M costs of integration are not recoverable from utility ratepayers, the decision was silent on capital costs. Energy Probe agreed that integration assets are providing some benefit to ratepayers and accordingly supported the position of OEB staff that 50% of the undepreciated integration capital costs should be added to rate base given the "benefits follow costs" principle. According to LPMA, OEB staff's 50% recommendation recognizes that a portion of the expenditures were integration-related and not recoverable through rates and the remainder of the expenditures were operations-related and recoverable through rates.

¹²² *Handbook to Electricity Distributor and Transmitter Consolidations*, January 19, 2016, pp. 8-9.

Pollution Probe submitted that the OEB could consider OEB staff's recommendation but include a stretch efficiency amount built into the rebasing term to provide ratepayers with permanent efficiencies.

Some parties (CCC, CME, OGVG, SEC and VECC) submitted that the OEB should not approve the addition of the \$119 million to 2024 rate base. These parties submitted that the five-year deferral period approved in MAADs Decision offered Enbridge Gas a reasonable opportunity to recover its transition costs. According to these parties, the OEB's MAADs policy is clear that incremental transaction and integration costs are not generally recoverable through rates. The MAADs policy states that the deferred rebasing period enables distributors to fully realize anticipated efficiency gains from the transaction and retain achieved savings for a period of time to help offset the costs of the transaction. CME argued that it is not the length of time of the rebasing period that is relevant, but whether Enbridge Gas had a fair opportunity to realize anticipated efficiency gains and offset the cost of the transaction. CME submitted that Enbridge Gas has had that opportunity.

SEC stated that Enbridge Gas's focus on the MAADs policy's statement that integration costs are not "generally" recoverable is flawed. While SEC agreed that "generally" does imply that in some exceptional circumstances the OEB may allow recovery, there was nothing exceptional about Enbridge Gas incurring capital and O&M for supporting integration activities. SEC and VECC both argued that the OEB was well aware during the MAADs proceeding that Enbridge Gas was planning to spend on integration-related capital projects and all integration costs might not be recovered in the five-year period, but the OEB made no such carve-out to its policy when it approved the five-year deferred rebasing period. VECC argued that allowing full recovery of integration related costs ignores the MAADs Decision and nullifies its intent.

CCC, CME and SEC further noted that Enbridge Gas had cumulatively over-earned by \$231.4 million between 2019-2022 which is more than sufficient to recover the remaining \$119 million of undepreciated integration capital. CCC submitted that this was in addition to the over-earnings in the period prior to the merger (2014 to 2018). APPrO submitted that conflating Enbridge Gas's actual return on equity during the deferred rebasing period with its integration-related capital spending undermines basic regulatory principles.

SEC disagreed with Enbridge Gas's assertion that if the OEB does not allow the recovery of undepreciated integration capital it will have a "chilling impact on future amalgamations and on utilities committing appropriate capital resources to fully

recognize available amalgamation savings”.¹²³ SEC submitted that Enbridge Gas’s concerns relating to future amalgamations can be raised in the OEB’s MAADs policy review and there is no reason to retroactively apply a new interpretation to benefit Enbridge Gas.

CCC and SEC examined the specific capital expenditures required to integrate the two legacy utilities. CCC and SEC referred to two real estate projects, the construction of the GTA East and West facilities at a total cost of \$67.3 million, submitting that real estate consolidation projects are clear examples of projects that would not have been undertaken in the absence of the amalgamation. CCC and SEC also cited the Contract Market Harmonization project (\$19.2 million) and the General Service Rebasing Changes project (\$17.9 million) that are also driven by amalgamation and are required to implement rate harmonization. SEC also indicated that, at the oral hearing, Enbridge Gas noted that the London Facilities project (\$49.5 million) was similar to the GTA East and West projects – all consolidation projects driven by the amalgamation. CCC and SEC submitted that the OEB should determine that the cost of none of these projects should be recoverable from ratepayers in line with the OEB’s MAADs policy.

In reply, Enbridge Gas argued that there is no principled basis for OEB staff’s 50% recommendation. Enbridge Gas submitted that it is not retaining 50% of the savings from the amalgamation; therefore, it should not absorb 50% of the remaining costs. Enbridge Gas argued that ratepayers are getting 100% of the ongoing benefits of the integration investments and it is appropriate that 100% of the undepreciated costs should be included in rate base.

Enbridge Gas further noted that the MAADs Handbook does not specifically address capital costs. According to Enbridge Gas, requiring a utility to absorb undepreciated capital costs of integration projects at the end of a deferred rebasing term changes how capital costs are recognized from a regulatory accounting perspective.

Enbridge Gas argued that there is no principled basis for relying on Enbridge Gas’s return on equity as a reason that ratepayers can avoid paying for the ongoing cost of assets required to provide ongoing service. Enbridge Gas also noted that customer protection related to overearnings was established through the earnings sharing mechanism during the deferred rebasing term.

Enbridge Gas argued that if a utility is responsible for the undepreciated capital costs it will stop utilities from voluntarily electing a deferred rebasing term of less than ten years.

¹²³ Enbridge Gas Argument-in-Chief, p. 88.

Furthermore, such a direction would have a chilling effect on future amalgamations if a utility's cost obligations for anything referred to as "integration" continue indefinitely.

Enbridge Gas submitted that if it is not allowed to recover the undepreciated integration related capital costs, ratepayers would receive a windfall gain. Enbridge Gas argued that ratepayers would receive the use of integration assets for free at the same time as they receive all the future benefits accruing from integration. This would be an inappropriate departure from the OEB's "benefits follow costs" principle, according to Enbridge Gas.

Findings

The OEB disallows the addition of the undepreciated integration capital in the amount of \$119 million to rate base. This amount shall not be recoverable from ratepayers. The OEB finds this to be consistent with the intent of the OEB's decision in the MAADs proceeding.

In the MAADs proceeding, Enbridge Gas requested a deferred rebasing period of ten years. The OEB in its decision granted a deferred rebasing term of five years and noted that "five years provides a reasonable opportunity for the applicants to recover their transition costs."¹²⁴ The OEB stated that the policy of permitting a deferred rebasing period of up to ten years was adopted to incent the consolidation of electricity distributors.

The OEB granted a deferred rebasing period of five years on the basis that the five years was a reasonable opportunity to recover transition costs. When hearing the MAADs application, the OEB was presented with evidence describing the nature of capital investments and the cost of those investments. After hearing that evidence, the panel clearly turned its mind to the five-year period as a reasonable opportunity to recover those costs during the five years against the savings that would be achieved and retained by the utility.

Enbridge Gas claimed that there is residual ratepayer value of the integration projects in 2024 and beyond. Enbridge Gas also raised the benefits follow costs principle. The OEB agrees that benefits should follow costs, yet the OEB must also consider the impetus for the specific costs incurred. For example, CCC and SEC referenced the GTA East and West facilities at a total cost of \$67.3 million submitting that real estate consolidation projects would not have been undertaken in the absence of the amalgamation. CCC and SEC also identified similar integration projects totaling \$153.9 million. The ongoing use of those buildings may provide benefits to ratepayers, yet the

¹²⁴ EB-2017-0306/0307, Decision and Order, August 30, 2018, p. 22.

cost would not have been incurred in the first place in the absence of amalgamation. The OEB rejects the assertion by Enbridge Gas that there is a windfall gain for customers. In this case, the benefits did follow the costs – Enbridge Gas made capital investments that yielded savings that exceeded the cost of those investments during the deferred rebasing period, savings that it got to keep. To allow some of that capital investment to now be added to the 2024 rate base, despite the MAADs Decision that concluded that a five-year deferral period would be sufficient to recover the cost of those investments with net savings to Enbridge Gas, which indeed occurred, would amount to a windfall to the utility.

Despite the five-year deferral period, Enbridge Gas chose to depreciate these integration capital assets beyond 2023, resulting in a net book value of \$119 million on its regulatory accounting books. That was a choice made by Enbridge Gas. Had Enbridge Gas chosen to fully depreciate its integration capital assets during the deferral period, depreciation expenses would have been higher, and earnings would have been lower than actually recorded from 2019 to 2023, but the savings retained by Enbridge Gas during this period would still exceed the cost of that investment. Capital expenditures related to integration during the five-year deferred rebasing term were \$252 million. Enbridge Gas indicated that it expected to achieve a total of \$327.6 million in savings for the 2019 to 2023 period.¹²⁵

Table 2 – Integration Savings as Achieved by Area

Line No.	Particulars (\$ millions)	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>
		Actual (a)	Actual (b)	Actual (c)	Estimate (d)	Bridge Year (e)
	<u>O&M Savings</u>					
1	Business Development & Regulatory	6.8	9.6	10.4	10.4	10.4
2	Customer Care	5.5	6.6	7.5	22.5	22.5
3	Distribution Operations	6.3	9.8	17.3	16.8	16.8
4	Energy Services	2.6	5.6	5.9	5.9	5.9
5	Engineering & STO	5.2	9.0	11.6	11.6	11.8
6	Central Functions	3.9	9.1	15.7	15.8	15.8
7	Other	2.0	2.7	2.8	2.8	2.8
8	Total Annual Savings	32.2	52.4	71.2	85.8	86.0

These savings are retained by Enbridge Gas and are more than sufficient to cover integration capital investments. The MAADs Decision has worked as intended, and in this case, five years were sufficient for Enbridge Gas to recover all transition and

¹²⁵ Exhibit 1, Tab 9, Schedule 1, p. 5.

integration-related costs. There is no basis to add any amount of the integration capital investment to the 2024 rate base.

Since the savings achieved as a result of amalgamation have exceeded the integration capital investments, with net savings being retained by Enbridge Gas during the deferred rebasing period, Enbridge Gas has not established a reasonable basis to support its request to include any integration capital in the 2024 rate base.

A few intervenors proposed that future integration projects should be funded by Enbridge Gas's shareholder. There may be additional costs incurred after 2024 for harmonization proposals that will be heard and decided in Phase 2 and Phase 3 of this proceeding. These would not be considered integration projects since the five-year deferral period has now ended.

4.3 Tax Variance Deferral Account

In the MAADs Decision, the OEB retained the Tax Variance Deferral Account (TVDA) for the Union Gas legacy areas and implemented it for the Enbridge Gas Distribution rate zone.¹²⁶ In Enbridge Gas's 2019 rates proceeding, the OEB required Enbridge Gas to follow the direction issued by the OEB in its July 25, 2019 letter.¹²⁷ In that letter, the OEB provided accounting direction to regulated utilities regarding Bill C-97. Bill C-97 provides for accelerated capital cost allowance (accelerated CCA) deductions for eligible capital assets acquired after November 20, 2018, also known as the Accelerated Investment Incentive. CCA is the portion of the capital cost of depreciable property that is deductible for tax purposes each year.

In its decision in Enbridge Gas's 2019 Deferral and Variance Account Disposition proceeding,¹²⁸ the OEB determined that 100% of the 2019 balances in the TVDA related to accelerated CCA were to be disposed as a credit (refund) to customers.

Enbridge Gas proposed to clear the forecast credit balance in the TVDA of \$6.8 million plus interest costs of \$0.5 million for a total of \$7.3 million. The balance represents 100% of the accelerated CCA impacts resulting from integration capital additions which occurred from 2020 to 2023.

Since the credit balance in the TVDA relates to integration capital projects completed during the deferred rebasing term, Enbridge Gas submitted that the benefit of the credit

¹²⁶ EB-2017-0306/0307.

¹²⁷ OEB Letter [Re: Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance](#), July 25, 2019.

¹²⁸ EB-2020-0134.

balance should accrue to the party (ratepayers or utility) who will be paying for the undepreciated cost of the integration capital projects on a go-forward basis.

As OEB staff recommended that Enbridge Gas be permitted to add 50% of the net book value of integration capital to the 2024 rate base, OEB staff submitted that 50% of the forecast credit balance in the TVDA of \$7.3 million (inclusive of interest) should be credited to ratepayers.

LPMA submitted that if all of the integration capital or a portion of it is included in rate base, then ratepayers should accordingly receive 100% of the balance in the TVDA or a portion of it as a credit.

FRPO and SEC opposed the inclusion of any integration capital in the 2024 rate base and accordingly submitted that the \$7.3 million of accelerated CCA should benefit Enbridge Gas's shareholders.

In reply, Enbridge Gas submitted that if the OEB does not approve 100% of the inclusion of integration capital in the 2024 rate base, then Enbridge Gas's shareholders should receive a corresponding portion of the credit balance in the TVDA related to the disallowed recovery from customers.

Findings

Given the OEB's decision to deny the proposed inclusion of integration capital in the 2024 rate base, the entire balance related to integration capital projects in the TVDA shall be disposed of in favour of Enbridge Gas.

4.4 Depreciation Policy & Overhead Capitalization

4.4.1 Depreciation

Enbridge Gas proposed a harmonized 2024 depreciation expense of \$879 million, representing an increase of \$141.9 million from the forecasted 2024 depreciation expense of \$734.1 million, using the previously OEB-approved depreciation methodologies and rates. The OEB-approved settlement proposal reduced the 2024 depreciation expense to \$866.2 million.¹²⁹

Enbridge Gas proposed to harmonize the depreciation methodologies and rates utilized by the legacy utilities of Enbridge Gas Distribution and Union Gas. In support of its proposed harmonized depreciation methodology, Enbridge Gas filed a study by Concentric Energy Advisors (Concentric) and requested approval for the following:

¹²⁹ Enbridge Gas Reply Argument, p. 202.

- **Account Harmonization:** the harmonization of certain former Enbridge Gas Distribution and Union Gas assets into common accounts
- **Harmonized Depreciation Procedure:** the use of the Equal Life Group (ELG) procedure for the amalgamated utility, in place of the Average Life Group (ALG) procedure previously used by Enbridge Gas Distribution and the Generation Arrangement procedure previously used by Union Gas
- **Harmonized Net Salvage Calculation:** the use of the Constant Dollar Net Salvage (CDNS) method at a credit-adjusted risk-free rate (CARF) of 3.75%. Enbridge Gas Distribution was previously approved to use the CDNS method and Union Gas was previously approved to use the Traditional Method
- **Updated Asset Life Parameters:** the use of asset life parameters/survivor curves and net salvage parameters recommended by Concentric in its 2021 depreciation study filed with the OEB after the amalgamation and subsequently updated in this proceeding

OEB staff presented expert evidence on depreciation by InterGroup Consultants Ltd. (InterGroup). IGUA presented expert evidence on depreciation by Emrydia Consulting Corporation (Emrydia).

InterGroup and Emrydia each assessed Concentric's evidence on Enbridge Gas's depreciation proposals and expressed their expert opinion in their respective reports. All depreciation related evidence was tested and compared through the interrogatory process and testimony at the oral hearing. The main areas in which these experts did not agree with Enbridge Gas and Concentric are as follows:

- **Depreciation Procedure:** Neither InterGroup nor Emrydia supported the proposed change to the ELG procedure. Both recommended the ALG procedure be used.
- **Asset Life Parameters:** InterGroup disagreed with Concentric's proposed asset life parameters for six accounts,¹³⁰ while Emrydia disagreed with Concentric's proposed asset life parameters for ten accounts, including two of the accounts addressed by InterGroup.¹³¹

¹³⁰ Exhibit M1, pp. 7-8.

¹³¹ Exhibit M5, pp. 8-9.

- **Net Salvage:**

- Net Salvage Method: InterGroup and Emrydia supported Concentric's use of the CDNS method. However, both experts took issue with Concentric's CDNS calculation.
- Net Salvage Parameters: InterGroup and Emrydia each disagreed with Concentric's proposed net salvage parameters for six accounts.¹³²
- Net Salvage Discount Rate: Emrydia supported the use of the weighted average cost of capital (WACC) of 6.03%. InterGroup recommended a CARF of 4.88% updated from 3.75% as of July 25, 2023.¹³³

During the oral phase of the proceeding, many depreciation-related scenarios were filed and the various recommendations of the three experts were compared. In all scenarios, the calculated 2024 depreciation expense excluded the impact of the OEB-approved settlement proposal.

In reply, Enbridge Gas provided the 2024 depreciation expense calculations comparing the \$879.0 million proposed harmonized depreciation expense to possible 2024 expenses using various recommended depreciation procedures and asset life parameters from Concentric, OEB staff and IGUA. Table 3 set out in the Asset Life Parameters sub-section below, provides this comparison assuming Concentric's CDNS calculation and net salvage parameters, not OEB staff's or IGUA's recommendations.¹³⁴

OEB staff submitted that the 2024 depreciation expense would be \$727.6 million, based on InterGroup's recommendations (ALG, asset life parameters, its CDNS methodology, net salvage parameters), or \$151.4 million lower than Enbridge Gas's proposed 2024 depreciation expense.

Depreciation Procedure

Submissions focused on the ELG and ALG depreciation procedures. The concept of adding an Economic Planning Horizon was raised, to set a terminal truncation date for assets and the depreciation expense so that assets would be fully recovered by the terminal date. Concentric, InterGroup and Emrydia agreed that an Economic Planning Horizon is not appropriate at this time.¹³⁵ The Units of Production depreciation procedure was also raised during the proceeding as an option for future consideration, a

¹³² Exhibit M1, pp. 7-8.

¹³³ Exhibit J17.5.

¹³⁴ Enbridge Gas Reply Argument p. 203.

¹³⁵ Enbridge Gas, Argument-in-Chief, p. 198-199.

means to depreciate assets based on production volume rather than asset life. While many parties recommended the OEB consider Units of Production in the future, no expert witness proposed, and no party recommended, utilizing Units of Production at this time.

Enbridge Gas stated that the ELG procedure modestly accelerated depreciation expense as the 2024 depreciation expense under the ELG procedure is \$83.4 million higher than the ALG procedure. Concentric testified that the use of the ELG procedure enhances the generational equity to all customers and is particularly appropriate given the energy transition issues. Concentric noted that the use of the ELG procedure is key to minimizing the risk of under-recovery of the capital assets and costs and decreasing the risk of stranded asset costs. Furthermore, Enbridge Gas stated that if there is a material risk of declining throughput in future years, a more accelerated recovery of depreciation should be undertaken.

Concentric indicated that the ELG procedure is recognized as the most precise procedure by depreciation authorities, using more complex mathematical calculations relative to the ALG procedure. Concentric claimed that the ELG procedure was the best available match to the historical procedures approved for Union Gas.

Enbridge Gas submitted that InterGroup and Emrydia did not identify any fault with the ELG procedure that would warrant not considering it. Enbridge Gas claimed that InterGroup and Emrydia also failed to appropriately include energy transition issues in their analysis.

OEB staff and IGUA submitted that while InterGroup and Emrydia considered energy transition issues to be real and present, the experts agreed that the ELG procedure itself was not designed to address energy transition issues. InterGroup and Emrydia indicated that neither ELG nor ALG were sufficiently nuanced to properly address energy transition concerns.

There was a wide range of views on whether the energy transition should be considered in the context of depreciation as summarized below:

- Energy transition should not be considered in this proceeding and the ALG procedure should be used. Accelerated depreciation may be appropriate in the future once further studies on depreciation considering the energy transition are completed
- Maintain the status quo until further studies on depreciation and the energy transition are completed

- The energy transition should be considered in this proceeding, and the ELG procedure should be used temporarily until further studies are completed
- There is no need to change the depreciation procedure as hybrid heat pumps, renewable natural gas, hydrogen and re-purposing of Enbridge Gas's assets will effectively mitigate any need for accelerated depreciation

Some parties (OEB staff, Energy Probe, LPMA, City of Kitchener, APPrO, CME, FRPO, VECC and IGUA) supported the use of the ALG procedure noting that ALG continues to be the most commonly used depreciation procedure in North America.¹³⁶ Specifically, IGUA submitted that increasing depreciation expense adds risk by creating more problems and inequities if based on untested assertions regarding generic future asset risk.¹³⁷ CME characterized ELG as a blunt instrument, front-loading depreciation for all asset classes in equal measure, without consideration of which assets will be more likely impacted by the energy transition.

IGUA submitted that ratemaking is not solely about mathematical purity. In the case of depreciation, for the past decade, the ALG procedure has resulted in the just and reasonable assignment of asset cost recovery. APPrO pointed to a recent decision by the Manitoba Public Utilities Board that rejected Manitoba Hydro's proposal to transition from ALG to ELG on the basis that ELG would result in unnecessarily high depreciation rates in the near term that are not just and reasonable.¹³⁸

Three Fires Group and GFN recommended that the OEB make any order relating to depreciation interim pending the outcome of a generic proceeding on risks of climate change and the energy transition. OGVG proposed a hybrid procedure, applying ELG or ALG depending on whether the asset was distribution, storage, transmission or general plant. Pollution Probe submitted that the amortization period should be truncated to a maximum of 15 years for all new capital commissioned starting in 2024. GEC and Environmental Defence suggested the ELG procedure be used on an interim basis, until further study is completed on Units of Production. GEC stated that Units of Production would match depreciation expense to the value customers receive, and it can be adjusted as more information on the energy transition is known.

In reply, Enbridge Gas reiterated that there was a consensus among parties that energy transition is not a myth and that foundational changes to the natural gas distribution business are inevitable. Enbridge Gas claimed that ELG is a good first step towards addressing the energy transition and no party argued that ALG is a step towards

¹³⁶ OEB staff Submission, p. 78; APPrO Submission, p. 34.

¹³⁷ IGUA Submission, p. 35.

¹³⁸ Manitoba Public Utilities Board, Order No. 101/23, August 24, 2023, pp. 12-13.

addressing the energy transition. Furthermore, no party supported the notion that lowering depreciation rates was an appropriate response to the energy transition. In contrast, Enbridge Gas submitted that accelerating depreciation modestly at this time is appropriate. Enbridge Gas argued that if the status quo is continued or depreciation expense declines relative to the status quo, the impact on future ratepayers will almost certainly be an even higher depreciation expense than would be the case if the ELG procedure was approved. Enbridge Gas responded to submissions regarding other depreciation methodologies raised during the proceeding such as Economic Planning Horizon and Units of Production and characterized its proposed increase in depreciation expense as modest in comparison to the expense that would result from applying Economic Planning Horizon or the Units of Production procedures.

Enbridge Gas also noted that parties appeared to agree that a number of questions need to be considered and answered, such as the appropriate denominator for the Units of Production and the applicable dates and assets which should be subject to an Economic Planning Horizon.

Findings

The OEB approves the proposed harmonization of certain assets into common accounts. The OEB also approves the ALG depreciation procedure for the amalgamated utility. The OEB finds merit in maintaining some consistency in procedure among the legacy and harmonized utilities. The OEB previously approved ALG for the legacy Enbridge Gas Distribution and a Generation Arrangement for Union Gas. However, Concentric testified that it would be impossible to adopt Union Gas's Generation Arrangement as a harmonized procedure to be applied to the legacy Enbridge Gas Distribution's assets.

Starting from first principles, asset depreciation for the purpose of ratemaking is based on establishing a schedule for the recovery of depreciation expense that matches the used and useful life of an asset. Typically, depreciation expense is recovered based on the average life of a portfolio of assets. This reduces intergenerational inequity among ratepayers because they will always be paying for the depreciation expense for the assets that are used to provide them with service over the life of those assets.

Depreciation policy is already based on risk – each asset class captures the risk of failure of the assets to establish an average life for the class based on the engineering estimate of the useful life of those assets and the actual experience with those assets. Adding consideration of the risk of stranded asset costs arising from the energy transition is not a fundamental methodological change. If the principle is that depreciation expense is recovered over the used and useful life of an asset, and the used and useful life of an asset is shortened as a result of ratepayers leaving the gas

system so that assets are no longer used or become underutilized before they reach the end of their physical life, this needs to be addressed in the utility's depreciation policy (see for example, the Alberta Utility Commission's treatment of stranded asset risk.)¹³⁹

This is a matter of prudence. It is not enough to say that if an investment was considered prudent when assets first went into rate base, then the utility is entitled to fully recover the depreciation expense regardless of whether the assets remain used and useful. The utility has an obligation to monitor and manage risk prudently.

Enbridge Gas has identified a risk of stranded asset costs due to the energy transition but has not assessed that risk, including whether to address it in its depreciation policy proposal.

The OEB will not approve Enbridge Gas's proposal to change its depreciation procedure at this time. While Enbridge Gas's proposal to change to the ELG methodology results in some acceleration in the recovery of the depreciation expense, the OEB does not accept the assertion that this proposal was responsive to the risk of stranded asset costs, since Enbridge Gas has not provided any meaningful assessment of that risk in its application. Further, the OEB is persuaded by the testimony of the InterGroup and Emrydia witnesses that neither the ELG nor ALG procedures were designed to address the energy transition risk.

Enbridge Gas needs to carry out a proper assessment of risk and determine the extent to which that risk should be addressed in its depreciation policy. Given that, this is not the time to change to a new methodology.

Currently there are two legacy methodologies, the ALG procedure used by Enbridge Gas Distribution and the Generation Arrangement procedure used by Union Gas. While the OEB is of the view that now is not the time to move to a new procedure, it is appropriate to harmonize the approach to be taken by Enbridge Gas on the basis of the ALG procedure.

¹³⁹ *FortisAlberta Inc v. Alberta (Utilities Commission)*, 2015 ABCA 295.

Asset Life Parameters

The table below summarizes the accounts and recommendations on asset life parameters where the depreciation experts were not aligned.¹⁴⁰

Table 3 – Proposed Asset Life Parameters

Asset Account Numbers and Description		Current Approved Parameters – EGD/Union	Concentric Proposed Parameters	OEB Staff Supported InterGroup Proposed Parameters (1)	IGUA Supported Emrydia Proposed Parameters (2)
456.00	UNDERGROUND STORAGE PLANT – COMPRESSOR EQUIPMENT	40-R2 (EGD) 35-R2.5 (Union)	40-R4	44-R4	44-R4(3)
457.00	UNDERGROUND STORAGE PLANT – REGULATING AND MEASURING EQUIPMENT	30-R1.5 (EGD) 30-R3 (Union)	35-R3	40-R2.5	40-R2.5(3)
464.00	TRANSMISSION – EQUIPMENT		30- L0.5 (50-S4 original proposed (8))	50-S4 (4)	
465.00	TRANSMISSION PLANT – MAINS	55-R4 (Union)	60-R4	70-R4	70-R4(3)
466.00	TRANSMISSION PLANT – COMPRESSOR EQUIPMENT	30-S3 (Union)	30-R4	Did not agree with Emrydia's proposal (6)	37-R4
472.35	DISTRIBUTION - STRUCTURES AND IMPROVEMENTS – MAINWAY		Truncation date of 2027 (2024original proposed (8))		Truncation date of 2028 (5)
473.01	DISTRIBUTION PLANT – SERVICES – METAL	45-L1.5 (EGD) 50-R1.5 (Union)	40-S0.5 (45-S1 original proposal (8))	45-S1 (4, 6)	50-L1
473.02	DISTRIBUTION PLANT – SERVICES – PLASTIC	45-L1.5 (EGD) 55-R3 (Union)	55-S3	Did not agree with Emrydia's proposal (6)	60-S3

¹⁴⁰ Enbridge Gas Reply Argument, p. 224; OEB staff Submission, p. 84; IGUA Submission, pp. 37-38.

474.00	DISTRIBUTION PLANT – REGULATORS	20-SQ (Union)	25-SQ	No opinion (6)	45-S1
475.21	DISTRIBUTION PLANT – MAINS – COATED & WRAPPED	61-R3 (EGD) 55-R4 (Union)	55-R3	61-R3 (70-R3 also considered)	65-R3 (IGUA noted 65 or 70 year life is more reasonable than 55 (7))
475.30	DISTRIBUTION PLANT – MAINS – PLASTIC	65-R3 (EGD) 60-L2 (Union)	60-R4	65-R3 (70-R4 also considered)	70-R2
478.00	DISTRIBUTION PLANT – METERS	15-S2.5 (EGD) 25-L1.5 (Union)	15-S2.5	15 years too short, 25 years too long (6)	25-L1.5

Notes:

- 1) OEB staff submission, p.84
- 2) IGUA submission, p.37-41
- 3) IGUA endorsed InterGroup's recommendations
- 4) OEB staff submission, p.86 – OEB staff did not support Concentric's revision for Account 464 and 473.01
- 5) Oral Hearing Transcript, Vol.18, p.70
- 6) Oral Hearing Transcript, Vol.17, pp.174, 177, 178
- 7) IGUA submission, p.39
- 8) Updated in the capital update

InterGroup estimated the impact of adopting ALG with its recommended asset life parameters would be a \$79.4 million decrease to the \$879 million proposed depreciation expense,¹⁴¹ whereas Concentric estimated the impact to be a decrease of \$110.1 million.¹⁴² In its submission, OEB staff suggested that Concentric's recommended asset lives for these accounts may be shorter than InterGroup's because Concentric, in applying its judgement, factored in energy transition considerations.

IGUA estimated the impact of adopting ALG with its supported Emrydia and InterGroup's asset life parameters would be a \$125 million decrease to the \$879 million proposed depreciation expense,¹⁴³ whereas Concentric estimated the impact to be a decrease of \$299.9 million.¹⁴⁴ OEB staff and IGUA argued that the InterGroup and

¹⁴¹ OEB staff Submission, p. 85.

¹⁴² Equal to proposed depreciation of \$879 million minus depreciation using InterGroup's asset life parameters of \$768.9 million (based on Enbridge Gas Reply Argument, p.203, Table 2 depreciation – OEB Staff Lives and Survivor Curves under ALG).

¹⁴³ IGUA submission, pp. 39-40.

¹⁴⁴ Equal to proposed depreciation of \$879 million minus depreciation using IGUA's supported Emrydia and certain InterGroup asset life parameters of \$579.1 million (based on Enbridge Gas Reply Argument, p.203, Table 2 depreciation – IGUA Lives and Survivor Curves under ALG).

Emrydia reports provided a detailed, specific and carefully reasoned analysis of the applicable underlying retirement data, peer analysis and reported management discussions, which formed the basis of their recommendations. When asked to compare recommendations during the oral hearing, Emrydia indicated that it generally agreed or accepted InterGroup's asset life parameter recommendations.¹⁴⁵

LPMA and VECC supported InterGroup's proposed asset life parameters while SEC, CME, FRPO agreed with the submissions provided by IGUA.

In reply, Enbridge Gas argued that the asset lives and survivor curves recommended by InterGroup's and Emrydia would reduce the depreciation recovery significantly below current recovery based on the historical inputs. Enbridge Gas stated that some submissions were contradictory, arguing to lengthen average service lives despite the energy transition risk, showing that the positions taken by intervenors are driven solely by a desire to reduce depreciation expense and rates.

Enbridge Gas stated that in the event that the OEB directs a customer attachment revenue horizon that is shorter than 30 years, Enbridge Gas will need to consider the implications on depreciation because there will be a substantial mismatch in customer attachment revenue horizon and depreciation assumptions.

Findings

The OEB reviewed the 12 asset classes in question, considering the range of proposals for each asset class and the overall range of proposals for all 12 asset classes. While Enbridge Gas submitted that the recommendations made by Concentric included consideration of the energy transition, it is not clear what impact that had on Concentric's recommendations. Elsewhere in this Decision and Order, the OEB has identified the need for Enbridge Gas to carry out a proper assessment of risk and determine the extent to which that risk should be addressed in its depreciation policy. Enbridge Gas has been directed to address this and other stranded risk mitigation options in its next rebasing application.

The OEB prefers the analysis provided by InterGroup and Emrydia. The OEB approves the changes to the asset life parameters proposed by InterGroup in Table 3 and supported by Emrydia during the oral proceeding.

The OEB notes Enbridge Gas's concern regarding a potential mismatch in revenue horizons for system access calculations and depreciation assumptions. This mismatch

¹⁴⁵ N.M5.Staff-1. For Account 475.3 Distribution Mains – Plastics, Emrydia continues to prefer its own recommendation of Iowa curve 70-R2.

has existed since E.B.O. 188 was issued in 1998 because industrial and contract customers have used a shorter revenue horizon than small volume customers.

Depreciation assumptions for new customer connections for small volume customers will not be relevant under the zero revenue horizon that the OEB is requiring as of January 1, 2025, as the cost of these new connections will not go into rate base.

Net Salvage Methodology

Net salvage value, also referred to as site restoration costs, is the cost to remove, decommission and restore affected sites less amounts received for selling off remaining pieces. Concentric, InterGroup and Emrydia were supportive of maintaining the CDNS method for determining net salvage for the amalgamated utility, which was utilized by Enbridge Gas Distribution. Union Gas utilized the Traditional Method.

However, InterGroup and Emrydia raised concerns with the way Concentric calculated net salvage under CDNS.¹⁴⁶ In particular, both InterGroup and Emrydia indicated that there was double counting of inflation in Concentric's CDNS methodology. InterGroup also stated that there was an offsetting error where there was no accretion of the present value of the double inflated salvage amount.¹⁴⁷

The CDNS method includes a discount rate that is used as an input. Concentric proposed a CARF rate of 3.75%, InterGroup proposed a CARF rate of 4.88% and Emrydia proposed the WACC of 6.03%.

OEB staff supported InterGroup's recommended calculation methodology of CDNS, the most updated CARF rate of 4.88% and InterGroup's net salvage parameters. OEB staff noted that while it agreed WACC may be appropriate in principle, the most current CARF rate of 4.48% would also be appropriate. Using the CARF of 4.48% and InterGroup's CDNS methodology and net salvage parameters resulted in a net salvage value of \$54 million, which is relatively close to the forecasted site restoration costs of \$55 million to \$62 million for 2024.¹⁴⁸ OEB staff indicated that there was a \$346 million surplus of net salvage that could be reduced during the rate-setting period.

However, OEB staff submitted that it would not be opposed to using the Traditional Method of determining net salvage as an alternative in conjunction with InterGroup's net salvage parameters if the OEB had concerns with the CDNS method. The Traditional Method estimates net salvage as a percentage of the original cost. It attempts to forecast "pay as you go" and evenly distributes the cost in nominal dollars, or the year of

¹⁴⁶ Oral Hearing Transcript, Vol. 18, pp. 11-13.

¹⁴⁷ Oral Hearing Transcript, Vol. 17, p. 180.

¹⁴⁸ OEB staff Submission, p. 93.

expenditure. OEB staff submitted that use of the Traditional Method would avoid mixing recommendations on various aspects of net salvage, which could lead to undesired results such as a net salvage accrual that is too low. LPMA, OGVG and VECC generally agreed with OEB staff's submission.

IGUA supported the use of InterGroup's CDNS calculation methodology. Alternatively, IGUA supported setting the 2024 net salvage provision to cover the net salvage forecast to be incurred in 2024. This approach would ensure that the net salvage accrual of approximately \$1.6 billion to date would remain intact through 2024. IGUA recommended the CDNS discount rate be equal to WACC. IGUA added that using WACC as the discount rate reflects that the value to future customers for the net salvage contributions made by current customers, is the avoided Enbridge Gas rate base. SEC, FRPO and CME generally agreed with IGUA's submission on net salvage.

Table 4 – 2024 Depreciation Expense with Different Net Salvage Options¹⁴⁹

Net Salvage Options	Enbridge Gas Asset Life Parameters		OEB staff Asset Life Parameters		IGUA Asset Life Parameters	
	ELG	ALG	ELG	ALG	ELG	ALG
CDNS @ 3.75% Concentric proposal	\$879.0 Proposed	\$795.6	\$826.6	\$768.9	\$665.0	\$579.1
CDNS @ 4.48% InterGroup proposal	n/a	n/a	\$791.9	\$711.4	\$631.8	\$550.6
CDNS @ 6.03% Emrydia proposal	n/a	n/a	\$656.2	\$668.3	\$588.7	\$513.6
Traditional Method	\$1,034.1	\$935.7	\$979.7	\$878.8	\$745.6	\$650.3

Enbridge Gas supported Concentric's CDNS methodology as it has been approved and successfully used for years. Enbridge Gas argued that neither InterGroup nor Emrydia provided details or explained how InterGroup's CDNS method is correct and would arrive at the appropriate provision. In addition, Enbridge Gas noted that Concentric will be undertaking the final depreciation calculations following the issuance of the OEB's decision. Enbridge Gas questioned how Concentric can be called upon to credibly apply the methodologies used by InterGroup and Emrydia when the methodologies are foreign to it.

¹⁴⁹ Reproduced from Enbridge Gas Reply Argument, p. 203. The Reply Argument includes the details of the calculations.

Regarding the discount rate, Enbridge Gas noted that a 4.48% discount rate would reduce the net salvage recovery compared to 3.75%. Enbridge Gas submitted that using a 6.03% discount rate equal to the WACC greatly reduces the net salvage provision and penalizes future ratepayers to the benefit of current ratepayers.

Like OEB staff, Enbridge Gas also stated that it is not opposed to the Traditional Method utilized by the legacy Union Gas. The Traditional Method might be one means of ensuring that the actual net salvage provision is sufficient to cover forecast annual removal costs and to add to the future site restoration costs accrual balance.

Enbridge Gas submitted that the OEB should not assume that there is a forecast surplus of \$346 million as referenced by OEB staff, as the ultimate costs required to complete future site restoration is not known.

Net Salvage Parameters

Net salvage is usually expressed as a negative value to reflect that it costs more to decommission and remove plant than what can be recovered by selling off residual pieces. In terms of the depreciation provision, a lower negative net salvage figure will generate a lower depreciation expense whereas a higher negative figure will generate a higher depreciation expense.

InterGroup proposed six net salvage parameters that were different than those proposed by Concentric. The net salvage parameters in question are shown in the table below.¹⁵⁰

¹⁵⁰ Enbridge Gas Reply Argument, p. 251

Table 5 – Proposed Net Salvage Parameters

Asset Account Numbers and Description		Current Approved Parameters - EGD (CDNS)	Current Approved Parameters - Union (Traditional)	Concentric Proposed Parameters (Traditional)	Concentric Proposed Parameters (CDNS)	InterGroup Proposed Parameters (Traditional) (1)
465.00	TRANSMISSION PLANT - MAINS	N/A	(15%)	(25%)	(12%)	(15%)
466.00	TRANSMISSION PLANT - COMPRESSOR EQUIPMENT	N/A	(5%)	(10%)	(7%)	(5%)
467.00	TRANSMISSION PLANT - MEASURING AND REGULATING EQUIPMENT	N/A	(10%)	(25%)	(15%)	(10%)
473.02	DISTRIBUTION PLANT - SERVICES - PLASTIC	(22%)	(40%)	(50%)	(26%)	(40%)
475.21	DISTRIBUTION PLANT - MAINS - COATED & WRAPPED	(51%)	(60%)	(80%)	(42%)	(40%)
475.30	DISTRIBUTION PLANT - MAINS - PLASTIC	(38%)	(40%)	(80%)	(38%)	(25%)

Notes:

- 1) OEB staff submission, p.95

Enbridge Gas's proposed net salvage accrual is \$96.3 million.¹⁵¹ In its submission, OEB staff noted that using all of InterGroup's recommendations, net salvage under InterGroup's CDNS calculation method at a discount rate of 3.75% would result in a net salvage accrual of \$59.8 million, or \$54 million using a discount rate of 4.48%.¹⁵² In reply, Enbridge Gas quantified the impact of InterGroup's recommendations to be a

¹⁵¹ Enbridge Gas Reply Argument, p.251.

¹⁵² OEB staff Submission p.96.

\$80.7 million reduction to the net salvage provision, which would prevent Enbridge Gas from recovering the full amount of its forecast annual costs.

Enbridge Gas noted that Union Gas was approved to use the Traditional Method for net salvage and the net salvage parameter under the Traditional Method cannot be compared to that under the CDNS method. Enbridge Gas submitted that InterGroup's proposed net salvage parameters result in either a previously approved net salvage parameter being continued or a reduction in the net salvage parameter relative to the previously approved figures. Furthermore, Enbridge Gas stated that InterGroup's recommended net salvage parameters were expressed under the Traditional Method. To be compared to Concentric's net salvage parameters under CDNS, Enbridge Gas explained that InterGroup's recommended net salvage parameters would need to be converted and would reduce the net salvage recommended by InterGroup even further. Enbridge Gas also emphasized that if a discount rate higher than 3.75% is used for the CDNS method, there will be a further material reduction to the net salvage provision, which could result in inadequate recovery to cover annual removal costs and add nothing to the site restoration costs accrual balance.

Findings

The OEB approves the Traditional Method for calculating net salvage for the amalgamated utility. The Traditional Method was utilized by legacy Union Gas and all experts agreed upon the calculation, unlike the CDNS method, and considered the Traditional Method a reasonable alternative to the CDNS method used by Enbridge Gas.

In considering these previously approved methods, the OEB is of the view that the Traditional Method is appropriate for the amalgamated utility. It is comprehensive and it avoids the constant dollar calculations at issue for the CDNS method.

The OEB agrees with OEB staff's submission that the Traditional Method avoids mixing recommendations on various aspects of net salvage, which could lead to undesired results such as a net salvage accrual that is too low.

The OEB also approves InterGroup's proposed net salvage parameters in Table 5. The OEB notes that four of the six life parameters are the same as the legacy Union Gas, while the other two are higher (less negative). In contrast, all six life parameters proposed by Concentric are lower (more negative). The OEB prefers the stability of InterGroup's recommendations relative to the legacy rates, until the future studies and reporting discussed in the next section are filed by Enbridge Gas.

Future Studies and Reporting

Some parties (OEB staff, IGUA, LPMA and SEC) submitted that depreciation can be used as a tool to address the energy transition, referencing InterGroup and Emrydia's testimony that the depreciation procedure should be purposefully designed to address the energy transition.¹⁵³ Most parties (OEB staff, CCC, CME, Environmental Defence, FRPO, GEC, IGUA, City of Kitchener, LPMA and SEC) submitted that Enbridge Gas should be required to provide depreciation studies that consider the energy transition, including but not limited to an Economic Planning Horizon, Units of Production procedure, and assets most likely to be impacted by the energy transition as suggested by Dr. Hopkins.

Emrydia recommended that Enbridge Gas be directed to complete a study on the ten largest accounts to assess the appropriateness of net salvage parameters.¹⁵⁴ The objective would be to provide recent data by asset account type to refine Enbridge Gas's net salvage cost estimates in the future. Each depreciation witness was afforded the opportunity to propose ten accounts for such a study. IGUA and OEB staff supported the ten accounts proposed by InterGroup for the purposes of the study.

In reply, Enbridge Gas agreed to consider other depreciation methodologies such as Economic Planning Horizon and Units of Production, and to track and study ten accounts for net salvage costs for the purposes of its next rebasing application.

Findings

For its next rebasing application, Enbridge Gas is directed to study options to ensure its depreciation policy addresses the risk of stranded asset costs appropriately. These options must encompass all reasonable alternative approaches, including the Units of Production approach. Enbridge Gas shall determine whether to propose changes to its approach to depreciation to account for the impact of the energy transition, recognizing that a failure to act prudently in relation to the risk of stranded assets will have an impact on the ability to keep those assets in rate base.

The OEB directs Enbridge Gas to track and study the ten accounts proposed by InterGroup with respect to net salvage. The ten accounts are as follows:¹⁵⁵

¹⁵³ SEC Submission, p. 95; OEB staff Submission, p. 76; City of Kitchener Submission, p. 7.

¹⁵⁴ IGUA Submission, p. 43.

¹⁵⁵ OEB staff Submission, p. 97.

- 473.01 Services Metal
- 473.02 Services Plastic
- 475.21 Mains Coated and Wrapped
- 475.3 Mains Plastic
- 477.00 Measuring and Regulating Equipment
- 465.00 Mains
- 466.00 Compressors
- 467.00 Measuring and Regulating Equipment
- 453.00 Wells
- 456.00 Compressors

Site Restoration Costs and Segregated Funds

To date, Enbridge Gas has accumulated net site restoration costs of \$1.6 billion.¹⁵⁶ The \$1.6 billion represents the presumed amount recovered in rates through depreciation, based on the salvage component applied to actual gross plant values which reduces rate base. Subsequent to these initial entries, gross plant values are adjusted to deduct actual removal and restoration costs.

Enbridge Gas explained that the \$1.6 billion collected to date has been used for operations, which reduces the capital (both debt and equity) that needs to be raised. Enbridge Gas estimated that the lower rate base has resulted in customers saving approximately \$1 billion between 2013 to 2022.¹⁵⁷ Enbridge Gas also records an unfunded regulatory liability associated with site restoration costs on its audited financial statements.¹⁵⁸ Based on Enbridge Gas's proposal, forecast net salvage accrual is \$96.3 million for 2024.¹⁵⁹ Concentric estimated the cost to decommission all of Enbridge Gas's assets currently in service to be approximately \$6.9 billion.

The OEB previously directed Enbridge Gas Distribution to examine the issue of whether a segregated fund should be established as a means of protecting ratepayers for site restoration costs recovered in rates.¹⁶⁰ In the current proceeding, Enbridge Gas maintained that the establishment of a segregated fund is not appropriate at this time. Enbridge Gas conducted a jurisdictional review and did not find any examples of utilities in North America that used a segregated fund. Enbridge Gas further noted that a segregated fund would be costly to set up and operate, and there would be many tax complications.

¹⁵⁶ Enbridge Gas, Argument-in-Chief, p. 185.

¹⁵⁷ Exhibit J17.10.

¹⁵⁸ Exhibit I.1.8-Staff 17.

¹⁵⁹ Exhibit J17.5, Table 1.

¹⁶⁰ EB-2012-0459, Decision with Reasons, July 17, 2014, p. 84.

No parties (and none of the depreciation experts) supported the establishment of a segregated fund in this proceeding. However, many parties submitted that the need for a segregated fund should be reassessed at Enbridge Gas's next rebasing.¹⁶¹ IGUA's depreciation expert, Emrydia, suggested that if the status quo was maintained, then to increase transparency Enbridge Gas should be required to begin separately tracking and reporting annual changes in the net salvage liability.

Findings

The OEB is concerned with the lack of transparency associated with the \$1.6 billion collected to date through rates. Currently, the OEB has no line of sight to the \$1.6 billion balance and underlying calculations. The fact that money has been collected in rates for the purpose of site restoration but used for other purposes means that site restoration remains an unfunded liability and is recorded as such in the company's financial statements. In the context of the energy transition, this unfunded liability is even more of a concern.

While a segregated fund may not be necessary at this time, tracking and reporting to validate the \$1.6 billion is overdue. The OEB is taking steps to address the unfunded liability.

The OEB approves the inclusion of site restoration costs in the revenue requirement for 2024. Enbridge Gas proposed \$96.3 million, but this will need to be recalculated in light of other findings in this Decision and Order. The money that will be collected in rates starting in 2024 will be used to start funding the liability, rather than using it to offset other costs, as has been the practice to date. A tracking account could be established to record the amounts collected through rates and to track actual spending related to site restoration. Any excess amounts would be tracked in the account and not be used to offset other costs. Enbridge Gas shall address the details of its proposed approach in the draft rate order process, including investment of this money when it is not being used for site restoration.

To address the existing unfunded liability, the OEB directs Enbridge Gas to file evidence in Phase 2 indicating how the annual amounts are calculated and to provide a long-term forecast of the total funds required to pay for site restoration costs. The forecast may be aggregated for the amalgamated utility for 2025, with the expectation that further segmentation may be warranted based on the ten asset accounts to be tracked.

¹⁶¹ OEB staff Submission, p.100; OGVG Submission, p.19; Environmental Defence Submission, p. 52.

4.5.2 Overhead Capitalization

Enbridge Gas requested approval for a harmonized overhead capitalization methodology to reflect the amalgamated operations of Enbridge Gas. Enbridge Gas implemented the harmonized overhead methodology effective January 1, 2020, and recorded the impact of the change in methodology in the Accounting Policy Changes Deferral Account (APCDA). The proposed harmonized overhead methodology and disposition of balances recorded in the APCDA are Phase 1 issues. Overhead capitalization implications for ICM applications will be considered in Phase 2 of this proceeding.

The proposed harmonized overhead method would allocate an overhead rate to plant assets, based on forecasted capital additions by asset class. Enbridge Gas stated that this approach was used by the legacy Union Gas and aligns capitalized overhead to asset classes and the projects they support in a given year. Enbridge Gas claimed its harmonized proposal was administratively practical and less costly than other alternatives. The indirect capitalization rate previously approved for Union Gas was 14.8%.¹⁶²

In its application, Enbridge Gas proposed \$310.5 million in capitalized overhead be included in the 2024 rate base based on a capitalization rate of 23.8%.¹⁶³ Enbridge Gas stated that the proposed methodology relative to the legacy approved methodologies would increase the capitalization rate from 22.7% to 23.8% and the capitalized overheads by \$15.4 million in 2024.¹⁶⁴ Enbridge Gas believed this difference was simply a function of the accuracy of the proposed overhead capitalization methodology. As a result of the OEB-approved settlement proposal related to other issues, proposed capitalized overheads have been reduced from \$310.5 million to \$292 million.¹⁶⁵ Parties did not settle on a final capitalized overhead amount as it would be dependent on the unsettled issues of the harmonized overhead capitalization methodology and the capital budget for 2024.

Enbridge Gas stated that if the \$310 million was not approved for inclusion in the approved capital budget, the difference would need to be added to O&M as an expense and when tax implications are included, this would increase the revenue requirement by \$348 million.¹⁶⁶

¹⁶² EB-2018-0305, Undertaking JT1.7.

¹⁶³ Exhibit 2, Tab 4, Schedule 2, p. 17.

¹⁶⁴ Enbridge Gas, Argument-in-Chief, p. 128.

¹⁶⁵ Enbridge Gas, Argument-in-Chief, p. 118.

¹⁶⁶ Exhibit J16.3.

Enbridge Gas stated that overhead costs are costs that can be linked to the creation of capital but cannot be directly associated with any particular asset or project. The harmonized overhead capitalization methodology is predominantly based on historical methods approved by the OEB and uses four cost categories: Operations Costs, Business Costs, Shared Services Costs, and Pension and Benefits Costs. Each cost category has a cost driver applied, typically determined by the nature of the underlying cost relationship or linkage to capital activity. The only new form of cost causality proposed in the harmonized overhead capitalization methodology is the addition of geographic diversity, which was added to accommodate the scale of the amalgamated utility. Enbridge Gas retained Ernst & Young to review and provide recommendations on the development of its overhead capitalization policy.

Operations costs are allocated based on actual spend to determine the following year's budgeted overhead capitalization rate. As a result, the capitalized amount would not be expected to change based on a prospective update to the capital program. Enbridge Gas stated that O&M costs indirectly supporting capital projects would not respond immediately, even to a material shift in the capital program, given that most of the reductions would be expected to impact direct costs for these projects.

Parties took issue with two aspects of Enbridge Gas's proposed capitalization methodology, namely indirect costs and the capitalization rate.

Indirect Costs

OEB staff submitted that Enbridge Gas should be required to quantify, on a best-efforts basis, indirect costs that would not be eligible for capitalization without regulatory approval as per US Generally Accounted Accepted Principles (USGAAP). LPMA supported this requirement. OEB staff questioned as to why Enbridge Gas should be allowed to continue to capitalize indirect overheads just because it is allowed under USGAAP. OEB staff noted that the majority of the utilities regulated by the OEB have adopted modified International Financial Reporting Standards (MIFRS) and indirect overhead costs cannot be capitalized under MIFRS. OEB staff also noted that if Enbridge Gas is required to adopt IFRS in the near future, it would not be able to capitalize indirect costs. FRPO, Pollution Probe, SEC, VECC submitted that Enbridge Gas should not be allowed to capitalize indirect costs.

LPMA submitted that the OEB should approve Enbridge Gas's proposed overhead capitalization methodology as no other methodology has been sufficiently tested in this proceeding.

VECC stated that Enbridge Gas's practice is the exception to that of other regulated utilities in Ontario as Hydro One reports under USGAAP with a capitalization rate of 8%

to 9%. Pollution Probe submitted that expensing indirect overheads will avoid the bloating of capital with unrelated costs and reduce risks related to stranded asset costs.

In reply, Enbridge Gas submitted that while it is prepared to attempt on a best effort basis to provide a high-level estimate of direct costs included in the indirect overhead capitalization figure, the amount may not be sufficiently material to warrant the exercise.

Enbridge Gas acknowledged that it is temporarily reporting under USGAAP until the earlier of January 1, 2027, or when there is a rate-regulated standard issued by the International Accounting Standards Board. Until then, Enbridge Gas submitted that it should continue the practice of capitalizing indirect overheads for principled reasons.

Capitalization Rates

Enbridge Gas applies a derived capitalization rate to projects. The proposed harmonized rate is 23.8% for 2024.

OEB staff argued that the operation regions capitalization rate should be revised to a three-year rolling average that incorporates actual and forecast information. Currently, the rate is based only on the most recent year's actual spending at the time the budget is determined. For the purposes of setting 2024 rates, OEB staff suggested that the capitalization rate should reflect data from 2022, 2023 (actual and forecast) and 2024 as approved by the OEB, instead of only reflecting 2021 actuals. Further, if the OEB approved a revision to the proposed capitalization methodology, OEB staff suggested that the change should be reflected in the APCDA starting in 2020.

SEC submitted that Enbridge Gas should be required to adopt an overhead capitalization methodology that updates the rates throughout the year to better reflect the actual mix of capital and operations work, similar to Hydro One's methodology. SEC stated that too much of the proposed overhead capitalization methodology is based on historical spending, and not reflecting the costs incurred and the capital work undertaken.

Energy Probe argued that Enbridge Gas has not provided adequate evidence to justify its increase in capitalization of indirect overheads relative to the legacy utilities. Energy Probe submitted that the Ernst & Young study did not conclude that the proposed harmonization capitalization methodology was appropriate.

In reply, Enbridge Gas stated that the proposed capitalization rate for the operations cost component of the overhead capitalization methodology is 35%, which is a decrease from the capitalization rate generated by historical methods.

Enbridge Gas acknowledged that 2022 actuals are available now. It calculated the impact of using 2022 data or an average of 2021 and 2022 data to determine capitalization rates, and the impact is less than \$1 million, which suggests that there is no real benefit in making the change proposed by OEB staff. Enbridge Gas claimed that it would be a “monumental exercise” to review and separate out comparable operations cost data from Enbridge Gas Distribution and Union Gas; therefore, any change should be applied on a prospective basis.

Enbridge Gas also noted that it is unable to determine what Hydro One’s process actually is. Enbridge Gas noted that it performs a monthly variance analysis on all applicable accounts, which allows for a reasonableness assessment in comparison to budget and considers the capitalization rate applied. Enbridge Gas stated that if Hydro One does the same monthly review, then its proposed overhead capitalization methodology already achieves the purported benefits of what SEC proposes.

Findings

The OEB approves the proposed overhead harmonization methodology, except for the capitalization of indirect overheads. The OEB does not approve the proposal to capitalize \$292 million in 2024. However, the OEB recognizes that a requirement to expense the entire \$292 million in 2024 would have a large impact on 2024 rates. Therefore, the OEB directs Enbridge Gas to expense \$50 million of the indirect overhead amount in 2024, calculate the revenue requirement impact and capitalize the remaining \$242 million. In subsequent years, during the IRM term, Enbridge Gas shall reduce the remaining capitalized amount by expensing a further \$50 million in each year. For example, in 2025, Enbridge Gas will expense a further \$50 million, reducing the capitalized amount of \$242 million to \$192 million.

In its next rebasing application, Enbridge Gas shall include its proposal to reduce any remaining capitalized indirect overhead balance to zero.

Enbridge Gas is temporarily reporting under USGAAP, which can only persist until the earlier of January 1, 2027, or a rate-regulated standard issued by the International Accounting Standards Board. It is only through an exception to USGAAP through ASC 980 that a regulator, such as the OEB, can allow the capitalization of indirect overheads. Otherwise, indirect costs must be expensed.

It is short sighted to continue the practice of capitalizing indirect overheads at the proposed level in the face of a transition to IFRS accounting, knowing the revenue requirement impact of expensing \$292 million in the transition year, and the resulting rate shock to customers. Furthermore, continuing with the proposed capitalization rate amplifies the stranded asset risk.

An implementation plan is required to migrate the remaining \$242 million balance of capitalized indirect overheads to O&M. As part of the IRM issue to be addressed in Phase 2 of this proceeding, Enbridge Gas shall file a proposal to reduce the capitalized indirect overhead balance by \$50 million in each year of the IRM term and expense it as O&M. In that proposal, Enbridge Gas could consider a mechanism similar to the capital pass-through mechanism approved in Union Gas's last IRM framework.¹⁶⁷

Other than the \$242 million addressed above, Enbridge Gas is no longer permitted to capitalize any further indirect overheads. It would appear unfair to afford one energy distributor a competitive ratemaking advantage based on the option of reporting under USGAAP rather than MIFRS, where this option is not available to those utilities.

Further, the underlying cost in 2024 may decrease as Enbridge Gas rationalizes and sizes its indirect overhead functions to align with its pending updated Asset Management Plan. This Decision and Order may impact 2024 actual capital spending, including the 17.0% reduction in the proposed overall capital expenditure budget.

Capital Reduction Impact on Gross O&M

Energy Probe, Pollution Probe, SEC and VECC argued that if the OEB does not approve Enbridge Gas's proposed capital expenditures, there should be an adjustment to gross O&M. Energy Probe submitted that Enbridge Gas should find an equivalent amount of savings in its O&M expenditures. Pollution Probe submitted that there should be an adjustment to O&M: (i) related to costs that could be capitalized when Enbridge Gas starts to track these costs in alignment with accounting standards; (ii) for an expected decrease in capital work expected; and (iii) an efficiency factor related to improving indirect overheads. Pollution Probe stated that indirect overheads should also be reduced by a similar factor as that proposed to the capital budget for 2024. SEC stated that if Enbridge Gas expects to do less capital work than forecast, the costs that support that work should be reduced correspondingly, especially in the context of the energy transition. SEC stated that the relationship may not be perfectly linear, but it simply cannot be said that there is no relationship. SEC noted that this relationship exists for the costs of business units such as Major Projects, Engineering, Asset Management, System Improvement, Integrity & IMS, the Operational Group and even Shared Services to some extent.

LPMA acknowledged that the overhead capitalization amount would not be impacted in the event of a small change to capital expenditures. However, LPMA submitted that if the OEB makes significant reductions to the capital budget, it would be reasonable to

¹⁶⁷ EB-2013-0202, Settlement Agreement, July 31, 2013, pp. 29-35.

assume that there would be a material change to the overhead capitalization amount that is added to O&M.

For 2024, Enbridge Gas stated that it already has its existing complement of management and employees in place. Furthermore, while a material reduction in the capital budget for 2024 would likely lead to the cancellation of certain projects in 2024, this reduction would primarily be implemented by the avoidance or cancellation of third-party contractor expenses. Enbridge Gas further noted that it is foreseeable that a material decrease in the capital budget could correspondingly increase the demands for maintenance related activities that need to be undertaken by Enbridge Gas, using internal resources that would be expensed as opposed to capitalized. This supports the need to retain current staffing levels or perhaps even increase staffing levels. However, Enbridge Gas stated that should it no longer require the same complement of staff to support capital activities, it would result in severance and reorganizational costs which were not included in the O&M budget.

Findings

The OEB will not make any changes to gross O&M for 2024, which includes indirect overheads proposed to be capitalized. While the reduction in the 2024 capital budget should reduce 2024 O&M related to capital project support, the requirement for more emphasis on monitoring, maintenance and repair of assets would increase O&M requirements. The OEB has insufficient evidence to determine the extent to which these would offset one another, and in turn, determine to what extent any adjustment would be appropriate.

Capitalization Study

Some parties (LPMA, VECC, CCC, and SEC) submitted that Enbridge Gas should be required to do an independent review to investigate alternate capitalization methodologies used by other utilities in North America. Some of these parties noted that Ernst & Young was retained to assist in the development of Enbridge Gas's overhead capitalization methodology but did not provide an assessment of it.

In reply, Enbridge Gas submitted that while it is prepared to engage an independent third-party expert to undertake an assessment of its overhead capitalization methodology at the next rebasing, it does not believe there is any value in undertaking a benchmarking study as details and mechanics used by other utilities are generally not publicly available.

Findings

The OEB finds that, as a next step to better understand Enbridge Gas's overhead capitalization methodology, Enbridge Gas shall engage an independent third-party expert to undertake an assessment of its overhead capitalization methodology, to be filed as part of its next rebasing application.

4.5 Accounting Policy Changes Deferral Account

The APCDA was created in the MAADs proceeding to record the impact of accounting changes as a result of the amalgamation that impact the revenue requirement. In this proceeding, Enbridge Gas proposed to dispose of the forecast December 31, 2023 balance of a debit amount of \$140.2 million in the APCDA, including forecast interest to December 31, 2023. The components of the \$140.2 million balance in the account are shown in the table below.¹⁶⁸

Table 6
Accounting Policy Changes Deferral Account

	\$M
Pension and OPEB Expense – Unamortized Pre-2017 Actuarial Losses and Prior Service Costs	156.0
Amortized Gas Supply Storage and Transportation costs	62.1
Interest during construction	1.5
Capitalization vs. Expense	-11.7
Depreciation expense	-31.2
Overhead capitalization	-36.5
Net APCDA balance for disposition	140.2

As part of the 2019 Deferral Account Disposition proceeding (EB-2020-0134) settlement proposal, the intervenors and Enbridge Gas agreed to postpone the review, allocation and disposition of balances in the APCDA until the end of Enbridge Gas's current deferred rebasing term.¹⁶⁹

¹⁶⁸ Enbridge Gas, Argument-in-Chief, p. 245.

¹⁶⁹ EB-2020-0134 Settlement Proposal, January 5, 2021, p. 10.

There were two items of dispute in this account. The first is related to the overhead capitalization methodology during the deferred rebasing term and the second item is Pension and Other Post Employment Benefit (OPEB) costs, specifically the former Union Gas's pre-2017 amortized actuarial gains/losses.

Overhead Capitalization

Since no balances accumulated during the deferred rebasing period were cleared, OEB staff submitted that if the OEB approves a change to Enbridge Gas's proposed overhead capitalization methodology, then the same methodology should be applied to the balances in the Overhead Capitalization line of the APCDA. OEB staff noted that Enbridge Gas's harmonized methodology was implemented in 2020 and the difference between the harmonized and historic methodologies have been recorded in the APCDA. If OEB staff's recommendation to calculate Operation Costs capitalization rates using a three-year rolling average was adopted, then OEB staff submitted that the same methodology should be reflected in calculating the balance of the APCDA starting in 2020. LPMA agreed with OEB staff's submission on this issue.

In reply, Enbridge Gas reiterated that its proposed overhead capitalization methodology was appropriate and therefore no changes with respect to overhead capitalization in the APCDA were required. Even if the overhead capitalization methodology was changed, Enbridge Gas argued that it would not be appropriate to apply changes to the overhead capitalization methodology on a retroactive basis, back to 2020, as suggested by OEB staff and LPMA. Enbridge Gas submitted that making changes retroactively seems to suggest that Enbridge Gas should have adopted the recommended approach at the time of harmonization of overhead capitalization policies even though the updated approach has nothing to do with harmonization.

Enbridge Gas further submitted that OEB staff and LPMA's argument is not consistent with the terms of the APCDA. The description of the APCDA, as noted in the MAADs Decision, is to record the impact of any accounting changes that affect revenue requirement, which are required as a result of the amalgamation of Enbridge Gas Distribution and Union Gas. Enbridge Gas submitted that it made changes to its overhead capitalization policy to harmonize approaches of Enbridge Gas Distribution and Union Gas. Enbridge Gas noted that the APCDA records the revenue requirement implications of the change during the time when the change has been in place.

Enbridge Gas argued that the changes proposed by OEB staff are incremental changes to the harmonized approach and these changes should not be considered to have been (or expected to have been) in place since 2020.

Findings

Given the OEB's decision on the harmonized overhead capitalization methodology, and the decision to require \$50 million of indirect overhead costs to be expensed as O&M in 2024, Enbridge Gas, if necessary, shall adjust the balances in Table 6, for the purpose of clearing this account. The change in the OEB's exception to USGAAP ASC 980 will be applied on a go-forward basis starting in 2024. The OEB's longer-term objective is for all indirect overheads to be expensed annually as incurred.

Pre-2017 Union Unamortized Actuarial Gains/Losses

Within the APCDA, the Pension & OPEB expense balance of \$156 million represents the remaining unamortized Union rate zone's pre-2017 pension and OPEB actuarial gains/losses.¹⁷⁰ Actuarial gains/losses arise from the difference between the actual and expected rate of return on plan assets for that period (funded pension plans) and from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount and salary inflation experience.¹⁷¹ Actuarial gains/losses are amortized and included in pension and OPEB expense (i.e., net periodic benefit cost) when certain criteria are met.¹⁷² Cumulative unamortized net actuarial gains and losses and prior service costs are presented as a component of Accumulated Other Comprehensive Income (AOCI) on the balance sheet (in the Consolidated Statements of Changes in Equity).¹⁷³

Prior to amalgamation, both Union Gas and Enbridge Gas Distribution recovered the amortized portion of actuarial gains/losses as part of the forecast pension and OPEB expense on an accrual basis in base rates. In the current proceeding, the OEB-approved settlement proposal includes an agreement that the accrual-based pension and OPEB expense is included in the agreed upon 2024 O&M budget. Therefore, Enbridge Gas would recover the amortized actuarial gains/losses in 2024.¹⁷⁴

For financial reporting purposes under USGAAP, Union Gas did not recognize a regulatory asset for its unamortized gains/losses but reflected it in AOCI.¹⁷⁵ Upon the amalgamation of Enbridge Inc. and Spectra Energy, there was no change to this treatment in Union Gas's 2018 financial statements. However, for Enbridge Inc.'s (the parent of Enbridge Gas) financial statements, pushdown accounting required Enbridge

¹⁷⁰ Enbridge Gas, Argument-in-Chief, p. 245.

¹⁷¹ Exhibit 1, Tab 8, Schedule 1, Attachment 1, p.17 – Enbridge Gas 2020 audited financial statements.

¹⁷² For example, when the cumulative unrecognized net actuarial gains and losses is in excess of 10% of the greater of accrued benefit obligation or the fair value of the plan assets, over the expected average remaining service life of the active employee group.

¹⁷³ Exhibit 1, Tab 8, Schedule 1, Attachment 1, p.17 – Enbridge Gas 2020 audited financial statements.

¹⁷⁴ Decision on Settlement Proposal, Aug. 17, 2023, Schedule A, Exhibit O1, Tab 1, Schedule 1, p. 32.

¹⁷⁵ Exhibit JT3.31, Attachment 1.

Inc. to write off Union Gas's unamortized actuarial gains/losses as of the 2017 acquisition date to goodwill because there was no identifiable asset (as Union Gas did not previously record a regulatory asset for its unamortized actuarial gains/losses in its financial statements) to allocate to the purchase price.¹⁷⁶ Subsequently, with the establishment of the APCDA,¹⁷⁷ the pre-2017 Union Gas unamortized gains/losses were transferred to Enbridge Gas's APCDA, a regulatory asset, in 2019. Accordingly, Enbridge Inc. reflected that regulatory asset in its 2019 financial statements.

OEB staff was not opposed to the proposed recovery of Union Gas's pre-2017 unamortized actuarial gains/losses. OEB staff submitted that the substance of the issue had not changed after the amalgamation and historically, both legacy utilities have recovered amortized actuarial gains/losses as part of their pension and OPEB expenses. However, OEB staff argued that the reduction should be equal to Union Gas's actual unamortized actuarial gains/losses for 2019 to 2023 net of the amortization that was embedded in base rates and already recovered for the same period. This would result in a reduction of \$80.2 million. Accordingly, OEB staff submitted that Enbridge Gas should be allowed to recover \$75.8 million from ratepayers (\$156 million - \$80.2 million). LPMA supported OEB staff's submission.

Some parties (CME, OGVG, SEC and VECC) opposed the recovery of the \$156 million. SEC submitted that the price paid by Enbridge Inc. to acquire Spectra Energy, with an 11.5% premium to the then-current share price, implicitly considered Union Gas's pre-2017 actuarial losses. On the closing date of the transaction, Enbridge Inc. complied with the relevant USGAAP accounting standards and wrote off \$250 million gross (\$185 million net of deferred taxes) of Union Gas's pre-2017 actuarial losses, which previously resided in AOCI on its balance sheet. If \$156 million is now approved for recovery, it would amount to a windfall gain for Enbridge Gas's shareholders, paid for by Enbridge Gas's ratepayers. According to SEC, it was the amalgamation of the parents (Enbridge Inc. and Spectra Energy) that necessitated the write-off, not the amalgamation between Enbridge Gas Distribution and Union Gas. SEC also argued that if ratepayers were required to pay the gross amounts, it would not be fair that Enbridge Gas gets the deferred tax benefit. SEC submitted that the remaining deferred tax balance should be applied against the balance in the APCDA before any amount is approved for recovery.

CME claimed that allowing Enbridge Gas to recover the actuarial losses in the APCDA would allow Enbridge Inc. to gain twice: first through a lower purchase price for Spectra Energy and second through a recovery from ratepayers. OGVG added that Enbridge Gas's shareholder has already been compensated for the value of the actuarial losses

¹⁷⁶ *Ibid.*

¹⁷⁷ APCDA was established in the Union Gas and Enbridge Gas Distribution MAADs Decision and Order EB-2017-0306/EB-2017-0307, August 30, 2018, amended September 17, 2018.

through the purchase price it paid for Union Gas and therefore it should not be allowed to recover Union Gas's pre-2017 actuarial losses in rates.

VECC noted that the establishment of the APCDA relates to the Union Gas pre-2017 actuarial losses and should be considered as a cost of amalgamation. Accordingly, the amount related to Union pre-2017 actuarial losses should not be recoverable from ratepayers.

In reply, Enbridge Gas maintained that the purchase price and valuation of shares did not involve a detailed review of the individual assets, liabilities, and equity balances of each of the Spectra Energy entities, including Union Gas. Enbridge Gas submitted that there is no conclusive evidence that the Union Gas pensionable receivable was accounted for in the purchase price.

Enbridge Gas maintained that the merger of Enbridge Inc. and Spectra Energy had no impact and the Union Gas pension receivable amount had always been recognized on the balance sheet. Union Gas continued to draw down the amount in a manner and quantum identical to the pre-amalgamation pension accounting basis.

Enbridge Gas also disputed intervenors' claims that recovery of the pre-2017 actuarial losses would be a windfall for Enbridge Gas. On the contrary, Enbridge Gas argued that ratepayers would receive a windfall if it is unable to recover the amount that is based on a mistaken theory that the amalgamation price extinguished the obligation of ratepayers. Enbridge Gas submitted that in the normal course of business, there is no debate that ratepayers pay towards a utility's pension costs (calculated on an accrual basis).

Enbridge Gas also disputed OEB staff's position that Union Gas's pre-2017 actuarial losses should be adjusted by amounts recovered through rates during the IRM term. Enbridge Gas argued that just because there was a specific amount included in Union Gas's 2013 base rates related to pension costs, the corresponding amount should notionally be applied to accrual-based pension costs each year.

As explained by Enbridge Gas's expert witness on pension plan design administration and reporting, Ben Ukonga from Mercer, the basis upon which Enbridge Gas has been amortizing amounts to drawdown the APCDA asset since 2017 is calculated by Mercer with the amortization amount updated annually by Mercer based on changes to Enbridge Gas's actuarial valuation. In accordance with the accounting standard,

cumulative unrecognized gains and losses are charged to the income statement each year through the net periodic benefit cost.¹⁷⁸

According to Enbridge Gas, the argument to reduce Union Gas's pension receivable is not only at odds with the way that pension accounting is performed but is also at odds with the principles of incentive regulation where rates are decoupled from costs.

Enbridge Gas submitted that if the pension receivable balance is reduced, it would amount to retroactive ratemaking. The financial results for the years 2013 to 2022 are complete, and rates have been set and recovered for those years. Enbridge Gas argued that reaching back to recapture earnings from prior years is not fair or appropriate.

Regarding SEC's suggestion that the amount should be expressed as the net balance including the remaining deferred tax benefit, rather than as the gross amount, Enbridge Gas explained that amounts recovered through deferral accounts are typically settled on a gross basis.

Findings

The OEB denies Enbridge Gas's proposed recovery of \$156 million of Pension & OPEB expenses as recorded in the APCDA for the pre-2017 Union unamortized actuarial gains/losses.

The OEB considered the sequence of events and in particular, the OEB's intent for the APCDA.

Prior to the Enbridge Inc. and Spectra Energy merger, Union Gas's unamortized actuarial gains and losses were recorded in AOCI in Union Gas and Spectra Energy's audited financial statements. Upon the merger, Enbridge Inc. was required to write off Union Gas's unamortized gains and losses to goodwill in accordance with ASC 805 – Business Combinations under USGAAP. Enbridge Gas stated that ASC 805 did not contemplate ASC 980 – Regulated Operations and Enbridge Inc. failed to recognize the amount as a regulatory asset. However, the recognition of a regulatory asset under ASC 980 relies on probable recovery and the disposition of the amount recorded in the APCDA is at the regulator's discretion. Furthermore, the pre-2017 Union Gas's unamortized actuarial gains and losses were not recorded as a deferred asset until 2018, after the amount had been included in goodwill as part of the prior transaction between the parent companies. The APCDA was subsequently established in 2019 during the MAADs proceeding. The amount in question was then transferred to the APCDA in Enbridge Gas's audited financial statements and identified as a regulatory

¹⁷⁸ Enbridge Gas Reply Argument, p. 320.

asset in Enbridge Inc.'s audited financial statements. This does not qualify as an accounting policy change that Enbridge Gas can rely on to record an amount that was written off as goodwill. Quite the opposite. Enbridge Gas submitted that it has consistently followed the methodology for determining accrual-based pension costs, underpinning Union Gas's 2013 OEB-approved rates to draw down the pension receivable balance each year for its Mercer actuarial valuation. This position was reiterated in its reply submission: "the methodology for determining the accrual based expense was employed consistently."¹⁷⁹

The OEB finds that Enbridge Gas's \$156 million entry in the APCDA was not consistent with the intent of the regulatory account. The OEB finds that the \$156 million was not the result of an accounting policy change after January 1, 2019. The APCDA was not a subsequent opportunity for Enbridge Gas to recharacterize \$156 million recorded as goodwill in 2018 as a regulatory asset in 2019. Further, goodwill should not have been included in a regulatory asset since goodwill is not recoverable in rates.

¹⁷⁹ Enbridge Gas Reply Argument, pp. 316-317.

5 OTHER ISSUES

5.1 Response to relevant OEB directions and commitments from previous proceedings

OEB staff submitted that Enbridge Gas appropriately responded to all relevant OEB directions and commitments made from previous proceedings as noted in Exhibit 1, Tab 13, Schedule 1 of the evidence. LPMA made a similar submission on this issue.

Pollution Probe raised the concern that Enbridge Gas is not implementing the OEB's IRP Decision and related IRP Framework as intended.¹⁸⁰ Pollution Probe recommended that the OEB consider options to ensure that the IRP technical working group is proactively included in all activities where IRP is considered. Pollution Probe further recommended that the OEB require Enbridge Gas to undertake a consolidated review by the IRP technical working group of all proposed projects requiring leave to construct and that Enbridge Gas must file the consolidated IRP technical working group comments with all leave to construct applications.

In reply, Enbridge Gas submitted that Pollution Probe's submissions regarding the work of the IRP technical working group were out of scope for this proceeding.

Findings

The OEB is satisfied that Enbridge Gas has appropriately responded to relevant OEB directions and commitments from previous proceedings. The OEB notes that concerns related to the IRP Framework may be addressed in Phase 2 of this proceeding, when the OEB considers the issue of incentive ratemaking mechanisms in the context of the energy transition.

5.2 Other Revenues

In the OEB-approved settlement proposal, parties agreed to Enbridge Gas's other revenue forecast, subject to two exceptions:

- There was no agreement on how Enbridge Gas's dispositions of property in 2024 and subsequent years should be included in the other revenue forecast
- There was no agreement on the appropriate treatment of the Natural Gas Vehicle Program

¹⁸⁰ EB-2020-0091, Decision and Order, Integrated Resource Planning Proposal, July 22, 2021.

The Natural Gas Vehicle Program was one of Enbridge Gas's safe bet actions, as indicated in the Energy Transition section of this Decision and Order.

5.2.1 Disposition of Property

Enbridge Gas's proposed forecast of other revenue excluded any forecast of property disposition gains or losses. Enbridge Gas submitted that land (but not buildings) associated with property dispositions are not depreciable assets for which ratepayers have borne a depreciation expense. As a result, sharing of the property disposition proceeds with ratepayers is not required by regulatory or legal principles. However, Enbridge Gas agreed to include proceeds from the sale of land that had been included in rate base as part of other income to be shared with ratepayers. Enbridge Gas indicated that the accounting would depend upon any earnings sharing framework to be addressed in Phase 2 of this proceeding.

Enbridge Gas noted that property dispositions are infrequent, uncertain, and not part of Enbridge Gas's normal course of business; therefore, no revenues from property dispositions should be included in the 2024 other revenue forecast. Enbridge Gas forecasted one disposition in 2024 with estimated capital proceeds of \$6.3 million.¹⁸¹

OEB staff supported Enbridge Gas's proposal to not include any amounts related to property disposition gains or losses in its 2024 other revenues forecast. OEB staff agreed with Enbridge Gas that there is considerable uncertainty regarding the timing and proceeds related to any property sales. OEB staff recommended the establishment of a deferral account to track any proceeds from property sales over the course of any approved IRM rate term with any balances to be considered in the future. This would enable the nature of the individual properties and reasons for the sales to be explored. CCC, LPMA and SEC supported OEB staff's submission on this issue.

SEC noted that Enbridge Gas only referred to gains or losses allocated to accumulated depreciation but did not address the proceeds that are related to the net book value of the building. SEC submitted that the proceeds allocated to any buildings should be credited to depreciation unless Enbridge Gas also credits those amounts separately, not just from the rate base. Otherwise, SEC argued that ratepayers would inappropriately continue to pay for those assets through depreciation even though they have been sold.

SEC agreed that land is non-depreciable, but it is included in rate base. SEC noted that it would be unfair to ratepayers to pay for the cost of capital on the value of the land in rate base, if ratepayers do not share in any of the gains of disposition. SEC submitted that Enbridge Gas's proposal was unfair. Accordingly, SEC submitted that 100% of the

¹⁸¹ Exhibit I.2.6-SEC-137, updated July 6, 2023.

proceeds from the disposition of buildings and 50% of the net gains (or losses) from the disposition of land should be credited to ratepayers. In the event that the land is replaced with other land to be used for utility purposes, 100% of the appreciation of value of the land should be credited to ratepayers.

In reply, Enbridge Gas argued that no deferral account is required to track and share proceeds from the sale of property. Enbridge Gas noted that for 2024, only one property is expected to be sold for approximately \$6 million. In addition, it would require significant administrative effort to establish, record and review a deferral account for just a single year according to Enbridge Gas. Enbridge Gas noted that many of the OEB proceedings in which land-related proceeds have been shared with ratepayers have been determined by way of settlement rather than the OEB's direct determination.

For future years of the proposed IRM term (2025 to 2028), Enbridge Gas proposed that any gains/losses from property disposition would be subject to sharing with customers under any approved earnings sharing mechanism (ESM). Enbridge Gas noted that historically, property dispositions during the IRM term have been treated within the ESM calculation.

In the event that the OEB decides to establish a deferral account to track property dispositions for 2024 or for the full IRM term, Enbridge Gas submitted that property dispositions should be shared 50/50 between Enbridge Gas and ratepayers. Establishing a 50/50 allocation according to Enbridge Gas creates certainty and avoids future debates about the nature of a particular transaction.

Enbridge Gas further clarified that the sharing of gains/losses relates to land and not buildings. Enbridge Gas noted that ratepayers already receive 100% of the benefits from the disposition of buildings through the adjustment to accumulated depreciation.

Findings

The OEB approves the establishment of a deferral account to track any proceeds from property dispositions with the objective that non-depreciable property dispositions be shared 50/50 between Enbridge Gas and ratepayers, and 100% of the benefits from depreciable property dispositions continue to accrue to ratepayers.

There is OEB precedent for approving similar deferral accounts to capture property dispositions for other utilities during an IRM term.¹⁸² The OEB agrees with OEB staff and intervenors that there is uncertainty around the timing and prices of property dispositions and the regulatory considerations may be unique to each property. This

¹⁸² EB-2019-0022/EB-2019-0031, Decision and Rate Order, January 23, 2020, pp. 17-19.

deferral account for Enbridge Gas will capture all properties, land and buildings, that are expected to be sold during the IRM term.

The deferral account shall be established for the 2024 Test Year and will apply for the entire rate term that is approved by the OEB in Phase 2 of this proceeding. Enbridge Gas is required to file the draft accounting order for this deferral account along with the Phase 1 draft rate order. The draft accounting order should include Enbridge Gas's proposed methodology for disposing of any balances that accrue from non-depreciable and depreciable property. Given the SEC submission, the OEB wants to ensure 100% of the benefits from depreciable property dispositions accrue to ratepayers through adjustments to accumulated depreciation or entries to this new deferral account.

5.2.2 Natural Gas Vehicle Program

Enbridge Gas proposed to expand the current Natural Gas Vehicle (NGV) program to all Enbridge Gas's franchise areas as part of its ancillary business activities.

The NGV program is primarily active in the legacy Enbridge Gas Distribution franchise areas where it is now focused on the medium- and heavy-duty vehicle market. Enbridge Gas views natural gas as a bridge fuel until there are commercialized electric alternatives, if ever.¹⁸³

The NGV program currently offers:

- compressed natural gas refueling station rentals
- compressed natural gas fuel cylinder and NGV refueling appliance rentals
- compressed natural gas tube trailer rentals (for off-pipe delivery and remote refueling stations)

Historically, when the NGV program underperformed, revenues were imputed to the program to avoid cross-subsidization of the program by ratepayers. However, the NGV program achieved the OEB's approved annual rate of return in 2014/2015 and has exceeded the required annual rate of return since that time.

Enbridge Gas proposed the following regulatory treatment for the NGV program:¹⁸⁴

1. Continue the NGV program as an ancillary activity for the utility
2. Expand the NGV program to all Enbridge Gas franchise areas
3. Continue the current practice of setting a customer project specific charge that is

¹⁸³ Exhibit I.1.14.STAFF-42.

¹⁸⁴ Exhibit 1, Tab 14, Schedule 2, p. 1; Exhibit I.1.14-STAFF-43.

levelized and constant for each month of the contract term

4. Modify the current regulatory treatment to remove the requirement to impute revenue when the achieved annual rate of return does not meet or exceed the OEB-approved rate of return, such that the NGV program is funded solely by the monthly service fees charged to participating customers over the life of the program. To the extent that monthly service fees do not recover the costs to serve a particular NGV customer, the last payment of the rental contract would include a true-up between actual and forecast costs to serve that particular customer.
5. If a NGV program customer decides to exit the contract before the end of the term, the customer would pay a termination fee based on the aggregate of all internal and external costs up to and resulting from the termination
6. Enbridge Gas will report on the profitability of the NGV program at its 2028 rebasing and would support the requirement to file a report in 2026 on the performance of the NGV program under the proposed framework that sets out the annual revenue and costs (including the rate of return)

Enbridge Gas indicated that the NGV program is consistent with and complementary to the Government of Canada's Green Freight Program and Clean Fuel Regulation (CFR) as owners and operators of compressed natural gas refueling facilities can generate, trade and sell credits under the CFR.

OEB staff supported Enbridge Gas's proposed NGV program noting that the program design ensures that there is no ratepayer subsidy. OEB staff noted that the service charge will be based on a fully allocated basis and Enbridge Gas would apply credit and security terms consistent with its practices for large volume gas distribution customers. OEB staff also recommended Enbridge Gas file a report in 2026 that would enable a review of the program in light of other energy transition evolutions. FRPO supported OEB staff's 2026 report recommendation.

LPMA generally supported the continuation of the NGV program as part of the regulated operations subject to certain caveats. LPMA submitted that the OEB should direct Enbridge Gas to file an annual report detailing the revenues and costs including the rate of return on the NGV program to ensure that ratepayers are not subsidizing the program in any manner. LPMA noted that there are competitive markets for fuel cylinders, vehicle refueling appliances and tube trailers in Alberta, Quebec and British Columbia. LPMA suggested that the OEB should direct Enbridge Gas to investigate the potential for a competitive market for NGV services in Ontario and report back to the OEB as part of its next rebasing application as the continuation of the NGV program as a regulated business may be hampering the development of a competitive market in Ontario.

Many intervenors (CCC, Energy Probe, Environmental Defence, Pollution Probe and VECC) submitted that the OEB should reject Enbridge Gas's proposal to include the NGV program as part of the regulated business. CCC urged the OEB to ensure ratepayers were fully protected. Energy Probe referenced section 29(1) of the OEB Act that requires the OEB to refrain from exercising its power where there is competition sufficient to protect the public interest. Even if there is no competitive market currently as claimed by Enbridge Gas, Energy Probe argued that a competitive market can emerge given that there is money to be made in the NGV business. In addition, Energy Probe noted that NGV is not an essential service.

Energy Probe and VECC argued that Enbridge Gas's NGV activity is counter to the goal of eliminating or reducing the number of vehicles that use carbon-based fuels. VECC submitted that if the OEB approved the continuation of the program within the regulated utility then it should order an independent audit of the fully allocated costs to ensure no explicit or implicit subsidies.

Environmental Defence submitted that the OEB should deny Enbridge Gas's request to expand the NGV program to the legacy Union Gas rate zones and treat it as a utility activity unless Enbridge Gas commits to restrict it to the delivery of renewable natural gas to the heavy transportation sector.

In reply, Enbridge Gas submitted that annual reporting of the NGV program would be overly burdensome and unnecessary for such a limited activity. Parties will have an opportunity to ask interrogatories related to the NGV program in its annual IRM rate filings.

Enbridge Gas also noted that it is somewhat late for Energy Probe to refer to section 29(1) of the OEB Act in final submissions. Enbridge Gas submitted that Energy Probe had not presented any evidence to substantiate a claim of a competitive market for NGV services in Ontario. Enbridge Gas reiterated that there is no competitive market for the type of turnkey NGV and compressed natural gas related services that Enbridge Gas provides through the NGV program. Additionally, Enbridge Gas did not believe that its role is to stimulate or induce competition or to investigate reasons why there is no competition in Ontario within this market. Enbridge Gas further submitted that restricting the NGV program to only use renewable natural gas in the heavy transportation sector would significantly limit the ability of the program to contribute to greenhouse gas reduction initiatives across the entire transportation sector and support the growth of the NGV market. Enbridge Gas emphasized that the use of conventional natural gas in the transportation sector still provides significant environmental benefits compared to traditional gasoline and diesel fuels.

Findings

The OEB accepts Enbridge Gas's proposed changes to the NGV program. The OEB is prepared to accept the NGV program as an ancillary business activity, on the provision that it is operated on a fully allocated cost basis.

The NGV program has been operating since the mid-1980s in the former Enbridge Gas Distribution and Union Gas rate zones. Consistent with the OEB's Decision in E.B.R.O 495, the former Enbridge Gas Distribution had been operating the NGV program as an unregulated ancillary business. The program is subject to fully allocated costing for rate treatment purposes. The former Union Gas exited the NGV line of business in 2000 and only in 2019 started working with the City of Hamilton to provide natural gas for city transit vehicles.¹⁸⁵

The NGV business has been operating as an ancillary activity. The NGV business is not an essential part of the distribution business and ratepayers should not be required to support it. The OEB finds that ratepayers should not assume any risk related to the transportation industry. If Enbridge Gas decides to continue the NGV program, it must be subject to fully allocated costs. While Enbridge Gas proposes that there will be a true-up in the last invoice under a customer's contract, this is not sufficient to prevent a cross-subsidy from ratepayers in the event that a customer does not complete its contract or fails to make any payment owing under the contract. The NGV program will be operated at Enbridge Gas's risk, including any shortfall or bad debt incurred by the program.

Enbridge Gas shall inform the OEB of its intent to expand the NGV program as proposed, as an ancillary activity operated on a fully allocated cost basis, as part of the draft rate order and provide a forecast of the fully allocated costs for 2024. Otherwise, without these additional safeguards, the NGV program is not approved as an activity within the regulated utility. In its reply submission, Enbridge Gas identified the implications if the NGV program is moved out of regulation. In particular, there would be a corresponding modest change to rate base, O&M and other revenue because the NGV program is currently forecast to produce a revenue sufficiency.

If Enbridge Gas elects to continue the NGV program on this basis, the OEB has the option of ordering an independent audit of Enbridge Gas's cost allocation to ensure no cross subsidization from ratepayers.

¹⁸⁵ Enbridge Gas, Argument-in-Chief, p. 266.

5.3 Historic Parkway Delivery Obligation Costs

In the OEB-approved settlement proposal, parties agreed with Enbridge Gas's proposed updated Parkway Delivery Obligation (PDO) Framework subject to certain modifications. Parties also agreed to defer the issue of Enbridge Gas's Parkway Delivery Commitment Incentive (PDCI) payment proposal to Phase 3 of this proceeding. However, the issue of PDO costs recovered from ratepayers during the deferred rebasing term (2019 to 2023) was not settled and was heard in Phase 1 of this proceeding.

In its 2013 rates proceeding,¹⁸⁶ Union Gas's direct purchase customers requested that Union Gas eliminate the PDO¹⁸⁷ and allow customers to deliver gas at Dawn because the cost to these customers to deliver gas at Parkway exceeded the delivery rate benefit of the PDO. In the 2014 rates proceeding,¹⁸⁸ Union Gas reached an agreement with intervenors on the PDO issue and the OEB approved the PDO Settlement Framework. The agreement establishes that the costs of reducing the PDO are borne by all customers of Union Gas. The guiding principle of the PDO Settlement Framework was to keep Union Gas whole rather than enhance or reduce its earnings over the IRM term.

Prior to the PDO Settlement Framework, Union Gas had 210 TJ/day of excess Dawn Parkway system capacity as noted in its 2013 cost of service application.

In the MAADs proceeding, the OEB determined that there was insufficient evidence to determine whether, as a result of the implementation of the PDO, ratepayers were overpaying for capacity on the Dawn Parkway system. The OEB directed Enbridge Gas to track actual costs and amounts recovered through rates related to the PDO during the 2019-2023 deferred rebasing period for review at its next rebasing proceeding.¹⁸⁹

In the current proceeding, Enbridge Gas argued that the revenue generated from the sale of 210 TJ/day of excess Dawn Parkway system capacity should accrue to Enbridge Gas and be included in utility earnings. Enbridge Gas argued that if adjustments for the excess capacity had been incorporated in base rates from 2019 to 2023, it would not have been kept whole, contrary to the agreement in the PDO Settlement Framework. If the excess capacity was not used to reduce PDO, Enbridge Gas argued that the capacity would have been available to sell in the open market.

¹⁸⁶ EB-2011-0210.

¹⁸⁷ The PDO refers to an obligation for Union Gas's large volume direct purchase customers east of Dawn to deliver gas at Parkway.

¹⁸⁸ EB-2013-0365.

¹⁸⁹ EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, pp. 48-49.

Enbridge Gas provided the actual PDO costs and compared them to the PDO costs in rates. From 2019 to 2022, the variance in the total PDO costs was a revenue shortfall ranging from \$0.73 million to \$1.16 million.

OEB staff submitted that Enbridge Gas had not over collected for the PDO from ratepayers over the deferred rebasing period based on the tracking information.

OEB staff also referenced the 2013 rates decision where the OEB acknowledged the excess capacity on the Dawn Parkway system, yet did not establish a variance account to capture variances related to the long-term transportation revenue forecast. The PDO Settlement Framework was established after Union Gas's 2013 rates were set. OEB staff argued that Union Gas was not able to sell the excess capacity to third parties as a result of using the excess capacity to reduce the PDO. Union Gas did not rebase in 2019 and the underlying principles that were used to set 2013 rates continued in the 2019 to 2023 rate term, according to OEB staff.

LPMA and Energy Probe agreed with the OEB staff submission that given the Union Gas's 2013 rates decision and the PDO Settlement Framework, there was no over-earning or double recovery related to recovery of PDO costs during Enbridge Gas's IRM and deferred rebasing term.

FRPO argued that Enbridge Gas had enhanced earnings as a result of the implementation of the PDO during the deferred rebasing term and ratepayers were paying twice for the same capacity.

FRPO noted that during the IRM term (2014 to 2018), the former Union Gas used Dawn-Kirkwall capacity to facilitate the PDO shift as contemplated by the settlement agreement. The eventual amount shifted was increased to 200 TJ/day using the Dawn-Kirkwall capacity. FRPO further noted that Union Gas increased the Dawn-Parkway system capacity with facility builds in three successive years, 2015 to 2017, for which the cost of the builds was included in rates using the available capital pass-through mechanism in the IRM framework. FRPO submitted that the additional costs remained in rates throughout the IRM term of 2014 to 2018 while rates escalated due to additional capacity builds effectively enhancing return while reducing risk. FRPO agreed that ratepayers accepted the PDO Settlement Framework and thus the cost consequences through the term of the agreement which ended in 2018.

However, FRPO argued that in-franchise ratepayers should not be burdened with the ongoing overearnings that accrued during the deferred rebasing period. FRPO submitted that the 200 TJ/day of temporarily available Dawn-Kirkwall capacity should be removed from rates after 2018 and returned to in-franchise ratepayers as of January

1, 2019. FRPO calculated this amount to be \$6.95 million on an annual basis for the deferred rebasing period (2019 to 2023).

CME and SEC agreed with FRPO that the OEB should make the necessary base rate adjustments to prevent double recovery starting January 1, 2019. While the double recovery was permissible through the Union Gas IRM period (2014-2018) according to the terms of the PDO Settlement Framework, CME and SEC argued that it became inappropriate as of December 31, 2018. SEC agreed with FPRO's calculated \$6.95 million annual amount to be returned to ratepayers.

Although Enbridge Gas did not rebase in 2019, CME and SEC did not accept Enbridge Gas's argument that it was entitled to continue recouping from base rates the costs of the 210 TJ/day of excess capacity as well as through the revenue derived from the sale of that same capacity after December 31, 2018.

In reply, Enbridge Gas noted that no one took issue with the treatment of PDO/PDCI costs or the consistency with the intent of the PDO Settlement Framework. Enbridge Gas therefore submitted that it did not enhance earnings and there was no basis to make a base rate adjustment for the 2019 to 2023 PDO/PDCI costs.

Enbridge Gas further noted that the PDO Settlement Framework did not end on December 31, 2018. The provisions of the PDO Settlement Framework continued to be observed through the deferred rebasing term. Enbridge Gas argued that some intervenors were attempting to rewrite history.

Findings

The OEB does not approve any rate adjustment to the 2019 to 2023 period associated with PDO costs.

The PDO Framework was established as part of a settlement agreement in the 2014 Union Gas rates proceeding.¹⁹⁰ The OEB approved the amalgamation of Enbridge Gas Distribution and Union Gas in 2018 with a five-year deferral of rebasing. As a result, rebasing did not occur in 2019 as anticipated in the 2014 settlement agreement. The MAADs Decision required Enbridge Gas to track the revenue and costs related to the PDO, which Enbridge Gas has done.

The period in dispute is the 2019 to 2023 deferred rebasing period. Parties appear to accept the OEB approved rates in effect during Union Gas's IRM term as being consistent with the PDO Framework. Enbridge Gas continued under the assumption that the PDO Framework was still in place post amalgamation. The critical question is

¹⁹⁰ EB-2013-0365.

the effect of the MAADs Decision on base rates, obligations and the PDO Framework from 2019 to 2023.

The OEB finds that the MAADs Decision did not change the principles of the PDO Framework, and in the absence of an express termination of the PDO Framework, the existing arrangement continued post amalgamation. While some rates and charges were updated in the MAADs Decision, Enbridge Gas did not rebase its rates effective January 1, 2019. Since January 1, 2019, Enbridge Gas's tracking for the 2019 to 2022 period indicates there was a revenue shortfall every year. The OEB finds no evidence that Enbridge Gas over-earned as a result of the PDO arrangement.

Based on the evidence before it, the OEB is not satisfied that there is a justification to make a retroactive base rate adjustment for 2019 to 2023.

5.4 Dawn Parkway Capacity Turnback

Turnback arises when ex-franchise customers do not renew their contracts resulting in excess capacity on the Dawn Parkway system. The capacity would “turn back” to in-franchise customers by default through higher cost allocations associated with an underutilized system.

In the 2016 Dawn Parkway System Expansion Project proceeding,¹⁹¹ parties expressed concern with the potential for substantial turnback on the Dawn Parkway system. The approved settlement agreement deferred the issue of Dawn Parkway system capacity turnback risk to the next rebasing application.

Enbridge Gas filed evidence in this proceeding that forecasts the system to remain fully contracted through to 2028 and considered turnback risk unlikely during the IRM term. Enbridge Gas did not seek any relief related to this issue.

The Dawn Parkway system is a 229 km gas transmission system that extends from the Dawn Hub to interconnections with TransCanada at Kirkwall and Parkway in Mississauga. The Dawn Hub is the largest integrated underground natural gas storage facility in Canada and is connected to most of North America's major supply basins. Enbridge Gas uses the Dawn Parkway system to deliver natural gas to in-franchise customers and to provide gas transportation services for ex-franchise customers.

¹⁹¹ EB-2014-0261.

ICF International Inc., retained by Enbridge Gas to review the utilization forecast, concluded that the Dawn Parkway system is likely to remain contracted to 2034.¹⁹²

FRPO filed a report by John Rosenkranz on the risk of Dawn Parkway system capacity turnback. In his report, Mr. Rosenkranz observed that while the likelihood that a large amount of Dawn Parkway system capacity would be turned back during the proposed IRM term may be small, the risk of turnback from utilities in New York and New England should not be ignored. These utilities in New York and New England contract on the Dawn-Parkway system with remaining terms of three years or less and have contracting alternatives. FRPO submitted that the main point of Mr. Rosenkranz's recommendation was that contract restructuring is a demand side IRP alternative that Enbridge Gas should consider before submitting a leave to construct application for future Dawn Parkway system expansion projects.

Even if the near-term risk of capacity turnback is low, Mr. Rosenkranz suggested Enbridge Gas implement measures to limit cost shifting between ex-franchise and in-franchise services such as including a buy-out option in reverse open seasons which would pay existing shippers to turn back capacity.

Enbridge Gas rejected Mr. Rosenkranz's proposal for a reverse open season with payments to shippers. Enbridge Gas submitted:

- there is no precedent for a similar approved mechanism in other jurisdictions
- shippers would not turn back capacity in the future without payment
- there is no mechanism to stop a shipper from receiving payment to exit one year and then bid for capacity the following year.

OEB staff and LPMA agreed with Enbridge Gas. OEB staff submitted that Mr. Rosenkranz's recommendations lacked analysis of how the buy-out option in a reverse open season would impact ratepayers.

LPMA submitted that the issue of turnback risk should be dealt with when Enbridge Gas brings forward an application to build a specific asset to meet an increase in demand.

CME and SEC submitted that a buy-out option could be beneficial to entities that accept the buy-out and other ratepayers could be better off.

¹⁹² Exhibit 1, Tab 11, Schedule 1, Attachment 1, "Assessment of the Future Utilization of the Enbridge Gas Dawn to Parkway System", October 11, 2022.

SEC submitted that the OEB should require Enbridge Gas to consider the buy-out approach and bring it forward to the IRP technical working group. SEC further submitted that the best way to mitigate Dawn Parkway turnback risk is to avoid further expansion altogether.

In reply, Enbridge Gas submitted that the appropriate place to consider IRP measures to avoid, delay or downsize a future Dawn Parkway capacity expansion should be in the context of an actual project. Enbridge Gas maintained that mandating and defining a specific demand side IRP alternative is not necessary now.

Enbridge Gas further submitted that there are serious conceptual flaws with Mr. Rosenkranz's report; therefore, an investigation to implement a buy-out mechanism should not be a priority for Enbridge Gas or the IRP technical working group at this time.

In conclusion, Enbridge Gas reiterated that no OEB direction is required on the Dawn Parkway capacity buy-out option.

Findings

The OEB finds that although the risk of turnback is low in the IRM term, the risk of under-utilization or future stranded assets cannot be ignored given the energy transition. This is a known risk and it is Enbridge Gas's obligation to manage the risk to avoid adverse impacts for ratepayers.

Enbridge Gas has many tools at its disposal to manage the risk. Whenever Enbridge Gas is considering the need for an expansion of the Dawn to Parkway system, it shall consider contractual terms, and procedures for incentives or payments for turn back, along with the range of other IRP considerations, to avoid or defer the need for expansion.

5.5 Deferral and Variance Accounts

In the OEB-approved settlement proposal, parties agreed to Enbridge Gas's proposals with respect to the continuation, establishment or closure of many deferral and variance accounts with some agreed to changes. The unsettled accounts and those raised during Phase 1 of this proceeding relate to the:

- Volume Variance Account
- PREP Variance Account
- Short-term Storage and Other Balancing Services Account (Union rate zones)
- Change to IFRS Deferral Account
- TVDA

- APCDA
- OEB Directive Deferral Account

Findings on the TVDA and the APCDA have already been provided in sections 4.3 and 4.5 of this Decision and Order.

5.5.1 Volume Variance Account

Enbridge Gas proposed two existing accounts applicable to general service rate classes in different rate zones:

1. Enbridge Gas Distribution – Average Use True-up Variance Account
2. Union Gas – Normalized Average Consumption (NAC) Account

For the Enbridge Gas Distribution rate zone, an average use true-up variance account records the revenue impact, exclusive of gas costs, of differences between the forecasted average use per customer and the actual weather normalized average use experienced during the year.

For the Union rate zones, the NAC account records the impact to delivery and storage revenue and costs resulting from the difference between the target NAC per customer included in OEB-approved rates and the actual average consumption. experienced during the year.

Enbridge Gas proposed to close both existing variance accounts and establish a Volume Variance Account. The Volume Variance Account would record the revenue impact, exclusive of gas costs, of the volumetric variance between the volume forecast in rates and the actual average use per customer and weather experienced during the year. This new account would apply to general service rate classes in all rate zones.

Enbridge Gas stated that the Volume Variance Account would capture both average use and weather variances. It would reduce volumetric risk in a symmetric and revenue-neutral manner, providing smoothing and certainty for both customers and Enbridge Gas. In a year where the actual weather is colder than the OEB-approved normal, customers would receive the benefit of being refunded delivery charges. In a year where the actual weather is warmer than the OEB-approved normal, Enbridge Gas would be able to recover its delivery costs from customers.

Enbridge Gas's proposed Volume Variance Account would be in effect until its proposed rate design, a straight fixed variable with demand (SFVD), is considered in Phase 3 of this proceeding.

Environmental Defence supported the establishment of a Volume Variance Account as Enbridge Gas does not control the weather and cannot mitigate the risks it faces, rather than increase costs to customers through a higher equity thickness.

Many parties (CCC, CME, FRPO, LPMA, Pollution Probe, SEC and VECC), along with OEB staff, recommended that the OEB deny Enbridge Gas's proposed Volume Variance Account as proposed in Phase 1 of this proceeding.

OEB staff supported a single average use account that operates similarly to the existing accounts applied to all general service customers. OEB staff submitted that the existing accounts worked well for the legacy utilities and ratepayers. OEB staff argued that completely de-risking of cost recovery related to weather is not required and Enbridge Gas should accept the weather forecast risk. In a cost of service proceeding, rates are set on a forward Test Year basis, and there is forecast risk implicit to the ratemaking model.

CCC argued that it was ironic that Enbridge Gas was seeking a significant increase in its equity thickness at the same time that it was seeking to eliminate its weather risk.

CME rejected Enbridge Gas's justification that actual weather versus forecast has been roughly symmetrical since 2013. In CME's opinion, this was not a valid reason for approving an average use account that includes weather risk.

FRPO submitted that there is insufficient evidence on how the Volume Variance Account would be implemented to respect the intent of de-risking average use in an equitable manner.

LPMA submitted that Enbridge Gas is at risk for the forecast of capital costs, consumption volumes and operating costs that flow into the traditional cost of service approach and the OEB should not remove weather from that list. LPMA submitted that the inclusion of weather risk is tied to equity thickness and if the OEB approves the proposed Volume Variance Account, then it should take this risk reduction into account when determining the appropriate equity thickness for Enbridge Gas.

Pollution Probe submitted that certain conditions be required if the Volume Variance Account is approved, including an analysis of variances due to demand side management and the energy transition for a consolidated consideration of all factors.

SEC submitted that the OEB should only approve the proposed Volume Variance Account if it captures variance on a weather normalized basis, similar to the existing accounts of the legacy utilities.

VECC opposed the expansion of the current average use accounts to include weather risks. As rate design issues will be addressed in Phase 3 of this proceeding, it was premature to make a fundamental determination regarding the addition of weather risks to average use accounts.

In reply, Enbridge Gas submitted that it was appropriate that both the company and ratepayers have protection against the impacts of weather through the requested Volume Variance Account. Enbridge Gas reiterated that it had no control over the weather and the evidence shows that over time the impacts from weather are relatively symmetrical.

Enbridge Gas further submitted that if the OEB does not approve the Volume Variance Account as proposed, then it agreed with the position of intervenors and OEB staff that the OEB should approve a single account that is similar to the existing Enbridge Gas Distribution Average Use True-up Variance and Union Gas NAC accounts. Enbridge Gas submitted that the mechanics and detailed description of the account can be addressed through the draft rate order process.

In reply, Enbridge Gas disagreed that further reporting requirements are necessary as it already provides the factors influencing variances for existing accounts and it is not possible to include consideration of demand side management audit reports.

Findings

The OEB denies Enbridge Gas's proposed Volume Variance Account. The OEB finds that Enbridge Gas should continue to assume the weather forecast risk that is part of the cost of service ratemaking process. However, the OEB finds it efficient to establish a harmonized average use account applicable to all general service customers in all rate zones, based on the objectives of the current variance accounts utilized by the legacy utilities.

Enbridge Gas shall establish a harmonized average use variance account based on the average use forecast methodology approved as part of the settlement proposal. This new forecast methodology, as an input to the load forecast, should affect the entries to the harmonized variance account. Enbridge Gas is directed to file an accounting order as part of the draft rate order describing the methodology that will be used to determine average use and the entries that will be recorded in the variance account.

The OEB will reassess the need for this variance account in Phase 3 of this proceeding.

5.5.2 Panhandle Regional Expansion Project Variance Account

Enbridge Gas proposed to exclude the Panhandle Regional Expansion Project (PREP) from rate base in 2024 and instead establish a unique levelized ratemaking treatment during the IRM term. The OEB approved the exclusion of PREP from 2024 rate base in this Decision and Order. Enbridge Gas's proposed levelized ratemaking treatment included a new variance account, which is at issue in this section of the Decision and Order.

Similar to how ICM projects were treated during the deferred rebasing period, Enbridge Gas proposed to establish rate riders to be charged to customers when the PREP is placed in service, if it is approved. The proposed levelized ratemaking treatment included the approval average unit rates (rate riders) and an associated variance account, the PREP Variance Account. The new variance account would capture any variance between the project's actual net revenue requirement and the actual revenues collected through the rate riders in place over the proposed IRM term.

Enbridge Gas claimed that the variance account would ensure that it does not over- or under-recover costs from customers during the IRM term. Enbridge Gas proposed that any cumulative balance in the account would be reviewed and cleared at the next rebasing.

OEB staff supported Enbridge Gas's proposed approach for PREP and supported the establishment of the PREP variance account.

SEC, CCC, FRPO, LPMA, Pollution Probe and VECC did not support Enbridge Gas's proposed levelized approach for PREP and therefore, a PREP variance account was not a consideration.

SEC proposed the establishment of a generic leave to construct (LTC) variance account to capture the revenue requirement included in base rates for any 2024 in-service additions subject to LTC approvals that are denied. CCC also supported the establishment of an LTC variance account.

In reply, Enbridge Gas submitted that no supplementary variance account treatment is required for LTC project-related revenue requirement for any 2024 in-service additions apart from the PREP and St. Laurent variance accounts.

Findings

The OEB approves the establishment of a PREP variance account to record the variance between the project's actual net revenue requirement and the actual revenues

that would be collected through any rate rider that may be approved by the OEB. The PREP variance account would be in place over the approved rate term.

5.5.3 Short-term Storage and Other Balancing Services Deferral Account

The Short-term Storage and Other Balancing Services Deferral Account has been in place for the Union rate zones before and during the deferred rebasing term. The account records the actual net revenues for short-term storage and balancing services, less a 10% shareholder incentive to provide these services, and less the net revenue forecast for these services as approved by the OEB for ratemaking purposes.

Enbridge Gas indicated that it inadvertently failed to include a proposal to continue this account as part of the settlement proposal. Since storage-related issues will be determined in Phase 2 of this proceeding, Enbridge Gas argued that the existing account should be continued until a Phase 2 decision is issued. Accordingly, Enbridge Gas requested continuation of this account.

OEB staff, FRPO and LPMA supported the continuation of the Short-term Storage and Other Balancing Services Deferral Account.

Findings

The OEB finds that it is appropriate to continue the Short-term Storage and Other Balancing Service Deferral Account until the OEB makes a determination on gas storage issues in Phase 2 of this proceeding.

5.5.4 Change to IFRS Deferral Account

Enbridge Gas is currently reporting under USGAAP as it has obtained an exemption to report under International Financial Reporting Standards (IFRS). However, this exemption is temporary and is expected to end during the proposed IRM term.¹⁹³ OEB staff submitted that Enbridge Gas should be required to establish an account to record the revenue requirement impact from changing to IFRS, in the event that such a change were to occur during the proposed rate term. No other party made a submission on this issue.

In reply, Enbridge Gas agreed with OEB staff's proposal. Enbridge Gas submitted that the IFRS deferral account should also record incremental administrative and implementation costs from any transition to IFRS.

¹⁹³ The exemption provided by the Ontario and Alberta Securities Commissions ends at the earlier of: (i) January 1, 2027; (ii) Enbridge Gas no longer has rate regulated activities; or (iii) there is a rate-regulated standard issued by the International Accounting Standards Board (Ex 1/Tab 8/Schedule 2/Attachment 1).

Findings

The OEB will not establish an IFRS deferral account at this time. Although there is a possibility that Enbridge Gas could be required to transition to IFRS during the OEB-approved rate term, the OEB finds it is premature to establish this account. The details of such an account would depend on the timing and the scope of cost impacts arising from a transition to IFRS, all of which are uncertain. Materiality is one criterion for establishing a deferral account and the OEB has no basis to consider any potential balance material to Enbridge Gas.

Enbridge Gas has the option of requesting the appropriate accounting order in a future rates or deferral and variance account disposition proceeding when there is greater certainty regarding a possible transition to IFRS.

5.5.5 OEB Directive Deferral Account

In its reply argument, Enbridge Gas requested the establishment of a new OEB Directive Deferral Account to record the incremental costs incurred by Enbridge Gas to respond to OEB directives or requirements from this proceeding. This account would capture and defer the cost of OEB directives for studies and/or reports to address energy transition related issues, as well as required work to develop and implement updated internal processes during the IRM term.

Enbridge Gas submitted that none of these costs are in base rates as the O&M budget was settled.

Findings

The OEB denies Enbridge Gas's request for a new OEB Directive Deferral Account for 2024. This request was first raised in the reply argument with no opportunity for other parties to make submissions on this request. In addition, the proposed basis for this account has not been sufficiently defined. If Enbridge Gas expects to incur significant incremental costs resulting from OEB directives in this proceeding, a deferral account can be requested based on specific cost estimates, subject to meeting the OEB's criteria for establishing new deferral accounts.

5.6 Earnings Sharing Mechanism for 2024

Enbridge Gas did not propose an earnings sharing mechanism (ESM) for the 2024 Test Year. The OEB-approved Issues List included the issue of whether an ESM for the Test Year was appropriate. In its argument-in-chief, Enbridge Gas submitted that an ESM for the Test Year was not required. Enbridge Gas noted that the cost of service process

already affords sufficient protection for ratepayers because it involves an extensive review of all elements of its Test Year forecast.

OEB staff agreed with Enbridge Gas that additional customer protection through an ESM for 2024 was not required.

Some intervenors (CCC, FRPO, Pollution Probe, SEC, VECC) submitted that earnings sharing provides an important protection mechanism for ratepayers and should be approved by the OEB. CCC did not see any downside in requiring an ESM for 2024 and proposed an ESM that shares earnings with ratepayers on a 50:50 basis for all earnings 100 basis points above its approved ROE. FRPO argued that Enbridge Gas and its legacy utilities have had a long history of over-earnings relative to the OEB approved rate of return. Pollution Probe and VECC recommended that the OEB adopt 50:50 sharing for all earnings 150 basis points above OEB approved ROE for 2024.

LPMA submitted that an ESM will be required if the OEB approves either an increase in the equity thickness or approves a levelized treatment for PREP.

LPMA argued that if the OEB rewards the increased risk to Enbridge Gas related to the energy transition through raising the equity thickness, then Enbridge Gas would be granted additional revenues for risks that may not materialize during the proposed IRM term through 2028.

In addition, LPMA submitted that if the OEB determines that it is appropriate for Enbridge Gas to deviate from current practice with respect to PREP then the OEB should also deviate from the current practice of not establishing an ESM for the cost of service Test Year. In the event that the OEB establishes an ESM for the 2024 Test Year then LPMA suggested that the associated deferral account should be asymmetric so that only earnings above a dead-band would be refunded to ratepayers. LPMA submitted that the dead-band should be set at 150 basis points if the approved equity thickness is 39% or less, and 100 basis points if the approved equity thickness is above 39%.

SEC supported an ESM for 2024. SEC noted that the OEB has approved an ESM framework in all of the most recent Custom Incentive Ratemaking proceedings for other large utilities, where the first year is set on a cost of service basis. SEC suggested that the appropriate ESM methodology should be considered in Phase 2 of this proceeding.

In reply, Enbridge Gas submitted that additional protection through an ESM is not necessary to protect against over-earnings in a cost of service year. Enbridge Gas noted that it typically finds ways to operate efficiently and earn above its allowed rate of return and it believed that such an approach should be encouraged.

In the event that the OEB requires an ESM for 2024, Enbridge Gas proposed to continue the parameters that were in place for the deferred rebasing term (i.e. 50:50 sharing for all earnings 150 basis points above OEB approved ROE for 2024), and which is proposed to be continued into the next rate term.

Findings

The OEB finds that an ESM for the 2024 Test Year is not required. The OEB has conducted a thorough review of all Phase 1 issues in this application which included extensive discovery and an oral hearing to test the evidence. The OEB is confident that the rates resulting from this Decision and Order are reasonable and appropriately reflect the costs to serve customers. Additional protection through an ESM is not necessary. An ESM for the IRM term will be considered in Phase 2 of this proceeding.

5.7 Exemptions From Certain Performance Metrics

Enbridge Gas is required to meet certain performance metrics as outlined in section 7 of GDAR. Section 7.2.1 requires a gas distributor to observe and track its performance with respect to certain service quality requirements (SQR). Enbridge Gas requested a partial exemption under section 1.5.1 of GDAR beginning in January 2023.

The current performance standards with the requested modified measures are set out below:

- Call Answering Service Level (CASL) – request to modify to achieve 65% of calls reaching the general inquiry number answered within 30 seconds, on an annual basis, with a minimum monthly standard of 40%. The current annual metric is 75% with a minimum monthly standard of 40%.
- Time to Reschedule a Missed Appointment (TRMA) – request to modify to attempt to contact customers requiring a rescheduled appointment within one business day of the original appointment window 98% of the time. The current metric requires customers to be contacted to reschedule an appointment within two hours of the original appointment window 100% of the time.
- Meter Reading Performance Measurement (MRPM) – request to modify to achieve no more than 2% of meters with consecutive estimates for four months or more. The current target is 0.5% of meters.

Enbridge Gas requested that these exemptions be applicable from January 2023 until the OEB orders otherwise.¹⁹⁴

¹⁹⁴ Enbridge Gas, Argument-in-Chief, p. 284.

In September 2022, Enbridge Gas provided the OEB with an Assurance of Voluntary Compliance, wherein it paid \$250,000 in penalties to the OEB and made certain commitments with respect to meeting its CASL, Abandonment Rate and MRPM targets for 2022.¹⁹⁵

In certain years, Enbridge Gas has not met four SQR metrics related to the CASL, TRMA, MRPM and Abandonment Rate and in 2021, Enbridge Gas did not achieve any of these four SQR metrics. Enbridge Gas stated that it continues to take all reasonable steps to achieve the SQR targets.

Table 7
CASL Actual Performance to Target (2019 to 2022)

Target	Actual	Actual	Actual	Actual
	2022	2021	2020	2019
75%	75.9%	64.3%	75.2%	79.0%

Enbridge Gas explained that the CASL was impacted in 2021 by increased call volumes due to COVID-19 and the consolidation of Enbridge Gas's two legacy utility customer information systems in July 2021 which introduced 1.6 million Union rate zone customers to the new systems. As a result of COVID-19, Enbridge Gas also experienced staffing shortages. Enbridge Gas stated that the majority of calls to the call centre are complex in nature as more customers are choosing to resolve non-complex matters through self-serve options.

Enbridge Gas's mitigation plans to improve performance on the CASL include: (a) implementing an augmented planning process to better assess and mitigate impacts from events with customer-facing impacts; (b) increasing staffing; (c) continuous improvement of digital channels; and (d) continuous improvement in response to customer surveys and internal reviews.

¹⁹⁵ EB-2022-0188, Enbridge Gas Assurance of Voluntary Compliance, September 12, 2022.

A summary of Enbridge Gas's historic TRMA performance is provided below:¹⁹⁶

Table 8
TRMA Actual Performance to Target (2019 to 2022)

Target	Actual	Actual	Actual	Actual
	2022	2021	2020	2019
100%	93.8%	97.0%	97.3%	97.0%

Enbridge Gas explained that it experienced challenges meeting the TRMA metric and Enbridge Gas and its predecessors historically have not met the metric. Enbridge Gas stated that this is despite its ongoing efforts to try and improve the results, and that the 100% target is unreasonable and impractical as it does not account for factors like emergency response (e.g., redirecting technicians to emergency calls), human error (e.g., record keeping errors) or technical error (e.g., telecommunication outages). Neither Enbridge Gas nor the legacy utilities have ever met the TRMA metric.

Enbridge Gas's mitigation plans to improve performance on the TRMA include:¹⁹⁷ (a) aligning existing process for identifying attempts to reschedule appointments; (b) leveraging technology to add additional customer contact options; (c) enhancing reporting of results and corrective action processes; and (d) ongoing communication of process to reschedule appointments.

A summary of Enbridge Gas's historic MRPM performance is provided below:¹⁹⁸

Table 9
MRPM Actual Performance to Target (2019 to 2022)

Target	Actual	Actual	Actual	Actual
	2022	2021	2020	2019
0.5%	4.1%	5.0%	4.4%	0.7%

Enbridge Gas explained that it experienced challenges meeting the MRPM metric since 2019 for several reasons including COVID-19 resulting in closed businesses, increased customer sensitivity to contact with meter readers, access issues during periods of

¹⁹⁶ EB-2023-0092, Exhibit G, Tab 1, Schedule 1.

¹⁹⁷ Enbridge Gas's mitigation plans aim to achieve a standard of 98% of customer appointments rescheduled within one business day for TRMA.

¹⁹⁸ EB-2023-0092, Exhibit G, Tab 1, Schedule 1.

lockdown, staffing issues attributable to quarantine/isolation periods and labour resource shortages.

Enbridge Gas also lost a key meter reading vendor in 2019 resulting in the need to onboard a new vendor. Meter reading vendors experienced hiring challenges with the attrition rate and level of absenteeism for meter reading personnel being the highest Enbridge Gas has experienced. Enbridge Gas also stated that 27 weather events in the 2020 to 2021 period limited the ability to safely access meters.

Enbridge Gas's mitigation plans to improve performance on the MRPM include: (a) working with meter reading vendors to increase hiring and conduct meter reading campaigns; (b) educating customers of the importance of meter reading and providing assistance to read their own meters; (c) customer outreach on arranging for meter reads and submitting customer meter reads; (d) field operations to support meter access; and (e) continuous improvement to support meter reading attainment and efficiency processes.

Enbridge Gas stated that the OEB should grant its request for a partial GDAR exemption for the CASL, TRMA and MRPM for the following reasons:

- The performance standards were established more than 15 years ago and are not reflective of current customer behaviours and expectations. For example, customer calls are more complex in nature as customers can use web-self-service options and chatbot features for less complex inquiries.
- There is a lack of alignment with the Distribution System Code performance standards:
 - The Rescheduling a Missed Appointment measure is an attempt to contact the customer prior to the appointment and an attempt to reschedule within one business day compared to the TRMA requirement to reschedule within two hours of the end of the original appointment.
 - The Telephone Accessibility measure requires 65% of calls answered in 30 seconds compared to the CASL requirement of 75% of calls answered in 30 seconds.
 - The Distribution System Code contains a force majeure provision that allows a utility to be relieved of obligations for events beyond its reasonable control and the GDAR does not.
- There are continuing impacts of external factors such as residual pandemic-related issues, labour market shortages, extreme weather events, global energy and climate change dynamics and the economic environment.

- Planned activities to align systems and meet industry standards (such as for cyber-security, Green Button and harmonization of rates and services) may impact metric performance.

OEB staff did not oppose Enbridge Gas's request for a partial exemption from GDAR performance measures related to the CASL, TRMA and MRPM for the 2024 calendar year. However, OEB staff submitted that the OEB should not grant a perpetual partial exemption from GDAR requirements. If Enbridge Gas believes that a partial exemption of GDAR beyond the calendar year 2024 is necessary, OEB staff suggested that this should be accomplished through a generic review of the SQR-related GDAR requirements for gas distributors.

As the power to create or amend natural gas rules (such as GDAR) rests with the OEB's Chief Executive Officer, OEB staff submitted that any request to amend GDAR should be dealt with outside of the current proceeding (and no determinations with respect to amendments to GDAR are appropriate in the current proceeding).

If the OEB agrees with OEB staff's position that any changes to the SQR-related targets are best addressed in a GDAR amendment-related process, OEB staff suggested that Issue 58¹⁹⁹ (to be heard in Phase 2 of this proceeding) can be limited to any scorecard additions, removals, or changes that are not set out in GDAR.

Many intervenors (BOMA, CCC, FRPO, LPMA, Pollution Probe, SEC and VECC) submitted that the OEB should reject Enbridge Gas's request for partial exemption from meeting GDAR performance measures.

BOMA opposed Enbridge Gas's request for a partial exemption from meeting the MRPM target with respect to commercial buildings. BOMA submitted that Enbridge Gas should be required to conclude its Advanced Metering Infrastructure pilots and develop its strategy, budget and implementation plan for commercial buildings by March 31, 2024. BOMA also submitted that Enbridge Gas should implement advanced metering for 20% of commercial buildings by the end of 2025, and for all commercial buildings by the end of 2026.

CCC, FRPO and SEC noted that in the MAADs proceeding, Enbridge Gas committed to generate savings without impacting reliability and service quality. As the OEB relied on these commitments when approving the amalgamation, the OEB should hold Enbridge Gas to its commitment.

¹⁹⁹ Are the proposed scorecard Performance Metrics and Measurement targets for the amalgamated utility appropriate?

In particular, CCC opposed an exemption from the MPRP and the CASL performance metric. CCC noted that the OEB and ratepayers expected that after the amalgamation, Enbridge Gas at a minimum would maintain and potentially enhance customer service levels. CCC stated that it was not appropriate to change the performance standards simply because Enbridge Gas is unable to meet them. CCC argued that COVID-19 and consolidation of the billing systems should not be an issue anymore and Enbridge Gas should be capable of meeting the metrics.

FRPO was “surprised and disappointed” by Enbridge Gas’s response to service quality issues that have arisen since amalgamation. Unbeknownst to FRPO, the OEB had engaged Enbridge Gas regarding these issues culminating in an Assurance of Voluntary Compliance. Further, FRPO criticized Enbridge Gas for requesting lower performance standards at the same time requesting recovery of integration capital spent to create the systems.

LPMA submitted that the value of the savings achieved through the merger has been reduced due to a deterioration in the levels of customer service. LPMA noted that these are customer-focused metrics and Enbridge Gas is essentially requesting a reduction to outcomes that impact ratepayers directly. LPMA submitted that any changes to performance levels should be done in the context of a full review of all metrics included within GDAR.

Pollution Probe argued that it is not in the public interest to grant such exemptions and that such exemptions would dilute performance rather than ensuring that a certain level of performance is maintained or improved.

SEC was specifically concerned with the request for a partial exemption from the MRPM performance target. SEC noted that the OEB had received several complaints from customers regarding estimated meter reads and large bills to catch up with actual consumption. SEC added that a number of its member schools have been negatively impacted by the high number of estimated bills, particularly in the former Union South rate zone. Increasing the existing target from 0.5% to 2.0% of meters with no read for four or more consecutive months would only exacerbate the problem of estimated bills and would provide relief to the company for poor performance. Accordingly, SEC submitted that the OEB should send a clear message to Enbridge Gas and deny the request to lower its service quality obligations.

VECC maintained that Enbridge Gas’s problems related to system integration and the COVID-19 pandemic should not be considered as sustainable reasons for not meeting certain metrics. VECC submitted that there should be no temporary exemptions for performance metrics that were previously attainable by the legacy utilities, but which have not been met recently due to either cost reduction measures or the inability of

Enbridge Gas to successfully integrate its systems. In reply, Enbridge Gas dismissed the claims by some intervenors that its underperformance relative to certain SQRs were within its control or caused by mismanagement of integration activities. In fact, the main factors for not meeting the SQRs are unrelated to the amalgamation and were outside the control of Enbridge Gas.

Enbridge Gas reiterated that despite its best efforts to meet SQRs through comprehensive mitigation plans, there remain ongoing challenges. Enbridge Gas noted that the residual impacts of the COVID-19 pandemic are continuing with respect to the labour market, specifically with respect to meter reading providers and call centre staff. In addition, customers working from home has increased access problems for meter readers. Enbridge Gas rejected FRPO's "naïve" assertion that Enbridge Gas should overcome access issues through customer service measures. Enbridge Gas submitted that despite its best efforts, access issues continue to account for approximately 1-3% of the total MRPM. While the more pronounced impacts of the pandemic have passed, Enbridge Gas noted that it continues to experience the residual impacts and this is expected to continue for the next several months.

Enbridge Gas claimed that the predecessor utilities have been unable to meet the TRMA and the 100% SQR target has always been unrealistic.

Enbridge Gas opposed BOMA's submission reiterating that it is conducting pilots for Advanced Metering Infrastructure but will not be in a position to bring forward a proposal for any group of customers within the next several months. Enbridge Gas further clarified that it does not track MRPM for different group of customers or for commercial buildings.

Enbridge Gas agreed with LPMA that a full review of GDAR is required. However, Enbridge Gas submitted that it needs a partial exemption in the interim period, otherwise it will not be in compliance with the OEB's GDAR requirements.

Findings

The OEB approves the partial exemption request to change the TMRA target metric to 98%. The OEB denies the partial exemption requests to change the CASL and MRPM target metrics.

In principle, a TRMA metric based on meeting a target 100% of the time appears impractical. Enbridge Gas's performance over the last four years is close to meeting the requested 98%, except in 2022 where the actual performance was 93.8%. The OEB is satisfied that setting the metric at 98% is appropriate and will continue to drive

improvement in performance. The revised metric shall be in place until the OEB orders otherwise or until such time as the OEB conducts a review of GDAR SQR metrics.

The OEB denies the partial exemption request to change the CASL target metric to 65%. The OEB notes that Enbridge Gas has been able to meet the current metric of 75% over the last four years except in 2021, when COVID was a mitigating factor. There is no basis for changing this customer facing metric.

The OEB denies the exemption request to change the MRPM target to 2.0% of meters. The current target of 0.5% of meters is maintained.

The OEB regards meter reading as a fundamental customer service provided by a gas distributor that directly impacts customer billing. While COVID issues may have existed in 2020 and 2021, the OEB is not convinced that Enbridge Gas invested sufficiently in its customer services to address and rectify this meter reading problem. It is too late now to change the experience for those customers affected. The OEB received many letters of comment in this proceeding regarding billing issues experienced by customers and the personal implications.

The OEB has considered the customer impact. This metric is based on estimating four consecutive bills. The result could be an unexpectedly large bill when an actual meter read takes place. From a customer's perspective, this is an unacceptable outcome, especially as the commodity cost of gas and the delivery cost have increased in recent years. Enbridge Gas needs to improve its performance rather than seek to change the metric. It is imperative that customers have accurate bills to manage their expenses, assess their energy costs and manage their energy activities accordingly. Changing the metric to 2% would lock in the adverse performance levels that occurred in unusual circumstances. The OEB finds that there are no unusual circumstances persisting in 2023, beyond Enbridge Gas's control.

In addition, the OEB believes that the Advanced Metering Infrastructure pilot project is a positive step in managing this metric in the future. Enbridge Gas is required to provide an update on this pilot project in Phase 3 of this proceeding.

6 IMPLEMENTATION ISSUES

Enbridge Gas requested OEB approval for interim 2024 rates based on the OEB's Phase 1 decision, to be effective January 1, 2024, irrespective of the timing of the implementation date of the Rate Order. Since the application is proposed to be reviewed in phases, Phase 1 rates should be declared interim because they may be adjusted to reflect the full impacts of determinations made in Phase 2. The determinations made in Phase 3 regarding cost allocation and rate design and harmonized rates will be prospective and will not impact prior rates.²⁰⁰

Enbridge Gas submitted that it was appropriate for the company to recover the full-year impact of any revenue deficiency/sufficiency approved in Phase 1 of this proceeding effective January 1, 2024.

Most intervenors (CCC, FRPO, LPMA, SEC and VECC) that made a submission on this issue supported the applicant's request for an effective date of January 1, 2024.

OEB staff and VECC noted that the Enbridge Gas cost of service application is one of the largest and most complicated applications to come before the OEB. OEB staff and VECC further agreed that Enbridge Gas made all filings in a timely manner. OEB staff submitted that if a rate order is issued after January 1, 2024, Enbridge Gas should be permitted to recover the entire revenue deficiency/sufficiency for the 2024 Test Year and the calculation of this recovery can be included as part of the draft rate order process in Phase 1 of this proceeding.

LPMA supported Enbridge Gas's proposal with two caveats. Firstly, if rates cannot be implemented on January 1, 2024, LPMA submitted that Enbridge Gas should provide as part of the draft rate order, detailed information on how the revenue adjustment rider would be calculated and implemented (one time charge or over a specified number of months) as well as how the amounts are allocated to the different rate classes. Secondly, the OEB should direct Enbridge Gas to implement rates as quickly as possible and not wait for the next Quarterly Rate Adjustment Mechanism (QRAM) after January 1, 2024, which would be April 1, 2024. LPMA noted that the winter months are high consumption months and waiting longer than required would levy additional costs onto customers based on their historical consumption.

In reply, Enbridge Gas confirmed that the rate adjustment rider would be calculated to recover the variance between the current approved revenue and the approved 2024 revenue requirement from the effective date of January 1, 2024 to the implementation date. Enbridge Gas proposed the rate adjustment rider to be applied prospectively over

²⁰⁰ Partial Settlement Proposal, June 28, 2023 (Updated July 14, 2023), footnote 6.

a period of time from the implementation date until the end of 2024 for both in-franchise general service and contract rate classes. Enbridge Gas further proposed a one-time adjustment for ex-franchise contract rate classes consistent with current practice. Enbridge Gas also confirmed that it will file detailed information as part of the draft rate order to allow the OEB and intervenors to verify the amounts and allocation of the amounts to all rate classes.

Agreeing with LPMA, Enbridge Gas proposed that it will implement the approved interim rates as soon as possible after approval, even where the implementation date is different from the implementation date of QRAMs.

Findings

The OEB accepts Enbridge Gas's proposal. The OEB finds that January 1, 2024 is the appropriate effective date for 2024 rates.

The OEB agrees with Enbridge Gas, intervenors and OEB staff that Enbridge Gas made all necessary filings in a timely manner in the current proceeding. Given that the rate order will not be issued until after December 31, 2023, the OEB finds that it is appropriate for Enbridge Gas to recover the entire variance between the current approved revenue and the approved 2024 revenue requirement from the effective date of January 1, 2024 to the implementation date.

The OEB also finds that the rate adjustment rider that will be designed to capture this variance will be applied prospectively over a period of time for both in-franchise general service and contract rate classes and as a one-time adjustment for ex-franchise contract rate classes. The OEB directs Enbridge Gas to file a detailed calculation for the rate adjustment rider in the draft rate order and propose a period of time over which the rate rider will be applied.

Further, the OEB accepts Enbridge Gas's proposal that the 2024 rates resulting from this Decision and Order, and as will be reflected in the Rate Order, will establish interim 2024 rates based on the OEB's Phase 1 Decision and Order. The OEB notes that the 2024 rates will be declared interim to reflect that the application is being reviewed in phases and the 2024 rates may be further adjusted as of January 1, 2024 to reflect the full impacts of determinations made in Phase 2 of this proceeding.

With respect to implementation timing for interim 2024 rates, the OEB agrees that these rates should be implemented as soon as possible after approval, even where the implementation date is different from the implementation date of the nearest QRAM proceeding.

The OEB notes that it issued a letter on October 4, 2023 directing that the Phase 2 evidence be filed in January 2024. Given the findings in the Decision and Order, the OEB will provide further guidance on the timing of Phase 2 evidence, as well as on the issues that it expects to be addressed in Phase 2, in due course.

7 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. Enbridge Gas shall file with the OEB, and forward to all intervenors a draft rate order attaching a proposed Rate Handbook reflecting the OEB's findings in this Decision and Order by **February 12, 2024**. The draft rate order shall include customer rate impacts and detailed supporting information showing the calculation of interim 2024 rates and the associated rate adjustment rider for the period from January 1, 2024 to the implementation date. Enbridge Gas should also propose the appropriate implementation date in its draft rate order.
2. The draft rate order shall also include draft accounting orders related to the deferral accounts established, revised or approved by the OEB in this proceeding which were not included in the settlement proposal of June 28, 2023 (as updated on July 14, 2023) and that are related to Phase 1 of this proceeding.
3. Enbridge Gas shall inform the OEB of its intent to expand the NGV program as proposed, as an ancillary activity operated on a fully allocated cost basis, and provide a forecast of the fully allocated costs for 2024 as part of the draft rate order.
4. Intervenors and OEB staff shall file any comments on the draft rate order with the OEB and forward them to Enbridge Gas on or before **February 26, 2024**.
5. Enbridge Gas shall file with the OEB and forward to the intervenors responses to any comments on its draft rate order on or before **March 11, 2024**.
6. Enbridge Gas's current approved rates as established in EB-2023-0330²⁰¹ will continue to apply on and after January 1, 2024, on an interim basis, until the rates approved in Phase 1 of this proceeding are implemented.
7. Enbridge Gas is exempted from section 2.2.2 of the Gas Distribution Access Rule to the extent necessary to give effect to the findings on the revenue horizon.
8. Enbridge Gas is granted a partial exemption from section 7.3.4.2 of the Gas Distribution Access Rule with respect to the Time to Reschedule a Missed Appointment service quality requirement. The target metric shall be 98% rather than 100%.

²⁰¹ EB-2023-0330, Decision and Rate Order, December 19, 2023.

9. For Phase 2 of this proceeding, Enbridge Gas shall:
- a. File an updated customer connection policy, applicable to projects connecting to the gas system after December 31, 2024, that is consistent with the OEB's findings in this Decision and Order.
 - b. File a proposal that will address the need to ensure that where a contribution in aid of construction has been paid for connection facilities to serve small volume customers for a new connection made on or after January 1, 2025, the new connecting customers do not pay for the connection facilities a second time through postage stamp rates.
 - c. File a proposal for a modified approach for connection charges for infill customers, consistent with the OEB's findings in this Decision and Order, to take effect January 1, 2025.
 - d. Review the energy comparison information in its informational and marketing materials, including its website,
 - i. to determine whether it fully discloses what is being compared and on what basis, and what assumptions are being used for the comparison
 - ii. make any necessary corrections to the information, or remove it, and
 - iii. file a report on the review it undertook and the actions it took as a result of the review.
 - e. File a proposal on how the reduction to the capital budget will be implemented during the proposed IRM term to address the change to the revenue horizon.
 - f. File a proposal to reduce the capitalized indirect overheads balance by \$50 million in each year of the proposed IRM term and expense it as O&M, consistent with the OEB's findings in this Decision and Order.
 - g. File evidence indicating how the annual amount for site restoration costs is calculated and to provide a long-term forecast of the total funds required to pay for site restoration costs.
10. For its next rebasing application, Enbridge Gas shall:
- a. File an Asset Management Plan that provides clear linkages between capital spending and energy transition risk. The Asset Management Plan should address scenarios associated with the risk of under-utilized or stranded assets and identify mitigating measures.
 - b. File a report examining options to ensure its depreciation policy addresses the risk of stranded asset costs appropriately. These options must encompass all reasonable alternative approaches, including the Units of Production approach.

- c. Track and study the ten accounts proposed by InterGroup with respect to net salvage and file a report on the results.
- d. File a proposal to reduce any remaining capitalized indirect overheads to zero.
- e. File an independent third-party expert study that assesses its overhead capitalization methodology.
- f. Perform a risk assessment and develop a plan to reduce the stranded asset risk in the context of system renewal.

11. Enbridge Gas is required to provide an update on the Advanced Metering Infrastructure pilot project in Phase 3 of this proceeding.

How to File Materials

Parties are responsible for ensuring that any documents they file with the OEB, such as applicant and intervenor evidence, interrogatories and responses to interrogatories or any other type of document, **do not include personal information** (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*), unless filed in accordance with rule 9A of the OEB's [Rules of Practice and Procedure](#).

Please quote file number, **EB-2022-0200** for all materials filed and submit them in searchable/unrestricted PDF format with a digital signature through the [OEB's online filing portal](#).

- Filings should clearly state the sender's name, postal address, telephone number and e-mail address.
- Please use the document naming conventions and document submission standards outlined in the [Regulatory Electronic Submission System \(RESS\) Document Guidelines](#) found at the [File documents online page](#) on the OEB's website.
- Parties are encouraged to use RESS. Those who have not yet [set up an account](#), or require assistance using the online filing portal can contact registrar@oeb.ca for assistance.
- Cost claims are filed through the OEB's online filing portal. Please visit the [File documents online page](#) of the OEB's website for more information. All participants shall download a copy of their submitted cost claim and serve it on all required parties as per the [Practice Direction on Cost Awards](#).

All communications should be directed to the attention of the Registrar and be received by end of business, 4:45 p.m., on the required date.

Email: registrar@oeb.ca

Tel: 1-877-632-2727 (Toll free)

DATED at Toronto, December 21, 2023

ONTARIO ENERGY BOARD

Patrick Moran
Presiding Commissioner

Emad Elsayed
Commissioner

Allison Duff
Commissioner (Concurring in Part)

8 DISSENT IN PART - COMMISSIONER DUFF

I do not support a zero-year revenue horizon for assessing the economics of small volume gas expansion customers. I do not find the evidentiary record supports this conclusion. The CIAC comparison table filed by Enbridge Gas did not even consider zero within the range of revenue horizon options. Zero is not a horizon. It is fundamentally inconsistent with the intent of E.B.O. 188 by requiring 100% of connection costs upfront as a payment, rather than a contribution in aid of construction. There was no mention of zero in E.B.O. 188 – yet a 20 to 30 year revenue horizon was considered.²⁰² To me, the risk of unintended consequences to Enbridge Gas, its customers and other stakeholders increases given the magnitude of this conclusive change.

The rationale provided in the majority decision to support zero is predicated on understanding considerations and circumstances facing developers. The rationale is conjecture as no developers intervened or filed evidence in this proceeding. In contrast, a recent OEB proceeding regarding a proposed housing development in Whitby included intervenor evidence, oral testimony and submission by the affected developer group, enabling the OEB to render a decision based on the evidence.²⁰³

A zero-year revenue horizon implies an indifference as to whether these developers decide to connect, or not connect, any gas expansion customers. Is the scenario of no-new-gas-connections, replaced by construction of all-electric developments, feasible? For example, would electricity generators, transmitters, distributors and the IESO be able to meet Ontario's energy demands in 2025? I don't know.

I find that a 20-year revenue horizon is appropriate for Enbridge Gas's small volume expansion customers, effective January 1, 2025. A reduction from the current 40 years to 20 years mitigates the risk of stranded asset costs resulting from switching away from natural gas as an energy source, thereby protecting existing customers. After 20 years, the risk should be fully mitigated by adding the contribution received upfront to the rate revenue received over 20 years from new customers. Any rate revenue received from these customers after year 20 would contribute to overall system costs. The 20-year revenue horizon would apply to new infill and expansion customers but not customers connected under the Natural Gas Expansion Program.²⁰⁴

²⁰² E.B.O. 188, Final Report of the Board, January 30, 1998, p. 15.

²⁰³ EB-2022-0024, Decision and Order – Phase 2, July 6, 2023, pp. 17-25.

²⁰⁴ O. Reg. 24/19: Expansion of Natural Gas Distribution Systems.

Mr. Neme recommended a 15-year revenue horizon in his evidence. This option was tested through the interrogatory and oral phases of the proceeding. I find his rationale compelling and equally applicable to 20 years, when the typical 18-year life of a new gas furnace is rounded up.²⁰⁵ An 18-year gas furnace life is also used in estimating energy savings from Enbridge Gas's DSM programs.²⁰⁶

Phase 2 of this proceeding is the appropriate juncture to consider the ratemaking implications of this change for Enbridge Gas, its customers and other stakeholders. Prior to setting rates for the remainder of the proposed IRM term 2025-2028, the ratemaking implications of the 20-year revenue horizon must be considered, such as forecast customer numbers, throughput volumes, capital expenditures, and CIAC collections.

The CIAC comparison table filed by Enbridge Gas simplified the CIAC and total contribution calculations by making certain assumptions. I cannot rely on the table's \$1,774 contribution per customer or total \$185 million collection in 2025 associated with the 20-year revenue horizon scenario as definitive calculations. For example, one assumption is that system access capital expenditures and customer connections from 2024 to 2028 would proceed as forecast irrespective of a revenue horizon change. A deeper understanding of all inputs, assumptions and forecasts is needed, and Phase 2 of this proceeding provides the opportunity for that review.

Phase 3 of this proceeding is the appropriate juncture to consider whether there is undue cross subsidization between new and existing customers resulting from a 20-year revenue horizon, assuming no negative rate rider. The intent of E.B.O. 188 was to avoid undue cross subsidization. In deciding issues of cost allocation and rate design in Phase 3, the extent of cross subsidization must also be considered in the context of Enbridge Gas's harmonization proposal, in which four geographic rate zones are harmonized to one.

I find the change to 20 years to be a measured, incremental approach to risk mitigation, while also signaling a significant evolution to the OEB's approach. The implications of changing from 40 to 20 years would be assessed, enabling a change in course if necessary. Such an incremental approach to deal with energy transition risks is consistent with the OEB's recommendations to the EETP.²⁰⁷

²⁰⁵ Exhibit M9, Evidence of Mr. Chris Neme. Energy Futures Group, p. 43.

²⁰⁶ Incentives for high-efficiency furnaces are not included in the most recent DSM Framework (EB-2021-0002); however, the OEB's current natural gas [DSM Technical Resource Manual](#) uses 18 years as the measure life for a new furnace.

²⁰⁷ Report of the OEB to the EETP, June 30, 2023, p. 12.

E.B.O. 188 established a maximum revenue horizon of 40 years. Applying 20 years for Enbridge Gas is within this maximum and preserves the provisions of a ten-year customer attachment horizon, a rolling project portfolio and the concept of a contribution. Also, a revenue horizon of 20 years could be applied uniformly to all small volume and large volume contract expansion customers.

In all other respects, I agree with Commissioners Moran and Elsayed.

Allison Duff
Commissioner