Ontario

ONTARIO ENERGY BOARD

OEB Staff Submission

Enbridge Gas Inc.

2024 Rates Application – Phase 1

EB-2022-0200

September 12, 2023

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Background and Submission Summary

On August 30, 2018, the Ontario Energy Board (OEB) approved the amalgamation of Enbridge Gas Distribution Inc. and Union Gas Limited.[1] In its decision, the OEB also approved a rate-setting framework and associated parameters for the deferred rebasing period of 2019 to 2023. The companies amalgamated to form Enbridge Gas Inc. (Enbridge Gas) effective January 1, 2019. Enbridge Gas is the largest natural gas distribution utility in Canada serving over 3.5 million customers.

Enbridge Gas filed an application with the Ontario Energy Board under section 36 of the *Ontario Energy Board Act*, *1998* seeking approval for changes to the rates that it 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 application since the two companies amalgamated.

In its Decision on Issues List and Procedural Order No. 2, the OEB set out the issues list to define the structure and scope of the proceeding. The OEB divided the review of the application into Phase 1 and Phase 2.[2]

A settlement conference was held from May 29, 2023, to June 9, 2023, with respect to Phase 1 issues in the proceeding. The intervenors and the applicant reached a partial settlement on the Phase 1 issues. The OEB approved the settlement in a decision issued on August 17, 2023.

An oral hearing was held over 18 hearing days, between July 13, 2023, and August 11, 2023. At the oral hearing, the OEB amended the dates for procedural steps subsequent to the oral hearing. Enbridge Gas filed its argument-in-chief on August 18, 2023.

The following is OEB staff's summary of its position on the key unsettled issues that were reviewed as part of Phase 1 of this proceeding. A detailed discussion, organized according to the Issues List, follows.

Summary of OEB Staff Position on Key Issues

- OEB staff supports shortening the revenue horizon for economic feasibility assessment from 40 years to 20 years in Enbridge Gas's customer connection policy for both system expansion and infill customers.

[1] EB-2017-0306 / 0307 (the MAADs Decision).
[2] As part of the OEB approved settlement proposal, parties agreed to address certain issues in a new Phase 3 of the proceeding.

- Enbridge Gas should be required to provide customers that request a connection with complete information on energy options for space heating.
- Enbridge Gas's capital budget related to customer connections should be reduced to reflect the higher contributions in aid of capital that will result from the proposed 20-year revenue horizon (reduction of $116.1 million).
- Enbridge Gas should be required to provide more information and analysis on certain matters (energy transition assumptions in load forecast, infrastructure repair options) and include forecast risk/stranded asset risk in its cost-benefit methodology for integrated resource planning (IRP)) as part of the IRP assessment process.
- The proposed 2024 capital expenditures should be reduced from $1,470.3 million to $1,198.8 million.
- Enbridge Gas should be permitted to include 50% of the net book value of integration capital to 2024 opening rate base.
- OEB staff generally accepts Enbridge Gas's proposed harmonized capitalized overhead methodology subject to certain proposed adjustments.
- OEB staff supports Enbridge Gas's proposal to exclude amounts related to property disposition gains or losses in the 2024 other revenues forecast and recommends the establishment of a deferral account to record proceeds from sales over the proposed rate term.
- Enbridge Gas should be required to use the Average Life Group depreciation procedure using InterGroup Consultants Ltd.'s (Intergroup) recommended asset life parameters; and InterGroup's Constant Dollar Net Salvage calculation method with its recommended net salvage parameters to determine net salvage costs at a discount rate equal to the most current credit-adjusted risk free rate of 4.48%.
- OEB staff submits that the need for a segregated fund for site restoration costs should be reassessed at the time of the next rebasing application.
- OEB staff supports an increase to the equity thickness from 36% to 38% in line with its expert London Economics International's recommendation and OEB staff's assessment of Enbridge Gas's risk.
- The OEB should not approve a Volume Variance Account for Enbridge Gas but, instead, establish an average use account for the amalgamated utility (which currently exists separately for both of the legacy utilities).

- In the event that the OEB approves recovery of Union Gas's pre-2017 unamortized actuarial gains/losses, OEB staff submits that only a partial recovery of $75.8 million should be approved.
- OEB staff supports Enbridge Gas's proposed approach to the Natural Gas Vehicle Program.
- OEB staff does not support the establishment of an earnings sharing mechanism for the 2024 cost of service year.
- OEB staff does not support monetary incentives for shippers to turn back capacity on the Dawn Parkway system.
- OEB staff supports Enbridge Gas's request for a partial exemption from the requirements of the Gas Distribution Access Rule in respect of certain performance metrics for 2023 and 2024. To the extent that permanent changes to the performance metrics are appropriate, they should be considered by the OEB through a broader review (and potential amendments to) the Gas Distribution Access Rule.

OEB Staff Submission

Issues List – Phase 1

A. Overall

Issue 1: Are the proposed rates and service charges just and reasonable?

OEB staff has not made any direct submissions on this issue. However, OEB staff notes that its recommendations on the Phase 1 unsettled issues, if accepted, would assist the OEB in setting interim rates and service charges that are just and reasonable.

Issue 2: Have the customer benefits identified in the amalgamation proceeding EB-2017-0306/0307 been realized having regard to the five-year deferred rebasing term that was approved?

Enbridge Gas Distribution and Union Gas filed an application with the OEB to amalgamate in November 2017 (MAADs application). The applicants prepared their applications on the basis of the OEB's *Handbook to Electricity Distributor and Transmitter Consolidations* (MAADs Handbook), which provides guidance on applications for mergers, acquisitions, amalgamations and divestitures (MAADs). [3] Accordingly, the applicants proposed a deferred rebasing period of ten years and a rate-setting framework based on the Price Cap Incentive rate-setting option.[4]

In the MAADs application, Enbridge Gas identified the estimated cost efficiencies and associated capital costs related to the amalgamation.[5] The capital investment required for the integration of systems and technology to support the amalgamation of Enbridge Gas Distribution and Union Gas was estimated to be between $50 million and $250 million. These investments were expected to deliver potential cost synergies of between $350 million and $750 million over the proposed 10-year deferred rebasing period. Table 1 shows the range of capital investments and the potential cumulative cost savings.

[3] *Handbook to Electricity Distributor and Transmitter Consolidations*, January 19, 2016, page 12 – consolidating distributor can chose a deferred rebasing period of 10 years with no supporting evidence.
[4] EB-2017-0306/0307.
[5] *ibid*

Table 1
High Level Minimum and Maximum Cost and Savings Estimate ($ Millions)

Item	Potential Capital		Potential O&M Savings	
	Minimum	Maximum	Minimum	Maximum
Customer Care	$25	$110	$120	$250
Distribution Work Management	$10	$90	$30	$150
Utility Shared Services	$5	$20	$15	$50
Storage & Transmission	$5	$10	$15	$50
Management Functions & Other	$5	$20	$170	$250
Total	$50	$250	$350	$750

In its decision issued on August 30, 2018, the OEB approved the amalgamation of the two legacy utilities effective January 1, 2019, granting Enbridge Gas a deferred rebasing term of five years.[6]

In its evidence, Enbridge Gas noted that it undertook significant operations and maintenance (O&M), and capital investments during the deferred rebasing term. Starting in 2019, Enbridge Gas tracked synergy savings and costs from integration initiatives in each area of accountability. Table 2 provides the savings by area of accountability.

Table 2

Integration O&M Savings as achieved by Area[7]

Areas of Accountability ($ millions)	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year
Business Development & Regulatory	6.8	9.6	10.4	10.4	10.4
Customer Care	5.5	6.6	7.5	22.5	22.5
Distribution Operations	6.3	9.8	17.3	16.8	16.8
Energy Services	2.6	5.6	5.9	5.9	5.9
Engineering & STO	5.2	9.0	11.6	11.6	11.8
Central Functions	3.9	9.1	15.7	15.8	15.8
Other	2.0	2.7	2.8	2.8	2.8
Total Annual Savings	32.2	52.4	71.2	85.8	86.0

[6] EB-2017-0306/EB-2017-0307, *Decision and Order*, August 30, 2018, p. 4.
[7] Exhibit 1, Tab 9, Schedule 1, Table 3, p. 5.

Over the deferred rebasing term (2019 to 2023), Enbridge Gas expects to incur approximately $252.2 million in capital expenditures related to integration efforts. Beginning in 2024, Enbridge Gas will reflect the impact of the efficiencies and cost savings resulting from the amalgamation in its going forward rates. Enbridge Gas noted that the expected annual savings in 2024 will be $86 million which will be reflected in 2024 rates. Enbridge Gas submitted that the annual integration synergies of $86 million demonstrate that the amalgamation of Enbridge Gas Distribution and Union Gas provides ongoing benefits to customers.

In the MAADs application, the former Enbridge Gas Distribution and Union Gas provided a range of $350 million to $750 million in O&M savings with an estimated capital spend between $50 million to $250 million. Enbridge Gas's capital expenditures related to integration during the deferred rebasing term were at the top end of the range at $252 million. The total cumulative savings over the deferred rebasing term as evident from Table 2 is expected to be $327.6 million. However, OEB staff notes that Enbridge Gas's savings estimate was based on a 10-year deferred rebasing term and not the five-year term that was granted by the OEB. Considering that a saving of $86 million is included in 2024 rates, OEB staff has extrapolated the $86 million from year six to ten to reflect estimated savings over a 10-year period. This results in total savings of $757.6 million for the ten-year period which is in line with Enbridge Gas's top end range of estimated savings.

Despite these savings, O&M costs have consistently increased from 2018 to 2024. The 2018 actual O&M for the former Enbridge Gas Distribution and Union Gas was $753 million (excluding demand side management costs) and this increased to $785 million in 2019 after amalgamation. The amount has consistently increased over the years, rising to $788 million in 2021 and $821 million (as per the approved settlement) in 2024. Enbridge Gas was able to achieve synergy savings largely through organizational restructuring and attrition in 2019. However, COVID-19 had a substantial impact on Enbridge Gas's operations and costs during this period and beyond. Enbridge Gas stated that COVID-19 restrictions led to a reduction in work volume from access limitations, supply chain issues and staff availability creating a backlog that needed to be addressed in subsequent years.

Enbridge Gas stated that in 2022, costs were higher due to significant inflation and increased compliance requirements. Enbridge Gas noted that other cost increases were driven by higher bad debt from economic conditions and prolonged higher commodity prices. In 2023, Enbridge Gas is expecting further cost pressures related to inflation, pension costs based on actuarial valuations and locate costs from the implementation of Bill 93. These cost pressures are expected to be mitigated by winding down integration work and the accumulation of integration synergy and productivity savings. Over the deferred rebasing term (2019-2023), the annual increase in utility O&M excluding DSM is expected to be 2.5%. Inflation, as measured by GDP IPI (Gross Domestic Product Implicit Price Index) is projected to grow at a rate of 3.1% per annum over the same period.

OEB staff acknowledges that the COVID-19 pandemic and post pandemic period resulted in challenges for businesses in terms of labour resourcing issues, inflation and supply chain bottlenecks. Under normal operating conditions, OEB staff would have expected that operating costs would decline in absolute terms post amalgamation. However, OEB staff does recognize the challenging environment created by COVID-19, and notes that O&M cost increases for Enbridge Gas during the deferred rebasing period were lower than inflation. Accordingly, OEB staff submits that customers did realize the benefits from amalgamation as identified in the MAADs proceeding within the context of the shortened five year deferred rebasing term as approved by the OEB.

OEB staff's submission on the appropriate rate treatment for the integration capital costs incurred is set out under Issue 6 & 7 (Rate Base and Capital Expenditures).

Issue 3: Has Enbridge Gas appropriately considered energy transition and integrated resource planning in relation to such things as:

- **a) load forecast**
- **b) deemed capital structure**
- **c) depreciation rates**
- **d) forecast capital expenditures**
- **e) allocation and mitigation of risk**

to determine new rates that will be effective January 1, 2024, considering relevant government policies and legislation?

Energy Transition – General

Energy transition generally refers to the global shift away from using fossil fuels to a more sustainable, renewable energy future that includes more innovation and customer choice. A growing focus on energy transition and government policy initiatives aimed at lowering greenhouse gas (GHG) emissions has raised questions about the future of natural gas, including concerns that existing and new natural gas capital assets will become underutilized and possibly stranded in the future. Therefore, energy transition was a major focus for both Enbridge Gas and many intervenors throughout the current proceeding. Enbridge Gas filed evidence detailing its perspective and approach to energy transition,[8] including how energy transition has been integrated into Enbridge Gas's business and planning processes. Enbridge Gas's approach to energy transition also informed and supported Enbridge Gas's proposals in other areas of its application, particularly load forecasting, capital expenditures, equity thickness, and depreciation.

Intervenor - Energy Transition Evidence

Evidence focused on energy transition was also filed by other parties:

- Evidence from Chris Neme of Energy Futures Group (EFG) on behalf of Environmental Deference (ED) and the Green Energy Coalition (GEC), covering many aspects of energy transition.
- Evidence from Dr. Asa Hopkins of Synapse Energy Economics Inc. on behalf of the Industrial Gas Users Association (IGUA), focused primarily on energy transition-related business risk and capital structure.
- Evidence from Ian Jarvis and Gillian Henderson of Enerlife Consulting Inc. on behalf of Building Owners and Managers Association (BOMA), focused on considerations for energy transition related to the commercial buildings sector.
- Evidence from Dr. Robert W. Howarth and Dr. Mark Jacobson, on behalf of ED, about 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 GHG emissions reductions targets and available alternatives for customers.

The Government of Canada has committed to reducing GHG emissions by 40% below 2005 levels by 2030, and to net-zero emissions by 2050 through the *Canadian Net-Zero Emissions Accountability Act*. The most notable action at the Federal level to reduce GHG emissions to date has been the implementation of an escalating carbon price, increasing annually and reaching $170/tonne CO_2e (carbon dioxide equivalent) by 2030.

The Government of Ontario has committed to reducing GHG emissions by 30% below 2005 levels by 2030 but has not committed to any longer-term target. Enbridge Gas noted that further policy direction from the Government of Ontario on its approach to the energy transition may be forthcoming after several reports currently under development – advice from the Electrification and Energy Transition Panel (EETP), and an

[8] Exhibit 1, Tab 10.

independent study on cost-effective energy pathways – have been received and reviewed by the Government of Ontario.[9]

Safe Bets

Given the uncertainty around how the energy transition will occur, Enbridge Gas's approach is shaped around what it considers to be safe bets[10], which are actions that:

- Support Ontario's near term GHG reductions, including achievement of the 2030 target; and/or
- Are required, regardless of whether a diversified or an electrification pathway unfolds in Ontario; and/or
- Maintain consumer choice, a safe and reliable natural gas system in a manner that considers pathway uncertainty, and/or pathway optionality until greater certainty around how best the transition is achieved.

The list of safe bet actions proposed by Enbridge Gas is:

- Maximizing energy efficiency (through demand-side management programs).[11]
- Increasing the amount of renewable natural gas (RNG) in the gas supply through a Low-Carbon Voluntary Program and supporting RNG upgrading.
- Reducing GHG 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
  - Implementing phase 2 of Enbridge's Low Carbon Energy Project (hydrogen blending)
  - Establishing an Energy Transition Technology Fund

[9] Exhibit J8.1, Attachment 1.
[10] Exhibit 1, Tab 10, Schedule 6, pp. 13-35.
[11] 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.

- Maintaining the gas system via Integrated Resource Planning and scope 1 & 2 emissions reduction focus (i.e., reducing Enbridge Gas's direct and indirect emissions arising from its utility operations, as distinct from emissions from Enbridge Gas's customers due to their natural gas use).

The only safe bet proposal where approval is specifically requested in Phase 1 of the rebasing proceeding is Enbridge Gas's proposal for the Natural Gas Vehicle Program (discussed under Issue 34).

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. Energy transition safe bet proposals with proposed capital spending over the rebasing term are investments in customer driven RNG injection stations and Compressed Natural Gas (CNG) Rental Stations, the Hydrogen Blending Grid study, phase 2 of the Low Carbon Energy Project (hydrogen blending),[12] and projects to support scope 1 and 2 GHG emissions reductions.[13] Hydrogen blending is discussed later in OEB staff's submission on Issue 3.[14]

Proposed capital expenditures on emissions reductions and energy transition initiatives over the rebasing term are shown in the bottom two rows of the table below. The bulk of capital spending in the "energy transition" category is related to spending on customer driven RNG injection stations that is ultimately recovered entirely through specific rates from those customers.[15] As can be seen in Table 3 below, investments in emissions reduction and energy transition are a small portion (roughly 4%) of Enbridge Gas's proposed spending over the rebasing term, in comparison to much larger spending on gas infrastructure, including significant capital spending on growth-related projects.

[12] This project will also be subject to a Leave to Construct Application.
[13] Enbridge Gas's approach to assessing IRP alternatives is also part of its Asset Management Plan, although the current AMP does not include funding for any IRP alternatives.
[14] See the sub-section titled, "Energy transition and Integrated Resource Planning impacts on load forecast and capital expenditures".
[15] Hearing Transcript, Vol. 14, pp.6-7.

Table 3
Enbridge Gas Forecast Capital Expenditures – 2024 to 2028[16]

Investment Sub-Category	2024 ($ million)	2025 ($ million)	2026 ($ million)	2027 ($ million)	2028 ($ million)
Gas Infrastructure – Replacement – Reactive	60.7	40.6	44.1	56.6	72.4
Gas Infrastructure – Replacement – Proactive – Short Term (1y+)	147.5	283.7	126.1	153.5	60.6
Gas Infrastructure – Replacement – Proactive – Long Term Cost Effectiveness	1.4	0.9	11.8	18.5	94.0
Gas Infrastructure – Sustainment	472.7	406.6	439.0	378.6	367.7
Gas Infrastructure – Growth – Customer Connections	333.6[17]	285.9	296.7	294.8	269.6
Gas Infrastructure – Growth – System Reinforcement	277.4	268.9	176.9	262.8	140.9
Business Sustainment	195.8	171.6	204.1	122.9	163.2
Emission Reductions	1.8	4.1	1.2	11.9	0.0
Energy Transition	134.1	55.0	31.5	28.0	35.7
Grand Total	**1665.2**	**1630.5**	**1406.7**	**1392.3**	**1279.5**
Grand Total net of Panhandle project reductions[18]	**1470.3**	**1623.8**	**1406.7**	**1392.3**	**1279.5**

Consideration of several safe bet proposals (the Low-Carbon Voluntary Program and the Energy Transition Technology Fund) will be considered in Phase 2 of the rebasing proceeding. These proposals have associated spending implications over the rebasing term that are non-capital in nature.

[16] Adapted with modification from Exhibit 2, Tab 5, Schedule 1, Page 13, Table 2 (updated).
[17] As shown in Exhibit J13.5, this value includes capital expenditures for general customer connections ($304.1 million), plus several additional categories such as metering costs and projects that are part of the Natural Gas Expansion Program. Because this table provides a different categorization of Enbridge Gas's capital expenditures than the categorization by asset class that Enbridge Gas traditionally uses (shown in Exhibit 2, Tab 5, Schedule 2, Page 2), the 2024 growth-related spending shown in Table 3 ($333.6 million for customer connections and $277.4 million in system reinforcement, minus $194.9 million for the Panhandle Regional Expansion Project, totaling $416.1 million) differs slightly from the value of $400.5 million that Enbridge Gas describes as its 2024 growth capital budget (and which OEB staff has used as the basis for its recommended reductions to the growth capital budget). Given the importance of these growth capital budget figures, OEB staff requests that Enbridge Gas explain the difference between the $416.1 million and $400.5 million described above.
[18] Accounts for capital expenditure reductions associated with the Panhandle Regional Expansion Project spending ($194.9 million in 2024 and $6.7 million in 2025), as Enbridge Gas has proposed removing the costs of this project from the 2024 capital budget proposal. Exhibit 2, Tab 5, Schedule 2, page 2.

Other safe bet proposals (maximizing energy efficiency through demand side management, carbon capture and sequestration, integrating gas and electricity system planning) do not have an associated proposal within the rebasing application.

Energy Transition Pathways Studies and Routes to Net Zero

As discussed in more detail later in OEB staff's submission on Issue 3[19], even with energy transition assumptions embedded, Enbridge Gas forecasts continued growth from 2023 through 2032 in both number of customers,[20] and peak (design hour) demand,[21] with overall volumes used by general service customers remaining flat over this period.[22] As a consequence, absent the use of lower-carbon gaseous fuels, GHG emissions from Enbridge Gas's general service customers would also remain flat through 2032. Any reductions in natural gas use from improvements in appliance efficiency or demand side management (DSM) programs are offset by customer growth. The energy transition assumptions reduce Enbridge Gas's customer emissions by only 1% in 2032 (from 30.313 million tonnes CO_2e to 30.279 million tonnes CO_2e), relative to a forecast based on Enbridge Gas's historical forecasting methodology with no explicit energy transition assumptions.

[19] See the sub-section titled, "Energy transition and Integrated Resource Planning impacts on load forecast and capital expenditures."
[20] Exhibit 1, Tab 10, Schedule 4, page 7, Figure 1.
[21] Exhibit 1, Tab 10, Schedule 4, page 11, Figure 3.
[22] Exhibit I.1.10-Staff-31, Attachment 1, p.1.

Table 4
Annual GHG emissions of volume forecast for general service customers (million tCO_2e)[23]

Year	Annual GHG Emissions	Emissions Savings	Annual GHG Emissions including Energy Transition
	(a)	(b)	(c) = (a)-(b)
2024	30.317	0.002	30.315
2025	30.312	0.004	30.308
2026	30.306	0.012	30.287
2027	30.298	0.024	30.274
2028	30.282	0.027	30.256
2029	30.261	0.029	30.232
2030	30.233	0.031	30.202
2031	30.275	0.032	30.243
2032	30.313	0.035	30.279

Many parties questioned how such a forecast can be compatible with energy transition and with federal and provincial objectives for deep reductions in GHG emissions. Enbridge Gas indicated that GHG emissions through 2032 will likely be lower than shown in Table 4 above due to increased use of renewable natural gas and hydrogen, and that continued gas use is compatible with a target of net zero emissions by 2050.

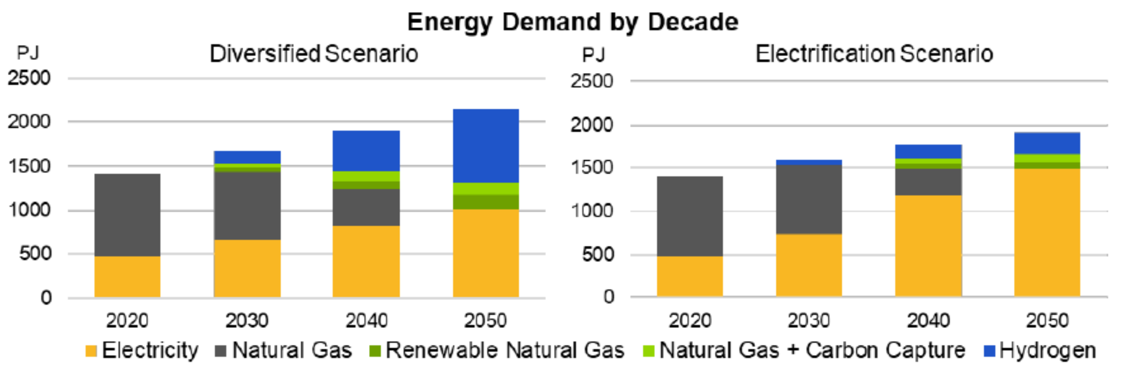
Enbridge Gas indicated that its vision of energy transition in Ontario is a diversified pathway that uses the natural gas and electric systems together, and includes a significant continuing role for the natural gas system, which transitions over time to a system that delivers almost exclusively low-carbon or zero-carbon gas solutions such as RNG and hydrogen, with perhaps a small amount of conventional natural gas combined with carbon capture.[24]

As support for this vision, Enbridge Gas filed two energy transition studies, the Energy Transition Scenario Analysis (by Posterity Group) and the Pathways to Net Zero Emissions for Ontario (P2NZ) (by Guidehouse).

[23] Exhibit I.1.10-Staff-28, p.2, Table 1.
[24] Exhibit 1, Tab 10, Schedule 5, pp. 21-25.

The P2NZ study compared two scenarios for Ontario's energy system by 2050 – a "Diversified Scenario" in which low and zero carbon gases and the gas delivery infrastructure are used in combination with end-use electrification to reduce GHG emissions in all sectors, and 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 – and concluded that the Diversified Scenario is more cost-effective in terms of overall energy system costs between 2020 and 2050. The Diversified Scenario models the total energy provided by gaseous fuels as increasing between 2020 and 2050, as conventional natural gas is replaced primarily by hydrogen but also by renewable natural gas and natural gas paired with carbon capture.[25]

Figure 1
Energy Demand by Decade

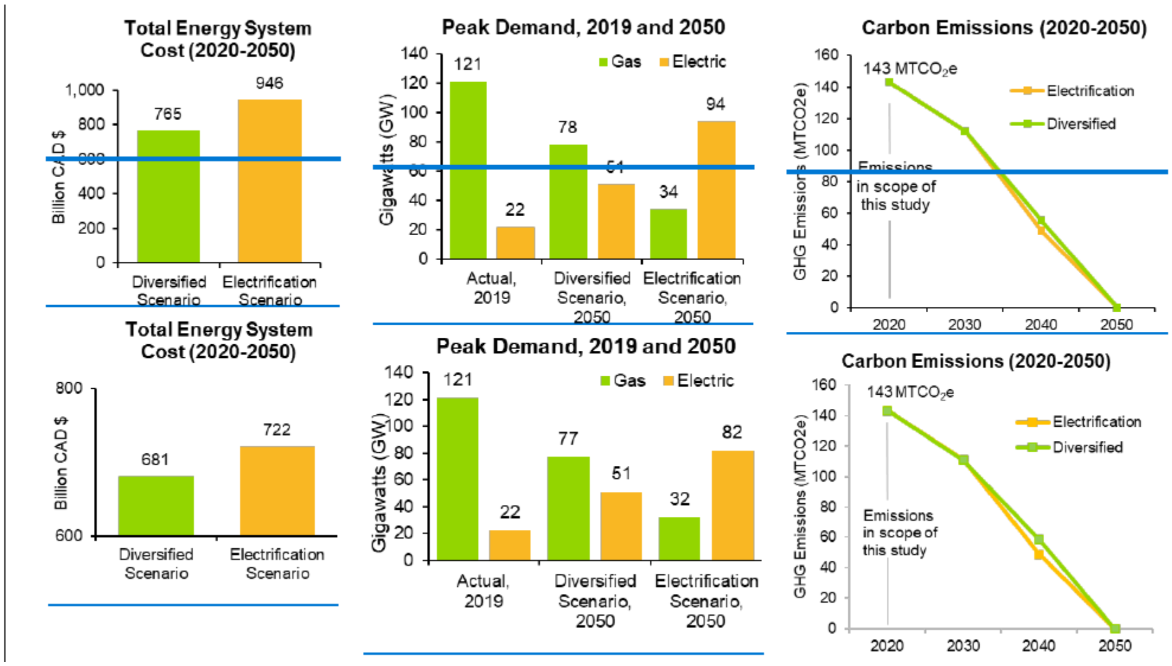


The inputs in the P2NZ study were discussed extensively in the interrogatory and technical conference phases of this proceeding. As a consequence, Guidehouse identified certain corrections and made several other changes resulting from questions and requests posed by intervenors. Guidehouse filed an updated version of its study, which had the impact of greatly reducing the cost differential between the Diversified and Electrification scenarios, relative to the originally filed study. The Diversified Scenario remained lower cost than the Electrification scenario, with a cost savings of roughly $41 billion (~6% difference) in total energy system costs over 2020-2050 relative to the Electrification pathway (versus a cost savings of $181 billion for the Diversified Scenario in the original version of the P2NZ study).[26]

[25] Exhibit KT 9.2, Figure ES-2.
[26] Exhibit KT 9.2, Figure ES-2.

Figure 2
Comparison of Key Results for Diversified and Electrification Scenarios

Figure ES-2. Comparison of Key Results for Diversified and Electrification Scenarios



Enbridge Gas noted that, based on the updated study, it “continues to believe and assert that the P2NZ Study provides support for showing that a diversified approach to achieving GHG emission reductions targets is as plausible as electrification”. Enbridge Gas also noted that the P2NZ 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.” [27]

Despite the updates, many parties continued to have concerns with assumptions in the P2NZ study. Many of these concerns are documented in the evidence filed by EFG.[28] EFG’s evidence also discussed how independent decarbonization pathways studies forecast higher levels of electrification than the P2NZ Diversified Scenario, and described some of the reasons why EFG believes that electrification will play a larger role than low-carbon gaseous fuels in a transition to net zero.[29]

Another scenario analysis discussed in the proceeding was the recently released energy futures scenario analysis of the Canada Energy Regulator (CER), *Canada’s*

[27] Enbridge Gas letter of April 4, 2023, *Update Re Guidehouse P2NZ Report.*
[28] Exhibit M9-GEC-ED, chapter 6.
[29] Exhibit M9-GEC-ED, chapters 3, 4.

Energy Future 2023. It was noted that in the net-zero scenarios used in this analysis, electric heat pumps are assumed to become the building heating technology of choice,[30] and thus the scenarios show a lower level of RNG/hydrogen use than in the P2NZ Diversified Scenario.

OEB Staff Submission

The energy transition represents a significant rethink of how Ontario will meet its energy needs in the future. It encompasses multiple sectors, multiple levels of government, and will play out over many years. Although the current proceeding clearly engages many energy transition issues, it is one of what will be many proceedings before the OEB that will deal with these or related issues. It should not be expected that this proceeding will be the final say on energy transition, even as it relates to natural gas and Enbridge Gas, but it is an important step. As the OEB noted in its report to the EETP:

> The work of the energy sector to facilitate the energy transition – including that of the OEB – will be iterative. Given uncertainties related to the pace of change, the OEB will ensure that our approach to regulation remains adaptable, flexible, and responsive to changing expectations and needs. The energy transition represents massive change; but not all problems need to be solved immediately. Instead, an incremental and prioritized approach that tackles issues one at a time will allow us to move forward, assess and change course as necessary.[31]

It is not possible at this stage to predict exactly how the energy transition will play out and it is not the OEB's role in this proceeding to determine the exact pathway that energy transition will take. However, OEB staff does believe that, based on the record in this proceeding, there is a high probability that the energy transition will follow a pathway with a less significant role for gaseous fuels (even if those are low or zero-carbon fuels) using Enbridge Gas's network than that described in the P2NZ Diversified Scenario.

Following the revisions to the P2NZ study, there is only a minor cost difference (6%) between the Diversified and Electrification scenarios, and this cost difference disappears entirely if the same carbon price is used in the two scenarios.[32] Given the large number of input assumptions and uncertainties in this type of scenario analysis, the OEB should not place much weight on the small cost premium of the Electrification Scenario as a compelling rationale that the Diversified Scenario is more likely for

[30] Exhibit K3.1, p. 49.
[31] Report of the Ontario Energy Board to Ontario's Electrification and Energy Transition Panel, p. 12.
[32] Exhibit M9-GEC-ED, p. 28.

Ontario. This study is one data point that should be considered alongside other evidence.

OEB staff finds the arguments suggesting likely practical limits to decarbonization of the gas network, as summarized in the evidence of EFG,[33] compelling, particularly the likely constraints on the supply of RNG and limits on using a high concentration of hydrogen with existing infrastructure and appliances. OEB staff agrees with EFG's statement that there is more technological uncertainty regarding a decarbonization pathway to net zero relying on low-carbon gaseous fuels than there is for a high-electrification pathway.

OEB staff's views should not be taken to mean that OEB staff opposes all investments in RNG or hydrogen, including Enbridge Gas's specific energy transition proposals for these fuels. These proposals should be judged on their own merits and may be of value even if the eventual role played by hydrogen and RNG in the energy transition ends up being smaller than their role in Enbridge Gas's energy transition vision. As discussed later in this section, OEB staff supports Enbridge Gas's proposal for a Hydrogen Blending Grid Study.

Given OEB staff's conclusions, the OEB should consider how to avoid negative outcomes for ratepayers when the transition away from conventional natural gas accelerates. The OEB should consider not only Enbridge Gas's specific energy transition proposals, but also its much larger proposed capital investments on gas infrastructure, particularly growth-related capital investments, using this lens. This includes managing risk associated with assets that may become stranded or underutilized as a result of the energy transition. OEB staff notes that the term "stranded asset risk" is generally used throughout the submission to refer to both risks associated with assets becoming completely stranded (i.e., no longer used at all) or becoming underutilized or partially stranded (still used, but at a level much lower than planned, e.g., such that project costs may significantly exceed project-specific revenues).

OEB staff's conclusions, as described above, inform its specific submissions related to energy transition, as summarized below, and described in more detail in later sub-sections under Issue 3.

[33] Exhibit M9-GEC-ED, chapter 4.

Table 5
Summary of OEB Staff Energy Transition Submissions[34]

Energy Transition Category	Staff Submission
Customer connections policy	• Shorten the revenue horizon for economic feasibility assessment from 40 years to 20 years in Enbridge Gas's customer connections policy for both system expansions and infills. • Require Enbridge Gas to provide, upon receipt of customer connection requests, information to prospective customers on energy options for building heating (e.g., natural gas only, hybrid gas/electricity, electricity only) in a manner and form to be determined by the OEB.
Load forecast and capital expenditures, including consideration of integrated resource planning (IRP)	• Reduce Enbridge Gas's customer connections capital budget to that supported by a 20-year horizon. • Require Enbridge Gas to review its energy transition assumptions in the load forecast on an annual basis and document any changes as part of its annual Asset Management Plan update, and track utilization of new growth-driven projects relative to forecast on an ongoing basis, to improve accuracy of forecasting and to assist in identifying stranded or underutilized assets. • Require Enbridge Gas to document how infrastructure repair options are considered in meeting system needs, and how the consideration of repair options relates to the IRP Assessment Process. • Require Enbridge Gas to value differences between project alternatives with regards to demand

[34] OEB staff's submission on the issues of rate base & capital expenditures, cost of capital and depreciation are summarized in this section as they relate to energy transition. However, OEB staff's submissions on the entirety of these issues are covered later in more detail.

	forecast risk/stranded asset risk in its benefit-cost methodology for IRP assessment. • In support of Leave to Construct or IRP Plan applications for system reinforcement needs, require Enbridge Gas to request information from impacted electricity distributors regarding electricity load forecast assumptions. • Enbridge Gas's 2024 capital budget should include funding for its hydrogen-related proposals.
Allocation of risk	• Enbridge Gas already bears some level of risk for stranded or underutilized assets, and no specific new determination in this regard is necessary. The OEB has numerous tools to address this risk issue, including prudence reviews when an asset enters rate base, and other ratemaking mechanisms where an asset becomes stranded or significantly underutilized later in its service life. OEB staff expects that any consideration of cost disallowance for stranded assets would take into account, amongst other things, whether Enbridge Gas's investment decision was reasonable based on the best available information at the time that the original investment decision was made. However, the OEB may wish to consider setting out new mechanistic approaches to risk sharing in the near future.
Equity thickness	• Increase Enbridge Gas's deemed equity thickness from 36% to 38%, recognizing an increase in energy transition business risk that is partially counterbalanced by other factors that decrease business risk.
Depreciation	• Require Enbridge Gas to prepare a

	depreciation analysis based on the "Units of Production" procedure (and other depreciation procedures available that can address energy transition implications related to depreciation) to be provided at the next rebasing.

OEB staff provides more details on these energy transition submissions in the sub-sections below.

Energy Transition Impacts on Customer Connections Policy (sub-issue)

Approval Requested

Enbridge Gas requested approval of its harmonized customer connections policy, to replace the separate previous OEB-approved policies for the Enbridge Gas Distribution and Union rate zones.[35] The customer connections policy describes the approach Enbridge Gas uses to ensure that projects to connect new customers meet all financial compliance requirements and will not result in undue cross subsidization between new and existing customers.

Enbridge Gas's customer connection policies are subject to the OEB's Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario (E.B.O. 188), which provides for a common analysis and reporting framework. As a result, Enbridge Gas's proposal to harmonize the previous OEB-approved policies did not include significant changes.

One aspect of the harmonized customer connections policy is a policy for Residential Infill Service Connections, with an associated Extra Length Charge (ELC).[36] 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's proposal for the length of free service connection and the ELC charge was based on updated cost data comparing the cost of Enbridge Gas to connect new customers as a function of the service length. 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.

[35] Exhibit 1, Tab 15, Schedule 1.
[36] Exhibit 8, Tab 3, Schedule 1.

Assessing Economic Feasibility of New Customer Connections

E.B.O. 188 sets an objective for Enbridge Gas that the Investment Portfolio of all of Enbridge Gas's new distribution customers (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 received by Enbridge Gas should exceed the costs incurred as a result of adding these new customers to the system, over the lifetime that the customer is connected to the system; thus, existing customers will be better off as a result of the new customer connections.

Enbridge Gas designs its customer connection policies to achieve this objective. Depending on the cost of 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 rate surcharge, or for infill customers, the ELC for pipe connections that are longer than the free service length.

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.[37] Connection costs for new construction system expansion projects are generally lower than for existing homes (infill projects), due to economies of scale. The initial cost to Enbridge Gas for a 20 metre connection to an existing main is approximately $6,000.[38] Connection costs have escalated sharply (9% annually) for Enbridge Gas in recent years, due to rising construction costs and additional costs related to municipal permit and restoration requirements.[39] The increase in costs resulted in the overall investment portfolio of Enbridge Gas (based on the customer connections policies in place at the time) not achieving a PI of 1.0 in the years from 2021 to 2023; i.e., the costs associated with adding these customers will be higher than the revenues received.[40]

Revenue Horizon and Implications of Energy Transition

While Enbridge Gas's application did not propose significant changes from previous customer connection policies, through the course of the hearing many parties raised concerns about 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

[37] JT 3.11.
[38] Exhibit 8, Tab 3, Schedule 1, Page 13, Figure 2.
[39] Exhibit 8, Tab 3, Schedule 1, Page 12-13.
[40] Exhibit I.2.6-SEC-118.

new customer will be financially feasible and achieve a PI greater than 1.0 – in light of the energy transition.

For both infills and system expansion projects, the economic analysis is based on a 40-year revenue horizon for residential and small commercial customers (20 years for large volume customers including contract customers). This revenue horizon is set out in E.B.O. 188.[41] Enbridge Gas's customer connection policies also provide 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 associated with serving new customers are heavily front-loaded, with the majority of costs being those detailed above, related to the initial work to physically connect the customer to the natural gas system. Revenues, on the other hand, are collected relatively equally over the full revenue horizon. Therefore, should new customers not remain Enbridge Gas customers for the full revenue horizon, all else being equal a project with a calculated PI of 1.0 would actually achieve a PI less than this, and would be uneconomic, leaving a revenue shortfall that must be recovered either from remaining customers or from Enbridge Gas, posing a stranded asset risk.

Some parties noted that, in light of the energy transition, a 40-year revenue horizon appears to no longer be appropriate, given the increasing likelihood over time (depending on the pathway of the energy transition) that customers may leave the natural gas system and pursue full electrification, as carbon prices/policies continue to become more stringent to meet emissions reductions objectives. As the proceeding developed, the OEB identified this as a matter of particular interest.[42]

EFG recommended using a revenue horizon of 15 years, noting that the typical life of a new gas furnace is roughly 18 years, and suggesting that it is most likely that a customer will electrify at the time that they need to replace their heating system.[43]

Enbridge Gas noted the possibility of using a "blended revenue horizon", on the assumption that some proportion of customers might leave the natural gas system at the end of life of their initial heating equipment, while others might remain.[44] While Enbridge Gas submitted that no change to the revenue horizon was required, it suggested that the outside bounds for a change to the revenue horizon should be to shorten the horizon from 40 years to 30 years.[45]

[41] E.B.O. 188, Appendix B, section 2.2(b).
[42] Procedural Order No. 6, June 23, 2023.
[43] Exhibit M9.GEC-ED, p. 43.
[44] Exhibit K 10.2, p. 140.
[45] *Argument in Chief of Enbridge Gas Inc.,* August 18, 2023 (Argument-in-Chief), pp. 110-111.

Cost Impacts of Shortened Revenue Horizon

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. Enbridge Gas estimated the average CIAC that new customers would need to pay under different revenue horizons, and the corresponding reduction in Enbridge Gas's customer connections capital budget. Relative to a 40-year revenue horizon, the impact would range from an average CIAC of $645 and 5-year capital budget reduction of $124 million using a 30-year revenue horizon, to an average CIAC of $4,428 and a 5-year capital budget reduction of $853 million using a 10-year revenue horizon. Enbridge Gas noted that the higher upfront costs borne by new customers may conflict with the provincial government's goals for home affordability, including the More Homes Built Faster action plan.[46]

Table 6
Customer Connections Capital Expenditure Supported by Different Revenue Horizons[47]

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	/u
3	25	210	208	219	221	235	1,094	220	1,140	/u
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	

Note: 40-year revenue horizon reflects the Company's most updated capital forecast

[46] *More Homes, Built Faster: Ontario's Housing Supply Action Plan 2022–2023*, https://www.ontario.ca/page/more-homes-built-faster.
[47] Exhibit J11.1, Table 1.

OEB Staff Submission

OEB staff submits that the OEB should require the following modifications to Enbridge Gas's customer connections policy.[48]

- A requirement to use a maximum revenue horizon of 20 years for all types of customers, instead of the 40-year revenue horizon defined in E.B.O. 188. Enbridge Gas should maintain the ability to use a project specific revenue horizon when the project life cycle is determined to be shorter than the prescribed time horizons.
  - However, natural gas expansion projects currently identified in O. Reg. 24/19: Expansion of Natural Gas Distribution Systems would be assessed using the previous (40-year) revenue horizon.
- Changes to the Residential Infill Service Connections policy to achieve a PI > 1.0 for these projects assessed using a maximum revenue horizon of 20 years. This may be done by modifying the amount of free connection, the cost per metre of extra length, or some other method.
- A requirement for Enbridge Gas to use the CIAC to cover any shortfall needed to bring a PI up to 1.0 for system expansion projects where new construction accounts for the majority of forecast load (i.e., with the exception of O. Reg. 24/19 projects, system expansion projects intended primarily to connect existing buildings, and for infill customers), as opposed to other OEB-approved methods involving rate surcharges.
- A requirement that, upon receipt of customer connection requests, for all types of customer connections, Enbridge Gas will provide information to prospective customers on energy options for building heating in a manner and form as may be required by the OEB.

OEB staff submits that with some exceptions, these changes should apply as of January 1, 2024. These exceptions are described later in this sub-section of OEB staff's submission on Issue 3. The rationale for these proposals is described in detail below. However, OEB staff will first respond to Enbridge Gas's concerns around process and the potential need to make changes to the Gas Distribution Access Rule (GDAR)[49], 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 amends

[48] Filed for approval as Exhibit 1, Tab 15, Schedule 1, Attachment 1.
[49] Argument-in-Chief, pp. 105-108.

> E.B.O. 188 can be made without also changing the GDAR. Section 2.2.2 of the GDAR specifically directs gas utilities to follow the E.B.O. 188 guidelines in attaching customers.

OEB staff believes sufficient evidence has been provided in this proceeding for the OEB to make a determination on a change to the revenue horizon to be used by Enbridge Gas. OEB staff does not believe a change to the revenue horizon conflicts with the fundamental principles of the economic feasibility approach used in E.B.O. 188, and would in fact be intended to ensure that expansions are economically feasible, aligning with the OEB's objective of facilitating rational expansion of transmission and distribution systems.[50]

With regard to whether a change in the language in the GDAR is necessary, OEB staff notes that Enbridge Gas's existing customer connection policies already include methodological approaches not described in E.B.O. 188 (e.g., the use of the Hourly Allocation Factor (HAF), the Temporary Connection Surcharge (TCS) and System Expansion Surcharge (SES) mechanisms) that reflect subsequent OEB decisions that came after E.B.O. 188. No amendments were made to section 2.2.2 of GDAR on account of those updates to the E.B.O. 188 methodologies, nor did any party (including Enbridge Gas, which proposed the HAF, TCS, and the current version of the SES)[51] suggest that such amendments were necessary. OEB staff observes that the OEB also has the power to exempt Enbridge Gas from a requirement of GDAR, though submits that this is not necessary in the current case for the reasons just stated. The requirement in GDAR should be read to include any subsequent updates to the methodologies approved in E.B.O. 188. OEB staff believes that the OEB's direction in this proceeding would be sufficient for Enbridge Gas to adjust its customer connection policies, without requiring an amendment to section 2.2.2 of the GDAR.

A 20-Year maximum revenue horizon should be approved. To address the concern of stranded, or underutilized, asset risk, including the risk of cross-subsidization from existing gas customers to new customers, the revenue horizon should be set to the average length of time a new customer is expected to remain connected to the gas system (assuming this is shorter than the technical asset life, which would otherwise be the limiting factor).

Based on OEB staff's general conclusions on energy transition, discussed earlier, OEB staff believes that a relatively high proportion of customers will electrify and exit the natural gas system after the initial life of their space heating equipment. Some

[50] OEB Act, s. 2 3.
[51] EB-2020-0094.

customers will likely remain on the system after that point, perhaps using hybrid heating systems. Other customers may exit the system prior to the end of life of space heating equipment, due to increasing carbon (or other) costs or personal preferences (particularly if these customers were not responsible for making the original request to connect to the gas system). These factors work in opposite directions, and OEB staff believes that the former is slightly more likely than the latter. OEB staff therefore submits that 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.

Although one cannot predict with perfect certainty how the energy transition will play out, OEB staff believes there is a high probability that the energy transition may follow a pathway with a less significant role for gaseous fuels. For space heating in particular, it seems likely that some combination of government led climate policies (which could include restrictions on gas use, incentives for low-carbon technologies, and/or carbon pricing), and improvements in the efficiency of heat pumps will mean that natural gas will become less cost competitive for customers compared to electricity in the coming years. Enbridge Gas has suggested that customers who electrify may still choose to pay a fixed connection cost and remain connected to the gas system for its resiliency value,[52] however this is uncertain and it seems unlikely that most customers would maintain a gas connection over the long term if their primary end use is no longer met by natural gas

OEB staff also briefly addresses two potential arguments that intervenors may make for using a shorter revenue horizon (perhaps as short as zero) than the average length of time a customer would be connected to the system.

- One reason for using a shorter time horizon, raised by EFG, is that because new customers are making use of existing system infrastructure, they would still have had a “free ride” if they remain on the system only long enough to exactly pay off their connection costs.[53] OEB staff does not agree with this proposition. E.B.O. 188 includes a provision for normalized system reinforcement costs associated with new customer connections, and thus ensures that existing customers are made better off for projects with a PI > 1.0. OEB staff agrees with Enbridge Gas’s submissions in this regard.[54]
- A second reason for using a shorter revenue horizon than the average length of time a customer is connected is to address market distortions. The argument is that, by making the high upfront connection costs that Enbridge Gas incurs invisible to potential new customers, the current customer connections policy is inducing a

[52] Argument-in-Chief, p.32
[53] Exhibit M9.GEC-ED, p. 44.
[54] Argument-in-Chief, p. 102.

market distortion, and possibly leading customers to make the wrong decision today as to what will be the best energy solution for them over the lifetime of their heating equipment.[55] This issue is exacerbated by the split incentive problem, where, for new construction projects, the party requesting a natural gas connection request (e.g., a developer) may not be the eventual building occupant paying for this connection, and may choose the lowest first-cost solution. Under the existing customer connections policy with a 40-year revenue horizon, most or all of the initial connection cost would not be borne by developers.

While OEB staff sees some merit for this view in the interests of consumer protection, OEB staff does not recommend setting a (shorter) revenue horizon based on this idea. OEB staff has proposed other measures to mitigate against market distortions (a requirement to use the CIAC for customer contributions for new construction projects, and a new requirement for Enbridge Gas to provide information to prospective customers on energy options in response to connection requests), described below.

Natural Gas Expansion Projects already selected for government funding in Phase 2 of the NGEP should be assessed using the previous (40-year) revenue horizon. Enbridge Gas noted that "[c]onsideration will have to be given to how the Government of Ontario mandated Community Expansion Program can continue". Enbridge Gas's evidence is that it would require more than $26 million in additional NGEP funding if the revenue horizon is reduced to 25 years. One solution would be to treat NGEP-funded projects as being subject to different (existing) customer attachment guidelines.[56] OEB staff agrees with Enbridge Gas and submits that natural gas expansion projects already selected for government funding in Phase 2 of the NGEP should be subject to the previous (40-year) revenue horizon, as projects were selected and government funding provided on this basis. The use of a System Expansion Surcharge for these projects could also be set using this 40-year revenue horizon. However, should future phases of the NGEP be undertaken, then (absent direction from the Government of Ontario), these projects could be assessed using the new revenue horizon (if any) determined by the OEB in this rebasing proceeding.

Enbridge Gas's Residential Infill Service Connections policy should be changed to achieve a PI > 1.0 for these projects based on a maximum revenue horizon of 20 years. On the same basis as OEB staff's submission regarding addressing the concern of stranded asset risk for system expansion projects, a maximum revenue horizon of 20 years should also be applied to achieve a PI > 1.0 for infill customers. As

[55] Oral Hearing Transcript, Vol. 6, pp. 116-117.
[56] Argument-in-Chief, pp. 100-101.

noted by Enbridge Gas,[57] any change to the revenue horizon could also involve Enbridge Gas reassessing the suitability of the ELC approach and proposing alternative methods for review and approval by the OEB. Alternatives include a straight fixed charge, a per metre charge that would apply to the entire service length, a combination of these or a full feasibility analysis for each infill service based on estimated costs and revenues to determine a CIAC. If the OEB determines that a change to the revenue horizon is appropriate, the OEB should require Enbridge Gas to develop and file a proposal for the treatment of residential infill service connections with the OEB as part of Phase 3 of this proceeding.

Enbridge Gas should be required to use a CIAC to cover any revenue shortfall for system expansion projects where new construction accounts for the majority of forecast load, as opposed to other OEB-approved methods. The rationale for this proposal is to partially address the split incentive problem introduced above, where the party requesting a natural gas connection request (e.g., a developer) may not be the eventual building occupant paying for this connection. The split incentive problem is only relevant to new developments and OEB staff has previously explained why it believes NGEP-funded projects should be treated differently.

OEB staff submits that the use of a CIAC (that would be paid by the developer, and indirectly factored into the sale price of the home), as opposed to a rate surcharge such as the System Expansion Surcharge (SES) or the Temporary Connection Surcharge (TCS) that would be paid back by the building owner over a longer period of time, does a better job of bringing the cost of connecting to the natural gas system into the developer’s economic decision-making process. By recovering a higher share of costs upfront, the CIAC also reduces any remaining stranded asset risk should the customer leave the system before the end of the 20-year period.

Enbridge Gas indicated that its unofficial policy has already been to use the CIAC instead of the SES/TCS for system expansion projects that are for new developments, to ensure that these costs are paid by developers, and not passed onto customers.[58] However, Enbridge Gas indicated that, should the OEB change the revenue horizon or make other changes related to customer connections, Enbridge Gas could potentially seek to make use of other approaches.[59] OEB staff submits that the use of the CIAC for new developments should be the preferred approach and should be incorporated into Enbridge Gas’s customer connections policy.

The split incentive problem is primarily relevant to new developments. OEB staff does

[57] Argument-in-Chief, p. 114.
[58] Technical Conference Transcript, Vol. 3, pp. 42-46.
[59] Oral Hearing Transcript, Vol. 10, pp. 128-129.

not oppose Enbridge Gas using other funding mechanisms for projects intended primarily to serve existing buildings, including infills. For system expansion projects, this could include the continued use of the SES or TCS as appropriate but applying these charges only for a maximum time equal to the modified revenue horizon (with the exception of NGEP-funded projects already selected for government funding, as discussed earlier).

With respect to Enbridge Gas's argument that the higher upfront costs being borne by new customers may conflict with the provincial government's goals for home affordability, OEB staff submits that one of the OEB's important roles in the current proceeding is to protect ratepayers (and Enbridge Gas) from stranded asset risk. This is central to the OEB's mandate as an economic regulator in the energy sector. Unnecessarily exposing consumers (and Enbridge Gas) to stranded asset risk is not an appropriate means of possibly marginally increasing home affordability.

OEB staff also notes that a developer could decide not to move forward with a natural gas connection (and elect to use a different HVAC configuration), which could mean the increased CIAC amount has not increased the cost of a home (assuming the alternative HVAC configuration is of a similar cost to the natural gas connection).

Enbridge Gas should be required to provide information to prospective customers on energy options. OEB staff proposes this new requirement for Enbridge Gas's customer connections policy, as a means of partially addressing concerns that customers may be making a decision to connect to the gas system with incomplete information.

In response to a question as to whether potential customers submitting connection requests were informed of options to use energy sources other than natural gas, Enbridge Gas indicated that it "serves new or upgraded natural gas service requests from residential and commercial/industrial customers under E.B.O 188 on the understanding that these customers are sufficiently informed about the available energy and technology solutions and that they have chosen the alternative that best suits their needs."[60]

An example was provided in the hearing that the information provided by Enbridge Gas to its customers on energy choices may be selective and incomplete, e.g., a factsheet provided to existing customers compared the cost of heating with natural gas to different energy sources including electric resistance heating but not more efficient electric heat

[60] Exhibit I.2.6-Staff-81.

pump technologies.[61]

OEB staff submits that Enbridge Gas should be required 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 for building heating (e.g., natural gas only, hybrid gas/electric heat pump, electric heat pump only) in a manner and form approved (at least initially) by the OEB, as part of this proceeding.

OEB staff is of the view that this information would support both Enbridge Gas's energy transition objective of supporting consumer choice on the path to net-zero,[62] and the OEB's consumer protection objectives for electricity and gas in the *Ontario Energy Board Act, 1998*.[63]

This information would enable prospective customers to make an informed decision on whether to connect to the gas system or whether another energy option is preferable, protecting the customer, and also reducing the risk (to the connecting customer or other ratepayers) of sunk connection costs/stranded assets, by reducing the likelihood that a customer may change energy sources prior to the end of their initial equipment life. OEB staff acknowledges that this proposal does not fully address the concern around split incentives, when the party making the connection request is not the end user. Builders may still choose an energy source based primarily on the initial cost to them, however, the information in this factsheet should still be of some value in assisting builders in understanding different energy options, and how these might be valued by customers.

Within the scope of the current proceeding, OEB staff is proposing the development of this factsheet as a requirement for Enbridge Gas only. However, the product envisioned by OEB staff is a fuel-neutral factsheet that both natural gas and electricity distributors would agree is accurate. Enbridge Gas may benefit from working with one or more electricity distributors in developing this factsheet.

Information provided in this factsheet could include the following:

- A description of space heating options for buildings, including natural gas only, hybrid solutions, electricity-only (including heat pumps), and potentially unregulated fuels (e.g., propane, heating oil, wood).
- Language indicating that customers should consider seeking advice from a

[61] Exhibit K2.1 (GEC Compendium), p. 37; and Oral Hearing Transcript, Vol. 2, p. 76-78.
[62] Exhibit 1, Tab 10, Schedule 6, p.31.
[63] OEB Act, s. 1(1)1 and 2 2.

consultant or HVAC provider regarding specific energy options and considerations for their building, including capital and installation costs, energy efficiency levels of heating equipment, and how to estimate building energy use and operating energy costs.

  - A reference to the OEB's Consumer Information and Protection website as an information source on electricity and natural gas rates in different service territories, and the different charges on natural gas and electricity bills.
  - A reference that Enbridge Gas or the local electricity distributor can provide additional information on any additional charges (e.g., connection costs) that may apply to the choice of natural gas or electricity, respectively.
  - Information on Federal Carbon Charge levels through 2030, and how the Federal Carbon Charge impacts natural gas and electricity bills.

- Information or links to any relevant utility/provincial/federal incentives for space heating technologies or energy efficiency measures, including language indicating that building energy efficiency measures may reduce space heating energy use and costs, and may also have impacts regarding the cost and sizing of the heating system.

OEB staff submits that Enbridge Gas should submit an initial version of this factsheet for the OEB's consideration as part of Phase 3 of this proceeding.

The new revenue horizon should be implemented on January 1, 2024 with some exceptions. In its Argument-in-Chief, Enbridge Gas noted some considerations regarding timing and implementation, should the OEB adjust the revenue horizon for customer connections.[64] Enbridge Gas indicated that:

> Enbridge Gas will require some time to fully implement a change to a shorter revenue horizon. Commitments and/or guidance have been provided to new customers as to the amount of their CIAC for upcoming new connections. Time will be required for system changes to implement new feasibility determinations. Enbridge Gas proposes, therefore, that any new customer attachment policy should apply on a prospective basis, for any new customers who approach the Company from and after January 1, 2025, and that currently planned additions be exempt from the new rules. As described below, a later date may be necessary. For example, it may take

[64] Exhibit J 10.13.

> longer for implementation of new ELC and/or SES or TCS charges or other treatment of infill customers that would have to be approved by the OEB through a follow-up process.[65]

OEB staff does not support delaying all changes to Enbridge Gas's customer attachment policy until January 1, 2025. OEB staff believes that there is risk that a large number of service requests will be made between January 1, 2024 to January 1, 2025 to attempt to avoid any increase in connection costs. In OEB staff's view, any customers who approach Enbridge Gas with a new connection request for a system expansion project after January 1, 2024 (assuming an OEB decision addressing this issue is released before this date) should have a feasibility assessment conducted using the modified revenue horizon (if any) that arises from the OEB's decision. OEB staff agrees with Enbridge Gas that changes should apply on a go-forward basis, and that fairness considerations suggest that "customers who have requested service in writing, received commitments and/or indications about CIAC requirements (or lack thereof) for new connections prior to that date should be subject to the existing rules."[66]

There will likely need to be different treatment for infill customers, as OEB staff has submitted that Enbridge Gas should propose an approach for infill customers in Phase 3 of this proceeding. OEB staff submits that the OEB should approve Enbridge Gas's original proposal – 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 – on a temporary basis until an updated approach for infill customers is approved by the OEB.

As noted earlier, staff also proposes that the requirement to provide information to prospective customers on energy options would be implemented following a review of communication materials by the OEB in Phase 3 of this proceeding.

Alternative options to address stranded asset risk associated with new customer connections should not be approved in the current proceeding. Several other options exist to address the stranded asset risk associated with new customer connections, including:

- Making exiting customers responsible for an exit fee if leaving the system prior to the cost of their connection being recovered, which could include requiring new

[65] Argument-in-Chief, p. 101.
[66] Argument-in-Chief, p. 116.

customers to provide financial assurance in support of the forecast revenue (as Enbridge Gas has indicated it uses on occasion for larger customers);[67]

- Making Enbridge shareholders, not ratepayers, responsible for any stranded assets associated with new customer connections.

EFG provided a perspective on the merits of these alternatives,[68] noting that both options 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 GHG reductions goals.

OEB staff agrees with EFG's conclusions and thus submits that shortening the revenue horizon is the primary tool that should be used by the OEB to mitigate stranded asset risk associated with new customer connections. OEB staff sees merit in Enbridge Gas considering expanding the use of exit fees (perhaps in combination with a reduced revenue horizon), but it is important that prospective customers be informed of any exit fees in advance of connection (and on any transfer of responsibility for the exit fee related to a change in building ownership), and that a change to the exit fee policy not be introduced retroactively. These considerations are proposed in order for the exit fee to be taken into consideration in the prospective customer's original decision-making about whether to connect to the gas system. OEB staff recommends 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. Additional discussion regarding the allocation of stranded asset risk is provided later in OEB staff's submission under Issue 3.[69]

Energy transition and Integrated Resource Planning impacts on load forecast and capital expenditures (sub-issue)

<u>Energy Transition Forecasting Assumptions</u>

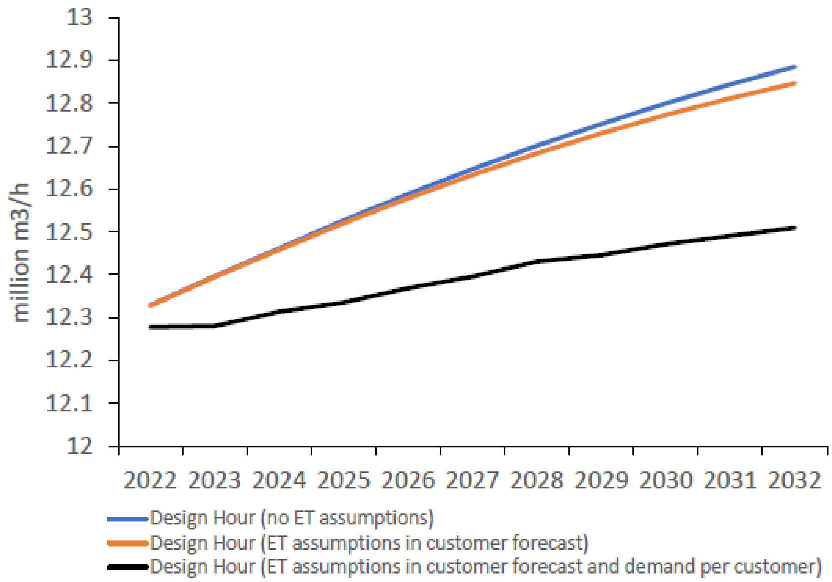
Enbridge Gas adjusted its forecasting approach to incorporate energy transition assumptions, to account for exogenous factors (e.g., impact of carbon price, improved appliance efficiency, customer decisions about whether to connect to Enbridge Gas's system) that could impact Enbridge Gas's forecast number of customers, average use, and peak demand (design day and design hour).[70]

Enbridge Gas's energy transition forecasting assumptions have only had a very modest

[69] See the sub-section titled, "Allocation of energy transition risk."
[70] Exhibit 1, Tab 10, Schedule 4.

impact. The impact of energy transition assumptions on design hour demand, which is used by Enbridge Gas to identify distribution system needs, is a decrease of 3% in design hour demand in 2032 (as compared to a forecast for 2032 with no explicit energy transition assumptions), and an impact less than this in prior years.[71]

Figure 3
Effects of Energy Transition Assumptions on Design Hour Demand[72]



Even with energy transition assumptions embedded, Enbridge Gas forecasts continued growth from 2023 through 2032 in number of customers,[73] and design hour demand,[74] with overall volumes used by general service customers remaining flat over this period.[75]

Impact of Integrated Resource Planning on Capital Expenditures

The Asset Management Plan (AMP) filed with the rebasing application is the first to take into account the OEB's Integrated Resource Planning (IRP) Decision,[76] which requires Enbridge Gas to consider IRP alternatives such as geotargeted energy efficiency to meet system needs, potentially avoiding or deferring traditional facilities projects.

Enbridge Gas's assessment of IRP alternatives to the projects in the AMP is still a work

[71] Exhibit 1, Tab 10, Schedule 4, pp. 10-11.
[72] Exhibit 1, Tab 10, Schedule 4, p. 11, Figure 3
[73] Exhibit 1, Tab 10, Schedule 4, page 7, Figure 1.
[74] Exhibit 1, Tab 10, Schedule 4, page 11, Figure 3.
[75] Exhibit I.1.10-Staff-31, Attachment 1, p.1.
[76] EB-2020-0091.

in progress. Enbridge Gas filed a draft guide outlining its process for conducting a technical evaluation of the viability of IRP Alternatives in meeting system needs.[77] Enbridge Gas also filed a partially complete analysis of IRP alternatives for specific system needs in the AMP and indicated that it would complete the technical evaluation for all system needs by Q3 2023, and would not proceed to implement a facilities solution for any system needs until this technical evaluation had been completed.

To date, Enbridge Gas has identified approximately 20 system needs where IRP is a technically viable option, primarily growth-related system reinforcement projects, but also some replacement projects.[78] These system needs will then proceed to more detailed analysis and an economic evaluation. As this stage of the assessment has not been completed, Enbridge Gas has not yet identified an IRP alternative as being the preferred approach to meeting a system need in the AMP.[79] Therefore, the capital budget is based on a traditional facilities solution for all system needs.

As part of the OEB-approved settlement agreement, parties agreed that the existing IRP Deferral Accounts will be modified to recognize off setting amounts in the account balances to reflect avoided capital cost impacts related to facilities projects that are delayed, avoided or downsized by IRP.[80] During the hearing, Enbridge Gas clarified that the exact details of this approach, and how the baseline will be connected to the capital planning evidence filed in this proceeding, will need to be worked out at a later date.[81]

Integrated Gas-electricity Planning and Electrification as an IRP Alternative

As noted earlier, Enbridge Gas has identified integration of gas and electric system planning as a safe bet for energy transition. Although Enbridge Gas did not file a specific proposal related to integrated gas-electricity planning, several pages of Enbridge Gas's argument-in-chief are devoted to a discussion of this topic and Enbridge Gas's support for integrated gas-electricity planning.[82]

Enbridge Gas noted that "coordinated energy planning would ensure that the demand forecast being used in its IRP alternative (IRPA) analysis reflects the electricity sector assumptions, plans, and costs. In addition, coordinated energy planning would allow for joint delivery of an IRPA in an area where both the electric and gas systems are facing a constraint."[83] However, Enbridge Gas indicated that "for coordinated energy planning

[77] Exhibit JT5.36, including attachments.
[78] Exhibit I.2.6-STAFF-82, including Attachment 1.
[79] Separately from the rebasing proceeding, Enbridge has also recently filed an application (EB-2022-0035) seeking approval of two IRP pilot projects.
[80] Exhibit O1, Tab 1, Schedule 1, p.54.
[81] Oral Hearing Transcript, Vol. 14, pp. 24-25.
[82] Argument-in-Chief, pp. 41-47.
[83] Argument-in-Chief, p. 43.

to be successful there must be commitment and actions taken by others in the industry, including the Government of Ontario, IESO, OEB and electric utilities. This will be extremely difficult to achieve without formal guidance and direction from the province."[84]

EFG recommended that the OEB should remove the current restriction on considering electrification measures as potential IRP alternatives, noting that gas utilities in other jurisdictions have begun to assess and propose IRP alternatives that include electrification in order to cost-effectively avoid expensive gas distribution system upgrades, in part due to consideration of the risk of stranded gas assets.[85]

In response to this recommendation, Enbridge Gas again noted the importance, but also the complexity, of coordinated gas and electricity system planning, and the expectation of future provincial direction on this topic through the work of the Electrification and Energy Transition Panel. Enbridge Gas indicated that it is not opposed to appropriate inclusion of electrification as an IRP alternative (and that it has proposed examining very limited use of electric IRP alternatives within its recently filed IRP pilot application), but believes that this may be better addressed in the context of a review of the IRP Framework.[86]

Impact on Load Forecast and Capital Expenditures from changes to Customer Connections Policy

Enbridge Gas's original application and energy transition assumptions did not contemplate any change to the revenue horizon for new customer connections or the resulting impact on the load forecast or customer connections. Enbridge Gas subsequently provided data estimating how Enbridge Gas's capital budget might change under different revenue horizons.[87]

These estimates regarding changes to the capital budget were based on the assumption that the number of customer connections would not change; however, Enbridge Gas also noted that changes to the revenue horizon could have a further impact on the customer forecast, as some forecast customers may choose not to connect due to the high CIAC.[88]

Hydrogen Blending

Enbridge Gas indicated that it believes that blends of up to 100% hydrogen will eventually be required in any pathway to net-zero, particularly for high-temperature

[84] Argument-in-Chief, p. 45.
[85] Exhibit M9-GEC-ED, p.48.
[86] Argument-in-Chief, pp. 73-74.
[87] Exhibit J11.1, Table 1.
[88] Argument-in-Chief, p.114.

industrial processes and heavy-duty transportation. While the role of hydrogen blending in reducing GHG emissions is supported by hydrogen strategies developed by both the provincial and federal governments, there remains uncertainty over specifically how hydrogen will contribute to the pathway to net-zero in Ontario. Despite current uncertainty, to recognize these federal and provincial strategies and to maintain pathway optionality and the role that hydrogen could play in a diversified pathway, Enbridge Gas submitted that, at minimum, it must take the following steps to prepare for wider-scale hydrogen blending in the future:

1. Implement Phase 2 of the Low-Carbon Energy Project
2. Complete a Hydrogen Blending Grid Study

Enbridge Gas stated that the use of hydrogen as an energy source is nascent and further research and development is required to maximize hydrogen's future path.

Intervenors raised concerns about the safety of blending hydrogen into the gas system in terms of potential leakage and the explosiveness of hydrogen.

Enbridge Gas's 2024 capital budget includes $9.5 million for hydrogen blending,[89] including $1.9 million in 2024 spending on Phase 2 of the Low-Carbon Energy Project ($9.0 million over the Asset Management Plan period), and $5.8 million in 2024 spending on the Hydrogen Blending Grid Study ($15.4 million over the Asset Management Plan period).[90]

Enbridge Gas is not seeking any approvals with respect to Phase 1 or Phase 2 of its Low-Carbon Energy Project in the current application. Phase 1 of Enbridge Gas's Low-Carbon Energy Project was approved by the OEB in October 2020 and went into service in October 2021.[91] In late 2023 or early 2024, Enbridge Gas plans to file a Leave to Construct application for Phase 2 of its Low-Carbon Energy Project.

Enbridge Gas proposed to complete a rigorous Hydrogen Blending Grid Study to assess: (a) its natural gas grid's current readiness to accept blends of more than 2% hydrogen; (b) any modifications required to accept higher blending percentages up to and including 100 percent; (c) the need for dedicated hydrogen pipelines; and (d) operational readiness in terms of Enbridge Gas's workforce (e.g., training and

[89] Argument-in-Chief, p. 156.
[90] Argument-in-Chief, p. 173. OEB staff requests that Enbridge Gas clarify the reason for the difference between the total of $9.5 million for hydrogen blending in the 2024 capital budget request and the sum of the forecast 2024 budget for the two hydrogen-related projects ($7.7 million for phase 2 of the Low-Carbon Energy Project and the Hydrogen Blending Grid Study combined).
[91] EB-2019-0294.

certifications).[92] Enbridge Gas would file a final report in Q3 2026 that would include fully costed recommendations related to the report's findings regarding hydrogen blending for an updated AMP.

OEB Staff Submission

Based on OEB staff's overall conclusions on energy transition pathways, OEB staff is of the view that Enbridge Gas's assumptions around energy transition impacts on the load forecast (prior to accounting for any change to the revenue horizon for new customer connections) may underestimate energy transition impacts, and thus overestimate peak demand and volumes, over the 5-year rebasing term and the 10-year term of the AMP.

With regards to IRP and its impact on capital expenditures, OEB staff believes that Enbridge Gas is meeting the intent of the IRP Decision as it relates to consideration of IRP alternatives for projects in the AMP.

OEB staff believes that the impact of IRP on Enbridge Gas's capital spending can largely be addressed through the IRP deferral accounts and through subsequent project-specific review and is not recommending significant changes to Enbridge Gas's approach to IRP. While Enbridge Gas's IRP assessment of projects in the AMP is still a work in progress, the IRP Framework includes checks and balances such that Enbridge Gas's consideration of IRP alternatives will be reviewed in advance by the OEB for major projects subject to a Leave to Construct approval, and Enbridge Gas will report annually on the most recent results of its IRP Assessment Process for system needs, including reporting on those system needs where a negative binary screening or technical/economic evaluation resulted in no further assessment of IRP alternatives.[93]

OEB staff makes six specific submissions related to energy transition and IRP with respect to load forecasting and capital expenditures as follows.

Enbridge Gas should review its energy transition assumptions in the load forecast on an annual basis and document any changes as part of its annual AMP update and should track utilization of new growth-driven projects relative to forecast on an ongoing basis. The IRP Framework already requires the AMP update to identify any material changes to the demand forecast, relative to the demand forecast that was assessed as part of the most recent rebasing application. OEB staff submits that, given the pace of the energy transition, Enbridge Gas should proactively be reviewing its energy transition forecasting assumptions as part of this annual update,

[92] Exhibit 4, Tab 2, Schedule 6; Oral Hearing Transcript, Vol. 3, p. 41.
[93] EB-2020-0091 Decision and Order, p. 83.

taking into account the new year of historical data,[94] as well as new policy developments and other information sources, and documenting how, if at all, these changes have impacted Enbridge Gas's AMP. This could potentially include the collection of new data to estimate energy transition impacts that may be material but are not considered in Enbridge Gas's original energy transition forecasting assumptions.

Several newer data points (not available at the time Enbridge Gas developed the energy transition assumptions in its original application) suggest a potentially greater impact of energy transition than Enbridge Gas forecasted in its original application, even in the near term:

- Enbridge Gas's 2022 data on actual customer connections showed a steep decline in fuel switching to natural gas from other energy sources in that year relative to previous years, although Enbridge Gas did not indicate whether it believed this to be related to energy transition or other factors.[95] As a result, Enbridge Gas's updated forecast (filed as part of the Capital Update) now forecasts much lower numbers of fuel switching in future years (the updated forecast now predicts 1,519 new customers fuel switching to natural gas in 2032, whereas the previous forecast had predicted 3,474).[96]
- The 2022 version of Enbridge Gas's annual survey (Residential Single Family Natural Gas End Use Studies) shows a decline in customer preference for natural gas. The 2022 survey found that 73% of surveyed customers would prefer natural gas for home heating in a new home, which is down from 77% in the 2021 survey, 83% in 2020 and 86% in 2019, and noted that "preference for geothermal and electricity in new home continues to trend upward."[97] Similarly, the 2022 survey found that that only 74% of existing customers would replace their furnace with a natural gas furnace, down from 84% in the 2021 Study and 94% in the 2020 End Use Study.

Enbridge Gas has noted that investment decisions including those reviewed in Leave to Construct applications will be based on the most recent forecasting information, taking into account new information subsequent to rebasing, which OEB staff supports. OEB staff notes that the energy transition assumptions are common assumptions across Enbridge Gas's system and can serve as a starting point for more granular adjustments.

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[94] In future forecasts, Enbridge Gas's approach to incorporating energy transition forecasting assumptions may need to change, as more of the impact of energy transition is likely to be captured in actual data (and thereby captured in the trend analysis), and this will need to be disentangled from Enbridge Gas's forward-looking energy transition forecasting assumptions.
[95] Exhibit J14.1.
[96] Exhibit K13.3, p.17.
[97] Exhibit I.1.10-GEC-7, Attachment 5, p. 19c. Data from different years of the survey is found in Attachments 1 to 5.

OEB staff also notes that the School Energy Coalition (SEC) requested actual versus forecast information at the project level for major growth-driven expansion or reinforcement projects taking into account annual changes in actual project utilization, and Enbridge Gas indicated that it could not provide this information, as it does not track customer adds or demand changes in direct relation to an individual project on an annual basis.[98] The information requested by SEC at the project level was: total load for affected customers, number and types of new customers/connections, average and peak demand of the affected customers, design day demand of the affected customers, and percentage of the capacity of the new pipe or other equipment utilized in the year, as well as information on cost-effectiveness based on the actual utilization data.

OEB staff submits that for new system expansion and system reinforcement projects going forward, Enbridge Gas should be required to track information of the nature requested by SEC. This would improve Enbridge Gas's ability to assess project results against the original forecast assumptions that were used to establish the need for the project and assist in assessing and improving the accuracy of Enbridge Gas's forecasting approach. OEB staff suggests that Enbridge Gas could propose modifications to the list proposed by SEC based on its understanding of what information is feasible or practical to collect. It may also be appropriate to use a minimum project cost threshold for this ongoing monitoring requirement.

This information will also be helpful to the OEB in the future as a way to identify projects that have become fully, or partially, stranded due to customer disconnections or changes in load. The OEB would gain helpful knowledge regarding which projects are showing signs of underutilization (or in other words, reduced project cost-effectiveness) to allow it to more closely consider whether the investment decisions are reasonable and whether the associated undepreciated costs should be recoverable from ratepayers.

As discussed further below, OEB staff believes that the OEB has the ability to employ additional tools under its ratemaking authority to address assets that become stranded or significantly underutilized after they are added to rate base. OEB staff expects that any consideration of cost disallowance for stranded assets would take into account, amongst other things, whether Enbridge Gas's investment decision was reasonable

[98] Exhibit I.2.1-SEC-99(a). For distribution system expansion projects that directly connect customers, Enbridge Gas does already collect information on the number of customer attachments and actual connection costs relative to forecast, to assist in determining the profitability index of the investment portfolio and meeting the financial monitoring requirements required by E.B.O. 188, Appendix B, section 3.2. However, this calculation is done for a single year, and Enbridge does not continue to track customer disconnections and impact on project revenues after this period (Technical Conference Transcript, Vol. 3, pp. 146-147).

based on the best available information at the time that the original investment decision was made.

Therefore, the OEB should require Enbridge Gas to inform the OEB if a project's actual results (e.g., project cost-effectiveness) varied from forecast by more than a certain threshold, when it first seeks to enter the asset into rate base, and at set intervals thereafter (e.g., as part of subsequent rebasing applications).

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. EFG recommended that Enbridge Gas assess trade-offs between repairing and replacing aging pipe,[99] which OEB staff agrees with. In light of energy transition and reducing the risk of stranded assets, the need to consider repair options is likely to take on greater importance within Enbridge Gas's planning and maintenance program. While it is perhaps implicit that Enbridge Gas is always expected to consider the possibility of repair as an option to meet system needs, EFG noted that the term "repair" is not mentioned in the IRP Framework.[100] The appropriate place for Enbridge Gas to document how repair options are considered and how they relate to the assessment of IRP alternatives may be in the guide it is developing (still in draft form) that describes its process for conducting an evaluation of IRP alternatives.[101]

Enbridge Gas should be required to value differences between project alternatives with regards to demand forecast risk/stranded asset risk in its benefit-cost methodology for IRP assessment. A similar recommendation was made by EFG, which recommended that the OEB require analysis of IRP alternatives under multiple possible future load forecasts.[102]

OEB staff agrees with Enbridge Gas that the IRP Framework acts as a measure to mitigate against stranded asset risk.[103] The primary reason for this (in addition to identifying solutions that are lower cost overall) is that IRP alternatives are less likely than facility projects to be one-time upfront capital investments, and are thus more amenable to adjustment should Enbridge Gas's load forecast and system needs change, e.g., if peak demand begins to decline due to energy transition.

However, it is unclear whether this likely benefit of IRP alternatives will be valued by Enbridge Gas as it compares the costs and benefits of IRP alternatives to traditional facility projects in its IRP assessments. The IRP Working Group examined this issue in

[99] Exhibit M9-GEC-ED, pp.47-48.
[100] Exhibit N.M9-Staff-3.
[101] Exhibit JT5.36, Attachment 2.
[102] Exhibit M9-GEC-ED, pp.48-49, 51-54.
[103] Argument-in-Chief, p.7.

the context of developing recommendations for a Discounted Cash Flow-Plus (DCF+) test for assessment of IRP alternatives. At that time, Enbridge Gas indicated that "it does not agree that demand forecast risk or stranded asset risk should be monetized as part of each DCF+ calculation, but that these risks could be considered on a general basis in the Enbridge Gas rebasing proceeding."[104]

While other measures to address demand forecast and stranded asset risk may form part of the OEB's decision in this proceeding, OEB staff is of the view that valuing differences between project alternatives with regards to demand forecast risk/stranded asset risk within the DCF+ test is an important tool that the OEB should make use of. OEB staff acknowledges that there are challenges in determining how to do this,[105] and is not recommending that the OEB require Enbridge Gas to adopt the specific approach proposed by EFG. OEB staff submits that Enbridge Gas should include a proposal as part of the DCF+ test it files for approval as part of its first non-pilot IRP application.

In support of Leave to Construct or IRP Plan applications for system reinforcement needs, Enbridge Gas should be required to request information from impacted electricity distributors regarding electricity load forecast assumptions. OEB staff believes that this information will be valuable in assisting the OEB in assessing the accuracy of Enbridge Gas's load forecast that underpins the project need (e.g., whether the forecast assumptions used by Enbridge Gas regarding population/economic growth and fuel choice are largely consistent with the assumptions used by electricity distributors).

Within the context of this proceeding, OEB staff is not recommending that the restriction in the IRP Framework preventing Enbridge Gas from providing funding for electrification IRP alternatives be removed. OEB staff notes that Enbridge Gas's recently filed IRP pilot application includes a proposal for limited use of electric IRP alternatives, and agrees with Enbridge Gas that consideration of a broader change to the IRP Framework to allow for the funding of electrification IRP alternatives is likely better addressed in the context of a review of the IRP Framework.[106] However, should the OEB determine that Enbridge Gas will be permitted to provide funding for electrification IRP alternatives in the current proceeding, OEB staff submits that the information Enbridge Gas should be required to request from impacted electricity distributors should encompass capacity needs on the electricity distribution system. This would help the OEB assess whether

[104] *Use of the Discounted Cash Flow-Plus Test in Integrated Resource Planning (IRP): Report of the Technical Working Group*, May 30, 2023, p. 53.
[105] Argument-in-Chief, p.74.
[106] Argument-in-Chief, pp. 73-74.

any targeted electrification IRP alternative would have any negative impacts on the electricity system.

Enbridge Gas's 2024 customer connections budget should be reduced in accordance with any change to the revenue horizon for customer connections. Should the OEB agree with OEB staff's recommendation for a 20-year revenue horizon, OEB staff submits that the impact of this change is a reduction of $116.1 million to the customer connection budget and $15.1 million to the system reinforcement budget. The total reduction is $131.1 million to the growth capital-related budget.

OEB staff notes that the budget for growth capital includes customer connections, system reinforcements including hydrogen blending and community expansion. The 2024 capital budget includes $400.5 million related to growth: $304.1 million for customer connections, $11.2 million for community expansion, and $85.2 million for system reinforcement. The 2024 capital expenditure for hydrogen blending of $9.5 million is included within the reinforcement spend of $85.2 million.[107]

OEB staff submits that if customers are required to pay a capital contribution as a result of the proposed reduction to the customer revenue horizon, the total capital spending on customer connections reduces from the proposed $304.1 million to $188 million, a reduction of $116.1 million for 2024.[108] In other words, if all forecasted customers connect, these customers would have to pay $116.1 million of the total cost as capital contributions, which operates to reduce the capital expenditures that would enter rate base.

OEB staff submits that it is appropriate for the full amount ($116.1 million) of the customer connection-related reduction to be applied to the 2024 capital budget.

OEB staff notes that there are two sources of uncertainty arising from a change in revenue horizon that would impact customer connection-related capital expenditures.

- First, should a large number of forecast customers choose not to connect due to a higher CIAC, this would further reduce the actual customer connections cost beyond the $116.1 million reduction proposed by OEB staff.
- Second, should the OEB's determinations on the timing of implementation (regarding both the timing of introduction of changes for new connection requests, and the approach used for customers who had contacted Enbridge

[107] Exhibit 2, Tab 5, Schedule 2, pp. 5-8.
[108] Response to Undertaking J11.1. The $116.1 million reduction reflects implementation of the shortened revenue horizon on January 1, 2024.

Gas regarding new connections prior to any change in connection policy but had not connected prior to 2024) mean that a proportion of customers in 2024 are still connected under the old revenue horizon, this would offset the above noted incremental reduction to customer connection costs.

Overall, OEB staff submits that these two factors reasonably offset each other (i.e., some customers may choose not to connect, which further reduces the customer connection costs beyond $116.1 million, while other customers will continue to be applied using a 40-year revenue horizon in 2024, which offsets OEB staff's proposed reduction to the customer connection budget). Due to the offsetting nature of these uncertainties, OEB staff submits that a reduction of $116.1 million to the customer connection budget is reasonable.

With respect to the system reinforcement budget, OEB staff notes that the $75.7 million budget[109] reflects the old revenue horizon. However, OEB staff submits that it is likely with a shortened revenue horizon, not all of the customers originally forecast to connect will actually connect due to the requirement for an increased CIAC. In its argument-in-chief, Enbridge acknowledged this possibility and noted:

> Should the OEB choose to reduce the revenue horizon for customer attachment feasibility analysis, it is important to recognize that this change could lower both the number of attachments and the associated capital budget.[110]

Although it is difficult to estimate the proportion of customers that will not connect to the distribution system, OEB staff is of the view that, at least, some customers will not connect. OEB staff has selected a conservative estimate of 20% to reflect the proportion of customers that will choose not to connect to the gas distribution system. Accordingly, OEB staff submits that spending related to system reinforcement should be subject to a 20% reduction. The system reinforcement spend for 2024 is $75.7 million ($85.2 million minus $9.5 million for hydrogen blending). A 20% reduction to this amount is $15.1 million.

Overall, OEB staff submits that the 2024 growth-related capital budget should be reduced by $131.1 million ($116.1 million + $15.1 million), and the associated in-service additions should be removed from 2024 rate base.

[109] The system reinforcement spend for 2024 is $75.7 million ($85.2 million minus $9.5 million for hydrogen blending).
[110] Argument-in-Chief, p. 168.

OEB staff does not believe that a variance account to track growth-related costs and revenues relative to what is reflected in 2024 rates is necessary. OEB staff's estimated reduction of $131.1 million reflects a reasonable estimate of the likely reduction to growth capital spending and Enbridge Gas should be expected to manage any variances within its overall capital budget.

Enbridge Gas's 2024 capital budget should include funding for its hydrogen-related proposals. OEB staff takes no position on Phase 2 of the Low-Carbon Energy Project, which will be the subject of a Leave to Construct application. OEB staff has no concerns with the inclusion of $1.9 million of capital expenditures in the 2024 capital budget related to this project as the amount is immaterial.[111]

OEB staff supports Enbridge Gas's proposal to conduct a Hydrogen Blending Grid Study. OEB staff agrees with Enbridge Gas that there is uncertainty regarding how hydrogen will contribute to the pathway to net-zero in Ontario. OEB staff shares the safety concerns raised by intervenors. Further research and development is required to help inform the OEB in terms of: (a) the role of hydrogen as a safe and reliable energy source; and (b) the rational expansion of the gas distribution system (including the mitigation of stranded asset risk). Therefore, OEB staff supports Enbridge Gas's proposal to complete a study on this matter.

Allocation of energy transition risk (sub-issue)

An issue raised in the current proceeding is whether the OEB should provide any direction on the allocation of stranded asset risk in light of energy transition. The question is whether Enbridge Gas should bear a greater responsibility for stranded asset risk associated with new investments, particularly growth-related investments, given that the risk of stranded assets as a result of energy transition now appears to be a higher probability risk than would have been the case previously.

<u>Enbridge Gas Perspective</u>

Enbridge Gas did not request any specific approval related to this issue, and indicated that it should fully recover the costs of prudently invested capital, and commented that, "Enbridge Gas has invested shareholder capital to serve its customers under a regulatory compact that allows the Company to earn a fair rate of return and for the recovery of prudently invested capital through the rates charged to its customers."[112] Enbridge Gas indicated that this approach should apply for both assets already in rate

[111] Argument-in-Chief, p. 173.
[112] Exhibit I.1.10-Staff-34.

base, and assets newly added to rate base going forward.[113]

It is OEB staff's understanding that Enbridge Gas's position is that it does not take any risk in respect of stranded assets. As explained by Enbridge Gas at the hearing, it is Enbridge Gas's view that once an asset is added to rate base the company is entitled to recover from ratepayers all of the costs associated with that asset over time: depreciation, cost of capital, related O&M expenses, etc.[114] Enbridge Gas believes that the OEB can employ regulatory mechanisms such as accelerated depreciation to address that risk to some extent. However, OEB staff understands Enbridge Gas's position to be that these mechanisms only involve different ways of recovering all of the costs associated with an asset from ratepayers: Enbridge Gas believes that it bears no risk for cost recovery associated with stranded assets once they have entered rate base.

Perspective of Other Parties and Experts

Experts for other parties cautioned about changing the allocation of risk, e.g., by assigning any stranded asset risk associated with growth-related investments such as customer connections to Enbridge Gas.

IGUA's energy transition expert, Dr. Hopkins, indicated that he saw challenges with creating a separate class of assets for which risk is allocated in a different fashion from the rest of Enbridge Gas's rate base (e.g., allocating a higher responsibility for stranded asset risk to Enbridge Gas for new capital spending versus assets already in rate base), or for a subset of new spending, e.g., growth-related investments.[115] Dr. Hopkins' recommended approach was to continue to hold Enbridge Gas to prudent decision-making within its regulated business, including investments related to new customer connections.

EFG noted that making Enbridge Gas's shareholder responsible for stranded assets associated with new customers could reduce ratepayer risk of stranded assets, but that there is still risk in the event that Enbridge Gas goes bankrupt. EFG also noted that changing the risk allocation would create incentives for Enbridge Gas to actively discourage customers from leaving the natural gas system, even if that was a desirable outcome for both customers and society given climate change goals.[116]

[113] Technical Conference Transcript, Vol. 2, pp. 147-148.
[114] Oral Hearing Transcript, Vol. 4, pp. 89-91.
[115] Exhibit N.M8.Staff-1(d).
[116] Exhibit N.M9.Staff-1.

OEB Staff Submission

OEB staff agrees with Enbridge Gas[117] that material stranded assets are unlikely over the proposed rate term, and even less likely for the 2024 cost of service year. However, this does not mean that the OEB does not need to consider stranded asset risk in this proceeding. Many of the assets that are proposed to enter service over the 2024-2028 rate term (including the assets proposed to enter rate base in 2024) have lengthy service lives of 40 or more years. These assets will be paid off over decades to come. The fact that there may be little risk of stranded assets over the proposed rate term, therefore, is of only limited importance.

OEB staff's submissions on energy transition have focused primarily on how to mitigate stranded asset risk associated with energy transition, but implementing these proposals will not entirely reduce the stranded asset risk to zero. Accordingly, the OEB does need to consider the question of who should bear the risk for new assets becoming stranded before they are fully depreciated.

In OEB staff's view, Enbridge Gas bears at least some of the risk for stranded assets. Although Enbridge Gas has referenced the "regulatory compact" in this regard, it is not clear to OEB staff on what basis Enbridge Gas believes the regulatory compact shields them from all risks related to stranded assets. Enbridge Gas's argument-in-chief does not address this issue in detail, and it is not known what if any case law Enbridge Gas is relying upon. OEB staff's review of the relevant case law suggests that Enbridge Gas is clearly exposed to risk for stranded assets.

The regulatory compact was described by the Supreme Court of Canada as follows:

> These goals have resulted in an economic and social arrangement dubbed the "regulatory compact", which ensures that all customers have access to the utility at a fair price — nothing more. As I will further explain, it does not transfer onto the customers any property right. Under the regulatory compact, the regulated utilities are given exclusive rights to sell their services within a specific area at rates that will provide companies the opportunity to earn a fair return for their investors. In return for this right of exclusivity, utilities assume a duty to adequately and reliably serve all customers in their determined territories, and are required to have their rates and certain operations regulated.[118]

The regulatory compact does not serve to shield a utility from risk for stranded assets (or any other investment decision), other than to note that it is the responsibility of the

[117] Argument in chief, para. 23.
[118] *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)* (Stores Block), 2006 SCC 4 (CanLII), para. 63.

regulator to balance the interests of the utility (and its shareholder) with those of the ratepayer. Indeed, the jurisprudence suggests that in many cases it will be appropriate for costs or revenues associated with stranded assets to be borne by the utility, and not ratepayers. For example, in *Stores Block* the Supreme Court noted:

> The argument that assets purchased are reflected in the rate base should not cloud the issue of determining who is the appropriate owner and risk bearer. Assets are indeed considered in rate setting, as a factor, and utilities cannot sell an asset used in the service to create a profit and thereby restrict the quality or increase the price of the service. Despite the consideration of utility assets in the rate-setting process, shareholders are the ones solely affected when the actual profits or losses of such a sale are realized; the utility absorbs losses and gains, increases or decreases in the value of assets, based on economic conditions and occasional unexpected technical difficulties, but continues to provide service both with regard to price and quality.[119]

The Alberta Court of Appeal has confirmed that regulators (subject to the particulars of their governing legislation and where circumstances warrant) have the power to allocate all of the costs related to stranded assets to the utility. In upholding a decision of the Alberta Utilities Commission to remove certain stranded assets from rate base (and thereby denying the utilities the ability to recover the remaining net book value of the assets through depreciation), the court commented:

> Ultimately, it is the regulator that is charged with fixing fair and reasonable rates and this role cannot be usurped unless one reads the legislation as guaranteeing a return of all investments in all circumstances. With respect, I am unable to find such a guarantee in the statutes or the regulations. There is no guaranteed return, merely an opportunity to earn a reasonable one. In my view, the UAD decision represents a reasonable approach that is well within the statutory authority vested in the Commission and also one that is in keeping with the jurisprudence from the Supreme Court as further interpreted by this Court.[120]

In another case, the Alberta Court of Appeal noted: “Fairness to consumers requires that the rate base include only assets used or to be used for operation of the utility and not assets with no production value.”[121]

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[119] Stores Block, para. 69.
[120] *FortisAlberta Inc. v. Alberta (Utilities Commission),* 2015 ABCA 295 (CanLII), paras 148-149. See also para. 131.
[121] *Atco Gas and Pipelines Ltd. v. Alberta (Utilities Commission)*, 2014 ABCA 28 (CanLII), para. 50.

OEB staff appreciates that there could be relevant differences in Alberta legislation versus Ontario legislation, and that without knowing the detailed circumstances regarding any future stranded assets, it is difficult to make a definitive pronouncement as to who would bear the risk in respect of any particular stranded asset. However, OEB staff submits that there are many circumstances under which it would be appropriate for the OEB to assign a portion of, or indeed all of, the costs associated with a stranded asset to Enbridge Gas. Enbridge Gas should not assume that it will not bear risk for stranded assets as they may arise.

However, OEB staff's conclusion does not mean that the OEB needs to explicitly assign some or all stranded asset risk associated with the energy transition to Enbridge Gas as part of its decision in the current proceeding. In OEB staff's view, Enbridge Gas already bears some level of risk for stranded assets, and no specific new determination in this regard is necessary.

OEB staff further submits that Enbridge Gas bears some risk for stranded and/or underutilized assets, both at the time the assets are proposed to enter rate base (i.e. at the time that a prudence review is undertaken) and also potentially after the assets are in rate base as part of the OEB's responsibility to ensure rates remain just and reasonable. The fact that an asset has been placed in rate base does not guarantee Enbridge Gas full recovery of all costs associated with the asset over the entire life of the asset (depreciation, costs of capital, O&M, etc.), and to the extent that an asset becomes stranded or significantly underutilized after it enters rate base, the OEB has the power to account for this through adjustments to rates.

As noted previously, OEB staff submits that the OEB should require Enbridge Gas to track utilization and cost-effectiveness information for new system expansion and system reinforcement projects going forward. OEB staff notes that this information will be helpful to the OEB in the future as a way to identify projects that have become fully, or partially, stranded due to customer disconnections or changes in load. OEB staff submits that the OEB has broad authority to adjust rates and consider disallowance of cost recovery for stranded assets, to achieve the objective of setting just and reasonable rates. However, OEB staff expects that any consideration of cost disallowance for stranded assets would take into account, amongst other things, whether Enbridge Gas's investment decision was reasonable based on the best available information at the time that the original investment decision was made.

Any requirements or guidance provided by the OEB in this rebasing proceeding will be applicable to all investments made by Enbridge Gas following the rebasing decision, and thus Enbridge Gas's adherence to this guidance would be in scope for any subsequent stranded asset review.

As noted by Dr. Hopkins, circumstances could change after the OEB's order in this case but before the decision to invest has been made, or it could become clear in the future that information was available to Enbridge Gas, which should have resulted in avoiding or amending an investment.[122] Enbridge Gas must seek and utilize the best available information as that information becomes available over the rebasing term.

Future approaches to allocation of stranded asset risk

In the future, and potentially as soon as the next rebasing, the OEB may want to consider whether, on a going-forward basis, the implementation of a mechanistic approach to cost sharing related to stranded, or underutilized, assets is appropriate. This could take the form of an automatic disallowance for a defined percentage of rate base additions when an asset becomes underutilized (based on a prescribed threshold for assessing when an asset is underutilized). However, there are certainly other risk-sharing mechanisms that could be applied.

OEB staff notes that there are many details that would need to be addressed prior to establishing any mechanistic risk sharing approach. Should the OEB wish to further explore these ideas, these matters may be better addressed through a policy consultation or generic hearing on this topic. OEB staff notes that a review of natural gas stranded assets and risk allocation was listed as a potential future initiative of the OEB in the OEB's most recent business plan.[123] Alternatively, this can be considered as part of Enbridge Gas's next rebasing application.

Energy transition impacts on deemed capital structure (sub-issue)

OEB staff's submission with respect to the appropriate deemed capital structure is covered in detail under Issues 20 and 21. For convenience, OEB staff has provided a brief summary of its argument here.

Enbridge Gas requested approval of a change to the deemed equity thickness of its capital structure. Enbridge Gas (supported by a study by Concentric) proposed that the deemed equity thickness increase from its current value of 36% to 42% by 2028, due to increased business risk. Enbridge Gas proposed a phased in approach, whereby deemed equity thickness would increase to 38% for the 2024 test year and increase by 1.0 percentage point per year from 2025 to 2028. Enbridge Gas indicated that energy transition is the most significant factor contributing to increased business risk.

IGUA's energy transition expert, Dr. Hopkins, provided evidence analyzing the business risk facing Enbridge Gas, including business risk arising from the energy transition. Dr.

[122] Exhibit N.M8.Staff-1(b).

Hopkins concluded that Enbridge Gas and Concentric have not adequately analyzed the energy transition impacts on Enbridge Gas's business and have not shown that it materially increases Enbridge Gas's capital-related risks. Dr. Hopkins (and IGUA's other depreciation expert, Dr. Cleary, who focused on other aspects of business risk) recommended that Enbridge Gas's deemed equity thickness remain at its current level of 36%. OEB staff's expert, London Economics International (LEI), recommended an increase in deemed equity thickness to 38%. LEI concluded that there is a modest increase in business risks for Enbridge Gas, particularly due to increase in risks associated with energy transition.

OEB staff submits that Enbridge Gas's deemed equity thickness should be increased from 36% to 38%, recognizing an increase in energy transition business risk that is partially counterbalanced by other factors that decrease business risk.

OEB staff's submission on the appropriate deemed capital structure and the business risk that energy transition poses to Enbridge Gas includes consideration of OEB staff's other energy transition-related submissions. However, the OEB's eventual findings on these other energy transition issues may impact the energy transition business risk experienced by Enbridge Gas. The OEB should consider its findings on all of the Phase 1 issues together when determining the appropriate value for deemed equity thickness.

Energy transition impacts on depreciation rates (sub-issue)

OEB staff's submission on depreciation is covered in detail under Issue 15. For convenience, OEB staff has provided a summary of its argument here.

Under the energy transition, some form of accelerated depreciation may be appropriate, if it is likely that assets that have not reached their technical end of service life may end up being no longer used and useful due to the energy transition. Enbridge Gas and its depreciation expert, Concentric Energy Advisors, considered the introduction of a system-wide economic planning horizon of 2050 for all assets (i.e, requiring all assets to be fully depreciated by 2050, given the possibility that they may no longer be used after that date due to the energy transition), and modeled the impact of this on deprecation rates, which was calculated to be an increase in the 2024 Test Year depreciation expense of $290 million, from $892 million to $1.2 billion.[124] Enbridge Gas and Concentric concluded that introducing an economic planning horizon for depreciation is not appropriate at this time, due to uncertainty as to how the energy transition will advance.

In its evidence, EFG recommended that Enbridge Gas be required to immediately assess and report back to the OEB by 2024 on alternative asset depreciation

[124] Exhibit 1, Tab 10, Schedule 4, pp. 17-18.

approaches. EFG noted a particular interest in a Units of Production procedure, whereby annual depreciation expense is proportional to expected usage in a given year relative to total expected lifetime usage, noting that this method may address inter-generational inequities caused by gas customers exiting the system and gas sales declining over time, and may offer greater flexibility to periodically adjust for evolving expectations about changes in the use of the gas system.[125]

OEB staff does not recommend any immediate changes to depreciation methodology based on potential energy transition impacts and agrees with Enbridge Gas that the use of a 2050 economic planning horizon for depreciation is not appropriate at this time.

OEB staff sees value in assessing the merits of the Units of Production procedure as a potential approach to accelerated depreciation. OEB staff submits that Enbridge Gas should be required to prepare a depreciation analysis based on the Units of Production procedure (and other procedures available that can address energy transition implications related to depreciation) for the next rebasing.

OEB staff also briefly discusses Enbridge Gas's comment that, should the OEB shorten the revenue horizon for new customer connections, a change in the approach to depreciation may also be necessary. OEB staff agrees that logically the lifetimes used for revenue horizon and depreciation of customer connection assets should converge on the same values. However, given the large amount of new capital spending over the rebasing term that Enbridge Gas proposes for new customer connections, OEB staff believes that a change in revenue horizon to what is likely a more accurate value is necessary now even with imperfect information, while the proper approach to depreciation may benefit from further analysis and is not as urgent (although action should not be delayed too long, or the impact of a change to the depreciation approach would be larger).

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

In the OEB approved settlement proposal, parties reached full settlement on this issue.

Issue 5: Has Enbridge Gas identified and responded appropriately to all relevant OEB directions and commitments made from previous proceedings?

OEB staff submits that Enbridge Gas has appropriately responded to all relevant OEB directions and commitments made from previous proceedings. Enbridge Gas outlined

[125] Exhibit M9-GEC-ED, pp.46-47.

the outstanding directive and commitments that have been addressed in this application in Exhibit 1, Tab 13, Schedule 1.

B. Rate Base (Exhibit 2)

Issue 6: Is the 2024 proposed rate base appropriate?

Issue 7: Is the forecast of 2024 capital expenditures underpinned by the Asset Management Plan, and in-service additions appropriate?

OEB staff addresses both Issues 6 & 7 together in the section below.

Enbridge Gas provided evidence to support its rate base and capital expenditures for the 2024 Test Year. Rate base includes net property, plant and equipment, plus an allowance for working capital.

In the OEB-approved settlement proposal, parties accepted Enbridge Gas's methodology for the determination of working capital and rate base. Parties also accepted Enbridge Gas's rate base up to, and including 2022, with some adjustments as outlined in the settlement proposal.

In its argument-in-chief, Enbridge Gas noted that it is requesting approval of the following changes to rate base relative to the rate base figures included in its Capital Update.

- Reduction to 2024 opening rate base to reflect the agreement in the settlement proposal to remove approximately $41 million related to WAMS (Work and Asset Management Solution) and Enbridge Gas Distribution's Greater Toronto Area Reinforcement Project overspend.
- Removal of the rate base value of the Dawn to Corunna project (on an interim basis), as this is being determined in Phase 2 of the proceeding.
- Removal of the land purchased for the GTA West REWS (Real Estate and Workplace Services) project ($24.5 million) for ratemaking purposes.

Enbridge Gas also noted that while the settlement proposal was based on the 2022 estimate rate base values, it believes the 2022 actual rate base value that underpinned the Capital Update should serve as the appropriate foundation for determining the 2024 rate base value (i.e. for which to add 2023 and 2024 capital activity), as they reflect actual 2022 capital activity (i.e. additions, retirements). Enbridge Gas further noted that the 2022 actual rate base values result in a lower 2022 ending net property, plant and equipment balance to be carried forward into 2023 and 2024, thus lowering the rate base values in each of those years, which benefits customers.[126]

[126] Argument-in-chief, pp. 76-78.

OEB staff submits that the above noted proposed changes to rate base relative to the Capital Update are appropriate as they are in accordance with the OEB-approved settlement proposal and/or reflect the most up-to-date information available.

The unsettled aspects of rate base are as follows:

a) Inclusion of integration capital in 2024 rate base
b) 2024 opening rate base amounts resulting from 2023 rate base additions
c) 2024 rate base amounts resulting from 2024 rate base additions
d) Consequential changes to 2024 rate base from other determinations

A summary of the financial impact of OEB staff's submission on the unsettled aspects of the rate base issue are set out in Table 7 below. OEB staff notes that lines 1 to 6 are capital expenditure figures while line 8 is a rate base figure. As the majority of the proposed reductions reflect capital expenditure amounts, OEB staff notes that impact on 2024 rate base would be less than $331.0 million.

OEB staff's detailed arguments on the unsettled rate base and capital expenditure matters are set out below.

Table 7
OEB Staff Proposed Rate Base & Capital Expenditure Adjustments

Line	Item	Proposed 2024 Rate Base Amt. or Capital Spending	Staff Proposed Reduction
1	NGEP – Selwyn	$4.4M	$1.5M
2	Customer Connection Costs	$304.1M	$116.1M
3	System Reinforcement Costs	$75.7M	$15.1M
4	Compressor Stations	$46.3M	$8.5M
5	Integrity Digs	$100.9M	$54.6M
6	St. Laurent Phases 3 & 4	$75.7M	$75.7M[127]
7	Subtotal (capital spending reduction for 2024)		$271.5M
8	Integration Capital (rate base)	$119.0M	$59.5M
	Total		$331.0M

[127] As discussed later, OEB staff submits that the 2024 St. Laurent-related costs should be removed from rate base. However, these costs may be recoverable through a rate rider depending on the outcome and timing of the relevant Leave to Construct proceeding.

Inclusion of Integration Capital Costs in 2024 Rate Base

There was no settlement regarding the inclusion of integration capital costs to the opening rate base for 2024. In its argument-in-chief, Enbridge Gas submitted that it is appropriate to include integration capital amounts to 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. Enbridge Gas further noted that in its Operating and Maintenance (O&M) expenses forecast, the company has credited customers with operating savings of $86 million that will benefit customers every year.

Enbridge Gas argued that the integration capital projects that were implemented during the deferred rebasing period were largely technology related initiatives that needed to be completed by Enbridge Gas Distribution and/or Union Gas in the absence of amalgamation. These expenditures are called "integration" because they involve combining activities or processes of the two utilities during the deferred rebasing term.

The OEB's MAADs policy states that incremental transaction and integration costs are not generally recoverable through rates. In order to address distributors' concerns, the OEB provided the opportunity for distributors to defer rebasing for a period up to ten years following the closing of a consolidation transaction. This deferred rebasing period is intended to enable 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.[128]

OEB staff acknowledges that Enbridge Gas only received approval of a five-year deferred rebasing term. Enbridge Gas has argued that the company could have decided to not pursue technology enhancements as the approved deferred rebasing term would have been insufficient to recover the depreciation through synergies given the life of the underlying assets. Enbridge Gas submitted that not undertaking integration activities would be inconsistent with the MAADs policy which is intended to incent the delivery of benefits.

During the deferred rebasing term, Enbridge Gas incurred $189 million in integration capital of which $70 million has already been depreciated. Enbridge Gas has accordingly requested that the undepreciated amounts totaling $119 million should be included in the 2024 rate base. Enbridge Gas argued that under the OEB's general principle of "benefits follow costs", it is appropriate that customers pay the ongoing costs of integration capital that will continue to benefit them after rebasing.

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

OEB staff acknowledges that Enbridge Gas customers have received sustained benefits from integration capital that was incurred during the deferred rebasing period. However, OEB staff notes that one of the outcomes in the regulatory framework under which the OEB assesses applications for consolidations is operational effectiveness, which requires continuous productivity and improved cost performance by distributors.[129] In other words, the OEB expects certain operational efficiencies from amalgamation and that these benefits should accrue to ratepayers. However, OEB staff agrees that Enbridge Gas did not receive the requested deferred rebasing period of 10 years that would have allowed Enbridge Gas to recover the entire integration capital cost investment through the synergy-related savings generated over the longer term.

The MAADs policy is clear that integration costs are generally not recoverable through rates. However, OEB staff also realizes that this policy should be assessed within the context of a permitted 10-year deferred rebasing period. Since Enbridge Gas received a five-year deferred rebasing term, OEB staff submits that Enbridge Gas should be able to include 50% of the net book value of integration capital into the 2024 rate base as it did not have sufficient time to recover the entire capital investment through the synergy savings as would have occurred if a longer deferred rebasing term was approved. Accordingly, Enbridge Gas should be permitted to include $59.5 million (50% of $119 million) in the 2024 rate base.

2024 Rate Base Amounts resulting from 2024 Rate Base Additions (and Associated 2024 Capital Expenditures)

Natural Gas Expansion Program (NGEP) Projects

Enbridge Gas proposed to include the original estimated net capital costs of its NGEP funded projects, which are expected to be in-service by the end of 2024, in 2024 rate base, regardless of the current estimated net capital costs. In Enbridge Gas's view, this is consistent with a past decision of the OEB.[130] Enbridge Gas stated that, in the rebasing application following a NGEP project's rate stability period, Enbridge Gas intends to include the residual actual project capital cost in rate base.[131]

In response to interrogatories and undertakings, Enbridge Gas provided information on the current estimated costs and timing for several of its NGEP funded projects. Generally, the updated forecast final costs of the projects are higher than the original estimated net capital costs. However, for the Selwyn project that has a forecast 2024 in-

[129] *Ibid*, pp. 4-5.
[130] EB-2020-0094, *Decision and Order,* December 4, 2020, section 3.3. This arose from an application for approval of a System Expansion Surcharge, a Temporary Connection Surcharge and an Hourly Allocation Factor.
[131] I.2.6-Staff-74.

service date, the current net capital estimate is $2.8 million, which is approximately $1.5 million lower than the original net capital estimate of $4.4 million. OEB staff notes that Enbridge Gas included the original net capital estimate of $4.4 million in 2024 rate base.[132]

OEB staff submits that including the original net estimated capital cost (i.e., net of NGEP funding) in rate base when the updated net capital estimate has increased relative to the original estimate is appropriate. This is aligned with the purpose of the rate stability period (i.e., the project proponent will assume the risk of cost overruns and lower connection rates during the rate stability period). However, OEB staff submits that Enbridge Gas should not be permitted to include amounts in rate base that are incremental to the amount that it currently believes it is actually going to incur. OEB staff submits that this is also contrary to the concept of a rate stability period and results in the recovery of costs that are not actually expected to be incurred. Therefore, with respect to the Selwyn project, OEB staff submits that only $2.8 million should be included in 2024 rate base (which is a reduction of $1.5 million).[133]

Asset Management Plan and 2024 Capital Expenditures

Enbridge Gas filed an Asset Management Plan (AMP) in support of its capital budget and the proposed 2024 capital expenditures. The AMP has been provided for the period 2023 to 2032 and forms the basis of Enbridge Gas's proposed capital expenditures for the 2024 Test Year and the proposed rate term that ends in 2028.

At the technical conference, Enbridge Gas indicated that it would report on any updates to the capital budgets in advance of the oral hearing. On June 16, 2023, Enbridge Gas filed a Capital Update reflecting changes to its capital budget for 2023 and 2024. In its Capital Update, Enbridge Gas revised the 2024 proposed capital expenditures from $1,491.3 million to $1,470.3 million.

Enbridge Gas's updated proposed capital expenditure for the period 2024 to 2028 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. Enbridge Gas stated that the capital spend profile supports customer growth and reinforcement expenditures that will support the

[132] JT6.3 Updated July 6, 2023.
[133] JT6.3 Updated July 6, 2023. OEB staff notes that for the Brunner (Perth East) project, Enbridge Gas has also included the original net capital cost in rate base, which is $0.9 million higher than the current net capital estimate. However, the OEB-approved settlement proposal has settled rate base matters for the period ending 2022. Therefore, OEB staff is not recommending any changes associated with the Brunner (Perth East) project.

addition of new customers, as well as expenditures associated with existing assets to maintain safe and reliable business operations.[134]

Before discussing specific expenditures, OEB staff will provide some brief comments on the AMP. Although Enbridge Gas has referred to the risks of energy transition in its AMP, the proposed expenditures do not reflect the risks related to energy transition. In section 4.2 of its AMP, Enbridge Gas explained its risk management process and how it identifies, evaluates, analyzes, addresses and monitors risks. At the oral hearing, the Enbridge Gas witness confirmed that it had not directly addressed energy transition risk and the related stranded asset risk in the AMP. Enbridge Gas clarified that it did not conduct any probability scenarios for changes in volume or peak demand as a result of energy transition.[135]

Enbridge Gas has proposed approximately $14 billion in capital expenditures for the 2023 to 2032 period. Considering that natural gas consumption is expected to decline significantly by 2050, it is not clear how $14 billion of capital expenditures that is on average recoverable over 40 years aligns with the potential for significant future declines in natural gas throughput. The proposed $14 billion of capital expenditures is close to the entire 2024 proposed rate base of $16 billion. Enbridge Gas expects to continue to add new customers and expand its rate base in what appears to be "business as usual". OEB staff does not believe that Enbridge Gas's proposed approach is appropriate in the context of energy transition. At the oral hearing, the Enbridge Gas witness agreed that natural gas volumes will fall over the next thirty years[136] and OEB staff submits that this volumetric decline needs to be considered starting in the current proceeding.

OEB staff further submits that at the next rebasing, Enbridge Gas should be required to file an AMP that establishes clear linkages between energy transition and capital spending in all operating areas including a discussion on scenarios and probabilities of stranded assets. OEB staff believes that future AMPs should focus on maintaining a viable natural gas distribution system in an environment of energy transition where one of the primary objectives should be to reduce the risk of stranded assets.

A discussion on some specific spending categories is provided below.

<u>Growth Spending – Energy Transition-related Capital Expenditure Reductions</u>

For reasons provided earlier in this submission (Under Issue 3), OEB staff submits that a reduction of $116.1 million to the customer connection costs for 2024 is appropriate.

[134] Exhibit 2, Tab 6, Schedule 1, p. 37.
[135] Oral Hearing Transcript, Vol. 14, p. 111.
[136] Oral Hearing Transcript, Vol. 14, p. 71.

Also, as discussed previously, OEB staff submits that a reduction of $15.1 million to the system reinforcement budget is reasonable. Overall, OEB staff submits that the 2024 growth-related capital budget should be reduced by $131.1 million ($116.1 million + $15.1 million), and the associated in-service additions should be removed from 2024 rate base.[137]

Compression Stations

The as-filed spending on compression stations was $38.9 million. In the capital update, the spending on this item was increased to $46.3 million, with $15.1 million of new spending.[138] One of the new spending items is related to $8.5 million for new projects identified through inspection activities and failures. At the oral hearing, OEB staff counsel sought clarification on this new spending. Enbridge Gas witnesses noted that the spending is related to the Multi-Sector Air Pollutants Regulations (MSAPR).[139] The program includes leak survey of compressor stations and where leaks are discovered, they are remediated through repairs or replacement. OEB staff notes that the MSAPR is not a new regulation and came into effect in 2017. Considering that Enbridge Gas has a sophisticated AMP and capital budgeting process, it is difficult to understand how such routine maintenance spending was identified in the Capital Update. OEB staff submits that such spending should have been identified in the normal maintenance planning process and if it was missed for some reason, then the additional spending should be absorbed within the capital budget. Therefore, the 2024 capital budget should be reduced by $8.5 million, and the associated in-service additions should be removed from 2024 rate base.

Distribution Pipe – Integrity Spending

In Table 5.2.3-4 of the AMP, Enbridge Gas provided amounts for planned integrity spending. This appears under “TIMP Retrofits and Digs” and “Inspection Program Integrity Retrofits and Digs” (planned integrity spending). The Transmission Integrity Management Program (TIMP) refers to performing in-line inspections including retrofits to enhance the amount and quality of condition data and digs to evaluate pipeline features.

[137] See OEB staff’s submission in the sub-section titled, “Energy transition and Integrated Resource Planning impacts on load forecast and capital expenditures” under Issue 3.
[138] Exhibit 2, Tab 5, Schedule 4, Table 8, p. 20. The revised capital budget of $46.3 million is calculated as $38.9 million (original budget) + $10.7 million (project carryforward) + $15.1 million (new projects) - $24.7 million (cancelled/deferred projects) + $6.3 million (other changes).
[139] Oral Hearing Transcript, Vol. 13, p. 186.

OEB staff recreated a portion of the Table 5.2.3-4 from the AMP that shows spending related to integrity digs in Table 8 below.

Table 8
Integrity Capital Spend (2023-2028)

Investment Name ($)	2023	2024	2025	2026	2027	2028
TIMP Retrofits and Digs	21.2M	21.8M	22.4M	20.7M	22.1M	2.8M[140]
Integrity Retrofits and Digs	51.6M	51.4M	27.0M	42.0M	26.2M	21.9M
TOTAL	72.8M	73.2M[141]	49.4M	62.7M	48.3M	24.7M

The total planned integrity spending in the category as per the AMP is $72.8 million in 2023 and $73.2 million in 2024. In the Capital Update, Enbridge Gas has increased the 2024 capital expenditure amount by another $27.7 million bringing the overall total to $100.9 million for that year.

Integrity retrofits and digs are part of a standard maintenance program and it is not clear why spending should increase to $101 million for 2024. At the oral hearing, the Enbridge Gas witness noted that the budgets are based on the expected number of digs and history of the pipelines. The digs are done to assess the condition of the pipelines. The witness further noted, “[b]ut it is a bit of a guessing game when it comes to establishing the right number.”[142]

OEB staff submits that, as confirmed by the Enbridge Gas witness, the planned integrity spending is not related to replacement of pipelines or major reinforcement where spending could be lumpy in nature. Such spending should generally be levelized. OEB staff notes that spending related to Corrosion Prevention Program, Service Relay Replacement Program and Relocation Program in Table 5.2.3-4 of the AMP are levelized across the 2023 to 2032 period. There is no reason why spending related to integrity digs cannot be levelized.[143]

[140] OEB staff notes that the TIMP Retrofits and Digs amount stays at the $2.8 million level for the 2029 to 2032 period.
[141] In the Capital Update, the 2024 total planned integrity spending increased to $100.9 million.
[142] Oral Hearing Transcript, Vol. 13, p. 189.
[143] Table 5.2.3-4: Distribution Pipe Capital Summary, Asset Management Plan, Exhibit 2, Tab 6, Schedule 2, p. 119.

OEB staff further notes that the average planned integrity spending for the 2025 to 2028 period is $46.3 million. If the original 2024 budget of $73.2 million is included in the calculation, the average for the 2024 to 2028 period is $51.7 million. At the oral hearing, OEB staff counsel sought clarification for the proposed spending for 2024 of approximately $101 million and how it compared to the average spend of $46.3 million (2025 to 2028). The Enbridge Gas witness noted that this was partly related to inspecting pipelines for not only external corrosion, but also internal corrosion. However, the spending on Corrosion Prevention Program in the AMP is fairly levelized with the amount ranging from $10.2 million to $11.6 million for the 2023 to 2032 period.[144] OEB staff submits that any inspection or prevention spending should be levelized as has been done for the other programs noted above.

OEB staff submits that the total spending for planned integrity activities should be set at $46.3 million, which is the average planned integrity spending for the 2025-2028 period, for 2024. There is no basis for the proposed updated budget of $101 million that Enbridge Gas admits was established based on a “guessing game.”[145] Therefore, the 2024 capital budget should be reduced by $54.6 million ($100.9 million – $46.3 million) and the associated in-service additions should be removed from 2024 rate base.

Panhandle Regional Expansion Project

Enbridge Gas has proposed a levelized treatment for the Panhandle Regional Expansion Project (PREP) and excluded the associated capital expenditures from the Capital Update. PREP is a significant project (forecasted in-service capital of $252 million for 2024).[146] Since the project has yet to receive Leave to Construct (LTC) from the OEB, Enbridge Gas has proposed to exclude the costs and incremental revenues that are attributable to the project’s forecast 2024 in-service component from the determination of the base 2024 cost of service revenue requirement. The treatment is similar to ICM projects that were considered by the OEB during Enbridge Gas’s deferred rebasing term (2019 to 2023).

Enbridge Gas will calculate a separate unit rate that will be based on the average of the five-year net revenue requirement and remain fixed for the duration of the incentive regulation term. In the event that the OEB does not grant LTC, no adjustment to base rates will be required and Enbridge Gas will not implement the rate rider.

[144] *ibid*
[145] Oral Hearing Transcript, Vol. 13, p. 189.
[146] 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.

Enbridge Gas has also proposed to establish an associated variance account, the PREP Variance Account (PREPVA), 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 IR term.

OEB staff supports the proposed approach and notes the simplicity of the rate mechanism in the circumstance that the OEB does not approve the PREP LTC.

St. Laurent Phase 3 and Phase 4 Projects

Significant investments in the 2024 capital budget are related to 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 Phase 3 and Phase 4 projects 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).[147]

In the OEB's Decision on the St. Laurent Ottawa North Replacement Project, the OEB denied Enbridge Gas's LTC application. The OEB noted that Enbridge Gas had not appropriately considered alternatives to the project. The OEB determined that Enbridge Gas had not demonstrated that the pipeline integrity is compromised, and that pipeline replacement is required at this time. The OEB urged Enbridge Gas to thoroughly examine other alternatives such as the development and implementation of an in-line inspection and maintenance program using available modern technology, and propose appropriate action based on its findings as part of its next rebasing application.[148]

OEB staff notes that the OEB's initial denial of the St. Laurent LTC application creates some uncertainty with respect to the likelihood and timing of any future approval of the St. Laurent project. OEB staff is not taking a position on the prudence or need of the St. Laurent project in the current proceeding. This will be determined in the relevant LTC application. However, OEB staff supports a treatment similar to PREP for the St. Laurent project.

In response to an undertaking, Enbridge Gas indicated that it did not consider applying the same levelized treatment to St. Laurent as is proposed to PREP due to differences in both the materiality and scope of the projects. The forecasted in-service capital for PREP in 2024 is $252 million compared to approximately $76 million for the 2024 segments of St. Laurent. Secondly, St. Laurent is a typical integrity replacement project

[147] Undertaking Response J13.21.
[148] EB-2020-0293 Decision and Order, May 3, 2022, p. 3.

as opposed to a growth driven project like PREP.[149] OEB staff is of the view that the scope difference should not be a concern as both projects are clearly material and the primary issue is the same for both projects; both projects need LTC and the proposed levelized approach is appropriate when there is uncertainty around timing and approval of the projects.

Accordingly, OEB staff submits that the levelized treatment should also apply to the St. Laurent project and $75.7 million should be excluded from the 2024 capital expenditures and the associated in-service additions should be removed from 2024 rate base. OEB staff notes that the costs of the St. Laurent Project would still be recoverable, assuming LTC approval, through rate riders instead of base rates.

In addition, as is discussed under Issues 31-33, OEB staff submits that a variance account similar to the PREPVA, that would capture any variance between the St. Laurent project's actual net revenue requirement and the actual revenues collected through the average unit rate that would be in place over the IR term should be established.

Overall 2024 Capital Expenditure Reduction

If the OEB accepts OEB staff's submissions with respect to 2024 capital expenditures, the resulting capital expenditures for 2024 are reduced by $271.5 million (as noted in Table 7), from $1,470.3 million to $1,198.8 million (and the 2024 rate base should be reduced by the in-service addition impact of these changes).

Issue 8: Are the proposed harmonized indirect overhead capitalization methodology and proposed 2024 overhead amounts appropriate?

Generally, OEB staff does not oppose Enbridge Gas's proposed harmonized capitalized overhead methodology, subject to requiring:

i) Enbridge Gas 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).

ii) A revision to the way the Operation Regions capitalization rate is determined as discussed below.

Prior to amalgamation, Enbridge Gas Distribution and Union Gas applied different OEB-approved overhead capitalization methodologies that used similar underlying principles, cost categories, and cost drivers. As part of the current application, Enbridge Gas

[149] Undertaking J13.1.

requested approval for a harmonized overhead capitalization methodology to reflect the amalgamated operations of Enbridge Gas. The harmonized overhead capitalization methodology 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. Cost drivers include capital expenditures, time analysis, weighted average rates, and burdening.[150]

Indirect overhead costs are costs associated with activities supporting asset creation but cannot be directly linked to any specific asset or asset group. These costs include supervision and oversight of capital activities, as well as support functions such as Finance, Legal, Supply Chain, Human Resources, and Technology and Information Services (TIS), etc. In its pre-filed evidence, Enbridge Gas requested $310.5 million in overhead capitalization to be included in the proposed 2024 rate base.[151]

In the pre-filed evidence of this application, Enbridge Gas quantified the amount of overhead costs capitalized (see Table 9 below). The amounts include both direct and indirect overheads. However, Enbridge Gas noted that it is unable to isolate and quantify the revenue requirement impact of indirect costs due to the lack of visibility within the current system that pools all direct and indirect overhead costs and does not segregate this detail at a capitalization level.[152]

Table 9
Impact of Proposed Harmonized Capitalization Method for 2024

	Historical Method		Enbridge Gas Harmonized Method		Variance
$M	**Capitalized Amount**	**Capitalized Rate**	**Capitalized Amount**	**Capitalized Rate**	**Capitalized Amount**
Operations Costs	121.9	36.0%	118.2	35.0%	(3.6)
Business Units Costs	56.1	11.1%	54.5	10.8%	(1.6)
Shared Services Costs	63.8	20.5%	72.7	23.4%	8.8
Pension & Benefits Costs	53.2	35.9%	65.1	43.9%	11.9
Total	**295.1**	**22.7%**	**310.5**	**23.8%**	**15.4**

As a result of the settlement proposal, capitalized overheads have been reduced to $292 million.[153] Enbridge Gas stated that if the $292 million capitalized overhead amount was not approved for inclusion in the capital budget, the difference will need to

[150] Ex 2/Tab 4/Schedule 2/page 9 of 21.
[151] Ex 2/Tab 4/Schedule 2/page 17.
[152] IRR 2.4-Staff-52a-b.
[153] Argument-in-Chief, p. 118.

be added to the net O&M total of $821 million.[154]

Indirect Overheads

OEB staff submits that Enbridge Gas should be required to quantify the indirect overheads that it has capitalized under ASC 980 for Regulated Operations, which otherwise would have been expensed under ASC 360 for Property Plant and Equipment had ASC 980 not been applied. OEB staff acknowledges that this could be a challenging undertaking, therefore, OEB staff submits that this quantification can be done and provided at the next rebasing application, on a Best-Efforts basis.

Ontario utilities previously reported under Canadian Generally Accepted Accounting Principles (CGAAP), which allowed for capitalization of indirect overheads. Since 2015, CGAAP is no longer applicable, and the majority of utilities have been required to adopt modified International Financial Reporting Standards (MIFRS) for regulatory reporting purposes. Under MIFRS, indirect overhead costs cannot be capitalized and utilities were required to change their capitalization policies to align with MIFRS so that indirect overheads are no longer capitalized.[155,156] There is therefore a legitimate question why Enbridge Gas should be treated differently, just because it is under USGAAP.

In OEB staff's view, Enbridge Gas's written evidence did not provide a convincing answer. Indirect costs are not eligible for capitalization under USGAAP Accounting Standard Codification (ASC) 360 for Property Plant and Equipment.[157] Therefore, Enbridge Gas relied on the USGAAP ASC 980,[158] which allows Enbridge Gas to capitalize indirect costs that it otherwise would not be able to under USGAAP. However, as Enbridge Gas acknowledged in the oral hearing, relying on ASC 980 to capitalize indirect overheads is somewhat circular, as ASC 980 permits capitalization only where regulatory approval is probable.[159]

Enbridge Gas also cited the OEB's Uniform System of Accounts for Class "A" Utilities. While the UsoA does contemplate the capitalization of indirect overheads, it was issued in 1996, a time when utilities were reporting under CGAAP. In any case, the UsoA

154 Argument-in-Chief, p. 118.
155 Page 8 of Article 410 of Accounting Procedure's Handbook, effective January 1, 2012, states that property, plant and equipment include any costs that are directly attributable to bringing an asset to the location and condition necessary for it to be capable of operating in the manner intended by management. It also states that administration and general overhead costs is an example of costs that are not property plant and equipment.
156 The OEB required mandatory changes to depreciation and capitalization policies aligned with IFRS as per its July 17, 2012 letter "Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013".
157 IRR 2.4-Staff-52a-b.
158 Ex 2, Tab 4, Schedule 1, pp.3-6.
159 Oral Hearing Transcript, Vol. 16, p. 23.

expressly states "[i]nclusion of any item or account in this prescribed USoA does not necessarily imply the Board's acceptance of any expenditure, revenue or procedure suggested by the use of such an account." During the oral hearing, Enbridge Gas agreed that the UsoA does not compel the OEB to accept capitalization of indirect overheads.[160]

Enbridge Gas also submitted that given the prior OEB approvals to capitalize indirect overheads specifically for Enbridge Gas Distribution and Union Gas, indirect overheads which support capital projects should continue to be allocated to capital projects as they are and continue to be part of the cost to complete capital projects.[161] OEB staff acknowledges the importance of past practice and prior approval. However, in OEB staff's view, the harmonization of the capitalization methodologies offers an opportunity to reassess whether continued capitalization is appropriate. As discussed below, OEB staff does not object in principle to the continued capitalization of indirect overhead by Enbridge Gas in this proceeding. However, OEB staff submits that Enbridge Gas should be required to quantify the indirect costs it has capitalized on a Best-Efforts basis at its next rebasing application.

Firstly, OEB staff acknowledges that even though most utilities regulated by the OEB are under MIFRS and do not capitalize indirect costs, other Ontario utilities under USGAAP, namely, Hydro One Networks Inc. and Ontario Power Generation, are reporting under USGAAP for regulatory purposes and currently have OEB approval to capitalize indirect costs.[162]

However, there is uncertainty as to whether Enbridge Gas will be able to continue using US GAAP or be required to adopt IFRS in the near future.[163] If that is the case, Enbridge Gas will likely no longer be able to capitalize indirect costs under IFRS. In this circumstance, Enbridge Gas would likely need to establish processes in advance of the transition date to track the indirect overhead costs that are currently capitalized under US GAAP but not permitted under IFRS. This impact would be reflected in the account that OEB staff suggests should be established later in this submission under Issues 31-33.

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[160] Oral Hearing Transcript, Vol. 16, p. 27.
[161] Argument-in-Chief, pp. 122-123.
[162] EB-2011-0110 Decision on Settlement Proposal and Order on Rates, Revenue Requirement and Charge Determinants for Hydro One Networks Inc., November 29, 2022; and EB-2020-0290 Decision and Order that approved the settlement proposal for Ontario Power Generation Inc.'s for Application for Payment Amounts for the Period from January 1, 2022 to December 31, 2026, dated November 15, 2021.
[163] Enbridge Gas has received an exemption from the Ontario and Alberta Securities Commissions to report under IFRS from and is permitted to report under USGAAP until the earlier of: (i) January 1, 2027; (ii) it 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).

Secondly, even though Enbridge Gas's written evidence did not convince OEB staff that the capitalization of indirect overheads is appropriate, Enbridge Gas's argument-in-chief lays out a principled case for capitalization, where it says:

> … the fact is that capital projects require the support of many departments within the Company and central functions. Where this support is, as a practical matter identifiable, the costs are directly allocated to a capital project. Where it is impractical to specifically identify a capital project which certain activities support, consistent with historical practice, it is appropriate to generate a methodology which calculates that portion of overheads which should be capitalized and that this methodology should include the pension and benefits burden…. If the indirect overheads are not included, the amounts being capitalized do not represent the full cost of the capital project.[164]

Though OEB staff generally agrees with the principle in the statement, the challenge, however, is where to draw the line in determining what indirect costs should be attributed to a particular capital project.

Lastly, as a practical matter, denying the capitalization of any indirect amounts would significantly increase rates: the revenue requirement impact in 2024 would be around $348 million.[165] However, OEB staff notes that the $348 million revenue requirement impact is based on denying overheads of $310 million (the amount from the pre-filed evidence), which Enbridge Gas has noted is not actually all indirect overheads. A portion of the $310 million is direct overheads, but Enbridge Gas is not able to disentangle it. OEB staff notes that denying capitalization would have an immediate revenue requirement impact in 2024, but consequently, the amount will no longer be included in rate base and subject to a return over the life of the associated asset. If capitalization were denied, consideration may need to be given to bill mitigation measures.

For these reasons, OEB staff does not object in principle to the continued capitalization of indirect overhead by Enbridge Gas in this proceeding. Moreover, OEB staff does not object to the proposed harmonized methodology that was developed on the advice of Ernst & Young – except in one respect, which is explained below under the Operation Capitalization Rates section. However, OEB staff submits that parties and Commissioners should have a clear picture of what the implications of approving or denying the capitalization of indirect amounts would be. Therefore, OEB staff submits that, at its next rebasing application, Enbridge Gas should be required to quantify the

[164] Argument-in-Chief, p. 129. Undertaking J16.3
[165] Argument-in-Chief, p. 135; Exhibit J16.3 (Enbridge Gas calculated the $348 million impact based on the pre-settlement capitalization amount of $310.5 million).

indirect costs it has capitalized on a Best-Efforts basis and provide that quantification at its next rebasing.

Operation Capitalization Rates

OEB staff submits that the Operational Regional group capitalization rates should be revised to reflect a three-year rolling average that incorporates actual and forecast information. For the purposes of setting 2024 rates, this would be 2022, 2023 (actual and forecast), and 2024 data as described further below. If the OEB approves OEB staff's proposed methodology for calculating the capitalization rate, the OEB may wish to direct Enbridge Gas to file the recalculated overhead amounts using this methodology as part of the draft rate order process. The change in overhead methodology should also be reflected in the balance of the Accounting Policy Changes Deferral Account (APCDA).

The proposed harmonized overhead capitalization methodology includes four cost categories: Operations Costs, Business Costs, Shared Services Costs, and Pension and Benefits Costs.[166] The Operations Costs category consists of groups that support Enbridge Gas's core field operations across the company's realigned seven geographic regions post-amalgamation. These groups oversee and directly support capital activities related to the natural gas delivery infrastructure. Operations Regional groups use region-specific capital spending proportions to determine separate allocation rates for seven regions, considering the diverse characteristics of each area. This approach reflects the allocation of resources for capital projects versus operations. The Operations Services and Governance group employs a weighted average of the seven Regional rates. Customer Attachment is fully capital, while Leak Survey and Locates are entirely O&M. The Operations VP Admin group uses a weighted average of these rates.[167]

Operations Costs are allocated based on the most recent year's actual spending at the time the budget is developed to determine the following year's budgeted overhead capitalization rate. For this proceeding, Enbridge Gas based the 2024 capitalization rate for Operation Costs on 2021 actuals.[168] Enbridge Gas explained that it used 2021 actuals since historical data dated three to four years back would not be comparable to the current organizational structure as the Operations Regional groups have undergone multiple organizational changes. Also, at the time the 2023 and 2024 budget was developed, 2022 actuals were not available.

[166] Ex 2, Tab 4, Schedule 2, page 9.
[167] Ex 2, Tab 4, Schedule 2, p.10.
[168] Oral Hearing Transcript, Vol. 16, p.36.

OEB staff submits that using the historical 2021 actuals for determining the capitalization rate for the future 2024 test year has some shortcomings. Firstly, it appears that 2021 actuals were selected more out of convenience, as that was the most current data at the time budgets were developed. Since that time, 2022 actuals and Q2 2023 actuals are now available but Enbridge Gas still proposes to use 2021 actuals.[169] Secondly, historical data may not necessarily be representative of the future, especially given the energy transition issues Enbridge Gas is facing. Enbridge Gas has argued that O&M costs indirectly supporting capital projects would not change immediately, even if there is a material shift in the capital program, given that most of the reductions would be expected to impact direct costs for these projects. Enbridge Gas would anticipate workforce-related costs to start to decline to reflect a sustained change in the capital program over the medium term when there is a continued reduction to the capital portfolio. Regardless of whether this statement holds true or not, the issue here is that the OEB is only setting 2024 rates and Enbridge Gas has confirmed that even though the data used in the overhead capitalization methodology is updated annually, the base capitalization rates will be set based on the 2024 forecast amounts and will not change. Enbridge Gas will also not be tracking any differences between actuals and amounts embedded in rates during the rate term.[170] Therefore, if the actual capitalization rates do decline during the rate term, this would not be reflected in rates.

To address this issue, OEB staff submits that the determination of Operation Costs capitalization rates can include a prospective component to it, similar to Business Costs where capitalization rates reflect a prospective time study.[171] Operation Costs can be based on a rolling three-year average that includes both historical and forecast data. For the purposes of determining the 2024 capitalized amount, OEB staff submits that the average of: (i) 2022 actuals; (ii) 2023 actuals up to Q2 and a forecast for the remainder of the year; and (iii) 2024 forecast be used. The 2024 forecast should be based on the capital spend that is ultimately approved by the OEB in this proceeding.

Should the OEB accept OEB staff's recommendation, it should require Enbridge Gas to provide the revised calculation of capitalization rates, the impact to capitalized overhead and revenue requirement, as part of the draft rate order process. OEB staff notes 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. In the OEB's 2019 Deferral and Variance Account disposition proceeding, Enbridge Gas brought forward 2019 balances in the APCDA for disposition. In the OEB approved settlement proposal, Enbridge Gas and the intervenors agreed to postpone

[169] Oral Hearing Transcript, Vol. 16, p. 37.
[170] Argument-in-chief, p. 133.
[171] Argument-in-chief, pp. 127-128.

the review, allocation and disposition of balances in the APCDA until the end of Enbridge Gas's deferred rebasing term.[172]

In the event that the OEB accepts OEB staff's recommendation to calculate Operation Costs capitalization rates using a 3-year rolling average that includes historic and forecast information, this should be incorporated in the harmonized methodology starting in 2020 and be reflected in the balance of the APCDA requested for disposition in this proceeding.

C. Load Forecast and Revenue Forecast (Exhibit 3)

Issue 9: Is the 2024 volume forecast by rate class and resulting revenue forecast appropriate? Is the 2024 storage and transportation revenue and upstream transportation optimization forecast appropriate?

In the OEB approved settlement proposal, parties agreed to Enbridge Gas's as-filed volumes forecast and revenues at existing rates, revenue forecasts for storage and transportation, upstream transportation revenue and optimization revenue subject to a change to the 2024 customer addition forecast.

In addition, parties did not agree to the establishment of the Volume Variance Account. OEB staff's submission on this issue is discussed under Issue 31-33.

Issue 10: Is the 2024 other revenue forecast appropriate?

Parties agreed to Enbridge Gas's as-filed other revenue forecast, subject to two exceptions:

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

The unsettled issue regarding property disposition is discussed below. The discussion on the appropriate treatment of the Natural Gas Vehicle Program is discussed under Issue 34.

Enbridge Gas requested OEB approval of its proposed forecast of other revenue to exclude any forecast of property disposition gains or losses. Enbridge Gas submitted that land (but not buildings) associated with property dispositions are not depreciable

[172] EB-2020-0134 Settlement Proposal, January 5, 2021, p. 10.

assets for which ratepayers have not, by definition, borne a depreciation expense and so sharing of proceeds is not required by regulatory or legal principles. 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. 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 as part of any earnings sharing framework that is approved by the OEB during Enbridge Gas's proposed incentive rate-setting mechanism (IRM) framework (to be addressed in Phase 2).

Enbridge Gas emphasized that not all proceeds from a property disposition constitute income; only the gains or losses on land are recorded as income and gains or losses on building dispositions are captured in accumulated depreciation.

Enbridge Gas noted that property dispositions are subject to uncertainties and timelines that may not be in its control. Property disposition timelines are influenced by several factors such as availability of replacement site, zoning and permitting, market conditions and construction issues. Further, property values can fluctuate significantly due to supply and demand dynamics in the commercial real estate market. Enbridge Gas argued that property dispositions are infrequent transactions that are not part of Enbridge Gas's normal course of business and therefore no revenues from property dispositions should be included in the 2024 Test Year. Enbridge Gas noted that its updated capital budget reduced the number of property dispositions from four to one in 2024 with estimated capital proceeds declining from $31 million to $6.3 million.[173]

OEB staff supports Enbridge Gas's proposal to not include any amounts related to property disposition gains or losses in its 2024 other revenues forecast (and therefore revenue requirement).

OEB staff agrees with Enbridge Gas that there is considerable uncertainty regarding the timing and proceeds related to any property sales. In addition, the extent to which the OEB may consider sharing any proceeds from property sales with ratepayers can depend on the details of the property that was sold. For example, a property that was sold but had its functions replaced by a new property that was purchased by Enbridge Gas might receive different treatment than a property that was sold because it was completely surplus (i.e. it wasn't replaced by some other property or asset).[174] Absent detailed information on what properties have been sold and why, it is not possible at this point to recommend what treatment might be appropriate for any particular property

[173] Capital Update, June 16, 2023.
[174] See, for example, *Toronto Hydro-Electric System Ltd. v. Ontario Energy Board*, 2009 CanLII 30148.

sale.

Therefore, OEB staff supports the establishment of a deferral account to track any proceeds from property sales over the course of an approved IRM rate term. Consideration of the method of disposition and the allocation of amounts (including, potentially, a determination that all the proceeds should be allocated to the utility) should be conducted in the future when there are entries into the account and the nature of the properties and reasons for the sales can be explored.

Issue 11: Are the proposals for harmonized load forecasting methodologies (heating degree days, average use, weather normalization, heat value, customer additions) and the 2024 Test Year results from those methodologies appropriate?

Parties agreed that the 2024 Test Year results from the forecasting methodologies are appropriate, but there was no agreement on the methodologies for capital planning and cost allocation purposes.

OEB staff notes that cost allocation will be addressed in Phase 3 of the proceeding.

D. Operating Expenses (Exhibit 4)

Issue 12: Are the proposed 2024 Test Year operating and maintenance expenses appropriate?

Issue 13: Are the 2024 proposed compensation related costs (including, FTEs, wages, salaries, benefits, incentives, overtime, pension and OPEB costs) appropriate?

Issue 14: Are the 2024 proposed shared services and corporate services costs appropriate, including the proposed Centralized Functions Cost Allocation Methodology (CFCAM)?

Parties agreed to an overall O&M budget envelope. Some exceptions are noted in the settlement proposal, which generally refer to the unsettled issue of the overhead capitalization methodology. The overhead capitalization methodology is addressed under Issue 8.

Issue 15: Are the proposed harmonized depreciation rates and the 2024 Test Year depreciation expense appropriate?

Enbridge Gas requested a 2024 depreciation expense of $879 million, which represents an increase of $141.9 million from the forecasted 2024 depreciation expense of $734.1

million using the prior approved depreciation methodology and rates.[175] Enbridge Gas's proposed depreciation methodology reflects the following:[176]

- Depreciation Procedure: A change to the Equal Life Group (ELG) procedure from the Average Life Group (ALG) procedure previously used by Enbridge Gas Distribution and the Generation Arrangement procedure used by Union Gas.
- No Economic Planning Horizon: Enbridge Gas does not propose to truncate service lives to a specific date.
- Asset Life Parameters: The proposed parameters are as recommended by Enbridge Gas's expert, Concentric Energy Advisors, in the depreciation study.
- Net Salvage: The Constant Dollar Net Salvage (CDNS) method using net salvage parameters as recommended by Concentric, and a discount rate equal to the credit-adjusted risk-free rate (CARF) of 3.75%.

During the proceeding, OEB staff's expert, InterGroup Consultants Ltd. (Intergroup) and IGUA's expert, Emrydia Consulting Corporation (Emrydia), each assessed Enbridge Gas's depreciation proposal and expressed their expert opinion in each of their reports and at the oral hearing. The main areas in which they do not agree with Enbridge Gas and Concentric are as follows.

- Depreciation Procedure: Both InterGroup and Emrydia do not support the change to ELG and recommend the ALG procedure be used. All experts agreed that an Economic Planning Horizon is not appropriate at this time.
- Asset Life Parameters: As noted in their respective reports, InterGroup disagreed with the proposed asset parameters for six accounts[177], while Emrydia disagreed with the proposed asset parameters for ten accounts.[178] Two of these accounts overlap between InterGroup and Emrydia. [179] Emrydia indicated that it generally agrees or accepts the asset life parameter recommendations made by InterGroup.[180] InterGroup did not suggest that Emrydia's recommendations be adopted, although they expressed some support for one of Emrydia's recommendations.[181]

[175] Argument-in-chief, p.175.
[176] *Ibid*, p.177.
[177] Exhibit M1, pp.7-8.
[178] Exhibit M5, pp.8-9.
[179] Overlapping accounts are Account 475.21 – Distribution Mains Coated and Wrapped, and Account 475.3 –Distribution Mains Plastic.
[180] N.M5.Staff-1. For Account 475.3 Distribution Mains – Plastics, Emrydia continues to prefer its own recommendation of Iowa curve 70-R2.
[181] Oral Hearing Transcript, Vol. 17, pp,174-178.

- Net Salvage:
  - Net Salvage Method: Both InterGroup and Emrydia were supportive of the CDNS method. However, both experts also noted issues with the way Concentric has calculated net salvage under CDNS.
  - Net Salvage Parameters: InterGroup disagreed with the proposed net salvage parameters for six accounts.[182] Emrydia stated that it generally supports the net salvage parameter recommendations made by InterGroup.[183]
  - Net Salvage Discount Rate: Both InterGroup and Emrydia questioned the discount rate used in Concentric's CDNS calculation.

OEB staff provides detailed arguments on the aforementioned areas below. In summary, OEB staff submits the following.

- Depreciation Procedure:
  - Enbridge Gas should be required to use ALG.
  - There should not be a change to depreciation methodology based on potential energy transition impacts at this time; however, Enbridge Gas should be required to do an analysis of the Units of Production procedure and provide the results of that analysis at the next rebasing application. Enbridge Gas should also provide procedures available other than the Unit of Production that can address energy transition implications relating to depreciation.
- Asset Life Parameters: Enbridge Gas should use the parameters recommended by InterGroup.
- Net Salvage:
  - Method and Parameters: Enbridge Gas should be required to use the CDNS method, based on InterGroup's calculation methodology of CDNS, and its recommended net salvage parameters. However, in the event that the OEB does not approve InterGroup's recommendations with respect to net salvage, OEB staff submits that using the traditional method and InterGroup's net salvage parameters would be the appropriate alternative.
  - Discount Rate: Enbridge Gas should be required to use the most current credit-adjusted risk free rate (CARF) of 4.48%.

[182] Exhibit M1, pp.7-8.
[183] N.M5.Staff-1.

- Reporting: Enbridge Gas should be required to report on ten accounts with respect to net salvage.

Depreciation Procedure

As noted above, Enbridge Gas proposed to use the ELG procedure, while InterGroup and Emrydia recommended the ALG procedure. OEB staff supports the use of the ALG procedure for the reasons discussed below. Enbridge Gas and Concentric have indicated that ELG is a good first step in addressing energy transition as it results in higher depreciation expense. However, OEB staff submits that it is not appropriate to use ELG as a tool to address energy transition at this time. OEB staff is of the view that it may be appropriate to use a depreciation methodology to address energy transition in the future. However, the methodology should be purposefully designed to address energy transition and should reflect the broader overall energy transition issues (including the potential risk of stranded assets and the appropriate allocation of that potential risk). OEB staff submits that while the outcome of ELG is higher depreciation expense, addressing energy transition is not the actual purpose of the ELG procedure.

Enbridge Gas stated that ELG is the best option to calculate depreciation for the following reasons:[184]

a) Enhances the generational equity for customers.
b) Provides superior matching of the depreciation expense to the consumption of assets providing service to customers.
c) More accurately reflects the actual useful life of the assets used as compared to the ALG procedure.

In its response to interrogatories, Concentric also provided the following advantages of using ELG for Enbridge Gas rather than ALG:[185]

a) Given the potential changes in use of fossil fuels and the unknown impact of such change on the Enbridge Gas system, the use of the ELG procedure best reduced the future risk of intergenerational inequity.
b) The ELG procedure has long been recognized as the most precise procedure by depreciation authorities, and has been advocated in various texts, periodicals and technical papers.
c) The use of the ELG procedure was the best available match to the historic procedures approved for Union Gas.

[184] Exhibit 4/Tab 5/Schedule 1/p.6.
[185] Exhibit I.4.5-Staff-173c.

ELG and Energy Transition

The ELG procedure results in a higher depreciation expense in the earlier years of an asset account.[186] An example of the ELG depreciation impact as compared to the ALG depreciation was provided in undertaking J17.4. When compared to ALG, the example shows that ELG results in depreciation that is 30% higher for years 1 to 5, and then eventually approximately 2% higher under ELG for years 15 to 40. For Enbridge Gas, the ELG procedure results in 2024 depreciation expense that is $83.4 million higher than the ALG procedure.[187]

In its argument-in-chief, Enbridge Gas and Concentric submitted that ELG is a good first step to addressing energy transition.[188] Enbridge Gas noted that the higher depreciation expense under ELG results in decreasing the risk of stranded assets and costs.[189] Furthermore, Enbridge Gas stated that Concentric noted that the approval and use of the ELG procedure in the calculation of the depreciation rates is key to minimizing the risk of under-recovery to Enbridge Gas of the investment in property, plant and equipment.[190]

OEB staff submits that the OEB should deny Enbridge Gas's proposal to use ELG for depreciation in the current proceeding.

Specifically, OEB staff questions whether ELG is the best depreciation procedure to address energy transition. OEB staff acknowledges that the outcome of applying ELG is that it increases depreciation expense when compared to ALG. However, ELG was not designed to address energy transition. In the cross-examination of InterGroup, Mr. Bowman was asked whether ELG could be considered as accelerating depreciation instead of being "aggressive", Mr. Bowman stated the following:

> I don't think that's correct. Mathematically, but, if that's the case, anything that throws money at the accumulated depreciation account would be, could be considered accelerated. I think ELG is not attempting to accelerate anything; it is still attempting to allocate the cost of assets over the years in which that asset is in service. It just thinks about measuring those years in a more granular manner. It has no accelerated component to it whatsoever except to the extent that it's, like I said, throwing dollars at a cumulative depreciation account. If the Board sees a need to do that, I think it would be better to do that more directly rather than through something like ELG.[191]

[186] Argument-in-Chief, p.181.
[187] Undertaking J16.7.
[188] Argument-in-Chief, pp. 180, 182.
[189] Argument-in-Chief, p.181.
[190] Argument-in-Chief, p.181.
[191] Oral Hearing Transcript, Vol. 18, p.47.

ELG is rarely used by utilities in North America (though Alberta is something of an exception); ALG is the most common procedure.[192] No OEB-regulated utilities use ELG. Many gas utilities that face the same uncertainty relating to the energy transition as Enbridge Gas use ALG.[193]

In its argument-in-chief, Enbridge Gas stated that InterGroup and Emrydia failed to appropriately include energy transition issues in their analysis.[194] OEB staff disagrees with this characterization. When InterGroup and Emrydia were asked about their recommendations in the context of energy transition, InterGroup stated that they did take energy transition into consideration, but their view of applying specific energy transition considerations for individual accounts was that the threshold to do so has not yet been met. Furthermore, the full picture of energy transition should be considered, along with depreciation. Emrydia also indicated that energy transition was a variable that was considered. Therefore, OEB staff is of the view that the two experts did consider energy transition in the broader context, when making their recommendations that the ALG procedure should continue to be used. In OEB staff's view, this approach was similar to Concentric's approach where it addressed energy transition broadly in its report but did not specifically identify it as a consideration when making recommendations on depreciation asset life parameters.

OEB staff notes that simply accelerating depreciation allows Enbridge Gas full recovery of its capital costs with no consideration as to whether it should be allowed to fully recover the costs of stranded, or underutilized, assets. OEB staff has previously argued, in OEB staff's submission on Issue 3,[195] that Enbridge Gas bears some risk associated with stranded assets. Therefore, OEB staff believes that, following the OEB's determination on other energy transition matters considered in this proceeding (discussed under Issue 3), Enbridge Gas will be better placed to assess the implications and propose an approach to depreciation that more specifically addresses possible changes to the depreciation methodology based on energy transition, including the potential risk of stranded assets and the appropriate methodology to allocate that potential risk, at the time of Enbridge Gas's next rebasing application.

<u>Units of Production Procedure</u>

The Units of Production depreciation procedure was discussed during the course of the proceeding as an alternative to ELG and ALG in light of energy transition. OEB staff submits that Enbridge Gas should be required to complete an analysis of the Units of

[192] Oral Hearing Transcript, Vol. 17, pp. 86-87.
[193] Oral Hearing Transcript, Vol. 17 pp.85-87.
[194] Argument-in-chief, p. 184.
[195] See the sub-section titled, "Allocation of Energy Transition Risk.".

Production procedure and provide the results of that analysis at the next rebasing application.

The Units of Production depreciation procedure can correlate recovery of an asset to throughput or delivered energy of the system. Mr. Bowman explained Units of Production as follows:[196]

> The units of production is a fundamentally different approach which bears no relation to ELG or ASL. It is an approach where you're taking the dollars and dividing by a denominator that is gigajoules, as the example that's been used, rather than the years, and so you are creating a unit based on gigajoule throughput as if gigajoules better represent the service value of the system.

Mr. Kennedy stated that the Units of Production procedure is an equitable tool that works well with changes in demand and supply.[197] However, as agreed to by the three depreciation experts in this proceeding, there are challenges with implementing this procedure which is expected to have significant impact to ratepayers. For example, consideration needs to be given to which accounts the procedure should apply to, the assumptions to use (e.g., estimating the total units of production – i.e., the denominator in the calculation), and, what should be the unit of measure in the calculation.[198] Therefore, OEB staff submits that Enbridge Gas should be required to do an analysis using the Units of Production procedure that provides options on how the procedure can be implemented (e.g., depreciation is tied to a measure of asset use, such as peak demand or volume throughput), the impact of applying that procedure under several load forecast scenarios, and how the procedure can be implemented if the total unit of production (i.e., denominator) is updated frequently for new assumptions that arise. Enbridge Gas should also provide procedures other than the Unit of Production that can address energy transition implications related to depreciation. The results of that analysis should be provided at the next rebasing.

<u>Revenue Horizon Applicable to Customer Connection</u>

In its argument-in-chief, Enbridge Gas stated if a reduction in revenue horizon applicable to customer connections is ordered, it may be necessary to make changes to its current depreciation proposal.[199] Enbridge Gas noted that the assets associated with customer connections have asset lives that are generally 40 years or more and it does

[196] Oral Hearing Transcript, Vol. 17, p.184.
[197] Oral Hearing Transcript, Vol. 16, p.113.
[198] Oral Hearing Transcript, Vol. 16, p.113, and Vol. 17, pp.2, 11, 17-18, 81.

not make sense to assume that new customers will remain for substantially less time than the asset lives associated with the connection assets.

OEB staff agrees that logically the lifetimes used for revenue horizon and depreciation of customer connection assets should converge on the same values. However, given the large amount of new capital spending over the rebasing term that Enbridge Gas proposed for new customer connections, OEB staff believes that a change in revenue horizon to what OEB staff believes is likely a more accurate value is necessary now even with imperfect information. OEB staff also notes that once customer connection investments have been made, those investments cannot be undone and recovery of these assets would need to be addressed. In contrast, depreciation, which reflects the pattern of recovery, can be changed if required, to allow for appropriate recovery. This is well captured by Dr. Hopkins, who noted that "…the effective near-term actions that can buy time and provide optionality going forward relate to treatment of capital: 1) limiting capital additions and 2) accelerating depreciation. Of these, the first is more important (because depreciation can be adjusted in the future, but capital cannot be un-invested)."[200] While the proper approach to depreciation may benefit from further analysis, it is not as urgent. As discussed above, OEB staff recommended that Enbridge Gas consider depreciation approaches (including the Units of Production procedure) that purposefully addresses energy transition in its next rebasing application.

Merits of ELG vs. ALG

As discussed above, OEB staff believes that no immediate changes to depreciation methodology based on potential energy transition impacts should be made at this time. Therefore, OEB staff submits that the depreciation procedure approved for Enbridge Gas should best reflect the intended purpose of depreciation, which is allocating the cost of an asset group over its expected life, in a systemic and rationale manner. OEB staff submits that this would be the ALG procedure for Enbridge Gas, the reasons for which are discussed below.

As previously noted, Enbridge Gas and Concentric stated that other advantages of using ELG in addition to addressing energy transition is that ELG is more mathematically accurate and provides enhanced generational equity, and it is the best available match to the Union Gas approved depreciation procedure. OEB staff addresses each of these items below.

Regarding ELG being more mathematically accurate and providing enhanced generational equity, OEB staff notes that InterGroup and Emrydia have provided their views on this. InterGroup stated:[201]

> Mr. Bowman: It may be more theoretically accurate for taking a group depreciation procedure and getting closer back to what an asset-by-asset depreciation would look like; it is not more accurate for the purposes of representing the service value provided by the assets, which I submit is the more critical question when you are dealing with just and reasonable rates.

OEB staff notes that this is further explained in an example provided in InterGroup's report.[202]

Emrydia also responded to Mr. Bowman's above comment on the accuracy of ELG and stated the following[203]

> Mr. Madsen: For clarity, I agree with Mr. Bowman's statement to that effect. My evidence goes through and explains how the ELG procedure will derive a depreciation rate on a theoretical basis, but the theory doesn't always line up with practice. And, when you apply it to the actual practice, and the facts that are present in Enbridge's case, you come to, in my opinion, an unreasonable result relative to what the ALG procedure would achieve.

Furthermore, Emrydia noted that, in practice, it is impossible to demonstrate objectively that the ELG procedure will always provide a superior estimate of the actual recovery of an investment as compared to the ALG procedure.[204]

OEB staff also notes that even though most depreciation professionals now have the modelling capabilities to run ELG calculations very easily,[205] ALG is still the most common depreciation procedure in North America.[206] Utilities transitioning to ELG are therefore rare, and Mr. Bowman gave the example of one case (Manitoba, with respect to Manitoba Hydro and Centra Gas Manitoba) where the utilities proposed ELG and there has now been 10 years of study over three hearings to fully address the proposal.[207] OEB staff notes that Manitoba Public Utilities Board recently issued a final order that rejected Manitoba's Hydro's proposal to transition to the ELG.[208]

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201 Oral Hearing Transcript, Vol. 17, pp.173-174.
202 Exhibit M1 – OEB Staff Depreciation, pp.14-19.
203 Oral Hearing Transcript Vol. 18, pp.70.
204 Exhibit M5 – IGUA Depreciation, p.21.
205 Oral Hearing Transcript, Vol. 17, p.88.
206 Oral Hearing Transcript, Vol. 17, p.87.
207 Oral Hearing Transcript, Vol. 17, p. 173.
208 Manitoba Public Utilities Board Order 101-23, August 23, 2023 page 12-13.

Concentric also noted that an advantage to using ELG is that it is the “best available match to the historic procedures approved for Union Gas”.[209] There are two problems with this statement. The first problem is that the same can be said for ALG – ALG would be a continuation of the procedure previously approved for Enbridge Gas Distribution. The second problem is that ELG is not the same as the Generation Arrangement procedure that was approved for use by Union Gas. Furthermore, during the oral hearing, Mr. Bowman clarified that Generation Arrangement is not an alternative to ELG or ALG, it is a method to organize assets for analysis.[210] In fact, Mr. Bowman stated that after this organization of assets, ELG or ALG can be applied going forward and Union Gas applied ALG.[211] Therefore, OEB staff submits that from a continuity perspective, ALG would be a better fit than ELG going forward.

OEB staff notes that all three depreciation experts have agreed that there needs to be mindful consideration of the transitional impacts of moving from one depreciation procedure to another.[212] During the oral hearing, this concept was explored in the context of the depreciation impact arising from the accumulated depreciation shortfall under various procedures.[213] Mr. Kennedy acknowledged that there are various approaches available to implement ELG, if ELG is approved, which can lessen the rate impact of transitioning to ELG, including the approach that is used in Alberta (a “hybrid approach”).[214] However, Mr. Kennedy indicated that, for an annual depreciation expense difference of $50 million to $60 million, when considered as a percentage of the total depreciation expense, he does not view this magnitude of change as “being outside the realm of reasonableness.”[215] OEB staff disagrees with this characterization. The 2024 depreciation expense under ELG is $83.4 million higher than the ALG procedure.[216] Furthermore, the proposed 2024 depreciation expense is $141.9 million higher than the 2024 depreciation expense of $737.1 million when using current approved depreciation rates (i.e., ALG for Enbridge Gas Distribution, Generation Arrangement for Union Gas and prior approved parameters, net salvage methodology and parameters, etc.).[217] Depreciation expense is the largest contributing factor to the

[209] Exhibit I.4.5-Staff-173c.
[210] Oral Hearing Transcript, Vol. 18, pp. 18-22.
[211] *Ibid*.
[212] Oral Hearing Transcript, Vol. 17, p.102.
[213] Oral Hearing Transcript, Vol. 17, pp. 95-98. The shortfall is the difference between the actual amount of accumulated depreciation recorded to date and what accumulated depreciation should have been recorded, had ELG or ALG been used from the beginning.
[214] Oral Hearing Transcript, Vol. 17, pp. 96-97.
[215] Oral Hearing Transcript, vol 17, pp. 95-98.
[216] Undertaking J16.7.
[217] Undertaking J16.7.

gross revenue deficiency, accounting for $187.5 million of the net $186.3 million deficiency.[218, 219]

Another benefit of ALG in this case is that it is not as sensitive as ELG to the selection of asset life parameters.[220] As discussed below, there is substantial disagreement among the depreciation experts as to the appropriate parameters for a number of accounts.

<u>Asset Life Parameters</u>

OEB staff supports the asset life parameters recommended by InterGroup and submits that the OEB should require that these parameters be applied. OEB staff notes that InterGroup commented on the asset life parameters recommended by Emrydia, and in general did not suggest that these recommendations be adopted, except for supporting Emrydia's recommendation for an asset life longer than the 15 years recommended by Concentric for Account 475 Meters, though not as long as the 25 years recommended by Emrydia.[221] OEB staff also notes that Emrydia was generally supportive of the asset life parameters recommended by InterGroup.[222] The two tables below summarize the asset life parameters recommended by InterGroup and the impact to depreciation.[223]

[218] Undertaking J17.11, Attachment 1, p.5.
[219] The net deficiency is composed of items that are deficiencies (e.g. depreciation) and sufficiencies.
[220] As noted in InterGroup's report Exhibit M1, p.6, the selected asset life parameter has a lesser impact under ALG.
[221] Oral Hearing Transcript, vol 17, pp,174-178.
[222] N.M5.Staff-1.
[223] Undertaking J17.12, Attachment 1.

Table 10
InterGroup's Asset Life Parameter Recommendations

	Account #	Account Description	Concentric Parameter per J17.9	InterGroup Parameter per J17.12	Emrydia's comments per N.M5.Staff-1
1	452.00	UNDERGROUND STORAGE PLANT - STRUCTURES AND IMPROVEMENTS	45-R3	45-R2.5	Agree with InterGroup
2	456.00	UNDERGROUND STORAGE PLANT - COMPRESSOR EQUIPMENT	40-R4	44-R4	Support InterGroup over Concentric. But recommends 45-R3
3	457.00	UNDERGROUND STORAGE PLANT - REGULATING AND MEASURING EQUIPMENT	35-R3	40-R2.5	Agree with InterGroup
4	465.00	TRANSMISSION – MAINS	60-R4	70-R4	Agree with InterGroup
5	475.21	DISTRIBUTION - MAINS - COATED & WRAPPED	55-R3	61-R3 (70-R3 also considered)	Continue to recommend 65-R3, but would also accept a 70-R3 curve
6	475.30	DISTRIBUTION - MAINS – PLASTIC	60-R4	65-R3 (70-R4 also considered)	Continue to recommend 70-R2.

Table 11
2024 Depreciation Impact of InterGroup's Recommended Asset Life Parameters

Account #	Account Description	2024 Gross Plant ($M)	2024 Depreciation: Concentric - ELG ($M)	2024 Depreciation: Concentric ALG ($M)	2024 Depreciation: InterGroup - ALG ($M)	Difference: InterGroup ALG vs. Concentric ALG ($M)	Difference: InterGroup ALG vs. Concentric ALG ($M)
			A	B	C	=C-B	= C-A
452.00	UNDERGROUND STORAGE PLANT - STRUCTURES AND IMPROVEMENTS	115.8	4.6	3.7	2.5	- 1.2	-2.0
456.00	UNDERGROUND STORAGE PLANT - COMPRESSOR EQUIPMENT	725.8	20.9	19.2	16.3	- 3.0	- 4.6
457.00	UNDERGROUND STORAGE PLANT - REGULATING AND MEASURING EQUIPMENT	108.9	2.8	2.5	1.9	- 0.5	- 0.9
465.00	TRANSMISSION – MAINS	3,128.6	55.3	51.3	42.4	- 8.9	-12.9
475.21	DISTRIBUTION - MAINS - COATED & WRAPPED	4,008.8	135.5	118.3	99.0	-19.2	-36.5
475.30	DISTRIBUTION - MAINS - PLASTIC	3,839.1	104.3	96.7	84.9	- 11.8	- 19.4
	TOTAL	**11,927.0**	**323.4**	**291.7**	**247.1**	**-44.7**	**- 76.4**

During the oral hearing, Concentric was asked whether InterGroup's and Emrydia's critiques led them to reconsider their analysis.[224] Concentric responded that it updated the parameters for certain accounts in the Capital Update. Specifically, the updates are as follows:[225]

[224] Oral Hearing Transcript, Vol. 17, pp. 107-109.
[225] *Ibid.* and Exhibit 2/Tab 5/Schedule 4/Attachment 1 filed on June 16, 2023.

Table 12
Asset Life Parameters Concentric Updated in Capital Update

Account #	Account Description	Original Parameter	Revised Parameter
452.00	UNDERGROUND STORAGE PLANT - STRUCTURES AND IMPROVEMENTS	40R3	45R3
464.00	TRANSMISSION – EQUIPMENT	50S4	30L0.5
472.35	DISTRIBUTION - STRUCTURES AND IMPROVEMENTS – MAINWAY	Truncation date of 2024	Truncation date of 2027
473.01	DISTRIBUTION – REGULATORS	45S1	40S0.5

The Capital Update indicated that the truncation date for Account 472.35 was revised from 2024 to 2027. In its report, Emrydia had noted the truncation date of either 2023 or 2024 to be an issue as it represented a one-time impact to depreciation that would be embedded in a single test year and applied annually throughout the rate term.[226] OEB staff notes that the revision of the truncation date should partly address Emrydia's initial concern. The Capital Update did not specifically identify the three other changes in asset life parameters noted in the table above. The Capital Update stated only that there were revisions made to depreciation rates to address concerns noted in an interrogatory relating to Account 466 and that the updated depreciation rates were reflected in an attachment that provided the depreciation calculation.[227] During the oral hearing, Ms. Nori from Concentric, identified the specific accounts that were updated. Ms. Nori stated that Account 452.00 was updated to 45R3, which was not the same as Mr. Bowman's recommendation of 45R2.5, but substantially similar. Concentric did not provide any further explanations for its revised recommendations. Therefore, OEB staff would not support the revisions to Accounts 464 and 473.01 that shorten the asset lives. OEB staff also notes that Mr. Bowman stated he would support Concentric's original proposal for Account 473.01 for a 45-year life, and not the revised 40-year life or 50-year life as recommended by Emrydia.[228] In its Capital Update, OEB staff notes that, Concentric also did not provide any reasons why it did not adopt InterGroup or Emrydia's other recommendations.

[226] Exhibit M5, pp.66-68.
[227] Exhibit 2, Tab 5, Schedule 4, p.29.
[228] Oral Hearing Transcript, Vol. 17, pp.176-177.

OEB staff notes that InterGroup's recommendations result in decreases from Enbridge Gas's proposed depreciation expense for all the noted accounts. InterGroup acknowledged that their recommendations reflect a longer duration for assets than Concentric's recommendations, however, they are not necessarily an extension over the current approved depreciation rates.[229]

OEB staff views the above as an important consideration as it is not clear why Concentric's recommended asset lives for these accounts are shorter than InterGroup's recommendations. In particular, OEB staff does not know whether Concentric's recommended lives for these accounts are shorter than InterGroup's because Concentric specifically factored in energy transition considerations. If that is the case, OEB staff submits that this would not be appropriate at this time, as discussed in the section under Depreciation Procedure – ELG and Energy Transition. During the oral hearing, Concentric indicated that it took into account energy transition when recommending asset life parameters in its report, however, Concentric also acknowledged that it did not mention energy transition as a consideration in the evidence that supported its recommendations for each specific account.[230] The report only contained a summary section that discussed energy transition.

Account 475.21 (Distribution Mains – Coated & Wrapped) was discussed during the oral hearing. As noted in Table 10 above, Concentric recommended a shorter asset life (55 years) than InterGroup's recommended asset life (61 years). Concentric confirmed that it considered the energy transition in its analysis of this account, which weighed in favour of a shorter life.[231] OEB staff notes that Concentric did not explain why or how energy transition considerations were applied to this account. During the oral hearing, Enbridge Gas suggested that core infrastructure such as Mains could be repurposed. This suggests to OEB staff that energy transition may not have a significant impact to Mains and therefore, should not have energy transition consideration applied to the account for depreciation purposes. [232]

When questioned on how much weight was put on energy transition when making recommendations, Ms. Nori of Concentric stated:

> We had many detailed conversations with EGI, including with [audio dropout] our energy transition, I'm sorry, team to get an understanding of what EGI's thoughts were as time goes on. Beyond that, I don't know that

[229] Oral Hearing Transcript, Vol. 18, p.23.
[230] Oral Hearing Transcript, Vol. 16, pp.135-137; Oral Hearing Transcript, Vol. 17, p.50.
[231] Oral Hearing Transcript, Vol. 17, pp.115-116.

> we had a specific percentage that we placed 25 percent on energy transition or anything of that sort.[233]

OEB staff understands that the selection of asset life parameters requires professional judgment. However, in OEB staff's view, Concentric has not provided a persuasive explanation – either in its depreciation study or in cross-examination – of how it factored the energy transition into its analysis of the life parameters for each account. OEB staff is left with the impression that there was a lack of analytical rigour in this regard, and therefore an element of arbitrariness.

In contrast, InterGroup and Emrydia provided detailed, specific and carefully reasoned analysis in support of its proposals for asset life parameters, tied to past asset performance (actuarial analysis), current asset plans as outlined by Enbridge Gas, and the experience of Enbridge Gas's peer utilities.[234]

Net Salvage

Concentric estimated the cost today to decommission all of the company's assets currently in service would be approximately $6.9 billion. To date, Enbridge Gas accumulated net site restoration costs of $1.6 billion.[235] The $1.6 billion amount represents the presumed amount recovered in rates, based on the salvage component in approved depreciation rates applied to actual gross plant values, net of actual removal and restoration costs incurred.[236] Enbridge Gas forecasted removal costs from 2023 to 2026 to be as follows:

Table 13
Forecasted Site Restoration Costs (SRC)

	2023	2024	2025	2026
Forecasted SRC to be incurred ($M) per I.1.8-Staff-17fii	$61.4	$62.8	$60.5	$55.5

Concentric, InterGroup and Emrydia were supportive of the CDNS method for net salvage. However, InterGroup and Emrydia raised concerns with the way Concentric calculated net salvage under CDNS. InterGroup and Emrydia also questioned the proposed discount rate that is used as an input to the CDNS calculation.

[233] Oral Hearing Transcript, Vol. 17, p.116.
[234] InterGroup's report Exhibit M1, p.28-45; Emrydia's report Exhibit M, p. 34-68.
[235] Argument-in-Chief. p.185.
[236] I.1.8– Staff-17a. Note that Enbridge stated that it would not be able to quantify the actual amount collected as it would be subject to actual versus forecast customer and volumetric variances.

OEB staff submits that the OEB should require Enbridge Gas to implement Intergroup's recommendations with respect to net salvage. Specifically, Enbridge Gas should implement InterGroup's CDNS calculation method and recommended net salvage parameters. OEB staff is of the view that the most current CARF rate of 4.48% is the appropriate discount rate to use in the CDNS calculation. In the event that that the OEB does not approve Intergroup's recommendations for net salvage, OEB staff submits that the traditional method with InterGroup's recommended net salvage parameters would be the appropriate alternative. The 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. OEB staff also submits that Enbridge Gas should be required to report on ten accounts with respect to net salvage at its next rebasing application.

CDNS Method

OEB staff supports InterGroup's recommendations as it relates to net salvage. In particular, OEB staff agrees with the use of the CDNS method, using InterGroup's calculation methodology of CDNS, and recommended net salvage parameters. OEB staff submits that the OEB should require Enbridge Gas to implement Intergroup's proposal. However, OEB staff would not be opposed to using the traditional method and InterGroup's net salvage parameters as an alternative.

In its argument-in-chief, Enbridge Gas stated that the CDNS method proposed by Mr. Kennedy in this proceeding is the same CDNS method he previously proposed that was approved by the OEB in 2014. Enbridge Gas argued that this methodology has worked.[237] OEB staff acknowledges that the OEB approved Enbridge Gas Distribution's adoption of the CDNS. However, OEB staff notes that the focus in that earlier proceeding was not the CDNS calculation itself.[238] Therefore, in OEB staff's view, the approval of the prior CDNS method does not imply that it is still appropriate going forward, given the concerns with respect to Concentric's CDNS calculation that have arisen in this proceeding.

Enbridge Gas also argued that the approved CDNS method has worked, at least directionally, in the sense that there has been no under-accrual of net salvage to-

[237] Argument-in-chief, p.188.
[238] The EB-2012-0459 Decision with Reasons for Enbridge Gas Distribution's 2014 to 2018 rate application, July 17, 2014, did not discuss the calculation of CDNS but discussed the following areas with respect to site restoration costs: (a) whether the CDNS method should be adopted; (b) If the CDNS method is adopted, whether there be any adjustments to Enbridge Gas's proposal, (c) the amount that should be collected for SRC going forward; and (d) whether the OEB should conduct a generic proceeding or review.

date.[239] However, OEB staff questions whether it will continue to work under Concentric's CDNS calculation. Mr. Bowman identified two issues with Concentric's CDNS calculation. The first issue is the double counting of inflation, which Emrydia also identified as an issue.[240] In its argument-in-chief, Enbridge Gas stated that the concern about double counting inflation is not correct, this erroneous assumption was demonstrated in Exhibit I.ADR-22 (which estimates the impact to depreciation resulting from InterGroup's and Emrydia's recommendations), and that Mr. Kennedy confirmed in oral evidence that his methodology does not double count inflation.[241] OEB staff is not convinced that there is no double counting. InterGroup and Emrydia had the opportunity to review I.ADR-22 and listen to Mr. Kennedy's explanation of his CDNS calculation during the oral hearing, and they both maintained their original positions that there was double counting of inflation.[242]

The second issue Mr. Bowman noted was that there was no accretion of the present value of the double inflated salvage amount. The impact of the second issue partially offsets the impact from the first issue. Mr. Bowman noted that there was only a relatively smaller impact ("not egregious")[243] from the two offsetting errors in Concentric's CDNS calculation, since the inflation rate (2%) and the proposed CDNS discount rate (3.75%) were relatively close in value. Mr. Bowman estimated the impact of using Concentric's CDNS calculation to be an under-recovery of net salvage accrual of $3 million to $14 million (depending on whether using ALG or ELG).[244] However, in the case where the rate of inflation is much lower than the discount rate used to present value the salvage amount (which has been double inflated), the resulting net salvage amount may be significantly under-accrued.[245] This is confirmed in Concentric's undertaking J16.6 where it estimates an extremely low net salvage accrual of $0.3 million per year (using an inflation rate of 2%, discount rate of 6.03%, Concentric's CDNS calculation method and a mix of both InterGroup and Emrydia's parameter recommendations) when forecasted SRC costs to be incurred is approximately $60 million. OEB staff notes that,

[239] Oral Hearing Transcript, Vol. 18, pp.36-37.
[240] Oral Hearing Transcript, Vol. 18, p.11-13.
[241] Argument-in-chief, p.189.
[242] InterGroup and Emrydia's cross examination occurred after Concentric's cross examination. Furthermore, Mr. Mondrow representing IGUA requested clarification on the net salvage calculation in I.ADR-22 in J16.6 (Oral Hearing Transcript, Vol. 16, p.86) and Mr. Richler representing OEB staff requested clarification on certain calculations in K16.2 which was updated from I.ADR-22 (Oral Hearing Transcript Vol. 17, pp.84-85). OEB staff assumes that as IGUA's expert witness, Emyrida would have reviewed I.ADR-22, which resulted in Mr. Mondrow's question at the oral hearing. OEB staff confirms that InterGroup reviewed I.ADR-22.
[243] Oral Hearing Transcript, Vol. 17. P. 180.
[244] Exhibit M1, pp. 53-54.
[245] Oral Hearing Transcript, Vol. 17, p. 199.

in its report, InterGroup recommended its own CDNS calculation that corrects for the issues noted in Concentric's CDNS calculation.

CDNS Discount Rate

OEB staff submits that the most current CARF rate of 4.48% should be used in InterGroup's CDNS calculation.

In its decision on Enbridge Gas Distribution's 2014 to 2018 rates, the OEB concluded that the discount rate used in the CDNS calculation should be examined in more detail.[246] In this proceeding, Concentric proposed to use the CARF of 3.75%. Enbridge Gas noted that the updated CARF as at July 25, 2023 is 4.48%.[247] Concentric recommended using the CARF on the basis that it is consistent with discount rates mandated by accounting standards for asset retirement obligations and estimating the discount rate in securitization calculations.[248] The CARF is also aligned with other pipelines in similar applications to the Canada Energy Regulator (CER).

In Emrydia's report, Emrydia argued that reliance on the accounting standards for asset retirement obligations to determine the discount rate under CDNS is not appropriate as CDNS and asset retirement obligations are not similar.[249] Furthermore, Emrydia is of the view that WACC should be used, because the collection of net salvage costs results in an accumulation of amounts in accumulated depreciation which offsets rate base. Therefore, the effective rate customers earn on the advance payment of net salvage costs is Enbridge Gas's WACC that would otherwise be issued to finance rate base.

OEB staff notes that the WACC presented in this proceeding is approximately 6%, which would result in a decrease to the net salvage accrual and resulting depreciation expense. InterGroup stated that the selection of the discount rate is a policy question regarding trade-offs between existing customers and future customers.[250] While InterGroup did not explicitly recommend that WACC be used, they expressed sentiments similar to Emrydia, stating that while there is no definitive technical insight to guide this decision, WACC most directly recognizes the full value of the net salvage funds that will be collected from current ratepayers, which will be credited against the rate base in future rate cases.

[246] EB-2012-0459, Decision with Reasons, July 17, 2014, p.62.
[247] Undertaking J17.5.
[248] Exhibit 4, Tab 5, Schedule 1, p.7.
[249] Exhibit M5 – IGUA Depreciation, pp.79-85.
[250] Exhibit M1 – OEB Staff Depreciation, p.53.

While OEB staff agrees that the WACC may be appropriate in principle, OEB staff submits that the most current CARF of 4.48% would be more appropriate in this proceeding. OEB staff notes that using the WACC of 6.14% in InterGroup's CDNS calculation (and also in Concentric's CDNS calculation) will result in a net salvage accrual that is much lower than the forecasted annual site restoration costs to be incurred from 2023 to 2026.

In undertaking J17.5, Concentric provided the net salvage accrual using various discount rates and argues that the results show that the CDNS methodology using a discount rate of 3.75% (or lower) with Concentric's recommended ELG method, average service lives and survivor curves provides for the recovery of sufficient site restoration costs, which is estimated to range from $55 million to $62 million from 2023 to 2026. At a discount rate of 3.75%, Concentric estimates the net salvage accrual to be $96.3 million, a potential over-recovery of $34.3 million to $41.3 million a year in site restoration costs (if actual site restoration costs incurred are as forecasted). At a discount rate of 4.48%, Concentric estimates the net salvage accrual to be $55 million, a potential under-recovery of up to $7 million a year in site restoration costs. The key to note in these amounts is that that this undertaking uses Concentric's proposals, which OEB staff disagrees with as is discussed above.

OEB staff notes that undertaking J17.9 quantifies the difference between using a discount rate of 3.75% and 6.03% to be a decrease in 2024 depreciation expense of $73 million under ELG and $62 million under ALG. OEB staff notes that these numbers were derived using life recommendations from both InterGroup and Emrydia, and uses Concentric's CDNS calculation method, and therefore, are not representative of OEB staff's submission of adopting only InterGroup's recommendations for net salvage.

For the depreciation impact based on InterGroup's recommendations, refer to Table 17 below – Depreciation Impact. OEB staff notes that InterGroup used a discount rate of 3.75% in its quantification of depreciation impact in undertaking J17.12. At a discount rate of 3.75%, InterGroup quantified the net salvage accrual to be $59.8 million. OEB staff requested that InterGroup quantify the impact to depreciation based on its recommendations, by changing the discount rate to a CARF of 4.48% and also, WACC of 6.14%.[251] InterGroup indicated that using a discount rate of 4.48%, depreciation would decrease by $5.8 million for a net salvage accrual of $54 million, and at 6.14%, depreciation would decrease by $17 million for a net salvage accrual of $42.8 million.

[251] If using the WACC as the discount rate, OEB staff notes that a WACC of 6.14% is appropriate based on an equity thickness of 38%.

OEB staff notes that InterGroup's CDNS calculation is less sensitive to a change in discount rate than Concentric's CDNS calculation, which estimated a decrease in depreciation of $62 million to $73 million when changing the discount rate from 3.75% to 6.03%. Therefore, in OEB staff's view, the CARF rate of 4.48% would be appropriate in this proceeding because it results in a net salvage value of $54 million, which is relatively close to the forecasted site restoration costs of $55 million to $62 million. OEB staff acknowledges that the resulting net salvage value of $54 million is slightly less than the forecasted site restoration costs to be incurred. However, OEB staff does not view this as a concern for two reasons. First, Enbridge Gas has already accumulated net site restoration costs of $1.6 billion, which represents the presumed amount recovered in rates, net of actual removal and restoration costs incurred (i.e. the amount that has been collected to date that has not been spent on site restoration costs yet).[252] Secondly, Concentric estimated that there is a net salvage surplus of $346 million.[253] The $346 million surplus represents the difference between the amount of net salvage collected to date (i.e. $1.6 billion) and what should have been collected based on Concentric's CDNS proposal in this proceeding ($1.2 billion). Therefore, any under-recovery of net salvage during the rate-setting period would operate to reduce this surplus.

If the OEB has concerns with using the CDNS methodology, OEB staff submits that the OEB may wish to consider the traditional method of net salvage as an alternative. In fact, Mr. Bowman stated:

> And as a result, I wouldn't recommend at all using Mr. Kennedy's CDNS approach. I wouldn't recommend using a higher discount rate with Mr. Kennedy's CDNS approach. If that is what the Board is considering, I would recommend abandoning CDNS all together and going to the traditional net salvage.[254]

The traditional method estimates net salvage as a percentage of the original cost to be depreciated and accumulated over the lifetime of an asset and attempts to forecast the pay as you go method and evenly distribute it in nominal, or year of expenditure dollars.[255] The traditional method has been widely used and the calculation method has been accepted. OEB staff notes that the use of the traditional method would increase depreciation expense. The estimated impact to change to the traditional method is shown in the table below. OEB staff notes that the increase in depreciation from using

[252] I.1.8– Staff-17a.
[253] I.1.8– Staff-17g.
[254] Oral Hearing Transcript, Vol. 17, p.180.
[255] Exhibit 4, Tab 5, Schedule 1, Attachment 1, p. 21.

the traditional method under Concentric's recommended parameters is significantly higher than the InterGroup and Emrydia recommended parameters. This is due to the higher net salvage parameters Concentric recommended when compared to those recommended by InterGroup.

Table 14
Impact of using Traditional Method

	Concentric's Calculation based on Concentric Lives, Curves and Net Salvage Parameters per J17.9 ($M)		Concentric's Calculation based on InterGroup and Emrydia Lives, Curves and Net Salvage Parameters per J17.9 ($M)		InterGroup's Calculation based on InterGroup's Lives, Net Salvage Parameters, CDNS methodology ($M) per J17.12 Attachment 1
	ELG	**ALG**	**ELG**	**ALG**	**ALG**
CDNS @ 3.75%	879.0	795.6	648.3	561.9	733.4
Traditional Method	1,034.1	935.7	686.4	595.4	781.0
Increase in Depreciation	**155.1**	**140.1**	**38.1**	**33.5**	**47.6**

Net Salvage Parameters

OEB staff supports the net salvage parameters recommended by InterGroup for the reasons set out in InterGroup's report. OEB staff notes Emrydia is generally supportive of the recommendations made by InterGroup. Specifically, Emrydia agrees that many of InterGroup's recommendations tend to maintain the level as currently approved while also aligning the rates with peers.[256] In the table below (Table 15), OEB staff provides a summary of depreciation impacts from the net salvage parameters recommended by InterGroup.

[256] N.M5.Staff-1.

Table 15
Impact of InterGroup's Net Salvage Recommendations[257]

Account#	Account Description	Concentric Net Salvage Parameters	InterGroup Net Salvage Parameter	InterGroup Depreciation Expense for All Recommendations ($M)	Incremental Depreciation Decrease from Using InterGroup Net Salvage Parameters and CDNS method ($M)*	Depreciation Decrease Between Intergroup Under ASL and Concentric Under ASL ($M)**
465.00	TRANSMISSION – MAINS	-25%	-15%	40.7	- 1.6	- 10.6
466.00	TRANSMISSION - COMPRESSOR EQUIPMENT	-10%	-5%	34.4	- 0.9	- 0.9
467.00	TRANSMISSION - MEASURING AND REGULATING EQUIPMENT	-25%	-10%	13.8	- 1.2	-1.2
473.02	DISTRIBUTION - SERVICES – PLASTIC	-50%	-40%	121.0	- 3.4	-3.4
475.21	DISTRIBUTION - MAINS - COATED & WRAPPED	-80%	-40%	83.8	- 15.2	- 34.5
475.30	DISTRIBUTION - MAINS - PLASTIC	-80%	-25%	68.3	- 16.6	- 28.5
	Total			362.0	- 39.0	- 78.9

*Decrease in depreciation represents the incremental change in depreciation (based on ASL InterGroup's life parameters) due to using InterGroup's net salvage parameters and CDNS method. Specifically, the difference is calculated as difference between 1) ASL and InterGroup Life Parameters to 2) ASL and InterGroup Life, Net Salvage Parameters, CDNS Method.

**Decrease in depreciation represents the difference between InterGroup depreciation (based on all InterGroup recommendations including using ASL) and Concentric's depreciation (based on all Concentric's recommendations but using ASL). Specifically, the difference is calculated as difference between 1) ASL and Concentric's Life and Net Salvage Parameters, CDNS Method to 2) ASL and InterGroup Life's and Net Salvage Parameters, CDNS Method.

For the accounts listed above, InterGroup disagreed with Concentric's basis for their recommendations. For example, certain outliers were not explained when using the retirement and cost of removal history of the account, and certain data related to peers which Concentric relied on appeared to be incorrect. In the oral hearing, the net salvage parameter for Account 475.21 was discussed. InterGroup's report noted that Concentric stated that the peer review shows that utilities' net salvage ranges from 25% to 90% for five utilities. InterGroup noted that Concentric provided an incorrect rate of -75% for AltaGas instead of -25% and an incorrect "requested" rate of -90% for Gazifère instead of -70%.

[257] Undertaking J12.17.

During the oral hearing, Ms. Nori stated that the appropriate rate to use for Gazifère requested net salvage was -90%, instead of the -70% InterGroup suggested based on Concentric's evidence relying on a newer depreciation study rather than the 2008 depreciation study InterGroup referenced.[258] However, no reference to the date of this new study was provided in the evidence on record. Further, as acknowledged by Ms. Nori, the referenced Gazifère net salvage rate is what was requested for approval and not the approved rate.[259] Therefore, the net salvage rate for the five peer utilities should be -25% for three utilities and -70% for the remaining two utilities. InterGroup recommended that net salvage of -40% is consistent with the actual retirement experience for this account.

OEB staff notes that using all of InterGroup's recommendations, net salvage under its CDNS calculation method at a discount rate of 3.75% would result in net salvage accrual of $59.8 million,[260] or $54 million using a discount rate of 4.48%.

Reporting Requirements

In its report, Emrydia recommended that Enbridge be required to provide certain reporting requirements relating to net salvage.[261] Enbridge Gas stated that it would not object to the reporting recommendations provided by Emrydia.[262] OEB staff submits that Enbridge Gas should be required to provide a report, as described below, at its next rebasing for ten accounts:

a. The current approach to salvaging the assets, including the approximate unit material and labour costs to salvage assets.

b. Alternative approaches available to salvage certain assets, such as abandonment in situ, and the implications such approaches may have on salvage costs.

c. Enbridge Gas's best estimate of the future costs to salvage the assets within each account, including the assumptions used to develop those estimates.

Emrydia submitted that the amount of net salvage to be collected in the future is uncertain.[263] Also, it is not clear what judgment Concentric applied to arrive at its recommended net salvage rates. Mr. Bowman also noted similar concerns during the oral hearing, stating that the historical record used to determine net salvage estimates is

[258] Transcript, Vol. 17, p.125.
[259] Transcript, Vol .17, p.125.
[260] Undertaking J17.12, Attachment 2.
[261] Exhibit M5 – IGUA Depreciation, pp.92-93.
[262] Undertaking J16.9.
[263] Exhibit M5 – IGUA Depreciation, p.92.

weak and that historical costs of interim replacements may not be representative of future abandonment costs.[264] OEB staff agrees with the reporting requirement recommended for the reasons Emrydia and InterGroup provided.

Emrydia and InterGroup recommended reporting requirements for the ten accounts in the table below. OEB staff notes that Emrydia and InterGroup recommended nine of the same accounts. Emrydia recommended Account 455 Underground Storage – Field Lines) with a gross plant balance of $258.9 million, while InterGroup recommended Account 477 (Distribution Measuring and Regulating Equipment) with an average plant balance of $1,132.6 million.[265] OEB staff also notes that Emrydia provided an alternative and suggested that Enbridge Gas be directed to study mains, services, compressors, and measuring/regulating equipment.[266] This suggestion, combined with the larger average plant balance in Account 477, leads OEB staff to suggest that Account 477 be used instead of Account 455.

Table 16
Ten Accounts Recommended for Net Salvage Reporting

	Account #	Account Description	Emrydia Recommended Account per J18.2	InterGroup Recommended Account per J18.1
	Underground Storage			
1	453	Wells	X	X
2	455	Field Lines	X	
3	456	Compressors	X	X
	Transmission			
4	465	Mains	X	X
5	466	Compressors	X	X
6	467	Measuring and Regulating Equipment	X	X
	Distribution			
7	473.01	Services Metals	X	X
8	473.02	Services Plastic	X	X
9	475.21	Mains Coated and Wrapped	X	X
10	475.3	Mains Plastic	X	X
11	477	Measuring and Regulating Equipment		X

264 Oral Hearing Transcript, Vol. 18, pp. 55-57.
265 I.4.5-IGUA-25, Attachment 3.
266 Undertaking J18.2.

Depreciation Impact

During this proceeding, there have been depreciation impacts provided for various combinations of asset life parameters, net salvage method and calculation, net salvage discount rate provided. For the reasons discussed above, OEB staff supports InterGroup's recommendations and the most current CARF rate of 4.48% as the discount rate for the net salvage CDNS calculation. InterGroup has quantified the impact to depreciation based on its recommendations in J17.12 as shown in the table below.

Table 17
2024 Depreciation Impact from InterGroup Recommendations

	Depreciation at Current Approved Rates per Undertaking J16.7	ELG Proposed by Concentric	ALG using Concentric Proposals	ALG using InterGroup Life Parameters	ALG under InterGroup Life and Net Salvage Parameters, and InterGroup CDNS Calculation at 3.75%	ALG under InterGroup Life and Net Salvage Parameters, and InterGroup CDNS Calculation at 4.48%**	ALG under InterGroup Life and Net Salvage Parameters, and Traditional Method
	A	B	C	D	E	F	G
2024 Depreciation	737.1	899.6	815.3	770.6	733.4	727.6	781.0
Difference from Proposed Depreciation			-84.3	-129.0	- 166.1	- 162.0	-118.6

*As noted in J17.12, there are inconsistencies between some of the data provided, where $892M was referenced as 2024 depreciation expense in the oral hearing.
**InterGroup quantified the impact of changing the discount rate to 4.48% (most current CARF) as requested by OEB staff.

The columns in the above table show the incremental changes to depreciation by changing one aspect of the depreciation proposal. The table starts with Concentric's proposed depreciation using ELG (column B), then shows Concentric's proposed depreciation using ALG (column C), then using ALG and InterGroup's asset life parameters (column D), then adding InterGroup's net salvage parameters using InterGroup's CDNS calculation methodology (columns E and F) or the traditional method (column G). OEB staff's recommendations would result in depreciation expense of $727.6 million as shown in Column F above. This would reflect OEB staff's submission that Enbridge Gas to be required to:

- Use the ALG depreciation procedure
- Use asset life parameters recommended by InterGroup
- Use the CDNS method for net salvage with a discount rate equal to the most current CARF of 4.48%. This should be based on InterGroup's calculation

methodology of CDNS and its recommended net salvage parameters. In the event that the OEB disagrees, OEB staff submits that the traditional method with InterGroup's net salvage parameters would be the appropriate alternative.

OEB staff also submits that Enbridge Gas be required to report on the following in its next rebasing application:

- An analysis of the Units of Production procedure. Enbridge Gas should also provide other approaches available that can address energy transition implications related to depreciation.
- Ten accounts with respect to determining net salvage costs at its next rebasing application.

Issue 16: Are the proposed 2024 Site Restoration Costs appropriate, and should the OEB establish a segregated fund for the Site Restoration Costs?

In its argument-in-chief, Enbridge Gas maintained that the establishment of a segregated fund is not appropriate.

To date, Enbridge Gas has accumulated net site restoration costs of $1.6 billion.[267] The $1.6 billion amount represents the presumed amount recovered in rates, based on the salvage component in approved depreciation rates applied to actual gross plant values, net of actual removal and restoration costs incurred.[268] Concentric estimated the cost today to decommission all of the company's assets currently in service would be approximately $6.9 billion.[269]

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.[270] In the current proceeding, Enbridge Gas proposed not to establish a segregated fund at this time but acknowledged that it may consider the need for a segregated fund if, and when, certain signposts arise. Enbridge Gas noted that its jurisdictional review did not find any examples of utilities in North America that used a segregated fund.[271] Enbridge Gas also identified certain drawbacks of establishing a segregated fund, including the rate impact where revenue requirement would increase by $93 million in the test year and $3.1 million annually thereafter. Enbridge Gas also estimated that the lower rate

[267] Argument-in-Chief. p.185.
[268] I.1.8– Staff-17a. Note that Enbridge stated that it would not be able to quantify the actual amount collected as it would be subject to actual vs. forecast customer and volumetric variances.
[269] Undertaking JT4.15.
[270] EB-2012-0459, Decision with Reasons, July 17, 2014, p.84.
[271] Argument-in-Chief, pp.200-202.

base resulting from the site restoration costs being recorded in accumulated depreciation has led to customers saving approximately $1 billion between 2013 to 2022.[272] Enbridge Gas further noted that a segregated fund would be costly to set up and operate, and there would be many tax complications.

OEB staff is of the view that the disadvantages of establishing a segregated fund outweigh the advantages of having a segregated fund at this time. OEB staff agrees with Enbridge Gas that there does not appear to be an imminent need for the establishment of a segregated fund. Furthermore, OEB staff is of the view that a segregated fund may be appropriate if there were concerns about Enbridge Gas's ability to access funds when required. There does not appear to be such concerns at this time, as Enbridge Gas stated that:[273]

> Should a significant amount of retirements occur unexpectedly and over a relatively short period of time, Enbridge Gas would use a combination of short term liquidity (i.e. commercial paper) and issuance of long term debt. At the same time, equity injections from its parent, Enbridge Inc., would ensure Enbridge Gas maintains its OEB-approved debt to equity ratio. The funds raised would be available for retirement activities.

Considering Enbridge Gas's ability to raise the required funds in a short period of time, OEB staff agrees that a segregated fund is not needed at this time. However, OEB staff is of the view that Enbridge Gas should reassess the need for a segregated fund at its next rebasing.

Issue 17: Are the proposed 2024 income and property tax expenses appropriate?

In the OEB approved settlement proposal, parties accepted Enbridge Gas's proposed methodology for determining 2024 income and property taxes. The final 2024 tax amounts will be determined after the OEB's determination on the unsettled issues.

[272] Undertaking J7.10.
[273] *ibid*

Issue 18: In relation to the 2024 Test Year gas cost forecast,

a) **Is the 2024 gas supply cost, including the forecast of gas, transportation and storage costs, appropriate?**

In the OEB approved settlement proposal, parties agreed to the as-filed 2024 gas supply cost, subject to the determination of load balancing costs including storage that will be determined in Phase 2 of the proceeding.

b) **Is the proposal for a common reference price methodology to set gas costs appropriate?**

In the OEB approved settlement proposal, parties agreed to address a common reference price methodology to set gas costs in Phase 3 of the proceeding.

c) **Is the proposed harmonized approach to determining gas costs (design day, operational contingency space, unaccounted for gas, Parkway Delivery Obligation) appropriate?**

In the OEB approved settlement proposal, for the purposes of determining gas supply costs for 2024 and subsequent years during the proposed IRM term, parties agreed to a modified version of the Enbridge Gas proposal for design day and design hour. The agreement on this issue is without prejudice to the positions that parties may take on design criteria and design day/design hour methodology in relation to capital budget and cost allocation issues in this proceeding or other future leave to construct proceedings.

d) **Is the 2024 Test Year forecast volumes of unaccounted for gas appropriate?**

In the OEB approved settlement proposal, parties reached full settlement on this issue.

e) **Is the proposal for an updated harmonized Parkway Delivery Obligation (PDO) Framework, and the recovery of costs, appropriate?**

In the OEB approved settlement proposal, parties agreed with Enbridge Gas's proposed updated PDO Framework subject to certain modifications. Parties also agreed to defer Enbridge Gas's proposal to offer the Parkway Delivery Commitment Incentive (PDCI) payment to the former Enbridge Gas Distribution Central Delivery Area customers to Phase 3 of the proceeding.

f) **Is the 2024 Test Year PDCI Forecast appropriate?**

While parties agreed to Enbridge Gas's proposed updated PDO Framework and the 2024 forecast of PDO/PDCI costs as part of the settlement proposal, there was no agreement regarding the 2019 to 2023 PDO/PDCI costs that have been recovered from ratepayers during the deferred rebasing term.

In the MAADs proceeding, the Federation of Rental-housing Providers of Ontario (FRPO) argued that Union Gas had enhanced its earnings as a result of the implementation of the PDO and ratepayers were paying twice for the same capacity. In its decision 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 are paying twice for the same capacity. The OEB required Enbridge Gas to track actual costs and amounts recovered through rates related to the PDO during the deferred rebasing period. The OEB noted that at Enbridge Gas's next rebasing proceeding it would review the costs and amounts recovered through rates to ensure that ratepayers are not paying twice for the required capacity.[274]

In the current proceeding, Enbridge Gas argued that the revenue generated from the sale of the excess 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 it adjusts for the excess capacity incorporated in base rates during Enbridge Gas's 2019 to 2023 deferred rebasing term, it will not be 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.

OEB staff provides a brief historical summary of the PDO issue below as it is relevant to the issue in the current proceeding. In its 2013 rates proceeding,[275] Union Gas's direct purchase customers requested that Union Gas eliminate the PDO[276] 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 obligation. In the 2014 rates proceeding[277], Union Gas reached an agreement with intervenors on the PDO issue and the OEB approved the agreed-to framework for reduction of the PDO. The agreement establishes that the costs of reducing the PDO are borne by all customers of Union Gas. This is because direct purchase customers with a PDO are conferring a benefit on all users of the Dawn-Parkway transmission system in terms of the avoided costs to build additional infrastructure to transport the gas from Dawn to Parkway. Customers of Union Gas bear the costs of transporting the gas from Dawn to Parkway or the incentive paid to direct purchase customers who still opt to deliver gas at Parkway (Parkway Delivery Commitment Incentive). The guiding principle of the PDO

[274] EB-2017-0306/EB-2017-0307, *Decision and Order*, August 30, 2018, pp. 48-49.
[275] EB-2011-0210.
[276] The PDO refers to an obligation for Union Gas's large volume direct purchase customers east of Dawn to deliver gas at Parkway.
[277] EB-2013-0365.

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 that proceeding, some intervenors argued for the establishment of a deferral account as it was possible that excess capacity could be contracted in 2013. In its Decision, the OEB accepted Union Gas's forecast for transportation revenues and did not require Union Gas to establish a deferral account. The OEB noted that it believed that Union Gas should continue to bear the forecast risk.[278]

In the current application, Enbridge Gas provided the actual PDO costs and compared them to the PDO costs in rates.

Table 18
PDO Costs (2019 to 2022)

Particulars ($000s)	Actual 2019	Actual 2020	Actual 2021	Estimate 2022 (1)
PDO Costs in Rates				
PDO Demand Costs	10,956	11,117	11,273	11,391
PDO Fuel Costs	1,640	1,404	1,517	2,067
PDCI Costs	12,614	12,766	13,551	15,521
Total	25,210	25,286	26.341	28,980
Actual PDO Costs				
PDO Demand Costs	11,217	11,379	11,535	11,654
PDO Fuel Costs	1,635	1,373	1,727	2,499
PDCI Costs	13,266	13,267	14,235	15,643
Total	26,117	26,019	27,497	29,797
Difference (2)				
PDO Demand Costs	(261)	(262)	(261)	(263)
PDO Fuel Costs	6	31	(210)	(432)
PDCI Costs	(652)	(501)	(685)	(122)
Total	(907)	(732)	(1,156)	(816)

[278] EB-2011-0210, *Decision and Order*, October 25, 2012, pp. 20-22.

Notes:

(1) The 2022 estimate includes actuals up to the end of July 2022.
(2) A positive amount represents a revenue surplus (cost in rates was greater than the actual cost) and a negative amount represents a revenue shortfall (cost in rates was less than the actual cost).

From 2019 to 2022, the variance in the total PDO costs ranges from a revenue shortfall of $0.73 million to $1.16 million (as shown in Table 18 above). Enbridge Gas submitted that the shortfall demonstrates that it has not over collected for the PDO over the deferred rebasing period.

As noted above, in the MAADs proceeding, FRPO argued that Union Gas had enhanced earnings as a result of the implementation of the PDO and ratepayers are paying twice for the same capacity. Union Gas charged ratepayers for the temporarily available capacity at an incremental cost to facilitate the PDO reduction. In addition, FRPO noted that Union Gas had additional capacity of 200 TJ/day resulting from Dawn-Kirkwall turnback, the costs of which are already recovered in rates. FRPO claimed that there is an equivalent of 200 TJ/day of Dawn-Parkway capacity that ratepayers are now paying in rates representing PDO reduction costs. Since the amount is less than the 210 TJ/day of original surplus, FRPO argued that ratepayers are paying twice for the 200 TJ/day. Accordingly, FRPO submitted that the ratepayer contribution of $9.7 million in rates representing PDO costs should be removed as a base rate adjustment for Union South customers.[279]

OEB staff notes that the OEB, in its 2013 Cost of Service decision, was aware that there was excess capacity on the Dawn Parkway system. However, the OEB approved Union Gas's forecast of transportation revenues and did not establish a variance account to capture variances related to the long-term transportation revenue forecast.[280] The revenue requirement for 2013 was set on that basis and if Union Gas could sell the excess capacity it would accrue to the shareholder subject to earnings sharing. The PDO Settlement Framework was established after Union Gas's 2013 rates were set. In accordance with the PDO Settlement Framework, Union Gas used the excess capacity to reduce the PDO. Therefore, Union Gas was not able to sell the excess capacity to third parties. 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 for the amalgamated utility.

Based on how rates were set in 2013 and the fact that no changes were made to transportation revenues or how excess capacity is treated in the MAADs proceeding,

[279] EB-2017-0306/2017-0307, *FRPO Final Arguments*, June 15, 2018, pp. 8-15.
[280] EB-2011-0210, *Decision and Order*, October 25, 2012, p. 22.

OEB staff submits that ratepayers are not paying twice for the same capacity. Union Gas was at risk for the 210 TJ/day of excess capacity as determined in the 2013 Cost of Service decision and it did not sell that capacity but used it to reduce PDO. In addition, the revenue shortfall as shown in Table 18 demonstrates that Enbridge Gas has not over-collected for the PDO during the deferred rebasing term.

Accordingly, OEB staff submits that the OEB should not make any adjustments to the 2019 to 2023 PDO/PDCI costs that have been recovered from ratepayers. OEB staff also believes that there is sufficient evidence on the record and the OEB does not need to canvass any further evidence on this issue to make this determination.

Issue 19: With respect to the Gas Supply Plan,

a) **Is the proposal for implementation of the 2024 Gas Supply Plan after the OEB's decision on matters relating to the 2024 Gas Supply Plan is issued, and for reflecting cost variances in gas cost deferral and variance accounts, with recovery being subject to prudence review, appropriate?**

b) **Is the proposal to extend the deadline for filing the next 5-Year Gas Supply Plan by an additional year appropriate?**

In the OEB approved settlement proposal, parties agreed with Enbridge Gas's proposal for implementation of the 2024 Gas Supply Plan after the OEB's decision on relevant matters in this proceeding is issued and to reflect the cost variances in the gas cost deferral and variance accounts. Parties further agreed that it is appropriate for Enbridge Gas to defer the filing of its next five-year gas supply plan for one year.

E. Cost of Capital (Exhibit 5)

Issue 20: Is the proposed 2024 Capital Structure, including return on equity, appropriate?

Issue 21: Is the proposed 2024 cost of debt and equity components of the capital structure appropriate?

With respect to Issue 21, in the OEB approved settlement proposal, parties agree to the as-filed debt rates and the use of the OEB's formula to set the return on equity value. The settlement proposal notes that the agreed-to rates for debt costs and equity will be applied to determine revenue requirement for 2024 when all components of the revenue requirement have been determined by the OEB.

There was no settlement of Issue 20 and OEB staff's submission on the appropriate equity thickness is set out below.

Enbridge Gas currently has, for regulatory ratemaking purposes, a deemed equity thickness of 36%, 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 equity thickness of 36%.[281] The equity thickness of 36% was originally established for the two predecessor utilities in the relevant cost of service applications where cost of capital was most recently reviewed.[282]

In this application, Enbridge Gas proposed to increase its deemed equity thickness from 36% to 42%. This is supported by the filed evidence of Concentric.[283] Concentric concluded that energy transition is the most important factor increasing Enbridge Gas's business risk (and hence the equity thickness relative to that business risk) since the cost of capital and business risk was last formally reviewed in proceedings before the OEB for Enbridge Gas Distribution and Union Gas in 2012. In terms of quantitative analysis, Concentric relies primarily on an analysis of four comparator groups. Through a comparison of statistics of the holdcos and opcos[284], Concentric concludes that Enbridge Gas's current deemed equity thickness is below that of the comparator groups and recommends a minimum equity thickness of 42%.

OEB staff retained London Economics International LLC (LEI) to assess Enbridge Gas's cost of capital evidence, including that of Concentric, and provide its independent assessment of that evidence and LEI's recommendation for a deemed equity thickness. LEI prepared a report which was filed on the record.[285] Based on its analysis, which 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 2022, LEI recommended an increase in the deemed equity thickness to 38% for 2024-2028. LEI found that energy transition has increased Enbridge Gas's business risk, but the amalgamation operates to partially offset that increased risk when compared to the prior cost of capital reviews in 2012.

IGUA retained Dr. Cleary as its cost of capital expert. Similar to LEI, Dr. Cleary did an independent assessment of Enbridge Gas's and Concentric's evidence. Dr. Cleary's

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[281] 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.
[282] EB-2011-0354 for Enbridge Gas Distribution and EB-2011-0210 for Union Gas.
[283] Exhibit 5, Tab 3, Schedule 1, Attachment 1 (the Concentric Report).
[284] Holding Companies and Operating Companies.
[285] Exhibit M2 – Staff Cost of Capital, April 21, 2023.

analysis considered the historical financial performance of Enbridge Gas and its predecessor utilities. 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%.

IGUA also retained Dr. Hopkins to perform an independent assessment of the impacts of energy transition on Enbridge Gas's financial metrics and business risk.[286] Dr. Hopkins' evidence was filed as Exhibit M8.[287] Dr. Hopkins concluded that Enbridge Gas's business risk had not increased and also referenced the uncertainties related to energy transition. Dr. Hopkins was not qualified as an expert on cost of capital, but OEB staff considers Dr. Hopkins' evidence and testimony on energy transition impacts on Enbridge Gas's business risk to be informative.

OEB staff submits that it would be appropriate to increase Enbridge Gas's deemed equity thickness from 36% to 38% for 2024 with no further increase from 38% for the remainder of the proposed rate plan (2025 to 2028).

OEB staff notes that an increase to 38% equity thickness is also recommended by OEB staff's expert witnesses, LEI, which concluded that there has been an increase in business risk for Enbridge Gas relative to the amalgamation in 2019 (and since the last cost of capital reviews for Enbridge Gas Distribution and Union Gas completed in 2012).[288] OEB staff supports LEI's recommendation and the evidence and analysis as documented by LEI in its evidence.

OEB staff submits that energy transition has operated to increase Enbridge Gas's business risk. This increase in risk is offset, to some extent, by the benefits of the amalgamation when compared to the prior cost of capital reviews in 2012, which is the last time that cost of capital was reviewed for Enbridge Gas (and its predecessor utilities).

OEB staff's submission on the cost of capital issue is arranged as follows:

1) Impact on Risk of the Amalgamation of Enbridge Gas Distribution and Union Gas
2) Impact on Risk of Energy Transition
3) Concerns with Concentrics's Evidence

[286] Dr. Hopkins was specifically qualified as an expert witness when testifying 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". Oral Hearing Transcript, Vol. 4, p. 152.
[287] Exhibit M8, May 11, 2023.
[288] Exhibit M2, April 21, 2023, p. 51.

4) OEB Staff's Position on Change in Risk for Enbridge Gas for 2024 and Future Considerations in the context of the OEB's Decision on Energy Transition-related Matters

Impact on Risk of the Amalgamation of Enbridge Gas Distribution and Union Gas

LEI considered the amalgamation in 2019 as the most critical point for assessing any change in Enbridge Gas's business risk. However, LEI also referred back to 2012, when the last cost of capital reviews for Enbridge Gas Distribution and Union Gas were completed.

OEB staff submits that both the prior cost of capital reviews completed as part of cost-of- service application reviews in 2012 and the amalgamation in 2019 are relevant points of comparison. The prior cost of service applications were the most recent time when 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 notes that there was no specific review of the cost of capital for the 2019-2023 rate plan considered in the MAADs proceeding.[289] OEB staff considers the fact that there was no review of the business risk for the proposed "Amalco" (Enbridge Gas) at that time appropriate. First, rates matters are not normally considered in detail as part of MAADs applications. Second, any forecasts of the strengths and weaknesses, and the risks faced or avoided as a result of the proposed amalgamation, would be speculative at best. Finally, in the proposed 2019-2028 rate framework, there was no proposed rebasing of rates at the outset of the plan; "Amalco" would continue with formulaic price cap rate adjustments. Without a cost-of-service review to rebase rates, there was no opportunity to review the business risk.

OEB staff notes that the above noted limitations would also apply to considerations made by investors and credit rating analysts. Credit rating agencies would tend to be conservative and so it is no surprise that there is little discussion of risk reduction due to the amalgamation in 2019 until there is clear evidence of this, such as is filed and being tested in the current application.

OEB staff submits that there are benefits and efficiencies accruing to Enbridge Gas from amalgamation, relative to that of Enbridge Gas Distribution and Union Gas as stand-alone natural gas distributors.

[289] EB-2017-0306/0307.

Enbridge Gas's amalgamation has created a much larger gas utility. Enbridge Gas has become one of the largest natural gas (operating) utilities in North America, and services one of North America's largest and most economically important regions, the Province of Ontario.

With the amalgamation, Enbridge Gas serves 3.7 million customers (including approximately 17,000 high volume customers) as of December 31, 2021.[290] In contrast, the three largest electricity distributors in Ontario – Alectra Utilities Corporation, Hydro One Networks Inc. and Toronto Hydro-Electric System Limited, serve 3.3 million customers combined as of December 31, 2021.[291]

While the number of customers does not tell the whole story, it clearly demonstrates the scale difference of Enbridge Gas to electricity distributors. And it is not only size, but with the amalgamation, the contiguous nature of many areas of the former Union Gas and Enbridge Gas Distribution areas afford more integrated capital planning and investment.

OEB staff submits that, while there remain challenges due to the different operations and planning of the predecessor utilities (common in most mergers and acquisitions), since amalgamation, Enbridge Gas has made material inroads in consolidating and integrating operations, planning and investment, such that improvements in capital and operational effectiveness and efficiencies have been and will continue to be realized, all else being equal.[292] Overall, OEB staff is of the view that the amalgamation has reduced the risk for Enbridge Gas since the last time that cost of capital was reviewed for Enbridge Gas (and its predecessor utilities).

Impact on Risk of Energy Transition

It is not possible to predict exactly how the energy transition will play out, and it is not the OEB's role in this proceeding to determine the precise pathway that energy transition will take. However, OEB staff does believe that, based on the record in this proceeding, there is a high probability that the energy transition may follow a pathway with a less significant role for gaseous fuels (even if those are low or zero-carbon fuels) using Enbridge Gas's network than that described in the P2NZ Diversified Scenario.

In terms of assessing equity thickness, however, simply because a change is underway

[290] 2021 Yearbook of Natural Gas Distributors. https://www.oeb.ca/oeb/_Documents/RRR/2021_Yearbook_of_Natural_Gas_Distributors.xlsx, Tab General Information.
[291] Yearbook of Electricity Distributors (2021) General Statistics (xlsx) (updated November 25, 2022) https://www.oeb.ca/sites/default/files/yearbook-General-Statistics-2021.xlsx
[292] EB-2017-0306, Exhibit B, Tab 1, pp. 25-37.

does not necessarily drastically change business risk itself. What is important is whether a firm can adapt and what efforts it undertakes to prudently react and adapt to the change, and on whether it adapts at a pace at least equal of that to the external change itself. OEB staff notes that a change in risk can be viewed in several ways.

First, is the firm’s (or sector’s) business risk changed in terms of the firm’s (sector’s) ability to adapt its operations as a result of the external (business environment) change, compared to what it was? In part, this will depend on what is the firm’s or sector’s ability to manage and mitigate the impact of the environmental[293] change. In large part, this considers that it is the firm’s (sector’s) responsibility to take action in light of the environmental change. It may also be common, particularly for a major socioeconomic change, that government and governmental bodies (such as regulators) will also act so as to facilitate change and to help to mitigate impacts on the firm (sector) and on the economy and society at large.

Second, how does the firm’s (sector’s) change in business risk fare relative to that of the economy generally or that of other sectors? A change in the economy generally, such as major upturns or downturns in the economy are handled differently. OEB staff submits that its formulaic approach for annually adjusting the return on equity (ROE) and deemed debt rates is actually the appropriate means for capturing these general changes in the economy. This was the intention when the current cost of capital policy was established in the 2009 consultative process, itself initiated in response to the late 2008 global financial crisis.[294] While not discounting that an independent assessment of Enbridge Gas on a stand-alone basis might result in (somewhat) different numbers, or dismissing the appropriateness of a more complete review of the policy, Concentric acknowledged the rationale (regulatory effectiveness) and suitability of the results of the OEB’s current approach on cost of capital.[295]

Therefore, the remaining element – not reflected in the OEB’s return on equity formula

[293] OEB staff will use the term “environmental” to refer to the change in the external business environment which is the source, and which will often be due to exogenous factors outside of the firm’s or sector’s control. This could be political, international, technological, health and safety-related, climatological or (meteorological) environmental. While firm or sector may not have full control, they do have the ability to rationally and prudently react to it in order to address and mitigate the impact of the environmental change, and their investors and lenders expect them of this (as do any regulators that the firm or sector may be subject to). There may be exceptions to this – major acts of war, whether civil or international, or severe natural disasters, may be examples. Based on the record, and what is known generally at this time, energy transition is not one of these, and Enbridge Gas and other firms should have the time and opportunity to react.
[294] EB-2009-0084, which resulted in the *Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities*, December 11, 2009.
[295] Oral Hearing Transcript, Vol. 8, p. 136.

that is updated annually for general economic movement – is how the firm- or sector-specific risks have changed relative to other firms or sectors. On this point, OEB staff submits that there is a relative change, directly related to energy transition, between two sectors, electricity and natural gas. This was referred to during the Vulnerable Energy Consumers Coalition's cross-examination of Concentric.[296] OEB staff submits that the natural gas and electricity sectors will be amongst the most impacted by energy transition. However, the impacts will be different for the two sectors, largely in the long run, but even in shorter horizons. Electric utilities will likely face challenges, for expanding their networks to accommodate anticipated higher electricity demand, but will also need to build more flexible, resilient and intelligent grids, while natural gas utilities may need to change their business models for decarbonization and for lower demand in the longer run, even if the exact pathway is not known. On this basis, OEB staff submits that, all else being equal, the relative business risk of the Ontario natural gas distribution sector has increased relative to that of the Ontario electricity distribution (and transmission) sector from when the current cost of capital policy was set (2009) and the last applications when Enbridge Gas Distribution's and Union Gas's cost of capital were formally reviewed in 2012. OEB staff even considers that this relative risk has changed since the amalgamation. Under its current cost of capital policy, the OEB uses the same ROE formula for all rate-regulated energy sectors in Ontario. Therefore, a change in relative risk is addressed through a change in the deemed capital structure (i.e., the deemed equity thickness). Overall, OEB staff is of the view that energy transition has increased the risk for Enbridge Gas to some extent since the last time that cost of capital was reviewed for Enbridge Gas (and its predecessor utilities).

<u>Concerns with Concentric's Evidence</u>

OEB staff summarizes a few of its concerns with Concentric's evidence below.
OEB staff submits that there needs to be a balance of both qualitative and quantitative evidence. OEB staff submits that Concentric's evidence relies too heavily on qualitative support. This is demonstrated through a number of examples.

First, OEB staff notes Concentric's reliance on presentations from the Brattle Group and government officials regarding possible gas bans that it has quoted in its evidence but did not corroborate. In response to an interrogatory, Concentric acknowledged that it had not done any analysis to corroborate the quotes, but stated that "[w]hile Concentric is not aware of any natural gas bans in Ontario, there is a risk of such gas bans given the circumstances referenced in the question."[297] In OEB staff's view, this is not convincing. There are very few risks that have a zero probability of happening.

[296] *ibid.*
[297] Exhibit I.5.3-Staff-199.

However, what has to be weighed is the probability of occurring and the impact if it does occur. Concentric has not done this.

As another example, Concentric quotes from the evidence of expert witnesses of the Attorney General of Rhode Island in a case regarding the proposed sale of The Narragansett Electric Company being considered before the State of Rhode Island Division of Public Utilities and Carriers.[298] In its discussion of this issue emphasizing how "going concern" is an operational risk due to the impacts of energy transition, Concentric relies heavily on the quoted material of the experts' evidence in this merger and acquisition case in Rhode Island.[299] However, in response to an interrogatory, Concentric acknowledged that the proposed sale was approved and the division (the decision maker) was satisfied with the evidence on energy transition and other environmental matters proposed by the applicants.[300] Concentric also had not quantified the risk or the time horizon of any "going concern" risk as it would apply to Enbridge Gas.[301] OEB staff submits that this is not convincing evidence; Concentric quoted evidence from some witnesses in a case but it did not provide the whole picture, including that the decision maker did not accept that evidence versus other evidence that minimized or dismissed the "going concern" risk due to energy transition based on what is currently known. And, in any event, they provide no evidence that Enbridge Gas faces any substantive "going concern" risk due to energy transition.

With respect to Concentric's quantitative analysis, OEB staff notes that Concentric focused on what it identifies as four "comparator" groups (Canadian operating companies (opcos), American opcos, Canadian holding companies (holdcos) and American holdcos). OEB staff considers that Concentric has overstated its quantitative analysis. Data for the holdcos are derived as the average of their subsidiary opcos, primarily on the approved ROEs for opcos for which data is available. OEB staff agrees with Dr. Cleary that there is very little to distinguish the Canadian and U.S. holdcos from each other, as the holdco data for both groups are derived primarily from U.S. opcos for both groups, with only a few Canadian opcos in the mix for some of the Canadian holdcos.[302] OEB staff also notes that Concentric has calculated the holdco ROE as a simple average of the allowed ROEs for its subsidiary opcos for which data is available; this simplification introduces measurement error. OEB staff considers that there is

[298] OEB staff notes that this is a division of a department of the state government, and separate from the public utilities commission of that state. The division adjudicates mergers and acquisitions involving regulated utilities in the state, while the public utilities commission is the economic regulator that sets rates, amongst other matters.
[299] Exhibit 5, Tab 3, Schedule 1, Attachment 1, pp. 45-46.
[300] Exhibit I.5.3-Staff-212 (a) and (b).
[301] Exhibit I.5.3-Staff-212 © and (d).
[302] Exhibit M – IGUA Cost of Capital, page 20.

essentially only one holdco comparator group.

With respect to the Canadian opco group, OEB staff considers the selected utilities to be a poor comparator group for Enbridge Gas. Using data from Concentric's supporting schedules filed with its evidence, OEB staff has compiled the following table to compare Enbridge Gas against the Canadian opcos.[303]

Table 19

Gross Plant – Canadian Companies

	Gross Plant ($M)	
	2020	**2021**
Enbridge Gas Inc	$20,640.000	$21,744.000
Canadian Operating Companies ($)		
AltaGas Utilities Inc.	$678.583	$724.640
ATCO Gas	$5,434.406	$5,470.814
Energir	NA	NA
FortisBC Energy	$7,413.000	$7,823.000
Gazifere Inc.	NA	NA
Heritage Gas Limited	$280.861	NA
Liberty Gas New Brunswick	NA	NA
Pacific Northerns Ga Ltd.	NA	NA
Pacific Northern Gas Ltd. (Fort St. John/Dawson Creek)	NA	NA
Pacific Northern Gas Ltd. (Tumbler Ridge)	NA	NA

The next largest Canadian opco, FortisBC Energy, is just over one-third of the size of Enbridge Gas, while Heritage Gas Limited is less than 2% of the size of Enbridge Gas. Some of the other Canadian opcos for which data was not available (NA) are likely even smaller. Not only are there size differences, but there are also differences in their operating territories and the length of time they have been operating. The Pacific Northern Gas operating companies are smaller utilities serving various territories and communities in the Rocky Mountains in British Columbia. Heritage Gas Limited (now known as Eastward Energy) services areas in the Halifax-Dartmouth-Bedford area of Nova Scotia, and has also a much shorter history.[304] Liberty Gas New Brunswick, while a larger gas distributor in New Brunswick, is much smaller and has been operating for much less time than to Enbridge Gas.

[303] Exhibit 5, Tab 3, Schedule 1, Attachment 1, p. 147 , Schedule 2 Analysis. See also the Microsoft Excel spreadsheet "EGI_Rebasing Appl_Concentric Equity Thickness Supporting Schedules_20221101.xls", November 1, 2022, Tab "Schedule 2 – Analysis". OEB staff notes that, in Concentric's tables on Tab "Schedule 2 – Analysis", Enbridge Gas' data are shown in $M, while those for the Canadian opcos are shown in $000. OEB staff have converted the data to be shown commonly in $M.
[304] Availability Map | Eastward Energy

While OEB staff does not dispute that these can be used as comparators, there needs to be adjustments to, and suitable caveats noted, in order to compare to Enbridge Gas. Concentric has not done so. Further, even in computing statistics for the Canadian opcos (and for the U.S. opcos), it has used simple averages and medians. For its comparator group analyses, the percentage depreciation for the Canadian opcos is the average for the four opcos for which data is available, ignoring the fact that FortisEnergy BC is nearly thirty times the size of Heritage Gas Limited in terms of Gross Plant.

OEB staff submits that Concentric's reliance on qualitative evidence (and assertions) with limited quantitative support, and elsewhere where Concentric is relying on quotes from other jurisdictions and from third parties and where Concentric has not always corroborated the reference material has caused OEB staff to place less weight to Concentric's evidence and conclusions.

OEB staff submits that these caveats of Concentric's report should be kept in mind when assessing the evidence of the three experts. In OEB staff's view, Dr. Cleary and LEI have provided more balanced and credible assessments of Enbridge Gas's business risk and the impact on the utility's financial performance and outlook; this is accomplished through a better balance of persuasive qualitative and quantitative evidence.

OEB staff makes the following submissions on how Dr. Cleary's and LEI's evidence provide a more balanced approach of qualitative and quantitative analysis of Enbridge Gas's financial performance and the appropriate deemed equity thickness.

Turning first to Dr. Cleary's evidence,[305] OEB staff notes that Dr. Cleary addresses Concentric's points through qualitative analysis, but also provides more substantive quantitative analysis in several areas:

- Section 3.3 ("A Quantitative Review of Enbridge Gas and Union Gas Performance") of Dr. Clreary's report examines the earned ROEs of Enbridge Gas and the predecessor utilities, Enbridge Gas Distribution and Union Gas, over the period 1990-2022, showing that Enbridge Gas and the predecessor utilities have earned at or above the allowed ROE in each year for most years in the 33-year period. Dr. Cleary comments that "[a] compelling way of reviewing the [financial] performance of utilities is to examine their ability to earn their allowed ROEs on a consistent basis. This is a bottom line measure of the total risks faced by these utilities".[306] OEB staff concurs that assessment of actual

[305] Exhibit M – IGUA Cost of Capital. April 21, 2023, commonly referred to as Exhibit M8.
[306] *Ibid*, pp. 13-15.

(realized) returns is very important – and even more so than for allowed returns; if this were not the case and allowed returns were the focus, then market participants (and credit rating agency analysts) would not be focused on quarterly earnings reports since allowed returns are determined through regulatory decisions and untied to quarterly earnings reports.

- In sections 4.2 (“Comparing the Risk of EG [Enbridge Gas] to US Utilities”) and 4.3 (“Comparing the Risk of EG to Canadian Utilities”),[307] Dr. Cleary provides his analysis of Enbridge Gas against the US and Canadian opcos. Tables 2, for the US opcos, and 3 (Canadian opcos) provide a more detailed quantitative analysis in support of his qualitative discussion in these sections.
- In section 5 (“Financial Risk and Credit Metrics”), Dr. Cleary provided a detailed analysis to provide an addition financial metric (EBITDA to interest) estimated from data provided by Enbridge Gas through interrogatories. In OEB staff’s submission, this is useful and detailed quantitative evidence not found elsewhere on the record.

Turning to LEI, OEB staff notes, at the outset, that LEI’s evidence similarly assesses Enbridge Gas’s evidence and that of Concentric, and provides its own qualitative and quantitative analysis and recommendations.[308] In its evidence, LEI assesses Concentric largely qualitative evidence, which LEI responds to. For example, LEI provides in Exhibit M2, Figure 9, a table summarizing Concentric’s analysis of business risks from energy transition, but adds a column with LEI’s qualitative comments on these risks and Concentric’s comments.[309] LEI then provides additional qualitative and quantitative support for its comments in Figure 9 on the following pages of its report,[310] which it then summarizes in Figure 18 (LEI’s summary of business risk factors for Enbridge Gas) and concludes that:

> there is a modest increase in business risks for Enbridge Gas, particularly due to an increase in risk from energy transition. LEI finds no material change in volumetric and regulatory risk, and a modest decrease in operational risk, primarily due to the amalgamation of EGD [Enbridge Gas Distribution] and Union Gas.[311]

LEI also provides its “Analysis of Enbridge Gas’s credit metrics and potential impact on

[307] *Ibid*, pp. 16-20.
[308] Exhibit M- OEB Cost of Capital, April 21, 2023, referred to as Exhibit M2.
[309] *Ibid*, page 18 of 60, Figure 9. Concentric’s analysis of business risks from energy transition.
[310] *Ibid*, pp. 18-34 of 60.
[311] *Ibid*, p. 34 of 60.

rating" in section 3.2.1 of its evidence.[312] In this section LEI provides a detailed qualitative and quantitative analysis, based on the rating matrices of certain credit rating agencies and their current and estimated metrics for Enbridge Gas Distribution. This credit rating metric analysis is a key factor underpinning LEI's recommended increase in the deemed equity thickness in order to maintain Enbridge Gas's creditworthiness in light of the increase in energy transition-related business risk.

Overall, OEB staff submits that Dr. Cleary's and LEI evidence have provided useful evidence for assessing Enbridge Gas's business risks and hence the commensurate deemed equity thickness through a better balance of qualitative and quantitative analyses supporting their recommendations.

<u>OEB Staff's Position on Change in Risk for Enbridge Gas for 2024 and Future Considerations in the context of the OEB's Decision on Energy Transition-related Matters</u>

OEB staff's recommendation for a 38% deemed equity thickness for setting 2024 revenue requirement and associated rates is based on its assessment on the record of the case, including the evidence of the experts – Concentric, LEI, and Dr. Cleary, and also informed by the evidence of Dr. Hopkins on the potential energy transition impacts on Enbridge Gas's financial metrics. OEB staff's recommendation has considered all of this in conducting its own analysis and coming to its conclusions and recommendation.

Overall, OEB staff considers that an increase in Enbridge Gas's equity thickness is warranted due to increased risk related to energy transition which is partially offset by the reduced risk resulting from the economies of scale and other operating efficiencies resulting from Enbridge Gas's amalgamation in 2019.

OEB staff notes that during the course of the proceeding many concerns have been raised with respect to stranded asset risk and there will likely be many proposals filed by intervenors on how to best address stranded asset risk. OEB staff's recommendation for a 38% deemed equity thickness includes consideration of OEB staff's energy transition-related submissions designed to mitigate energy transition risk to both Enbridge Gas and to ratepayers, and OEB staff's submission regarding the appropriate assignment of risk for any assets stranded or underutilized as a result of the energy transition. However, the OEB's findings on these energy transition issues may impact the energy transition business risk experienced by Enbridge Gas. The OEB should consider its findings on all of the Phase 1 issues together when determining the appropriate value

[312] Ibid, section 3.2.1, pp. 35-39 of 60, and Section 5, Figure 34: Forward-looking credit metric analysis based on recommended equity ratio of 38%, p. 52 of 60.

for deemed equity thickness.

Issue 22: Is the proposed phase-in of increases to equity thickness over the 2024 to 2028 term appropriate?

In its application, Enbridge Gas proposed to phase in its proposed equity thickness increase from 36% to 42% over the plan term (2024 to 2028). Enbridge Gas noted that this proposal is to help mitigate the increases in rates experienced by ratepayers. Enbridge Gas proposed to increase the deemed equity thickness from 36% to 38% for 2024 rates and 1% each year until 2028. Under its proposal to increase the deemed equity thickness to 42% by the end of the plan term (2028), Enbridge also proposes an incremental adjustment to the inflation-less-productivity (I -X) adjusted revenue requirement for each year from 2025 to 2028.

If the OEB accepts OEB staff's submission recommending a deemed equity thickness of 38%, OEB staff submits that no equity thickness transition is necessary. OEB staff submits that an increase to 38% equity thickness can be implemented for 2024 revenue requirement and rates through the traditional cost of service methodology, with no subsequent phase-in during the subsequent 2025-2028 IRM term.

However, should the OEB approve an equity thickness greater than 38%, OEB staff does not oppose an equity thickness transition plan subject to any considerations related to the bill impacts that arise from the overall findings in the decision. OEB staff submits that an equity thickness transition plan may be entirely appropriate to mitigate bill impacts for ratepayers. However, the bill impacts will not be known until the OEB renders its decision and Enbridge Gas implements the findings in its draft rate order.

OEB staff submits that Enbridge Gas should make a proposal, in its draft rate order, with respect to the implementation of the OEB-approved equity thickness in the context of the overall bill impacts arising from the OEB's decision. At that time, the OEB will be in a better position to determine whether an equity thickness transition is necessary.

F. Revenue Deficiency/Sufficiency (Exhibit 6)

Issue 23: Is the proposed 2024 Test Year Revenue Deficiency calculated correctly?

The revenue requirement and revenue deficiency are mathematical calculations and are derived from the other components of the application (such as Rate Base, O&M and Cost of Capital). Once the OEB makes its decision in Phase 1, OEB staff will review the revenue requirement calculation in the draft rate order process and assess whether it accurately reflects the OEB's decision and is calculated appropriately.

G. Cost Allocation (Exhibit 7)

Issue 24: Is the 2024 Cost Allocation Study including the methodologies and judgements used and the proposed application of that study to the current rate class design, appropriate?

In the OEB approved settlement proposal, parties reached an overall resolution of the cost allocation and rate design issues in order to support the timely approval of 2024 rates on an interim basis. Interim rates for 2024 would be set through adjustment of existing rates by proportionately allocating the impact of any revenue deficiency/sufficiency determined in Phase 1 to each existing rate zone and rate class.

Parties also agreed that in Phase 3 of this proceeding, Enbridge Gas will provide further evidence about cost allocation and rate harmonization options. The cost allocation and rate harmonization proposals will be subject to OEB approval in Phase 3.

H. Rate Design (Exhibit 8)

Issue 25: Is the proposal to set 2024 rates using current rate classes and an updated harmonized cost allocation study appropriate?

Issue 26: Is the proposed rate design proposal for the gas supply commodity charge and gas supply transportation charges appropriate?

Issue 27: Is the proposed rate implementation and mitigation plan for 2024 rates appropriate?

As noted in Issue 24 above, in the OEB approved settlement proposal there was complete resolution with respect to the above issues for purposes of setting interim rates in Phase 1 of the proceeding.

Issue 28: Are the proposed changes to the terms and conditions applicable on January 1, 2024, to existing rate classes appropriate?

In the OEB approved settlement proposal, parties agreed to certain changes to the terms and conditions for Phase 1 of the proceeding with the majority of the issues to be resolved in Phase 3.

Issue 29: Are the proposed miscellaneous service charges, including Rider G and Rider M, appropriate?

In the OEB approved settlement proposal, parties agreed to most of the proposed miscellaneous service charges with the exception of the extra length charge (ELC).

The current approved extra length charge is $32 per additional metre for the Enbridge Gas Distribution rate zone and $45 per additional metre for the Union rate zones. Despite increases in construction costs, Enbridge Gas notes that these rates have remained constant for several years and require updating to reflect the latest marginal cost per metre.

Enbridge Gas proposed that residential infill customers be provided with the first 20 metres at no cost. Enbridge Gas has further proposed an ELC of $159 per metre across the entire franchise area, in excess of the 20-meter threshold.

As discussed previously in OEB staff's submission on Issue 3, OEB staff submits that the OEB should approve Enbridge Gas's proposal – 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 – on a temporary basis until an updated approach for infill customers is approved by the OEB.

Issue 30: Are the proposed Direct Purchase Administration Charge (DPAC) and Distributor Consolidated Billing (DCB) charges appropriate?

In the OEB approved settlement proposal, parties reached full settlement on this issue.

I. Deferral & Variance Accounts (Exhibit 9)

Issue 31: Is the proposal for harmonization of certain existing deferral and variance accounts appropriate?

Issue 32: Is the proposal to close and continue certain deferral and variance accounts and establish new ones appropriate?

Issue 33: Is the proposal to dispose of the forecast balances in certain deferral and variance accounts appropriate?

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 (DVAs) with some agreed to changes. A number of DVAs will also be addressed in Phases 2 and 3 of the proceeding.

The proposed DVAs or balance dispositions that remain unsettled for Phase 1 of the proceeding are related to:

- Volume Variance Account
- Panhandle Regional Expansion Project Variance Account
- Short-term Storage and Other Balancing Services Account (Union rate zones)
- Tax Variance Deferral Account
- Accounting Policy Changes Deferral Account

<u>Volume Variance Account</u>

Enbridge Gas proposed to close the following existing variance accounts and replace the existing accounts with a new account for the amalgamated utility:

a) Enbridge Gas Distribution – Average Use True-up Variance Account
b) Union Gas – Normalized Average Consumption (NAC) Account

For the Enbridge Gas Distribution rate zone, the average use account was established to record the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer, for general service rate classes, embedded in the volume forecast that underpins the general service rate classes and the actual weather normalized average use experienced during the year.

For the Union rate zones, the NAC account was established to record the impact to delivery and storage revenue and costs resulting from the difference between the target NAC included in OEB-approved rates and the actual NAC experienced during the year for general service rate classes.

Enbridge Gas proposed to close the existing rate zone-specific variance accounts and establish the Volume Variance Account. The Volume Variance Account would record the revenue impact, exclusive of gas costs, of the volumetric variance between the actual average use per customer and weather experienced during the year relative to the volumes forecast in rates for the general service rate classes.

Enbridge Gas stated that the Volume Variance Account reduces volumetric risk in a symmetric and revenue-neutral manner for both customers and Enbridge Gas. In a year where actual weather is colder than the OEB-approved normal, customers receive the benefit of being refunded delivery charges. In a year where actual weather is warmer than the OEB-approved normal, Enbridge Gas is able to recover its delivery costs from customers. In its argument-in-chief, Enbridge Gas indicated that the risk from over and under-recovery due to weather has been roughly symmetrical in recent years. Enbridge Gas further noted that the variances on a yearly basis can be meaningful, so the Volume Variance Account provides smoothing and certainty for ratepayers and the company alike.

Enbridge Gas confirmed that the proposed Volume Variance Account will remain in effect until the implementation of the proposed straight fixed variable with demand rate design, a proposal that will be considered in Phase 3 of this proceeding. If the OEB approves some other rate design approach, Enbridge Gas submitted that the proposed Volume Variance Account will continue to be required to capture average use and weather variances.

OEB staff submits that the existing average use and NAC accounts should be replaced by a single average use account that operates similarly to the existing accounts but is applied to all of Enbridge Gas's general service customers. OEB staff notes that both the legacy utilities (Enbridge Gas Distribution and Union Gas) have had these accounts for many years, and it has worked well for the utilities and ratepayers. OEB staff believes that complete de-risking of cost recovery related to weather is not required and Enbridge Gas should accept the weather forecast risk that is part of the cost-of-service ratemaking process. In a cost-of-service ratemaking process, rates are set on a forward test year basis, and this means that there is forecast risk implicit to the ratemaking model. Sometimes the outcome of the risk favours the utility and sometimes the risk favours ratepayers. However, this does not imply that steps should be taken to completely eliminate the risk. If complete protection was required, rates would be set on a historic and not on a forecast basis. Forecasting the different elements of ratemaking such as capital costs, consumption volumes, customer attachments and operating costs is an important aspect of setting rates on a prospective basis. The ratemaking process includes an inherent risk that is related to how the forecast deviates from the actual outcome.

Accordingly, OEB staff submits that the OEB should not approve a Volume Variance Account. Instead, the OEB should establish a single average use account for the amalgamated utility. If the OEB agrees that a single average use account should be established for the amalgamated utility, OEB staff submits that the OEB should require Enbridge Gas to file a draft accounting order for this account (and an associated explanation regarding the operation of the account) as part of the draft rate order process in Phase 1 of the proceeding.

Panhandle Regional Expansion Project Variance Account

As discussed previously under Issues 6 and 7, Enbridge Gas proposed a levelized treatment for PREP. The proposed treatment is similar to the treatment applied to an ICM project. Similar to how ICM projects were treated during the deferred rebasing period, Enbridge Gas proposed to establish an associated variance account, the Panhandle Regional Expansion Project 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 proposed IRM term.

The variance account would ensure that Enbridge Gas does not over or under recover during the IRM term. The clearance of any cumulative balance in the account is proposed to occur at the next rebasing.

As previously stated in the rate base section of this submission (Issues 6 & 7), OEB staff supports Enbridge Gas's proposal for PREP. Therefore, OEB staff also supports the establishment of the PREP variance account, which OEB staff notes operates similarly to other ICM-related variance accounts approved for use during Enbridge Gas's deferred rebasing term.

St. Laurent Project Variance Account

If the OEB accepts OEB staff's submission with respect to the St. Laurent project (levelized treatment similar to PREP), a variance account for the St. Laurent project that operates similarly to the PREP Variance Account should also be established. OEB staff submits that the OEB should require Enbridge Gas to file a draft accounting order for this account (and an associated explanation regarding the operation of the account) as part of the draft rate order process in Phase 1 of the proceeding.

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 rate-making purposes.

In its argument-in-chief, Enbridge Gas indicated that it inadvertently failed to include the need to continue this account as part of the settlement proposal. Since storage-related issues will be determined in Phase 2 of this proceeding, there will continue to be excess utility storage space in the legacy Union rate zones until at least a determination on storage is made by the OEB in Phase 2 of this proceeding.

Accordingly, Enbridge Gas has requested continuation of this account. OEB staff submits that until a determination on storage matters is made in this proceeding, tracking and sharing of short-term storage and balancing services revenues with ratepayers continues to be required. OEB staff therefore supports the continuation of the Short-term Storage and Other Balancing Services Deferral Account.

Accounting Policy Changes Deferral Account

Enbridge Gas proposed to dispose the forecast December 31, 2023 balance of a debit amount of $140.2 million in the Accounting Policy Changes Deferral Account (APCDA), including forecast interest to December 31, 2023. The breakdown of the balance in the account is shown in the table below.[313]

Table 20
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**

Overhead Capitalization

As discussed under Issue 8 regarding overhead capitalization, if the OEB approves a change to Enbridge Gas's proposed overhead capitalization methodology, OEB staff submits that the change should be reflected in the balance shown in the Overhead Capitalization line of the APCDA. OEB staff notes 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. In the event that the OEB

[313] Argument-in-chief, p.245.

accepts OEB staff's recommendation to calculate Operation Costs capitalization rates using a 3-year rolling average that includes historic and forecast information, this should be incorporated in the harmonized methodology starting in 2020 and be reflected in the balance of the APCDA.

Pre-2017 Union Unamortized Actuarial Gains/Losses

Within the APCDA, the Pension & Other Post-employment Benefits (OPEB) Expense balance of $156 million represents the remaining unamortized Union rate zone's pre-2017 pension and OPEB actuarial gains/losses.[314, 315] 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.[316] Actuarial gains/losses are amortized and included in pension and OPEB expense (i.e. net periodic benefit cost) when certain criteria is met.[317] 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).[318]

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 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.[319]

For financial reporting purposes under USGAAP, Union Gas did not recognize a regulatory asset for its unamortized gains/losses but reflected it in AOCI.[320] Upon the merger 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 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 (i.e. as Union Gas did not previously record a regulatory asset for its unamortized actuarial gains/losses in its

[314] Enbridge Gas confirmed that this line item only relates to actuarial gains/losses and there were no past service costs per I.4.4-Staff-133.
[315] Argument-in-chief, p.245.
[316] Exhibit 1, Tab 8, Schedule 1, Attachment 1, p.17 – Enbridge Gas 2020 audited financial statements.
[317] Criteria is 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.
[318] Exhibit 1, Tab 8, Schedule 1, Attachment 1, p.17 – Enbridge Gas 2020 audited financial statements.
[319] Decision on Settlement Proposal, Aug. 17, 2023, Schedule A,/Exhibit/O1 Tab 1/Schedule 1/p.32.
[320] JT3.31, Attachment 1.

financial statements) to allocate the purchase price.[321] Subsequently, as a result of the Union Gas and Enbridge Gas Distribution merger, and the establishment of the APCDA,[322] the pre-2017 Union unamortized gains/losses were transferred to deferred assets for both Union Gas and Enbridge Inc. in each of their 2018 audited financial statements. The balance was then transferred to Enbridge Gas's APCDA in 2019 and Enbridge Inc. transferred the balance to a regulatory asset in its 2019 financial statements. Table 21 below summarizes how the pre-2017 Union unamortized actuarial gains/losses appeared on the financial statements for Union Gas/Enbridge Gas and Enbridge Inc.

Table 21
Presentation of Union's Pre-2017 Unamortized Gains/Losses in Financial Statements

	2017	2018	2019
Events	Spectra/Enbridge Inc. merger Feb. 17, 2017	Original MAADs decision Aug. 30, 2018	Enbridge Gas Inc. formed and APCDA effective Jan. 1, 2019
Union Gas (2017 and 2018)/Enbridge Gas (2019) Audited Financial Statements	AOCI	Deferred Asset	APCDA
Enbridge Inc. Audited Financial Statements	Goodwill	Deferred Asset	Regulatory Asset

Recoverability of Pre-2017 Union Unamortized Actuarial Gains/Losses

In the event that the OEB approves recovery of Union Gas's pre-2017 unamortized actuarial gains/losses, OEB staff submits that only a partial recovery should be approved. In principle, OEB staff does not oppose the proposed recovery of Union Gas's pre-2017 unamortized actuarial gains/losses because OEB staff does not believe the substance of the issue has changed after the merger/amalgamation. Historically, Union Gas and Enbridge Gas Distribution have recovered amortized actuarial gains/losses as part of their pension and OPEB expenses. Going forward, Enbridge Gas will continue to recover its pension and OPEB expenses. In OEB staff's view, the financial reporting aspect (i.e., transferring the unamortized actuarial gains/losses to goodwill) may not be relevant for regulatory reporting. However, OEB staff submits that the $156 million requested for disposition should be reduced by $80.2 million to $75.8 million, so as to avoid over-recovery of Union Gas's pre-2017 unamortized actuarial

[321] *ibid.*
[322] 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.

gains/losses.

OEB staff acknowledges that some of the arguments raised by intervenors have merit. In particular, during the oral hearing, Enbridge Gas stated that it would be reasonable to assume that Enbridge Inc. and Spectra Energy would have considered the effect of accounting rules on the unamortized gains/losses, either explicitly or implicitly when they negotiated the transaction.[323] The fact that the unamortized gains/losses was subsequently accounted for as goodwill could be seen as an indication that the recoverability was not necessarily expected because goodwill is typically not recoverable for regulatory purposes. And the subsequent establishment of the APCDA, allowing for potential recovery of the amount can be seen as a “windfall” as Mr. Rubenstein referred to it in the oral hearing.[324] Therefore, OEB staff would support a reduction in the amount that may be approved for disposition.

If the OEB approves the recovery of the pre-2017 Union unamortized gains/losses and views a reduction to the proposed amount as appropriate, OEB staff submits 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 as shown in the table below.

Table 22
Amortization of Union’s Unamortized Gains/Losses

($M)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	
	Opening Balance (1)	**Actual Amortization (2)**					**Closing Balance**
A	211.3	17.50	12.30	12.10	9.10	4.30	156.0
	Opening Balance (1)	**Amortization Embedded in Rates (3)**					**Closing Balance**
B	211.3	27.1	27.1	27.1	27.1	27.1	75.8
Difference (= A-B) (4)	**0**	**-9.60**	**-14.80**	**-15.00**	**-18.00**	**-22.80**	**-80.20**

(1) per I.4.4.-Staff-133 line 31

(2) per I.4.4.-Staff-133 line 26

(3) per JT3.37, Attachment 1, p.3 (line 6)
(4) Note that the amortization amounts in the table represents amortized losses, which are included as an expense that is recovered in Pension and OPEB expense. Therefore, negative numbers in the difference line of this table represents an over-recovery of costs.

As shown above, Enbridge Gas has recovered $80.2 million more than actuals during 2019 to 2023. As the amortization amount draws down the balance, and the residual

[323] Oral Hearing Transcript, Vol. 15, p.38.
[324] Oral Hearing Transcript, Vol. 15, p.55.

unamortized balance is requested for recovery, this effectively means that Enbridge Gas will recover a total of $291.5 million ($27.1 million x 5 years+ $156 million) if the proposed $80.2 million reduction is not included. This results in a material over-recovery relative to the $211.3 million original opening balance.

OEB staff understands Enbridge Gas's view is that simply because there was a specific amount included in Union Gas's 2013 base rates related to pension and OPEB costs does not mean that the corresponding amount is or should notionally be applied to accrual-based pension and OPEB costs each year.[325] However, OEB staff notes that this is not always true. For example, the Post-Retirement True-Up Variance Account (PTUVA) was approved to be established as proposed by Enbridge Gas in the current proceeding.[326] For the PTUVA, the variance in the revenue requirement impact of actual pension and OPEB costs greater than $10 million compared to the amount embedded in rates in any year may recover (or will credit) the actual amount outside of the $10 million dead band from (or to) ratepayers.

As noted above, the $156 million represents Union Gas's unamortized pre-2017 actuarial gains/losses upon the merger. Without the $80.2 million reduction, Enbridge Gas would over-recover $80.2 million of the unamortized actuarial losses. Therefore, OEB staff submits that if the OEB were to approve Enbridge Gas's recovery for pre-2017 Union actuarial gains/losses, only $75.8 million should be approved.

Potential Change to IFRS Deferral Account

Enbridge Gas is currently reporting under USGAAP as it has obtained an exemption to report under IFRS. However, this exemption is temporary and is expected to end during the IRM term.[327] Therefore, OEB staff submits that Enbridge Gas 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.

Tax Variance Deferral Account

As part of the settlement proposal, parties agreed that the Tax Variance Deferral Account (TVDA) will be modified to stipulate that 100% of any impacts from tax rule changes, or the availability and use of tax credits (or similar mechanisms) specifically directed at energy transition activities, will be recorded in the account. The question of

[325] Argument-in-chief, p.252-253.
[326] Decision on Settlement Proposal, Aug. 17, 2023, Schedule A, Exhibit O1, Tab 1, Schedule 1, p.32
[327] The exemption provided by the Ontario and Alberta Securities Commission 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).

sharing balances in the account will be determined at the time that the amounts in the account are cleared.

Enbridge Gas has 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 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.

In its submission on rate base and capital expenditures (Issue 6 and 7), OEB staff recommended that Enbridge Gas should be permitted to add 50% of the net book value of integration capital additions to the 2024 rate base. In accordance with that argument, OEB staff submits that 50% of the forecast credit balance in the TVDA of $7.3 million (inclusive of interest) should be credited to ratepayers.

J. Other

Issue 34: Is the proposed regulatory treatment of the Natural Gas Vehicle Program appropriate?

Enbridge Gas proposed to expand the current Natural Gas Vehicle (NGV) Program to all Enbridge Gas's franchise areas and to continue to operate its NGV Program as part of its utility business activities.

Enbridge Gas Distribution and Union Gas initiated their respective NGV programs in the mid-1980s. The programs operated as unregulated ancillary businesses that complemented the core utility business and were subject to fully allocated costing for rate treatment purposes. The initial programs focused on: (a) the conversion of light-duty vehicles from gasoline to compressed natural gas (CNG); and (b) establishing public CNG refuelling stations. The cost of the programs' assets were included in utility rate base. To the extent that the programs did not meet the OEB's required annual rate of return, revenues were imputed (i.e., the programs were subsidized by ratepayers). Excess revenues contributed to utility earnings and were subject to any Earnings Sharing Mechanism.[328] Union Gas paused its program for a time but reinitiated it shortly before the two utilities amalgamated.

The NGV Program is primarily active in the legacy Enbridge Gas Distribution franchise

[328] I.1.14-CCC-34.

areas where it is now focused on the medium- and heavy-duty vehicle market. Enbridge Gas stated that there are no commercialized electric alternatives to natural gas as a transportation fuel for heavy trucks. Enbridge Gas views natural gas as a bridge fuel until there are commercialized electric alternatives, if ever.[329]

The NGV Program currently offers:

1. CNG refueling station rentals
2. CNG fuel cylinder and NGV refueling appliance rentals
3. CNG tube trailer rentals (for off-pipe delivery and remote refueling stations).

Historically, the NGV Program underperformed and revenues were imputed. However, the NGV Program achieved the OEB's required 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:[330]

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 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 required 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.[331]
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

[329] I.1.14.STAFF-42.
[330] Exhibit 1, Tab 14, Schedule 2, page 1; Exhibit I.1.14-STAFF-43.
[331] OEB staff notes that the combined impact of the fourth and fifth proposal set out in the list above is that customers pays the full cost of its service.

performance of the NGV Program under the proposed framework that sets out the annual revenue and costs (including the rate of return).

Enbridge Gas's AMP includes strategies to support investments for NGV stations.

Enbridge Gas has indicated that the NGV Program is consistent with and complimentary to the federal government's Green Freight Program and Clean Fuel Regulation (CFR) as owners and operators of CNG refuelling facilities can generate, trade and sell credits under the CFR. Moving from diesel fuel to natural gas as a transportation fuel for heavy trucks results in lower emissions (20% lower emission factor and up to 90% less NOx levels). Enbridge Gas further noted that the NGV Program supports the objectives of the proposed Low-Carbon Voluntary Program by encouraging the adoption of natural gas vehicles and the development of CNG refueling facilities.

Enbridge has not conducted any studies or analysis on the potential of the NGV program to become a stranded asset. NGV Program assets are underwritten by long term take-or-pay contracts that ensure the recovery of their fully allocated costs over the life of each contract from the customer that benefits from the service.[332]

Enbridge Gas believes that OEB approval of its NGV proposals will support continued growth and development of natural gas as a transportation fuel and thereby benefit ratepayers (including NGV Program customers) and help to achieve energy transition objectives.[333]

OEB staff submits that Enbridge Gas's proposed changes to its Natural Gas Vehicle (NGV) Program should be approved because:

1. The proposed regulatory treatment will end non-NGV ratepayer subsidization of the NGV program, should the NGV Program ever again fail to achieve the OEB's required annual rate of return.
2. Ratepayers will be protected as per Enbridge Gas's proposed regulatory treatment. To ensure there is no ratepayer subsidy, the final service charge will be based on the actual costs of the facilities on a fully allocated basis and all other O&M and related costs will also be included in the analysis to determine the charge. In addition, Enbridge Gas will apply credit and security terms consistent with its practices for large volume gas distribution customers.

[332] I.1.14-PP-26.
[333] I.1.10-GEC-51, I.1.14.STAFF-42.

3. Fuel switching from gasoline and diesel to natural gas in the medium- and heavy-duty vehicle markets can help to reduce GHG emissions, even if only until more electric or hydrogen alternatives become commercialized.[334]
4. Regardless of whether more electric or hydrogen alternatives become available in the future, the proposed regulatory treatment mitigates the risk of stranded assets for ratepayers.

In its argument-in-chief, Enbridge Gas supported the suggestion of OEB staff to file a report in 2026 setting out the actual revenues and costs, including the rate of return on the NGV Program, so as to allow parties to assess the performance of the proposed NGV Program. OEB staff submits that the OEB should make the filing of this mid-term report a requirement of any approval of the NGV Program.

Issue 35: Is the proposed regulatory treatment of the Distributor Consolidated Billing Program appropriate?

In the OEB approved settlement proposal, parties reached full settlement on this issue.

Issue 36: Is the proposal for the extension of the existing financial terms of the Open Billing Access Program for ten months until October 31, 2024 appropriate?

In the OEB approved settlement proposal, parties reached full settlement on this issue.

Issue 37: Is it appropriate to have an earnings sharing mechanism for 2024?

Enbridge Gas does not support an earnings sharing mechanism (ESM) for 2024. Enbridge Gas also does not believe that an ESM deferral account should be established for the cost-of-service rate year. OEB staff agrees with Enbridge Gas's position.

Enbridge Gas proposed an ESM for its IRM framework that will be reviewed in Phase 2 of the proceeding. OEB staff notes that this approach is consistent with the previous two incentive rate-setting terms, from 2008 to 2012 and from 2014 to 2018. In the previous incentive rate-setting terms for both legacy utilities, an ESM was in place for the incentive rate-setting years but not the cost-of-service years.

In its argument-in-chief, 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. Enbridge Gas submitted that it was unnecessary and

[334] OEB staff notes that the Government of Canada launched the Incentives for Medium- and Heavy-Duty Zero-Emission Vehicles (iMHZEV) Program on July 11, 2022. As a result of this and similar programs, the use of natural gas as a bridge fuel could be short lived.

counter-intuitive to now impose an ESM on top of the extensive review that has already occurred to determine just and reasonable rates.

Enbridge Gas referred to some settlement agreements with electricity distributors that did apply an ESM in a cost-of-service rate year, but Enbridge Gas argued that such settlements should not serve as precedent for this case given the nature of the many compromises that settlement agreements may involve.

OEB staff submits that the review in a cost-of-service process is thorough where all elements of a utility's business are reviewed. Essentially, the cost-of-service process aligns rates to costs on a forecast basis and this means that the resulting rates appropriately reflect the forecast costs to serve customers. This proceeding has had sufficient discovery with thousands of interrogatories, a technical conference for follow-up questions and a lengthy oral hearing of more than four weeks. It is OEB staff's view that the record is sufficient for the OEB to set just and reasonable rates, including setting a revenue requirement for 2024. Including an ESM would imply that ratepayers need additional protection from what a cost-of-service review process affords. OEB staff is of the opinion that additional protection through an ESM for the Test Year is not required. Accordingly, OEB staff submits that an ESM for the 2024 Test Year should not be implemented.

Issue 38: How should Dawn Parkway capacity turnback risk be dealt with?

In the OEB approved settlement proposal, parties accepted the establishment of the Dawn Parkway System Surplus Capacity Deferral Account (DPSSCDA). The DPSSCDA will record the actual revenue from the sale of all or a portion of the forecast 89 TJ/day Dawn Parkway system surplus capacity, to be credited to ratepayers.

In the 2016 Dawn Parkway System Expansion Project proceeding, parties expressed concern with the potential for substantial turnback on the Dawn Parkway system.[335] As part of the settlement agreement in that proceeding, parties agreed that the issue of Dawn Parkway system capacity turnback risk should be addressed as part of the next cost-of-service application.

In response to the concerns expressed by intervenors, Enbridge Gas filed evidence in this proceeding to forecast the long-term utilization of the Dawn Parkway system. However, Enbridge Gas is not seeking any specific 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

[335] EB-2014-0261.

Mississauga. The Dawn hub is one of the most liquid natural gas trading hubs in North America, 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.

The Dawn Parkway system currently has excess capacity available in 2023 and 2024. This excess capacity will be offered to shippers on a long-term or short-term basis. Several US Northeast customers have contracted for additional long-term capacity on the Dawn Parkway system commencing in 2019, 2020 and 2021. While Enbridge Gas recognizes that there is some risk that specific customers could turn back capacity, it maintains that capacity could be re-contracted after it is released.

Ontario natural gas-fired power generation customers also hold considerable capacity on the Dawn-Parkway system and that capacity is required to meet the demand for electricity in Ontario. In addition, Quebec and Eastern Canada utilities hold considerable capacity on the Dawn Parkway system with some turnback potential during the proposed IRM term. However, Enbridge Gas notes that these customers have highly seasonal loads and use Dawn storage in conjunction with the Dawn Parkway system transportation path to manage their gas supply needs, minimizing the risk of substantial turnback on the system.

Enbridge Gas expects the Dawn Parkway system to remain fully contracted through to the end of the proposed IRM term (2028). This position is further supported by ICF International Inc., a consulting firm that reviewed the utilization of the Dawn Parkway system. The ICF analysis concluded that the Dawn Parkway system is likely to remain contracted through to 2034 at current levels.[336]

In the event that there is Dawn Parkway system capacity turnback during the IRM term, Enbridge Gas will bear the cost consequences of such turnback because the revenue requirement that recovers Dawn Parkway system costs will not be adjusted. Alternatively, if some of the existing surplus capacity is contracted during the IRM term, ratepayers will receive the associated revenues through the DPSSCDA.

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 will be turned back during the proposed IRM term may be small, the risk of turnback by utilities in New York and New England should not be ignored. This is because utilities in New York and New England have alternatives

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

to the Dawn-Parkway system, do not rely on Dawn storage services and the remaining terms of their contract with Enbridge Gas is for a term of three years or less.

Even if the near-term risk of capacity turnback is low, Mr. Rosenkranz suggested that it would be prudent for Enbridge Gas to implement measures to limit cost shifting between ex-franchise and in-franchise services if turnback occurs and to avoid future expansion of the Dawn Parkway system by including a buy-out option in reverse open seasons. In other words, pay existing shippers to turn back capacity.

At the oral hearing, Mr. Rosenkranz agreed that the question of allocating costs for the Dawn Parkway system should be addressed at the next rebasing.[337] It is not clear why Mr. Rosenkranz is suggesting that this should be addressed at the next rebasing. OEB staff submits that the appropriate place to address the general cost allocation of Dawn Parkway system costs is in Phase 3 of this proceeding. Therefore, OEB staff has made no submission on this issue at this time and will reserve its submission to a later phase of this proceeding.

In its argument-in-chief, Enbridge Gas rejected Mr. Rosenkranz's proposal for a reverse open season with payments to shippers. Enbridge Gas cited several issues with the proposal: (1) there is no precedent of similar approved mechanism in other jurisdictions; (2) shippers would not turn back capacity in the future without payment; and (3) 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 agrees with Enbridge Gas's arguments on this matter.

Mr. Rosenkranz's suggestion lacks any analysis of how the proposal would impact ratepayers. Mr. Rosenkranz suggests that ratepayers should pay shippers for releasing their capacity and this payment could be as much as a future cost of build.[338] In other words, if a future expansion costs $100 million, the entire $100 million could be offered to shippers for giving up their capacity and ratepayers would pay for the supposedly avoided build. Mr. Rosenkranz further suggested that the shipper that receives a payment is not barred from bidding for capacity in a future open season. OEB staff submits that Mr. Rosenkranz's proposal would be a significant cost to ratepayers as the ratepayers would have to bear the entire cost of the project as compared to a build where there may be a revenue offset from ex-franchise transportation services. OEB staff further submits that the proposal would be extremely lucrative for shippers and no shipper would turn back capacity without requiring payment from Enbridge Gas in the future. This would set an undesirable precedent. Mr. Rosenkranz further suggests that

[337] Oral Hearing Transcript, Vol. 8, p. 30.
[338] *ibid*, p. 39.

the shipper that receives a payment is not barred from bidding for capacity in a future open season.

Although the objective of avoiding a capacity build is a desirable outcome, such outcomes can be achieved through the IRP process. Implementing a payment mechanism to shippers will very likely lead to unintended consequences. In conclusion, OEB staff submits that the OEB should not accept Mr. Rosenkranz's proposal for a payment mechanism to shippers for releasing capacity on the Dawn Parkway system.

Issue 39: Is the proposed harmonized methodology for determining the amount of storage space and deliverability required to serve in franchise customers appropriate, and is the proposed allocation of storage space and deliverability among customers appropriate?

In the OEB approved settlement proposal, parties agreed that the determination of the proposed harmonized methodology for determining the amount of storage space and deliverability required to serve in-franchise customers, and the proposed allocation of storage space and deliverability among customers is appropriately determined in Phase 2 of this proceeding where other storage and utility/non-utility cost allocation issues are being addressed.

Issue 40: Should the OEB grant Enbridge Gas's request for a partial exemption for 2024 from the Call Answering Service Level, Time to Reschedule a Missed Appointment and Meter Reading Performance Measurement targets set out in GDAR?

Enbridge Gas is required to meet certain metrics related to the scorecard which includes service quality requirements (SQR) as outlined in Section 7 of the OEB's Gas Distribution Access Rule (GDAR). Enbridge Gas is requesting a partial exemption under Section 1.5.1 of the GDAR beginning in 2023 to replace the existing service quality requirements (SQR): Call Answering Service Level (CASL), Time to Reschedule a Missed Appointment (TRMA) and Meter Reading Performance Measurement (MRPM) with the modified measures as set out below:

- CASL – achieve 65% of calls reaching the general inquiry number answered within 30 seconds with a minimum monthly standard of 40%. The current annual metric is 75% with a minimum monthly standard of 40%.
- TRMA – 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.

- MRPM – 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 or until such time as the OEB conducts a review of the GDAR SQR metrics to modernize the SQRs to account for the current business environment and customer needs, behaviours and expectations.[339]

Enbridge Gas provided the OEB with an Assurance of Voluntary Compliance in September 2022, wherein it made certain commitments with respect to meeting its CASL, Abandonment Rate and MRPM targets for 2022 (2022 AVC).[340] Enbridge Gas's mitigation plans for 2022 are set out in the AVC; the mitigation plans for 2023 are set out in Enbridge Gas's 2023 GDAR Exemption Request Application;[341] and the mitigation plans for 2024 and beyond have been filed as part of Enbridge Gas's application.

In its application, Enbridge Gas filed its scorecard results for 2017 to 2021.[342] Enbridge Gas's actual scorecard results for 2022 have been provided as part of its ongoing 2022 Utility Earnings and Disposition of Deferral and Variance Account Balances proceeding.[343] In certain years, as described further below, Enbridge Gas has not met four SQR metrics related to the CASL, TRMA, MRPM and Abandon Rate and in 2021, Enbridge Gas did not achieve any of these four SQR metrics. Enbridge Gas stated that this was despite the fact that Enbridge Gas took and continues to take all reasonable steps to achieve the SQR targets.

<u>CASL</u>

The CASL metric measures the number of calls reaching the general inquiry number answered within 30 seconds divided by the number of calls received. The annual performance standard under GDAR for the CASL is 75% with a minimum monthly standard of 40%. A summary of Enbridge Gas's historic CASL performance is provided below:[344]

[339] Argument-in-Chief, August 18, 2023, p. 284.
[340] EB-2022-0188 Enbridge Gas Assurance of Voluntary Compliance, dated September 12, 2022
[341] EB-2022-0276; In that proceeding, Enbridge Gas requested a similar partial and temporary exemption from certain SQRs in the GDAR for 2023. The OEB, in that proceeding, stated that "[g]iven this issue is already part of a proceeding, the OEB finds that it would not be efficient or in the public interest to commence a new process in respect of the above-referenced application at this time.''.
[342] Exhibit 1, Tab 7, Schedule 1, Attachment 1.
[343] EB-2023-0092, Exhibit G, Tab 1, Schedule 1.
[344] *Ibid*.

Table 23
Enbridge Gas CASL (2019 to 2022)

Target	Actual	Actual	Actual	Actual
	2022	**2021**	**2020**	**2019**
75%	75.9%	64.3%	75.2%	79.0%

Enbridge Gas has been able to achieve the CASL metric in recent years except for in 2021. Enbridge Gas stated 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 stated that even though it has been able to achieve this metric, except in 2021, an increasing trend in call complexity means that Enbridge Gas cannot answer as many calls in the 30 second CASL requirement and that focusing on decreasing call handling time can result in a less positive customer experience.[345]

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.

TRMA

The TRMA metric tracks the percentage of customers contacted to reschedule the work within two hours of the end of the original appointment time. The annual performance standard under GDAR for the TRMA is 100%. A summary of Enbridge Gas's historic TRMA performance is provided below:[346]

[345] Exhibit I.7-STAFF-12
[346] EB-2023-0092, Exhibit G, Tab 1, Schedule 1.

Table 24
Enbridge Gas TRMA (2019 to 2022)

Target	Actual	Actual	Actual	Actual
	2022	2021	2020	2019
100%	93.8%	97.0%	97.3%	97.0%

Enbridge Gas has 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:[347] (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.

MRPM

The MRPM represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The annual performance standard under GDAR for the MRPM is no more than 0.5%. A summary of Enbridge Gas's historic MRPM performance is provided below:[348]

Table 25
Enbridge Gas MRPM (2019 to 2022)

Target	Actual	Actual	Actual	Actual
	2022	2021	2020	2019
0.5%	4.1%	5.0%	4.4%	0.7%

[347] Enbridge Gas's mitigation plans aim to achieve a standard of 98% of customer appointments rescheduled within one business day for TRMA.
[348] EB-2023-0092, Exhibit G, Tab 1, Schedule 1.

Enbridge Gas has 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 lockdown, staffing issues attributable to quarantine/isolation periods and labour resource shortages. If one meter reader misses work for a 14-day period, 8,000 meters could go unread. This makes it difficult for Enbridge Gas to “catch up” on those meter reads. With over 3.8 million customers, if 19,000 meters have consecutive estimates on average each month, the metric is not achieved. Once a meter has a consecutive estimate for four months or more, it will count towards the metric in a minimum of two-meter reading cycles.

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.

In addition to the ongoing challenges meeting SQR metrics, 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 the 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 (DSC) performance standards and no allowance for force majeure relief in the GDAR. The DSC provides the following:
    - 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 DSC contains a force majeure provision that allows a utility to be relieved of obligations for events beyond its reasonable control.
- 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.

The evidence provided suggests to OEB staff that Enbridge Gas is making an effort to improve its performance relative to the SQR targets. OEB staff notes that 2023 is almost over and it is not aware that Enbridge Gas's performance has deviated relative to the commitments it made in the 2022 AVC and on that basis does not oppose an exemption for 2023.

OEB staff also takes no issue with Enbridge Gas's requested partial exemption of the GDAR performance measures related to the CASL, TRMA and MRPM for the 2024 calendar year.as long as Enbridge Gas continues to take all reasonable steps in line with its evidence regarding its mitigation plans to achieve the SQR targets going forward.

However, OEB staff submits that the OEB should not grant a perpetual partial exemption from the GDAR requirements in the current proceeding. If Enbridge Gas believes that a partial exemption of the GDAR beyond the calendar year 2024 is necessary, OEB staff submits that it should ask the OEB to consider amending the GDAR. OEB staff submits that amendments to GDAR (if appropriate) are preferable to repeated requests for exemptions. OEB staff is of the view that a full assessment of the implications of any amendments to the GDAR are best addressed as part of a process whereby the gas distributors (Enbridge Gas and EPCOR Natural Gas Limited Partnership (EPCOR)) and ratepayer representatives are engaged. OEB staff notes that it is important that EPCOR be involved in this process as it is also subject to the performance measures under GDAR.

OEB staff notes that in the Decision on Issues List and Expert Evidence and Procedural Order No. 2, the OEB stated the following[349]:

[349] *Decision on Issues List and Expert Evidence and Procedural Order No. 2*, dated January 27, 2023, p. 4.

> Determination of whether to consider and make an amendment to a rule is assigned to the Chief Executive Officer under sections 44 and 45 of the OEB Act. Furthermore, GDAR applies to all gas distributors and the OEB does not intend to expand the scope of an Enbridge Gas rates proceeding to consider whether to recommend a review of GDAR. To the extent that parties believe there is good reason to review GDAR, it is open to them to ask the Chief Executive Officer to carry out such a review under the process provided in the OEB Act.

As the power to create or amend natural gas rules (such as the GDAR) rests with the OEB's Chief Executive Officer, any request to amend the GDAR should be dealt with outside of the current proceeding (and no determinations with respect to amendments to the GDAR are appropriate in the current proceeding). OEB staff notes that the process for creating or amending a rule is set out in section 45 of the OEB Act.

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 is of the view that Issue 58[350] (to be heard in phase 2 of the proceeding) can be limited to any scorecard additions, removals, or changes that are not set out in the GDAR.

K. Rate Implementation

Issue 41: How should the OEB implement the approved 2024 rates relevant to this proceeding if they cannot be implemented on or before January 1, 2024?

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. 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 the proceeding effective January 1, 2024. Enbridge Gas noted that it had acted responsibly in the proceeding and met all timelines.

OEB staff notes that the Enbridge Gas cost of service application is one of the largest ever to come before the OEB. OEB staff agrees that Enbridge Gas has been responsible throughout the proceeding and has made all filings in a timely manner. OEB staff submits 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

[350] Are the proposed scorecard Performance Metrics and Measurement targets for the amalgamated utility appropriate?

and the calculation of this recovery can be included as part of the draft rate order process in Phase 1 of the proceeding.

- All of which is respectfully submitted –