ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule. B);

AND IN THE MATTER OF an Application by Enbridge Gas Inc, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2024.

REPLY ARGUMENT OF ENBRIDGE GAS INC.

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Introduction

1. On August 18, 2023, Enbridge Gas Inc. (Enbridge Gas, or the Company) submitted its Argument in Chief (AIC) setting out its position on the unsettled issues in Phase 1 of this 2024 Rebasing proceeding.

2. Enbridge Gas received submissions in response to its AIC from OEB staff and from the following intervenors: Association of Power Producers of Ontario (APPrO); Building Owners and Managers Association (BOMA); Canadian Manufacturers & Exporters (CME); Consumers Council of Canada (CCC); Energy Probe Research Foundation (EP); Environmental Defence (ED); Federation of Rental-housing Providers of Ontario (FRPO); Ginoogaming First Nation (GFN); Green Energy Coalition (GEC); Russ Houldin (Houldin); Industrial Gas Users Association (IGUA); City of Kitchener (Kitchener); London Property Management Association (LPMA); Ontario Greenhouse Vegetable Growers (OGVG); Pollution Probe (PP); Quinte Manufacturers Association (QMA); Coalition for Renewable Natural Gas (RNG Coalition); School Energy Coalition (SEC); Three Fires Group Inc. (Three Fires); and Vulnerable Energy Consumers Coalition (VECC).

3. This is Enbridge Gas's Reply Argument responding to the submissions received from other parties and from OEB staff. For the purposes of this Reply Argument, Enbridge Gas repeats and relies upon the evidence that it has filed in this case (including testimony) and upon its AIC. To ensure a complete view of the Company's position on the outstanding issues, the Reply Argument should be read together with the Company's AIC.

4. The submissions from OEB staff and intervenors total over 900 pages in length. Notwithstanding the length of this Reply Argument, Enbridge Gas has not attempted to respond to each and every argument or comment made in the submissions of others.

Enbridge Gas highlights that any lack of explicit reply by the Company to any argument or comment should not be taken as agreement with the particular point.

5. Enbridge Gas has organized this Reply Argument in the same manner as AIC, setting out the Company's position under headings taken from the Issues List, focusing on the outstanding issues for which Enbridge Gas seeks an OEB determination or direction. Before this, Enbridge Gas sets out an overview of its response to submissions of other parties, as well as a brief discussion of items raised by parties that do not fit within the headings and topics that follow.

Overview

6. There are three main items of context influencing the outstanding items in this case: energy transition, amalgamation and integration, and ongoing customer requirements, expectations and demand. Each of these shape the Company's requests, and will influence the OEB's decision.

7. While energy transition has become the dominant issue in this proceeding, the primary purpose of this Application is to set rates effective January 1, 2024. Assuming approval of Enbridge Gas's proposals, and including the impacts of the Settlement Proposal, the new rates (inclusive of gas costs and delivery) to be approved in this Application will result in an average 2024 rate increase that is less than the inflation rate applicable to Ontario electricity utilities. The approximate bill increase is smaller for many of the Company's customers, because of the positive impacts of clearance of deferral and variance accounts.

8. Any decision on 2024 rates must be made in the context of current energy policy. Current Government of Ontario policy is clearly supportive of the role of natural gas, now and into the future. This is seen in the objectives of the *OEB Act*, and in the Powering Ontario's Growth Report, the Natural Gas Expansion Program and the *More*

Homes Built Faster Act. At this time, there is no Government of Ontario policy that sets a path to net zero. Everyone awaits the Electrification and Energy Transition Panel (EETP) report that will inform the Government of Ontario and may be used by the government to set further policy.

9. Enbridge Gas agrees that energy transition is happening. Everyone recognizes, though, that there is much uncertainty. It is simply incorrect to suggest that Enbridge Gas has decided to "do nothing" or "delay, delay, delay" in response to energy transition. The evidence and testimony in this case show that the opposite is true. In fact, Enbridge Gas has stepped into a leadership role in the energy transition discussions in Ontario, commissioning the first of its kind report analyzing the potential pathways for Ontario to reach net zero energy emissions and in pursuing and proposing actions that appropriately balance serving Ontario's energy needs in a reliable and cost-effective manner with known climate change objectives.

10. However, the fact that there is clearly policy yet to be developed and implemented means that there is insufficient clarity for Enbridge Gas to adopt, or the OEB to mandate, policies, practices and projects that presume no role (or a very limited role) for the Company in the coming years. Furthermore, Enbridge Gas has demonstrated why and how the gas system will continue to be important in meeting the energy needs of Ontario in a reliable and cost-effective way in a low-carbon future. This view is echoed by the Government of Ontario in its recent Powering Ontario's Growth Report.[1]

11. Energy transition policies are appropriately the domain of the government and not the OEB and speculating on a future state in advance of government direction is at best unproductive and at worst results in not meeting the reliability, affordability and energy

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[1] Filed at Exhibit K1.5.

access needs of Ontario. As the Ontario Minister of Energy confirmed in his letter of June 26, 2023 to Enbridge Gas President, Michele Harradence, regarding governance arrangements during Ontario's energy transition, the OEB and the IESO are enabled "to discharge their responsibilities to the sector and the public by focusing on their respective mandates and statutory obligations and delivering outcomes that promote the interests of consumers as well as the stability and sustainability of the energy sector."[2] In this respect, Minister Smith specifically cited the following two guiding objectives under section 2 of the *OEB Act* regarding the OEB's responsibilities related to gas:

a) To facilitate rational expansion of transmission and distribution systems; and

b) To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

12. Enbridge Gas has set out a measured approach to respond to energy transition throughout this Application. This includes an initial energy transition plan (ETP) and "safe bets", updated customer attachment policies, an approach to continue to update demand forecasting and system planning with a more regional level focus and create an updated ETP that draws on the recommendations from participants in this proceeding (as explained in this Reply Argument), harmonized depreciation methodologies and rates and an increase in equity thickness to recognize increased risk. These steps and measures are incremental, allowing for steady progress in uncertain circumstances.

13. Customer attachment policies, and particularly the applicable revenue horizon, have received a lot of attention. Having considered the submissions received from OEB staff and intervenors, Enbridge Gas is updating its proposal from what is in evidence and AIC, so that the Company's harmonized customer attachment policies will

[2] Exhibit J8.1.

incorporate a 30-year customer attachment revenue horizon, on an interim basis. The Company will require until January 1, 2025, for implementation. The Company further proposes that the Commissioners in this case could recommend a generic proceeding (or rulemaking process) to complete a fuller review of whether further changes to gas distributor customer attachment policies are appropriate, taking into account energy transition. That is what would make the approval of the 30-year revenue horizon in this case "interim".

14. Enbridge Gas maintains its request for an increase to 42% equity thickness. Enbridge Gas has the lowest equity ratio amongst North American utilities and as such cannot compete for capital on comparable terms (both internally within Enbridge as compared to its other utilities including those recently acquired, and externally). Furthermore, such a low equity thickness does not meet the Fair Return Standard. The recent BCUC decision increasing the FortisBC (the natural gas distributor's) equity ratio substantially from 38% to 45% not only supports the Company's position, but it also reinforces the significant business risks and uncertainty that natural gas utilities are facing with energy transition and meeting the elements of the Fair Return Standard, namely the capital attraction and comparable investment requirements.

15. Much of Enbridge Gas's Application is focused on the impacts of amalgamation and the next steps towards harmonization. This includes the sustainable integration savings of $86 million that are being credited to customers as part of 2024 rates. Outstanding integration/harmonization related issues addressed in this Reply Argument include integration capital expenditures, and harmonized policies related to overhead capital, customer connections and depreciation rates.

16. Enbridge Gas has successfully implemented the largest utility amalgamation in Ontario history in a very short time. The Company had only five years and worked quickly to implement important changes and updates. Customers have benefited from

those savings and will continue to do so. OEB regulatory principles support that customers should pay for the remaining costs (primarily unrealized depreciation) of implementation projects that continue to provide benefits. The associated annual costs are much lower than the integration savings embedded in revenue requirement.

17. Harmonization of depreciation policies provides a good opportunity for the OEB to take a prudent first step towards an updated approach that will see better reflection of future asset lives in depreciation rates. The proposed approach adopts a more accurate depreciation and salvage methodology from that which is currently in place for the EGD and Union rate zones.

18. The proposed level of depreciation expense also strikes a balance between addressing energy transition and considering ratepayer impacts, by ensuring the adoption of a methodology that better reflects current period consumption of an asset, reasonable service lives that still exceed a 2050 outlook and reasonable net salvage costs reflecting current and expected retirements. The Company's recognition of energy transition has not been to speculate on what an end state might be but what is a reasonable starting point to recognize that the energy transition is underway, resulting in a modest acceleration of depreciation expense to mitigate excessive rate shocks in the future. Intervenors providing alternate depreciation proposals have illogically conflated or combined the acknowledgement of energy transition (which they agree with) with a deceleration of depreciation expense.

19. The OEB has all necessary and relevant information to implement the measured approach proposed by Enbridge Gas. As energy policy evolves in the province, necessary further changes can be made at the next rebasing application.

20. Lost in the focus on energy transition is the vital importance of Enbridge Gas maintaining a safe, reliable and cost-efficient gas distribution system. The Company

serves 4 million customers in almost every urban centre in Ontario. Natural gas accounts for more than 30 percent of Ontario’s energy mix and is the primary source of heat for Ontario families and homeowners. Natural gas supplies peak energy requirements equivalent to three to five times the peak of Ontario’s electricity grid.

21. Continued capital investment is required to maintain a safe and reliable system. As the steward of a critical energy delivery system that millions of Ontarians rely on (particularly on the coldest and warmest days), Enbridge Gas will not and cannot run any part of its system to failure. The importance of system resilience and reliability is barely mentioned in submissions from intervenors and OEB staff. The Company’s AMP and capital budget presented explain why the forecast funding is required. The capital budget remains reasonable to allow the Company to sustain safe, reliable and compliant operations over the next several years, with the majority of the budget focusing on replacement and capital maintenance work to address short-term system needs. The proposed 2024 spending is also in line with historical levels from 2014 to 2023 once capitalized overheads and leave-to-construct (LTC) investments are separately accounted for. Enbridge Gas is taking diligent steps in continuing to implement the Integrated Resource Planning (IRP) Framework and expanding its Distribution Integrity Management Program (DIMP) to explore opportunities to avoid or defer new facilities where feasible.

22. In the pre-filed evidence, discovery, Oral Hearing and argument, Enbridge Gas has presented a very complete and compelling case. In AIC, Enbridge Gas set out the relief sought for each outstanding issue, with detailed discussion of the evidence and rationale supporting that position.

23. Enbridge Gas maintains most of its requests. However, having reviewed the submissions of OEB staff and intervenors, the Company has made several alterations or additions to its requested relief:

a) Inclusion of a 30-year customer attachment revenue horizon within its proposed harmonized customer attachment policies, effective January 1, 2025.

b) Suggestion that a generic proceeding to review gas distributor customer attachment policies may be appropriate.

c) Inclusion of a true-up for 2023 closing rate base, to be done with the Phase 2 Rate Order, to reflect actual 2023 results.

d) Amendments to 2024 capital expenditures forecast to reflect the current net capital estimate for the Selwyn Community Expansion project and reclassify the St. Laurent project using a levelized rate treatment.

e) Creation of three new deferral accounts:

   i. OEB Directive Deferral Account (OEBDDA)

   ii. St. Laurent Project Variance Account (SLPVA)

   iii. Potential Change to IFRS Deferral Account

24. Before concluding this Overview, Enbridge Gas will comment upon a few themes that emerged from the submissions of intervenors and OEB staff.

a) *Is Enbridge Gas doing enough on energy transition?*

   There is a division of opinion about whether Enbridge Gas is taking appropriate steps and moving at a proper pace in response to energy transition. Some endorse the Company’s measured approach, while others argue that much more should be done immediately. Not surprisingly, most of the loudest criticisms come from environmental groups (ED, GEC, PP) who may be less concerned about cost impacts than customer groups. This opposition seems louder by the fact that there are three organizations with virtually the same mandate participating in this case.

   Nobody points to a template for what has been done or is being done in other jurisdictions that sets a path for what should be considered in Ontario because such a template does not exist, even in jurisdictions with world-leading emission reduction targets and policies. As explained in AIC and this Reply Argument, Enbridge Gas is taking appropriate steps to review and respond to energy transition in a measured fashion and in accordance with known information and established processes. In this Reply Argument, Enbridge Gas sets out how it will continue its efforts in this area through the IR term and at the next rebasing, recognizing the iterative nature of energy transition.

b) *Proposals for additional processes, reports and studies*

A common theme in the submissions from many parties is that Enbridge Gas should be preparing further studies, reports and plans to file with the OEB. Topics to be addressed include energy transition, depreciation and customer attachments. Many parties argue for future OEB processes and proceedings (both Enbridge Gas specific and generic) to take place during the 2025 to 2028 IR term. Some parties argue for, or mention, a shorter IR term.

Enbridge Gas disputes the need for immediate new studies and proceedings. The Company believes that it is more appropriate to address energy transition through ongoing planning and through an updated ETP to be prepared in the coming years and filed in the next rebasing case. Enbridge Gas will conduct appropriate stakeholder engagement on these items and will adapt for government policy direction when known. This is a more appropriate use of time and resources. It is also a fair use of time and resources, taking into account how much time is required for already-planned current and next steps[3] as well as the fact that the timing of when further government policy direction will be provided is unknown.

Enbridge Gas agrees with other parties that a generic hearing about gas distributor customer attachment policy, taking into account impacts from energy transition, is appropriate. In this case, this topic saw much argument, but virtually no evidence. It is also a topic that impacts more than the participants in this case, including EPCOR, and one which would benefit from the perspective of other stakeholders (municipalities, IESO, electric LDCs, builders etc.). The Company therefore proposes interim implementation of harmonized customer attachment policies using a 30- year customer attachment revenue horizon (starting in 2025), pending any further determination in a generic proceeding.

None of the requests for further studies and processes were anticipated in the Company's filing. None of the associated costs are in base rates. The Company's O&M budget was settled, with a $50 million reduction, based on the filed budget which did not contemplate further directives, studies or proceedings based on items such as energy transition, customer attachments or depreciation during the IR term. Enbridge Gas is therefore requesting that

[3] Phases 2 and 3 of this current Application will not be complete until the end of 2024 (at the earliest), and implementation will follow. Work on the next rebasing will start shortly thereafter, with key decision and inputs necessary by 2026 to allow for time to go through budget development (2027), evidence filing (2027) and OEB process (2028) to set rates for 2029.

the OEB establish an OEB Directive Deferral Account to record the incremental costs incurred by Enbridge Gas to respond to OEB directives or requirements from this proceeding.

c) *Contradictory messaging*

SEC has it right when they remark that one could be forgiven for observing that parties are talking out of both sides of their mouths. Enbridge Gas observes that the positions taken by many parties on energy transition and financial issues do not hang together. It cannot be right that energy transition is an existential threat that will result in the end or significant curtailment of the gas system (as some parties assert) but also that asset lives should be lengthened and depreciation rates should not be increased, or that business risk has not increased to justify higher equity thickness.

Enbridge Gas has proposed a consistent, measured approach in its proposals for 2024. There is no immediate change to wind down the capital spending needed to maintain a safe system. There is no immediate change to a customer attachment policy that assumes new customers will leave the system as soon as they can. There is no move to a fundamentally different depreciation approach. Instead, steps are being taken to address each of these items in an incremental way, taking account of the existence, but also the uncertainty, of energy transition on the gas system.

d) *Accusations of windfall gains to Enbridge Gas, when the opposite is true*

Intervenors advance a number of arguments about costs that Enbridge Gas should not recover (in whole or in part), including integration capital, historic Union pension costs and 2023 customer attachment capital costs. Some parties also argue that Enbridge Gas should refund some PDO/PDCI revenues. A common argument advanced by intervenors is that recovery of some or all of these items would be a “windfall”, because Enbridge Gas has “over earned” during the deferred rebasing term.

There is no windfall. Each of these items is something for which customers should be paying. The intervenor argument that responsibility is avoided because of the impact of amalgamation (in the case of integration capital and in the case of the Union pension receivable) is to confer a windfall on ratepayers.

To say that past overearnings should be refunded towards past expenses ignores the principles of incentive regulation and the rules against retroactive ratemaking.

And finally, to say that overearnings will fund all contested items is wrong. The disallowances and refunds sought by intervenors far exceed "over earnings". The Company's total "over earnings" over the four completed years of the deferred rebasing term are $231.4 million.[4] The "over earnings" average to around $58 million per year, from total earnings attributable to common equity of approximately $500 million per year. For context, in no year did the Company reach the level of 150 basis points over allowed ROE that triggers earnings sharing. Against that backdrop, some intervenors argue for total disallowances or refunds of $336.5 million[5], all of which would be reflected in 2023 or 2024. That is in addition to the net $67 million revenue requirement reduction impact of the Settlement Proposal, that included a disallowance of $41 million for completed capital projects[6], which is a cost being absorbed by Enbridge Gas. Therefore, in addition to ignoring the fundamental principle that incentive regulation and deferred rebasing are meant to encourage efficiencies and ignoring that confiscating "over earnings" from long-completed years is retroactive ratemaking, it is also plain to see that the so-called "over earnings" will not fund the disallowances claimed.

25. In each of the following sections of this Reply Argument, Enbridge Gas summarizes the relief requested for each outstanding issue (including the updates noted above) and the Company's response to submissions from other parties. Rather than restating those here, the Company points the OEB to the Overviews included at the start of each section.

26. In summary, for the reasons set out in evidence, AIC and Reply Argument, the Company requests that the OEB issue each of the Approvals Requested described in the "Summary of Approvals Requested" at the end of this Reply Argument.

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[4] Exhibit J14.10.
[5] The $336.5 million is comprised of integration capital ($119 million) + Union pension receivable ($156 million) + PDO/PDCI revenues ($34.75 million, based on the numbers set out at page 18 of the FRPO Submission) + 2023 customer attachments proposed disallowance ($26.8 million).
[6] Exhibit O1, Tab 1, Schedule 1, pages 14 and 25. Note that the $90 million revenue requirement reduction from the Settlement Proposal included removing the impacts of the Dawn to Corunna project from Phase 1, to be considered in Phase 2 – that is what results in the net $67 million impact.

27. Approval of Enbridge Gas's requests will result in modest rate impacts that are less than inflation. Taking into account the reduction to the revenue deficiency resulting from the Settlement Proposal[7], the approximate increase to revenues and average rate increase (for gas costs and distribution costs together) resulting from approval of Enbridge Gas's Application is around 3%. This is lower than the OEB's 2024 inflation factor for electricity distributors (4.8%) and for electricity transmitters (5.4%).[8] In accordance with the Settlement Proposal, the Phase 1 rate adjustment will be implemented pro rata for all rate classes and rate zones. There may be differential impacts on rate classes and rate zones as a result of Phase 2 and/or Phase 3 determinations.

<u>Out-of-Scope Items</u>

28. Before addressing intervenor submissions about the outstanding issues in this case, Enbridge Gas would like to set out items that are not addressed in this Reply Argument. These are items that are not included in the Issues List, and that are not related to determinations that are necessary to set rates for 2024.

29. While Enbridge Gas is not addressing these out-of-scope items, that does not mean that the Company agrees with intervenor positions on the items. To the contrary, unless otherwise stated, Enbridge Gas does not accept the related intervenor positions.

30. The following are examples of items included in intervenor submissions that Enbridge Gas says are out-of-scope, and which are not substantively addressed in this Reply Argument.
    a) Requests related to Advanced Metering Infrastructure (AMI).[9]

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[7] Decision on Settlement Proposal, August 17, 2023, page 2.
[8] 2024 Inflation Parameters letter, June 29, 2023. OEBltr_2024 inflation_updates_20230629
[9] BOMA Submission, pages 9-10.

b) Proposal for shorter rate term[10] - this is a Phase 2 issue.

c) Proposed changes to E.B.O. 134.[11]

d) Request for guidance about reducing LTC thresholds.[12]

e) Requests related to DSM programming and implementation.[13]

f) Requests for changes to IRP Framework[14], and to IRP Pilot Projects[15]. In the Energy Transition section of this Reply Argument, Enbridge Gas does provide some response to intervenor submissions about changes to IRP process and approach, however, changes to the IRP Framework are not in scope and the IRP Pilot Projects are being considered in a separate proceeding.

g) Argument that the OEB should prescribe what type of hybrid heating that Enbridge Gas can offer.[16]

A. Overall

Energy Transition

31. 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.

[10] CCC Submission, page 9.
[11] GEC Submission, page 33.
[12] Ibid, page 35.
[13] PP Submission, pages 40-41.
[14] See, for example, PP Submission, pages 30-31.
[15] BOMA Submission, page 11.
[16] SEC Submission, page 43.

32. There are also two energy transition-related issues that will be dealt with as part of Phase 2 (Issue 52, “Are the specific proposed parameters for an Energy Transition Technology Fund and associated rate rider appropriate?” and Issue 53, “Are the specific proposals to amend the Voluntary RNG Program and to procure low-carbon energy as part of the gas supply commodity portfolio, appropriate?”).

Summary and Relief Sought

33. Energy transition considerations bear upon several rate-related topics, such as capital expenditures, equity thickness and depreciation and Enbridge Gas has addressed the specific rate-making considerations in those sections of this Reply Argument. In this section, Enbridge Gas addresses the more general comments of OEB staff and other parties about energy transition, including views on allocation and mitigation of risk. As explained in AIC, Enbridge Gas reiterates that it is not seeking any discrete relief in Phase 1 related to energy transition.

34. Many of the intervenor proposals request the OEB to convene a future regulatory process or require future actions of Enbridge Gas. These proposals are largely out- of-scope for this proceeding as they do not relate to setting rates for the 2024 to 2028 rate term. Nevertheless, Enbridge Gas agrees that additional work is required to address energy transition, recognizing its iterative, uncertain, and evolving nature. Enbridge Gas has always intended to evolve its ETP to account for changing government policies and energy market dynamics.[17]

35. For further clarity and to be responsive to parties’ concerns, Enbridge Gas provides its views on next steps in the energy transition planning process, or energy evolution, to address some of these comments. In summary, Enbridge Gas recognizes that more

[17] Exhibit 1, Tab 10, Schedule 6, pages 39 to 40.

regional level scenario planning can help optimize capital expenditures on long lived assets and Enbridge Gas will target a revised ETP for its next rebasing application. Enbridge Gas has carefully considered the evidence in this proceeding to inform its plans for evolving its ETP and intends to proceed in a manner largely consistent with the recommendations of several intervenors and IGUA's expert, Dr. Hopkins. As envisioned, the evolved ETP will consist of a business analysis that informs the Enbridge Gas capital and operational plans, subject to available information, including:

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

36. On an annual basis and informed by broad stakeholder engagement, Enbridge Gas will update its demand forecasts and reflect these changes within the annual AMP updates. Below, Enbridge Gas previews the timeline and process for the next iteration of its ETP, including how stakeholders will be engaged and how any government policy direction will be incorporated. Enbridge Gas does not support the OEB convening a generic proceeding on energy transition in advance of the next rebasing application because it would likely not be as efficient or effective as a more business-led planning process.

37. Enbridge Gas also reiterates its commitment to continuing with its "safe bets", subject to required regulatory approvals, to maintain steady progress on energy transition while remaining flexible and adaptable to pending government policy direction. Two very important components of its "safe bets" and current ETP are the Enbridge Gas demand-side management (DSM) programs and IRP. Although these matters are subject to separate regulatory processes, Enbridge Gas emphasizes that these

activities continue to be a high priority for Enbridge Gas and for its capital planning processes.

Submissions by Other Parties

38. Enbridge Gas will address the submissions of parties more specifically in the response section below. However, for the purpose of providing some general observations, Enbridge Gas notes that parties are significantly divided on energy transition as follows:

a) Some ratepayer groups (APPrO, VECC, OGVG, LPMA and QMA) and EP provide qualified support of the Enbridge Gas energy transition proposals, have concerns about rate increases and seek continued action on energy transition by Enbridge Gas, government, the OEB and others.

b) Certain large volume customer groups (IGUA, CME) do not anticipate significant changes during the rate term with respect to business risk and energy transition, noting lack of government policy and clarity on how the electric grid will accept capacity increases. They support Enbridge Gas awaiting clarity on these matters before conducting a quantitative assessment of capital recovery risk and risk mitigation plan and do not support interim rate increases.

c) Similar to IGUA and CME, CCC believes that Enbridge Gas needs a more robust ETP and that safe bets are actions Enbridge Gas is already taking. They are seeking a shorter rate term and limited rate increases in the interim.

d) Kitchener supports the use of RNG, hydrogen and CCUS and holds municipal climate change aspirations but believes Enbridge Gas's ETP is insufficient, and they are concerned about rate increases.

e) Environmental interest groups (GEC, ED and PP) and SEC equate energy transition with electrification and the inevitable abandonment of the Enbridge Gas natural gas system, except for limited uses beyond 2050 largely for industrial applications. All are seeking a large reduction in capital expenditures to curb growth and optimization of the gas system.

f) Indigenous groups (TFG and GFN) provide strong endorsement of the Indigenous Working Group (IWG) for its importance and precedential value. They submit Enbridge Gas has failed to take adequate steps to address risk of climate change and energy transition and ask the OEB to initiate a generic proceeding using an integrated gas and electric approach, including assessing risk on vulnerable, remote, and Indigenous communities.

g) OEB staff explains the evolving nature of energy transition, notes the OEB's limited role, states there is a high probability of a less significant role for gaseous fuels and makes several recommendations aimed "to avoid negative outcomes for ratepayers when the transition away from conventional natural gas accelerates."[18]

39. All parties that made final submissions have expressed a view on energy transition and the sufficiency of Enbridge Gas's actions to date as reflected in the evidence. What is apparent from these submissions is that there are many different views on how energy transition will evolve, the role of Enbridge Gas and how those assumptions should be factored into both rate-making and other proposals in this proceeding. Many expressed views are incompatible with one another and seek OEB intervention into matters that are not squarely within the OEB's mandate.

40. At the most basic level, there is even disagreement about the definition of energy transition, with OEB staff suggesting it "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."[19] VECC counters that a more accurate description is how climate change is being addressed through policies which reduce carbon and other greenhouse gases (GHGs) and in many places this includes carbon sequestration and replacing higher emitting fuels (e.g., coal) with lower ones (e.g., natural gas).[20] The VECC definition is more neutral and fuel and technology agnostic than OEB staff's definition.

41. This disparity of views only serves to underscore the unsettled nature of energy transition. Parties are nonetheless largely aligned on three things:

a) The lack of clear government policy, especially in Ontario;

b) The need for further work and stakeholder engagement; and

[18] OEB staff Submission, page 17.
[19] Ibid, page 7.
[20] VECC Submission, page 4.

c) The need for coordinated energy planning.

42. Enbridge Gas addresses each of these matters in how it plans to embark upon the next iteration of its ETP, as explained further below. For the purposes of this proceeding, Enbridge Gas has navigated through the uncertainties in a measured and consistent way with appropriate proposals to address energy transition in a manner that balances the need to continue providing safe and reliable service with moving towards a lower-carbon future.

43. Given that Enbridge Gas is not seeking OEB approval of its ETP in this proceeding, what is the OEB's role? The OEB has determined that energy transition is relevant as it relates to the matters set out in Issue 3. In that context, energy transition and whatever meaning parties ascribe to it is a factor to be considered in determining the Issue 3 rate-making issues – nothing more and nothing less.

44. As OEB staff states, "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 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."[21]

45. SEC explains that "a decision by the Commissioners to require a societal shift away from fossil fuels, at a given pace and in a stipulated manner – is also neither appropriate nor legally correct. The OEB Act contains no jurisdiction to do so."[22] And, "It would be an error for the Commissioners to try to determine what should happen. It is not the mandate of the OEB or this panel to make a determination, for example, that

[21] OEB staff Submission, page 16.
[22] SEC Submission, page 8.

full electrification is the best government policy, or the most appropriate way to lower greenhouse gas emissions."[23] Enbridge Gas agrees with SEC on this.

46. VECC notes all but one of the objectives set out in the OEB Act with respect to gas regulation (the promotion of energy conservation and efficiency) are related to maintaining the longevity of the natural gas system and this includes the requirement to facilitate the rational expansion of the transmission and distribution system. The OEB does not have a mandate to reduce GHG emissions.[24] Neither does the OEB have a mandate to restrict Ontario residents' choice of energy source.[25] Similarly, Enbridge Gas urges the OEB to avoid wading into the realm of government policy and restricting customer choice on energy transition. The OEB must not attempt to dictate these matters and must instead be guided by them as it considers the rate-making issues for which energy transition is one of many factors.

Enbridge Gas Response to Other Parties' Submissions

Enbridge Gas Actions to Date on Energy Transition

47. First and foremost, Enbridge Gas will address the parties' submissions that Enbridge Gas has failed to take adequate steps to date to address energy transition. For instance, SEC states Enbridge Gas is only delaying and taking a "wait and see" approach.[26] TFG, GFN and CCC submit that Enbridge Gas has not done a robust enough ETP.[27] PP states that Enbridge Gas "has shown no tangible efforts to take action in the interest of Ontario energy consumers."[28]

48. This characterization fails to recognize and appreciate the immense uncertainty associated with the roller-coaster of policy, technology and customer preferences

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[23] SEC Submission, page 10.
[24] VECC Submission, page 8.
[25] Ibid, page 6.
[26] SEC Submission, pages 11-12.
[27] TFG Submission, page 3; GFN Submission, page 3; CCC Submission, page 8.
[28] PP Submission, page 5.

related to energy transition. Enbridge Gas has been working on energy conservation and low-carbon initiatives for many years[29], riding the energy policy roller-coaster and having to pivot to satisfy new legislative and regulatory requirements in each instance. A poignant example of this is the complete shift in Ontario government policy over the last decade with many of the environmental policies implemented by the Liberal government being swiftly unwound by the Conservative government in late 2018. To provide a sampling of how government policy can change quickly and significantly affect energy transition and energy utilities, here is a brief timeline of those events and how carbon pricing and rates were impacted:

- Cap and Trade was established by the Liberal government through the *Climate Change Mitigation and Low-carbon Economy Act* in May 2016, with an implementation date of January 1, 2017.
- OEB issued "Report of the Board" Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap & Trade Activities"[30]
- In accordance with the framework, EGD[31] and Union[32] filed compliance plans for 2017 and 2018.
- Before a decision could be provided in the 2018 compliance plan application, the newly elected Conservative government ended Cap and Trade through the *Cap and Trade Cancellation Act*.
- EGD and Union applied for the removal of the Cap and Trade related charges from customers and clearance of Cap and Trade costs.
- In June 2018, the *Budget Implementation Act, 2018 No. 1* received Royal Assent. Part V included the *Greenhouse Gas Pollution Pricing Act* (GGPPA).
- In October 2018, the federal government confirmed that Ontario would be covered by the GGPPA, including the Federal Carbon Charge (FCC) effective

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[29] See Exhibit 1, Tab 10, Schedule 6, pages 19-20 for a summary of the industry-leading DSM and energy efficiencies activities of Enbridge Gas and its predecessors that have, between 1995 and 2021, driven a cumulative reduction of 57.8 million tCO_2e while supporting customer choice.
[30] EB-2015-0363.
[31] EB-2016-0300 and EB-2017-0224.
[32] EB-2016-0296 and EB-2017-0255.

April 1, 2019, and the federal Output Based Pricing System (OPBS) effective January 1, 2019.

- EGD and Union filed applications related to the FCC and a joint application in January 2019.[33]
- In September 2020, the Government of Ontario announced that the federal government had accepted the Ontario Emissions Performance Standards (EPS) and large emitters would move from the OBPS to the EPS.
- In September 2021, the federal government updated the GGPPA to remove Ontario from the OBPS, and the Ontario EPS program begam effective January 1, 2022.
- In 2018, cap and trade compliance plans (EGD and Union), the carbon price forecast for rate setting was $18.99/tonne CO2e (tCO2e).
- In 2019, FCC was $20/tCO2e, which increases $10/tCO2e per year until 2022 and $15/tCO2e per year from 2023 to 2030 when it reaches $170/tCO2e.
- In 2023, the price of carbon under the GGPPA is $65/tCO2e. In comparison, in Quebec and California, the price of carbon is approximately $40/tCO2e. i.e. this is the price carbon would be in Ontario today had the province stayed in the Cap and Trade Program.

49. As another example of the impact of changing policies, Enbridge Gas notes that it took early steps to include RNG in its supply mix when, in 2018, EGD and Union developed a plan for RNG procurement. This plan was included in the Company's 2018 Cap and Trade compliance plans in accordance with the OEB's Cap and Trade Framework and there was government support, including funding, for this initiative.[34] This initiative was discontinued by the new provincial government in July 2018.[35] Progress on RNG was stalled as a result of these policy changes. Enbridge Gas subsequently applied for the Voluntary RNG Program in 2020, in response to the Made in Ontario Environment Plan.[36]

[33] EB-2018-0187/0205.
[34] EB-2017-0224, EB-2017-0255.
[35] EB-2017-0224/0255/0275, Procedural Order No. 7.
[36] EB-2020-0066.

50. During this same time period, EGD also proposed a regulated geothermal loop offering in conjunction with provincial funding through the Green Ontario Fund (GreenOn), and a memorandum of understanding with the Ontario Geothermal Association.[37] This application was subsequently withdrawn when the Ontario government discontinued GreenOn and withdrew the funding for ground source heat pumps. In addition, during the IRP Framework proceeding "Enbridge Gas sought approval to use non-gas alternatives, including electricity-based solutions, as IRPAs, and specifically requested confirmation from the OEB as to whether or not non-gas alternatives can be considered. Potential non-gas alternatives could include electric air source heat pumps, geothermal systems, and district energy systems."[38] The OEB in its Decision found that "as part of this first-generation IRP Framework, it is not appropriate to provide funding to Enbridge Gas for electricity IRPAs."[39]

51. Despite this policy roller-coaster and the continued lack of policy certainty, Enbridge Gas has taken all reasonable and prudent steps to date to address matters related to energy transition in this proceeding. As noted by APPrO, "Enbridge has appropriately considered energy transition and integrated resource planning to determine new rates that will be effective January 1, 2024, considering relevant (i.e., existing and enforceable) government policies and legislation. Speculating on future government policy or legislation for the purpose of setting rates is inappropriate."[40]

52. EP and LPMA agree: "Enbridge has appropriately considered energy transition and integrated resource planning considering the uncertainty about Ontario government plans."[41] And, "EGI has adequately considered energy transition and integrated

[37] EB-2017-0319.
[38] EB-2020-0091, Decision and Order, Issued July 22, 2021, page 31.
[39] Ibid, page 35
[40] APPrO Submission, page 8.
[41] EP Submission, page 3.

resource planning – at this time – considering the relevant government policies and legislation that exist at this time…[for the] determination of new rates that will be effective January 1, 2024.[42] QMA goes further by pointing out that Enbridge Gas's "carefully considered" efforts to address energy transition[43] need to be buttressed by the Ontario government providing "leadership and the coordinating effort necessary to bring the appropriate parties together to build-out the implementing framework necessary… [for] a net-zero carbon future."[44]

53. It is worth repeating the facts that highlight the importance of the Enbridge Gas system – that natural gas plays a prominent role in the Ontario energy mix, providing approximately 30% of Ontario's energy needs on an annual basis and 3 to 5 times the electric peak demand in winter.[45] The Enbridge Gas system provides a level of reliability and resilience unequaled by any other energy source in Ontario.[46] Enbridge Gas continues to connect approximately 40,000 general service customers per year and that number is not projected to decline by any significant amount over the proposed rate term of 2024 to 2028.[47] Included in the new connections occurring during the rate term are the 27 community expansion projects that the Ontario government is supporting with funding through its Natural Gas Expansion Program because "Expanding natural gas will make life more affordable for families and businesses, and will help to increase economic development and job opportunities for these communities."[48]

[42] LPMA Submission, page 8.
[43] QMA Submission, page 2.
[44] Ibid, page 6.
[45] Exhibit 1, Tab 10, Schedule 2, pages 1-2.
[46] Ibid, pages 4-10.
[47] Exhibit I.2.6-ED-94 (Updated 2023-07-06), Tables 2 and 4.
[48] Government of Ontario. (2023 January 25). Energy and electricity. Natural Gas Expansion Program. https://www.ontario.ca/page/natural-gas-expansion-program

54. Enbridge Gas remains focused on continuing to provide safe and reliable service to its almost 4 million customers in Ontario, satisfying its statutory obligation to serve in accordance with Ontario government laws and objectives. It is not the role of Enbridge Gas to discourage new customers from connecting to the gas system. As OGVG notes, Enbridge Gas customers would not want to pay for Enbridge Gas to do that.[49] The OEB has agreed with this, stating in the generic community expansion proceeding, “The environmental groups have submitted that the utilities should be required to assess sustainable energy technologies for all community expansion projects. The OEB agrees with the position of OEB staff that utilities are primarily in the business of gas distribution and should not be required to provide detailed assessments of alternative technologies such as solar and geothermal as part of the community expansion applications.”[50]

55. What other parties are expecting Enbridge Gas to do or have done in the context of energy transition is unprecedented and fraught with uncertainties. It is clear from the evidence that jurisdictions across North America are grappling with energy transition, and none have been able to “figure it out” yet. While reflecting on energy transition best practices during the Oral Hearing, IGUA’s expert Dr. Hopkins pointed out that no single jurisdiction has got it right – even the “best” jurisdictions: “My sense is that there are bits and pieces that are emerging in different places… if we could pull those pieces together, right?” Dr. Hopkins mentions Massachusetts, New York and California as “states that have sort of wrestled with this the most completely in their own different ways.” But he adds “not to say that everything in any – in California, New York or Massachusetts is perfect.”[51]

[49] OGVG Submission, page 13.
[50] EB 2016-0004, Decision with Reasons, page 29.
[51] 5 Tr.125-126.

56. Despite that no other jurisdiction has figured this out yet, even those with world-leading targets and policies, several intervenors expect that Enbridge Gas should have developed "a more robust ETP plan."[52] Specifically, intervenors believe that Enbridge Gas should have an omniscient view or use a crystal ball to determine future government policy, electricity planning and capacity, and customer preferences to inform the expected use and state of its gas system in 30 years' time or to be able to model all possible future scenarios, probabilities and associated risk allocation. Without this, some parties conclude that it is impossible or very difficult for the OEB to properly determine Enbridge Gas rates for the next rate term. Rate-making has taken a back seat to energy transition in the eyes of these parties, even though the OEB has no GHG reduction mandate.

57. For instance, SEC is critical of what they believe to be Enbridge Gas's "wait and see" approach, and that the absence of a government-mandated path to net zero should not result in a "status quo" planning assumption, implying that Enbridge Gas should be able to predict the unknown long term government policy direction for planning purposes.[53] SEC carries on to claim that "Enbridge should be required to assess the probability of full future utilization of each asset at or before the time it is brought into service"[54] and provides the following "simple example" that is evidently not so simple when one considers it more carefully:

> **2.4.14** A simple example may be appropriate. If Enbridge proposes to replace the pipes serving a town or part of a town, it should prepare a calculation of the cost to do so, and the revenues it expects to generate from the customers in that town over time that are fairly applicable to these new pipes (as opposed to the rest of the system). This can all be done through normal cost allocation processes.
>
> **2.4.15** That calculation should include the probability that some or all of those customers will move away from using natural gas, whether or not there are external incentives to do so. It should also include the probability that some or all of that replacement system may have to be replaced in the future prematurely in order to carry hydrogen.

[52] For example, see CCC Submission, page 8.
[53] SEC Submission, page 11.
[54] Ibid, page 37.

> **2.4.16** If, after taking into account those contingencies, the applicable revenue is not sufficient to cover the cost to build, Enbridge should either not build, or should segregate the cost that is covered by future revenues from the cost that is not. [55]

58. Here are only a handful of complexities associated with SEC's "simple example":

    a) Many of the Enbridge Gas facilities are not dedicated to an identifiable customer or group of customers, so it is not clear how Enbridge Gas would determine the probability of different revenue streams it could generate in association with proposed replacement facilities. SEC states this can be done "through normal cost allocation processes," but Enbridge Gas does not have a cost allocation process to identify revenue streams with certain segments or components of its system that it determines requires replacement. Also, upon what information should Enbridge Gas rely to inform its probability analysis of revenue generation? Should it use customer surveys, electric LDC data, municipal plans, market penetration potential of heat pumps or low carbon gaseous fuel in the region or other information? Given the polar opposite views of the parties in this proceeding, there is not likely to be any agreement, let alone consensus on these variables and probabilities.

    b) Assuming it would be reasonably possible for Enbridge Gas to determine probabilities and revenue/cost allocation associated with the proposed replacement project (which Enbridge Gas asserts it would not be), then on what basis should Enbridge Gas determine whether to proceed with the project? For instance, if the cost/revenue calculation results in anything less than a 100% cost recovery, should the project not proceed?

    c) If Enbridge Gas were not to replace an existing pipeline because of such an analysis, Enbridge Gas may have to abandon that pipeline because it will not run its system to failure, for obvious public safety and environmental reasons. Existing customers would then be left without gas service, regardless of whether they wanted to continue the service or not. These customers would have to find another means of meeting their energy needs, likely in short order. This may or may not be feasible or possible, depending upon the customer's individual circumstances and the availability of other energy services in that area. Further, customers may have to resort to energy sources that have higher GHG emissions than natural gas when faced with possible energy system constraints. This is an untenable outcome and is certainly not one that is

[55] SEC Submission, pages 37 to 38.

contemplated by the existing regulatory regime. EP briefly referred to this possibility as the “stranded customers” problem.[56]

59. Another example of an intervenor that has jumped on the bandwagon of unrealistic expectations of Enbridge Gas is Kitchener Utilities, which is itself a gas distributor. Instead of providing an indication of how Kitchener Utilities intends to meet its stated objectives of achieving its Transform WR 80% GHG emissions reduction by 2050 and more aggressive interim target of 50% by 2030, it states that Enbridge Gas has to respond to Transform WR and “develop an action plan to ensure that targets are met while maintaining customer demands and business sustainability.”[57] Kitchener does not indicate in its submission whether it intends to reduce its own demand on the Enbridge Gas system, but as a Rate T3 transmission customer, it has the right to do this at any time with the proper notice (of 3-6 months, depending upon the service).

60. Kitchener states that it is currently developing a low carbon strategy to meet the requirements of Transform WR[58], but it does not give any indication of what that plan is or may be, what the energy pathway might look like, who will bear the transition costs, what scenario modeling it is considering, what its customers are saying and doing, or any other details. We must assume Kitchener Utilities has not considered these details despite its aspirational targets, yet it aims criticism towards Enbridge Gas for not ensuring Kitchener-Waterloo’s targets are met. If Kitchener Utilities has not conducted this sort of planning, how does it expect Enbridge Gas to fill the void? It would be difficult for Enbridge Gas to assign probabilities of reduced service in that region without further directions from Kitchener Utilities, and this is not a unique situation.

[56] EP Submission, page 5.
[57] Kitchener Submission, page 5.
[58] Ibid.

61. Enbridge Gas appreciates the submissions from intervenors that have taken a more realistic and pragmatic view of energy transition related events and have largely accepted the actions that Enbridge Gas has taken to date. Intervenors and experts have also acknowledged the importance of the Enbridge Gas work to date, including the P2NZ and ETSA studies: IGUA's expert Dr. Hopkins noted the importance of these works in his evidence[59], and OEB staff expert Mr. Goulding (LEI) noted in the Oral hearing that Enbridge Gas's pathways studies were a helpful "big-picture strategy" exercise that should be completed periodically.[60] QMA is supportive of the "measured preliminary approach EGI is taking with its energy transition planning and "safe bet" scenarios."[61]

62. The ETP that Enbridge Gas has presented in evidence was a prudent first step for Enbridge Gas to incorporate energy transition into its planning and design processes. The ETP work included in-depth analyses and discussion on how energy transition could impact Enbridge Gas's annual and peak demand volumes and number of customers (ETSA) and ultimately the energy systems in Ontario (P2NZ). While there are mixed opinions about the study results, it is evident that Enbridge Gas has taken the necessary and proactive steps to initiate the work and perhaps more importantly, the discussions of how energy transition could unfold in Ontario.

63. These actions by Enbridge Gas have been taken in a relative void of direction from other key stakeholders in Ontario. IGUA's expert Dr. Hopkins shared in the Oral Hearing that the sequence of energy transition progress in the more advanced states in the U.S. such as Massachusetts and New York was "big picture" first from the state government, followed by regulator action to facilitate dialogue, and then response by utilities.[62] Similarly, OEB staff's expert Mr. Goulding cautions that "it is always

[59] Exhibit M8, page 54.
[60] 9 Tr.90-91.
[61] QMA Submission, page 6.
[62] 5 Tr.86-87.

dangerous for a regulated entity to get out too far ahead of its regulator or the associated policymakers… other than participating in those [broad pathways] studies, one could argue that it would be imprudent for a company to come up with its own plan before seeing the outcome of all those other activities”.[63]

64. The comprehensive energy system-wide analysis for Ontario represented in the ETSA and P2NZ is the first of its kind, and in conducting those studies, Enbridge Gas is taking a leading but prudent role in starting the Ontario energy transition discussions even in the absence of government policy or OEB direction. Subsequent work, including IESO's Pathways to Decarbonization (P2D) report and the Ministry of Energy's Cost Effective Pathways Study, have benefited from the insights and learnings from the P2NZ Study. Later in this section, Enbridge Gas provides its responses to the specific intervenor critiques of the ETSA and P2NZ studies, none of which invalidate the importance of the initial work that Enbridge Gas has done on this front.

65. As noted in the OEB staff’s submission to the EETP, an iterative approach to what, how and when energy transition is factored into energy system planning is necessary to allow for changing conditions and factors to be assessed and allow for the plan to be incremental and adaptable. Energy system planning should be flexible and nimble as there are many factors to consider as energy transition continues to unfold in Ontario. This will ensure that system reliability and resiliency as well as customer choice and affordability are kept in balance with the necessary GHG emission reductions.[64]

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[63] 9 Tr.94.
[64] Ontario Energy Board. Report of the Ontario Energy Board to Ontario’s Electrification and Energy Transition Panel, June 30, 2023, page 12. https://www.oeb.ca/sites/default/files/uploads/documents/reports/2023-07/oeb-report-EETP-20230630-en.pdf

66. The approach that Enbridge Gas has taken in its ETP aligns with this advice, as it sets out safe bet actions for Enbridge Gas to pursue that are needed regardless of what pathway comes to fruition in Ontario, to maintain pathway optionality in a time of uncertainty, to drive near term emission reductions and/or to maintain its system during the transition.

Diverse Views on Electrification

67. Enbridge Gas has acknowledged that electric heat pumps will have a significant role to play in the energy transition[65] and that it is possible for some consumers to achieve cost savings from installing heat pumps. However, it is important to note that there are many variables associated with the costs of installing and operating heat pumps and that there is not enough evidence on the record for the OEB to assume, as some intervenors have done, that a large portion of Enbridge Gas customers will convert to electric heating before or when their gas furnace is at the end of its life.

68. For instance, GEC points to the IESO P2D statement that "Technological improvement in cold-weather heat pump technology was assumed" and the availability of various ASHP models were noted to show that alternatives are available to provide heating in cold climates.[66] However, in order for a cold climate air source heat pump (ccASHP) to provide 100% of the space heating requirement, the heat demand for the home would have to be less than or equal to 24,000 Btu/hr, as this is the amount of heat noted as being provided by the ccASHPs to which GEC refers.[67] This is highly unlikely unless the home has undergone extensive building envelope improvements to dramatically reduce the thermal demand. Therefore, auxiliary heating (resistive or otherwise) would be required to serve any incremental heating demand beyond the noted 24,000 Btu/hr. This in effect will reduce the effective coefficient of performance

[65] 3 Tr.89.
[66] GEC Submission, page 7.
[67] See undertaking Exhibit J18.7.

(COP) of the heating system and increase the electricity demand during the peak demand period.[68]

69. GEC also states that a residential homeowner will save over $18,000 by switching to efficient electric heating.[69] It is critical to assess the interests of actual home/business owners to determine what actually motivates their energy-related decision making. Enbridge Gas cautions against relying on theoretical cost-effectiveness analysis as a singular basis for determining consumer energy interests and decisions. Ignoring the wide range of potential upfront costs for conversion due to unique building characteristics and other decision drivers is an oversimplification.[70]

70. The Enbridge Gas customer engagement survey provides actual insights into the energy interests and motivating factors of consumers. Affordable pricing is a priority for residential and small commercial customers, while safety, reliability and environmental impacts also play a dominant role in their decision making. Medium and large business customers added predictable pricing as a driver.[71] Clearly the decisions of energy consumers are multi-dimensional, but affordability is key. The OEB endorsed these findings as valid in their recent approval of a number of community expansion leave to construct applications in which ED and PP challenged the Enbridge Gas customer surveys. Despite this, the OEB concluded in each instance that the Enbridge Gas market survey data and letters of support from the communities established the need for the projects.[72]

71. Despite GEC's claims about the lifecycle cost effectiveness of heat pumps, their own expert Mr. Neme acknowledges that full electrification may not be appropriate or

[68] See Exhibit J11.5.
[69] GEC Submission, page 8.
[70] See Exhibit J11.5.
[71] Exhibit 1, Tab 10, Schedule 5, page 17.
[72] For example, see EB-2022-0248, Decision and Order, page 12.

desirable in all cases: "I have not said in this report that I propose that all heating in Canada be converted to electricity… there may well be communities where that's really challenging, or at least where air source heat pumps may not make sense and you need ground-source heat pumps, or biofuels would be a better alternative. I don't think we can ever suggest, or that it would be prudent to ever suggest, that there is a one-size-fits-all solution for everybody, everywhere."[73]

72. From an overall energy pathway perspective, several intervenors have concluded there is a much higher probability of high electrification than a more diversified pathway materializing by 2050. Other intervenors have pointed out the many uncertainties associated with this assumption. Enbridge Gas submits that it is too premature for the OEB to determine which pathway is most probable.

73. For instance, GEC implies that electrical system capacity will be fine due to several reasons - efficiency of electricity technologies, improving efficiency over time, vehicle to load technology, building efficiency, government funding, proven technologies, additional generation coming online over decades.[74] There is no guarantee of this. Using data provided by GEC's expert Mr. Neme, space heating is shown to account for 94% of space conditioning energy demand for a typical home.[75] If buildings electrify for winter heating, winter demand will dwarf summer demand due to space heating resulting from the use of ASHP. Electricity system capacity will need to expand significantly, and the P2NZ Study indicates that peak electricity demand will increase to 51-82 GW depending on the scenario. The IESO in their P2D Report, which does not achieve economy wide net-zero, indicates that peak electricity demand

[73] 6 Tr.65-66.
[74] GEC Submission, pages 11-12.
[75] Exhibit N.M9.EGI-90, Attachment, "Equipment" worksheet. Space heating share of total space conditioning energy demand = annual gas use in kWh / (annual gas use in kWh + annual electricity use for heating + annual electricity use for AC).

will more than double to 60 GW.[76] IESO also notes in the P2D Report that increased electrification of transportation and heating requirements in buildings will lead to a winter peaking system and changes the shape of demand during the day, which "would represent a significant operability challenge"[77]; however, an operability assessment was not performed and "[f]urther planning work is necessary to understand how to manage the transition in a reliable way from now to 2050".[78]

74. SEC states that Ontario has never had a problem producing enough electricity, implying that everything will be fine in the future: "we always know we can do it. It is always about choosing <u>how</u> to do it."[79] SEC quotes Dr. Hopkins who said "[w]e are not suffering from a limited amount of sun and wind," concluding that "[w]e do not need to invent anything new."[80] These are naïve statements, ignoring the fact that Ontario has never had to accommodate the level of demand growth that could occur over the next few decades with a deep electrification pathway. Sun and wind power is limited by land availability, there is a lack of sun and wind at certain times of day/seasons, and while much of the "how" of the technology may be known, the costs and time required to ramp it up may be prohibitive. It also ignores the fact that small modular reactors (SMRs) are an unproven technology[81] and that battery storage on a large scale does not exist today[82].

75. It is not consistent to state that electrification relies upon known and proven technologies while at the same time stating that vehicle to grid and other distributed

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[76] This increase in demand is inclusive of nearly 5 GW of demand reduction due to energy efficiency measures impacting peak (Exhibit J11.4, page 29). As demonstrated by the IESO, energy efficiency cannot be solely relied upon to mitigate increases to peak electricity demand due to electrification.
[77] IESO Pathways to Decarbonization report, filed at Exhibit J11.4, page 27.
[78] Ibid, page 32.
[79] SEC Submission, page 31.
[80] Ibid.
[81] IESO Pathways to Decarbonization report, filed at Exhibit J11.4, page 4.
[82] IESO on page 29 of their Pathways to Decarbonization report state that the 4,500 MW of battery storage that does not exist today will be required by 2050.

energy resources (DER) technology will mitigate peak demand, particularly considering how nascent and unproven these emerging technologies are. Also, while the government has recently announced in their Powering Ontario's Growth Report 8.5 GW of new and refurbished large scale nuclear, this is only about 10% of the total new capacity the IESO identified in their P2D work and just this 10% could take 10 to 15 years to build.[83] Also highlighted is that 20 GW of new capacity is required to replace generation that will come to the end of its life or be phased out.[84] The point is that current announced capacity builds do not meet the requirements of the pace or scale needed to replace what is coming to end of life, let alone build what may be required to accommodate electrification more broadly as explored by the IESO in their P2D, nor the full electrification of the economy as alluded to by intervenors.

76. This is not to suggest that the government or the IESO will not reliably deliver electricity now or in the future, simply that the generation and transmission capacity required to fulfill the demand associated with significant electrification is simply not being built or planned for yet and both the costs and associated timelines are very uncertain.

77. In its submission, APPrO points out that any discussion of a shift towards deep electrification (sourced from non-emitting energy sources) must also consider: a) whether the electricity grid can support such an increase in demand, and b) whether there would be acceptable impacts on energy reliability, affordability and customer choice. APPrO concludes that "there is currently no evidence in this proceeding that addresses these vital questions,"[85] and therefore any fundamental changes in Enbridge Gas's plans on the basis of energy transition would be inappropriate and potentially risky. EP agrees and puts it more bluntly: "if electricity distributors in

[83] Exhibit K1.5, page 61.
[84] Ibid.
[85] APPrO Submission, page 14.

Ontario do not have a large amount of spare capacity on each of their feeder circuits, then transition from gas to electricity cannot take place until the electricity distributors build additional capacity, which may take years, cost a lot of money, and increase rates."[86]

Enbridge Gas Future Steps on Energy Transition

78. It is important to emphasize that Enbridge Gas always intended to evolve its ETP and to include more stakeholder collaboration and involvement.[87] Upon review of Dr. Hopkins' recommendations, Enbridge Gas agrees that a regional level analysis is an important addition to Enbridge Gas's next ETP. Enbridge Gas believes that this work would be most valuable to initiate, scope and conduct once government policy is clarified; however, it may be necessary to start the work sooner to meet expected OEB filing timelines. Understanding that the EETP's recommendations are not expected until the end of 2023 at the earliest, associated government policies will be issued sometime following these recommendations, likely after a consultation period, and that Enbridge Gas will require time to complete regional analysis, develop associated plans and proposals and engage stakeholders, Enbridge Gas submits that the appropriate time to file its evolved ETP is with its next rebasing application.

79. Assuming that the next rebasing filing would be for 2029 rates, Enbridge Gas would need to file its evidence by Fall 2027. The business planning processes required for Enbridge Gas to develop the next iteration of its ETP involves a sequential workflow of inputs, analyses, and outputs between internal work groups. There are dependencies between system planning and design activities with asset management optimization that must be followed by financial planning activities. These activities are typically completed over the course of 2 years. Enbridge Gas expects it would require an additional 2 years to layer on energy planning considerations such as scenario

[86] EP Submission, page 4.
[87] Exhibit 1, Tab 10, Schedule 6, pages 39-40.

development, probability analysis and enhanced stakeholder engagement. Enbridge Gas would have to commence this exercise in early 2024 to meet the filing timelines for its next rebasing application.

80. Dr. Hopkins' recommendation is aligned with this timing and order of events. He states that Enbridge Gas should, following the publication of Ontario's Pathways study and the conclusions of the EETP, conduct a detailed business analysis that informs the company's capital and operational plans to be brought forward in the next rebasing application.[88] Dr. Hopkins reiterated this when he noted that Enbridge Gas should "… undertake detailed business analysis … based on the outcome of the Ministry of Energy's study, and to share the outcome and methods of that analysis with the OEB and stakeholders."[89] Dr. Hopkins does not take explicit notice of the additional time the Ontario government will likely take to consider and consult on the EETP findings, but Enbridge Gas must factor this into its ETP timing and process nonetheless.

81. Dr. Hopkins further described how he thought the analysis should be completed:

> The first essential step is for the utility to develop a business plan for managing the firm in the changing public policy and competitive context in which it operates. That plan should identify and quantify risks and opportunities, including when they would manifest in impacts on the company as well as what their impacts would be. This plan should include a comprehensive assessment of electricity and gas utility roles in decarbonization, gas load forecasts, infrastructure needs, gas price forecasts, analysis of customer counts and consumption patterns by customer type, and the availability and costs of alternative fuels.[90]

82. Dr. Hopkins notes that such a plan should also inform analysis and selection of additional mitigating actions. These actions could include (1) detailed and careful examination of any choice to invest in new gas system infrastructure, (2) reevaluation of depreciation approaches for each type of utility asset, (3) develop partnerships with

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[88] Exhibit M8, page 6.
[89] Exhibit N.M8.STAFF-3.
[90] Exhibit M8, page 53.

electric utilities to cost effectively meet winter peak needs through the gas system and (4) evaluation of low-carbon fuels such as green hydrogen or biomethane.[91]

83. Dr. Hopkins offers additional recommendations to the OEB on how the OEB may assist in determining the best path forward for the business plan development. Dr. Hopkins recommends that:

    1. Consultants retained to support the business analysis should be contracted to the OEB (and not Enbridge Gas);

    2. The OEB should require Enbridge Gas to conduct the business analysis and share the results, methods and tools of the analysis with stakeholders (subject to any confidentiality constraints);

    3. Stakeholders be allowed to participate in the scenario development "in the level that they are capable of" and the OEB should ensure that the scenarios cover all appropriate scenarios with input from utilities; and

    4. The OEB's review and guidance on this analysis should be aligned with provincial and federal policy and pathway decisions. [92]

84. Importantly, Dr. Hopkins notes that "it most likely would not [be] helpful for the OEB to develop scenarios that are inconsistent with core tenets and principles of the provincial pathway."[93] ED supports Dr. Hopkins' recommendations on the role of the OEB as it relates to the energy transition scenario development that would inform the business analyses but ED acknowledges that the business planning and modelling can be conducted by Enbridge Gas independently.[94]

85. As noted above, Enbridge Gas agrees that the involvement of selected and relevant stakeholders is critical for the development of the business analysis; however,

[91] Exhibit M8, pages 53-54.
[92] Exhibit N.M8.PP-1.
[93] Ibid, page 2.
[94] ED Submission, page 23.

Enbridge Gas respectfully disagrees that the OEB should retain the consultant for this work and be responsible for the day-to-day administration of the engagement and business planning activities. Enbridge Gas can provide the OEB with its plans for stakeholder engagement at the appropriate time, or as requested by the OEB, to ensure that the regulatory objectives are achieved.

86. Some ratepayer groups (CCC, IGUA, SEC), environmental interest groups (ED, GEC) and Indigenous groups (TFG) agreed with Dr. Hopkins' recommended approach; however, some felt that it should be completed prior to the next rebasing and that many aspects of the Company's current filing should not be adopted, or should only be partially adopted, until this evolved energy transition plan is complete and considered by the OEB in a subsequent hearing that would take place in the coming years (i.e., before the next rebasing). Some parties, such as GFN, LPMA, and VECC, suggest that this next step should instead be a generic hearing, perhaps after policy is created to implement the EETP proposals. Enbridge Gas does not favour convening a generic OEB proceeding to address these issues as it believes that a business-led approach is most appropriate, similar to the views of Dr. Hopkins and ED set out above. As Dr. Hopkins noted in the Oral Hearing:

> So we are not going to set a path for energy transition, like, oh, we have some grand proceeding, and we settle it all, and we're done, an off we go. Right? This is an ongoing thing with iterative learning over the course of now through the indefinite future.[95]

87. Enbridge Gas appreciates the different perspectives and agrees that continuing this work is critical and that waiting for government policy will delay next steps. Although it prefers to wait for government policy, Enbridge Gas plans to begin the work and evolve the scope if and when policies are announced to ensure continued progress. Enbridge Gas notes however, that without policy, and perhaps even with policy that is not sufficiently clear, reaching consensus on critical elements such as which scenarios

[95] 5 Tr 140.

to run and determining if and how to assign probabilities will be extremely difficult, highly contentious and both time and resource intensive given the different parties' biases on how they think the energy transition should unfold. The work must be scoped to ensure that the stakeholder process is effective in terms of the breadth and depth of involvement of relevant stakeholders while not becoming overly burdensome to the overall process and timelines to use the development scenarios.

88. Dr. Hopkins also noted this difficulty in assigning probabilities and in creating scenarios when he stated "In order to -- you know, some aspects of trying to summarize the results of those different scenarios, you are going to need to assign them weights or probabilities in some way. That is challenging. Right? Different people are going to have different perceptions about how likely they think different scenarios are going to be to happen. This is a challenge for all different kinds of long-term resource planning–type analyses."[96] In addition, Dr. Hopkins noted "I think you have to be careful about, you know, again, having been on the consultant side of this, right? - careful about saying, well, you know, anybody can ask anybody to rerun a scenario with changed parameters. Right? That is a recipe for it takes forever and costs a lot of money, so, you know, having some sort of filtering process there."[97]

89. It is important to highlight that with or without government policy, executing upon Dr. Hopkins' recommended approach is not a simple nor straight-forward endeavor. The complexity and time required to complete this type of comprehensive planning is supported by the fact that Dr. Hopkins himself is unaware of any gas utility that has fully implemented this type of approach. Not even the utilities highlighted in his evidence as operating in areas with well-established world-leading government policies and supportive regulatory processes have fully incorporated this type of

[96] 5 Tr.54-55.
[97] 5 Tr.62.

energy transition planning into their business.[98] Therefore, Enbridge Gas submits that the degree to which each aspect of Dr. Hopkins' recommendation can be completed by the next rebasing period must still be scoped and evaluated from a practical perspective. Although Enbridge Gas recommends beginning this work while waiting for government policy, because of this complexity and the need to evolve to incorporate any future policy, the Company maintains that it is still appropriate to file its evolved ETP with the OEB no sooner than its next rebasing.

90. Enbridge Gas agrees with intervenors' perspectives that gaining stakeholder inputs on this work is critical and will, therefore, invite relevant stakeholders to engage in discussions at milestone checkpoints to ensure that parties stay informed and that the Company solicits feedback and input on the critical elements.

91. Although Enbridge Gas recommends that its broader regional analysis and associated plans and proposals are not brought forward until the next rebasing application, it is important to note that Enbridge Gas will continue to evolve its demand forecasting process. As part of this work, Enbridge Gas will engage with customers, municipalities, and local distribution companies (LDCs) to solicit insights and, where possible, planning level information to determine the quantitative impact to Enbridge Gas's specific demand forecast inputs, such as timing and location of impacts. On an annual basis, this information will be considered and, where appropriate, incorporated into the Company's demand forecasts. All changes will be reflected within the annual AMP updates.

Coordinated Energy Planning

92. It is abundantly clear that parties agree with Enbridge Gas that coordinated gas and electric planning would enable a more well-informed and prudent energy transition

[98] 5 Tr.126-127.

plan and assist in capital investments. As noted by EP, “energy transition cannot be only about getting rid of gas without considering what will replace it and when.”[99] Similarly, LPMA notes that “the Board should also not be making decisions that impact energy transition trajectories in the absence of detailed evidence on the impact of electricity distributors, transmitters and generators. To do so would be like walking up a cliff in the fog and not knowing where the edge of the cliff is”.[100]

93. As further noted by EP, GFN and VECC, it is important that there are no stranded customers and that due consideration be given to vulnerable communities, amongst which may be remote and northern communities including many First Nations. Coordinated energy planning would better inform any demand forecast scenarios that are created by utilities, as well the assignment of probabilities to these scenarios especially within a regional analysis. For example, without coordinated planning, stakeholders could demand that certain theoretical futures be modelled that they think are possible, even though they are not feasible, practical, or operationally sound given a region’s current electricity capacity and future growth plans.

94. As Enbridge Gas noted in the Oral Hearing and within its submission to the EETP, for coordinated planning to be truly effective, clear direction must come from the government on elements such as the objectives of coordinated planning, which planning activities need be coordinated, how coordinated planning will be governed, amongst other things.[101] Without this direction Enbridge Gas is left with only one inefficient and cumbersome option, which is to approach each region’s electric LDC(s) and municipality, attempt to bring them together in discussions, and request and

[99] EP Submission, page 8.
[100] LPMA Submission, page 5.
[101] 3 Tr.138-142; Exhibit K1.4.

maintain their planning level data and associated assumptions. This is the approach that was proposed by OEB staff[102] and supported by SEC.[103]

95. Enbridge Gas submits that, although this is the approach it has begun taking, this is not an effective way to coordinate Ontario's energy planning. This approach results in each party, specifically the electric utility and municipality, determining whether they can and/or want to engage with Enbridge Gas on coordinated planning and whether they can and/or want to provide planning level data and insights. For instance, Enbridge Gas is finding that LDCs may not want to share data that is not already publicly available, for confidentiality or other reasons, and/or they may not be resourced for this type of engagement or have coordinated energy planning as a priority. This could potentially result in fragmented and inconsistent results for coordinated energy system planning even within a regional analysis.

96. This also places a monumental responsibility on Enbridge Gas to engage and motivate LDCs to participate in the process. Additionally, it may create confusion with LDCs about their obligations to include energy transition considerations in their energy system planning and the applications brought forward to OEB for approval. It is important to note that there are 60 LDCs in Ontario, 58 of which are regulated by the OEB, and this could lead to very different "versions" of what coordinated planning entails.

97. As discussed throughout the Oral Hearing, coordinated energy planning is a key focus for the province's EETP. Specifically, the EETP has noted that, with respect to coordinated planning, they are looking for opportunities to improve long-term, integrated energy planning between the electricity and fuels sectors, including exploring topics such as roles and responsibilities for the province/energy agencies,

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[102] OEB staff Submission, page 19.
[103] SEC Submission, page 84.

and options to optimize demand and decarbonize future energy supply systems.[104] The recommended next steps from the EETP related to this work are expected this fall. GEC's assertion that "Enbridge feels that it's somebody else's job to host that integration exercise"[105] is inaccurate. The government has confirmed through the EETP that it expects to be directing this work.

98. It is Enbridge Gas's hope that the EETP recommendations and any associated government policy will be issued in short order; however, Enbridge Gas reiterates that a lack of government direction will not prevent it from continuing to engage with the electricity sector to the extent that it can and electric LDCs choose to reciprocate. Enbridge Gas will report on stakeholder engagement activities, including with the electricity sector as part of its LTC and IRP Plan applications and in the Company's next ETP.

Allocation and Mitigation of Risks in the Energy Transition Context

99. In AIC[106], Enbridge Gas described its approach to allocation and mitigation of risk as addressing risk though measured growth and continued focus on sustainment activities to provide safe and reliable service, for instance by incorporating IRP and appropriate demand assumptions to lower the risk of oversized or unnecessary assets being built. Many parties agree that there is no apparent risk of stranded assets for Enbridge Gas in the near term, and certainly not during the proposed 2024 to 2028 rate term.[107]

100. In the longer term, Enbridge Gas has been clear that its ETP, safe bets and other proposals in this proceeding are developed with a view to addressing energy transition

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[104] Government of Ontario. (2023 July 26). Energy and electricity. Electrification and Energy Transition Panel. https://www.ontario.ca/page/electrification-and-energy-transition-panel
[105] GEC Submission, page 9.
[106] AIC, pages 7-8.
[107] OEB Submission, page 47; PP Submission, page 35; IGUA Submission, page 17; CME Submission, page 41; APPrO Submission, page 7.

in an appropriate manner and minimizing stranded asset risks through means such as adjusting its demand forecasting, a continued focus on DSM programming and IRP, pursuing alternative uses of the gas system like low carbon fuels and NGV, and other decarbonization activities such as CCUS. Enbridge Gas has incorporated reasonable assumptions in its demand forecasting for the rate term, based on known information. Enbridge Gas has been clear that this forecasting will be updated and refreshed as new information is gathered. Mr. Coyne described how the steps that Enbridge Gas is taking, and their timing makes sense relative to what he is seeing in other jurisdictions:

> MR. DAUBE: Not enough information, but aren't those the types of proactive measures that the company should be at least investigating if it wants to be proactive in the sense of attempting to mitigate risks of a death spiral and other risks that it faces in the energy transition?
>
> MR. COYNE: Mr. Coyne responding. In our experience, Mr. Daube, we see utilities just beginning to do this work. This is a new environment that we are in and, as we discussed in our evidence in various places, we are now seeing states and commissions creating studies, groups, working with utilities, much like we see here in Ontario with the energy minister beginning to undertake a pathways study, to try to understand these implications. <u>These are big, complex issues. They are bigger than Enbridge; this affects the entire energy economy of Ontario. So we are seeing studies that are just beginning to be initiated that address these issues and all their complexities and understand what these pathways would look like on jurisdiction-by-jurisdiction basis. I would expect companies like Enbridge to participate in that process and to begin, as I sense it has, to account for them in its planning process.</u>
>
> MR. DAUBE: Isn't Enbridge in as good as a position as anyone, including the government, <u>to analyze its assets on an asset-by-asset basis, under various scenarios, toward understanding whether any of its specific assets are more or less at risk under certain energy transition scenarios</u>?
>
> MR. COYNE: <u>I think eventually, yes. I think today, no.</u> And the reason I say that is that, in order to be able to do so, it would have to be able to make certain assumptions around what costs are going to be on a going forward basis, how customers are going to respond to them, introduce assumptions pertaining to efficiencies for gas heat pumps and availability of gas heat pumps and electric heat pumps. So those are very complex studies. And, to do so, as I mentioned in yesterday's discussion, we were actually interviewed by the commission that is studying this issue for Ontario, and one of our pieces of advice was that electric and gas companies need to work together on these issues because their knowledge together is what is necessary to begin to address these complex issues. And so I think some combination of the government, companies like Enbridge, companies like Hydro One in Toronto, working with companies that have the tools to

> conduct these studies, is ultimately the best way to get a big picture. And then, once that big picture is created, then companies like Enbridge can begin to ask: Do we have assets that are at risk under these various scenarios? So that's the way I would expect it to unfold.[108] (emphasis added)

101. As explained above with respect to the Enbridge Gas actions to date and planned future ETP, Enbridge Gas plans to start conducting more regional asset impact assessments in the future, in coordination with stakeholders, and will adjust planning and forecasting assumptions periodically as government policies and market dynamics change. Until that information is known and assessed through appropriate planning tools, Enbridge Gas is not in a position to determine any more specific potential utilization or stranding impacts on capital assets.

102. Enbridge Gas agrees with OEB staff and SEC that no specific new determination on stranded asset risk is required in this proceeding.[109] Enbridge Gas also agrees that the OEB has tools available to address the allocation of risk issue. This includes prudence reviews, deferral and variance account disposition proceedings and tracking mechanisms that help determine the accuracy of actuals relative to forecasts. For instance, Enbridge Gas is subject to specific reporting requirements in relation to LTC projects to track actual costs relative to forecast costs. OEB staff has recommended Enbridge Gas review its energy transition assumptions in its load forecast on an annual basis, document any changes as part of its AMP update and track utilization of new growth-driven projects relative to forecast.[110] Enbridge Gas will update its demand forecasting on an annual basis and document any changes as part of its AMP, as indicated above. Issues related to utilization tracking are addressed in the Capital section of this Reply Argument.

[108] 9 Tr.28-30.
[109] OEB staff Submission, page 19; and SEC Submission, page 39.
[110] OEB staff Submission, page 18.

103. In any event, it is not appropriate at this time to take the view that Enbridge Gas should be specifically at risk any more than is currently the case for stranded asset risks on new facilities constructed in accordance with OEB-approved guidelines and policies. Also, it is imperative that the OEB not apply hindsight to any such consideration and that any allocation of risk determination be made on the basis that a decision to construct facilities was reasonable based on the information available to Enbridge Gas at the time the original investment decision was made. Such determinations will be dependent upon the facts of the particular case, and it is not productive to debate in the abstract concepts such as a mechanistic approach to risk sharing in the future.

104. There is no evidence on the record for the OEB panel to even consider such an approach in this proceeding and it would be uncharted territory for the OEB to do so. As SEC noted, the case law mandates giving utilities the opportunity to recover prudently incurred costs plus a fair return on invested capital over the long run.[111] That is the starting point for any future discussion about allocating risks for stranded or underutilized assets.

105. OEB staff referenced case law from Alberta that supports a proposition that costs or revenues associated with stranded assets may be borne by the utility and not the ratepayers.[112] In each case, the court was dealing with whether stranded assets subject to extraordinary retirement should be removed from rate base and not whether assets that remain used or useful should be subject to extraordinary rate treatment. These cases are distinguishable on that basis and not applicable to the OEB staff recommendation in this proceeding that the OEB consider a utilization tracking mechanism to assess risk allocation for underutilized assets.

[111] See *Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44, paragraphs 16-17.
[112] OEB staff Submission, pages 47-50.

106. Further, in any future review of stranded asset risk, the OEB will need to consider the many proposals that Enbridge Gas has made in this and other proceedings to attempt to address stranded asset risk (e.g., safe bets, harmonized depreciation proposal) that may be or were not approved by the OEB. Issues related to depreciation are addressed in that section of this Reply Argument.

Hydrogen Initiatives

107. The Capital section of this Reply Argument addresses the overall capital expenditure relief Enbridge Gas is requesting for this Application, including the capital earmarked for the Hydrogen Blending Grid Study (Grid Study). In this section, Enbridge Gas provides its response to the intervenor submissions on the Grid Study, the LCEP Phase 2 and pursuit of hydrogen initiatives in general.

108. Hydrogen blending is one of the important safe bet activities that Enbridge Gas is undertaking to address GHG emissions and also to reduce the risk of underutilization and stranding of gas system assets. As is described in detail in AIC, integration of hydrogen and hydrogen technologies into energy systems can add value by enhancing the productivity and flexibility of deployed assets. This is aligned with the federal and provincial hydrogen strategies and climate change policies that outline how hydrogen and RNG will be critical to meeting GHG reduction goals, regardless of the energy pathway taken.[113] The many benefits of hydrogen are well-documented in AIC and evidence.

109. Although Enbridge Gas is already successfully conducting hydrogen blending today in Markham, it must conduct the Grid Study to assess:

a) Natural gas grid readiness to accept various blends of hydrogen;

[113] AIC, page 57.

b) Any modifications required to accept higher blending percentages up to and including 100%;
c) The need for dedicated hydrogen pipelines; and
d) Operational readiness in terms of Enbridge Gas's workforce.[114]

110. OEB staff supports Enbridge Gas's proposal to conduct the proposed Grid Study (including the $15.4 million set out in the AMP) and agrees that 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). OEB staff also has no concerns with the inclusion of $1.9 million in the 2024 capital expenditures budget related to the LCEP Phase 2.[115] The specifics of the LCEP Phase 2 project, including its timing[116], will be addressed as part of the pending LTC.

111. Only six intervenors provided specific comments on the Grid Study. Three are supportive (EP, QMA and CME) and three are supportive of only some aspects but not others (SEC, ED and PP). Other intervenors are supportive of Enbridge Gas's hydrogen initiatives more generally. For instance, APPrO believes that hydrogen will be an important fuel stock for gas-fired generation and this will be key for reliability of the electricity grid.[117] Kitchener considers hydrogen to be a part of their strategy to meet GHG emissions targets.[118]

112. Only GEC appears to be completely unsupportive of the proposed hydrogen initiatives, even though they acknowledge, "No one is suggesting that all the current

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[114] Exhibit 4, Tab 2, Schedule 6; 3 Tr 41.
[115] OEB staff Submission, page 45.
[116] PP Submission, page 19 states that Enbridge Gas should not proceed with the LCEP Phase 2 project until the results of the Phase 1 project are available.
[117] APPrO Submission, page 5.
[118] Kitchener Submission, pages 5-6.

gas load will switch to electricity. Biofuels and hydrogen are likely to play a significant role for certain industries and parts of the transportation sector."[119] Nevertheless, GEC does not appear to see any role for Enbridge Gas in providing this assistance to the industrial and transportation or any other sector.

113. Regarding the Grid Study specifically, ED and PP state that the OEB should require Enbridge Gas to conduct formal stakeholder sessions to reduce the pro-gas bias seen in the P2NZ Study.[120] Enbridge Gas does not think it would be appropriate or efficient to conduct such sessions and this additional process would inevitably increase the time and cost of the Grid Study. The nature of the Grid Study is a very technical engineering assessment in accordance with the Canadian Standards Association's Z662-23 Oil & Gas Pipeline Systems Code (CSA Z662) and is not conducive to significant involvement of stakeholders. CSA Z662 is already very detailed and prescriptive about what is required for the technical engineering assessment and it would be redundant and inefficient to consult with intervenors on this level of detail and scope of work. Enbridge Gas will consult with its technical regulator, the Technical Standards and Safety Authority, on any aspects of this work as required.

114. More specifically, the inputs to the Grid Study will include Enbridge Gas's detailed asset information, technical literature and hydrogen research and use the approach that Enbridge Gas developed for the LCEP Phase 1 project centering on the four key elements:[121]

a) Assessment of existing gas distribution/transmission network
b) Assessment of existing end-user network, appliances and equipment
c) Operational readiness and reliability
d) Integrity and risk management

[119] GEC Submission, page 11.
[120] PP Submission, pages 16-17; and ED Submission, page 48.
[121] Exhibit 4, Tab 2, Schedule 6, pages 8-9.

115. ED states that the Grid Study should be focused on the provision of green hydrogen to large volume customers in high concentrations up to 100% because it is highly unlikely that hydrogen will be an effective way to heat buildings.[122] Enbridge Gas submits that this would be much too narrow a focus of the Grid Study given the much broader applications that hydrogen is likely to have, as recognized by the federal and provincial hydrogen strategies. Also note that blending at any level requires that an engineering assessment be performed, so it is clearly more efficient to conduct one study for all customer types.

RNG

116. AIC presented a comprehensive summary of the role that RNG could play as a "safe bet" in achieving GHG emission reductions, describing in detail the rapidly evolving competitive supply environment in North America. Some parties like ED, GEC, and OEB staff, while supportive of the potential role of Enbridge Gas's pipelines in delivering RNG, believe that RNG scarcity and/or high price will be significant constraints to RNG potential, challenging the notion that technological advancements and RNG imports could significantly improve RNG feasibility.

117. The RNG Coalition, representing the renewable gas industry, asserts that renewable gas can indeed play a meaningful role to the energy transition in Ontario due to the rapid growth of the industry across North America and Enbridge Gas's potential first mover advantage over later adopters.[123] Their citation of the International Energy Agency's forecast of a twenty-seven-fold increase in global RNG supply by 2050 relative to 2020 levels[124] suggests that technological advancement will most certainly accelerate, and learnings from the more advanced European markets will enable even

[122] ED Submission, page 47.
[123] RNG Coalition Submission, page 4.
[124] Ibid.

faster growth in the North American market than recent published estimates of RNG potential would indicate.

118. Enbridge Gas's evidence in the 2024 Rebasing proceeding includes proposals related to the procurement of low-carbon energy including RNG as part of the gas supply commodity portfolio beginning in 2025.[125] This evidence will be updated and considered as part of Phase 2 of the 2024 Rebasing proceeding. If approved, these proposals will help support and accelerate the development and supply of RNG in Ontario and beyond.

Integrated Resource Planning

119. Although many aspects of IRP are out of scope for this proceeding, some intervenors have raised a multitude of concerns related to the IRP screening and evaluation process and Enbridge Gas's level of consultation with the IRP Technical Working Group (TWG). Enbridge Gas will provide its general views on intervenor submissions about IRP in this section and will address the specific items related to capital expenditures in the Capital section of this Reply Argument. In general, Enbridge Gas submits that it is not necessary for the OEB to make any orders related to IRP in this proceeding as the issues raised by intervenors will be addressed in the normal course as part of the existing IRP processes, including future IRP-related project filings and IRP TWG discussions.

120. Contrary to PP's claim that there is unanimous stakeholder concern that Enbridge Gas is not executing upon the OEB's IRP Decision and related IRP Framework,[126] numerous intervenors[127] and OEB staff support the Enbridge Gas IRP initiatives and conclude that Enbridge Gas has met the intent of the IRP Decision. OEB staff believes

[125] Exhibit 4, Tab 2, Schedule 7.
[126] PP Submission, page 29.
[127] APPrO, EP, QMA and OGVG.

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.[128]

121. ED and PP request that the OEB direct Enbridge Gas to increase its IRP efforts, as they believe the Company is moving too slowly. Enbridge Gas disagrees with these claims. Implementing IRP into a utility's established asset management planning process is complex and time intensive. Enbridge Gas has made significant progress in its IRP implementation since receiving the IRP Framework Decision in July 2021, and has fulfilled all OEB directives issued as part of that Decision. Since that Decision, Enbridge Gas:

- Consulted with the IRP TWG on the two items that the OEB noted as priorities within its IRP Framework Decision, including:
    - *IRP Pilots:* consulted on potential IRP pilot projects, as well as on the program design for chosen IRP pilots and filed with OEB; and
    - *DCF+ Test:* consulted on evolving the DCF+ test, including:
        - Working with Guidehouse to complete a review on how the DCF+ test could be evolved;
        - Consulting with the IRP TWG on evolving the DCF+ test, with an OEB IRP DCF+ Report issued in June 2022; and
        - Preparing to, as directed, file a DCF+ Guide with its first non-pilot IRP Plan;
- Hired and onboarded 15 IRP personnel across the organization to support the development and implementation of new IRP processes;
- Evolved its asset management planning processes, including the addition of an "IRP Appendix B" within its AMP that indicates each project's binary screening, AMP assessment and, if applicable, IRP Plan status. As part of this, Enbridge Gas developed IRPA technical assessment documentation which has supported the assessment of projects that have passed the IRP Binary

[128] OEB staff Submission, page 38.

screening. The majority of the large number of projects within Enbridge Gas's AMP have been technically evaluated;

- Developed and implemented new IRP stakeholder engagement processes, including creation of an IRP site within Enbridge Gas's website, as well as holding its first round of regional stakeholder engagements across all seven of its planning regions, with additional regional sessions planned for Q4 of 2023;
- Developed and rolled out its Pilot Project Area Stakeholder Engagement Plan and delivered initial webinars with pilot project stakeholders, including meetings with municipalities, LDCs, IESO, Hydro One, in-person public meetings and meetings with municipal councils;
- Completed, as directed, an interruptible rates study, filed in this proceeding;
- Filed two Annual IRP Reports which have included documentation of demand-side IRPAs including Enhanced Targeted Energy Efficiency (ETEE) and supply side alternatives.
- Participated and led the content development for the majority of the 27 TWG meetings held to date; and
- Implemented one IRP Plan (Kingston), deferring approximately $24 million in capital.

122. Enbridge Gas believes this progress is more than reasonable given the many facets of its planning process that must be modified, and that the advancement has happened in parallel with Enbridge Gas's 2024 Rebasing proceeding. In fact, in the most recent 2022 Annual IRPWG Report, OEB staff indicated that Enbridge Gas has made significant progress towards implementing the IRP Framework in 2022, as compared to 2021.

123. A number of parties[129] have suggested that the OEB review the IRP Framework or enhance the IRP alternatives through the addition of electrification alternatives. Enbridge Gas does not support the opening of the IRP Framework at this time, given

[129] GEC Submission, page 34; ED Submission, page 44; PP Submission, page 30.

that the framework was only approved in July 2021 and that the Company does not yet have the important learnings that will come from the implementation of the IRP Pilot Projects and other IRP plans that will be implemented over the next year or two. However, much like how the Company proposed to examine the limited use of electric IRP alternatives in its IRP Pilot application, the Company will propose other potential IRP Framework modifications, as applicable and appropriate, in future IRP Plan applications. Enbridge Gas will review these potential modifications with the IRP TWG, where appropriate, prior to filing an application with the OEB.

124. In addition, Enbridge Gas emphasizes that it would be extremely valuable to wait for the EETP's recommendations and any associated government policies prior to reviewing the IRP Framework. This is especially important with respect to coordinated energy planning, as the two sectors would have to coordinate on any geotargeted IRP electrification plans to prevent impacting the safe and reliable delivery of energy within a geotargeted area.

125. Specifically on the funding of electrification measures, GEC and ED both asked the OEB to enhance the IRP guidelines to remove the prohibition on funding of electrification measures.[130] Enbridge Gas is not opposed to the appropriate inclusion of electrification as an IRP alternative and as noted above is proposing to examine the limited use of electric IRP alternatives in its IRP Pilot application. Enbridge Gas's IRP Pilot proposal (EB-2023-0335) includes, on a limited participant basis, a proposal to offer an additional incentive for ccASHP and ground source heat pumps (GSHP) in the Pilot Project's ETEE-version of the HER+ offering for Parry Sound, subject to OEB approval.

[130] GEC Submission, page 34; ED Submission, pages 44-45.

126. While the first-generation IRP Framework does not yet make provisions for Enbridge Gas to explicitly fund electric IRPAs, the OEB acknowledges that “[t]his may be an element of IRP that will evolve as energy planning evolves, and as experience is gained with the IRP Framework.”[131] The Company believes the Parry Sound Pilot Project offers an opportunity to evaluate the potential applicability and feasibility of electrification measures in an isolated environment. Enbridge Gas expects that broader implementation of electrification measures in the future, as mentioned above, will require coordinated energy planning across energy sources, including discussion and engagement between Enbridge Gas and the electric sector, to ensure a holistic assessment of the impact of these types of measures on the respective systems. The above noted proposal to offer an incentive, on a limited participant basis, for ccASHP and GSHP in conjunction with its ETEE-version of the HER+ offering.[132] will support and inform such future works and collaboration and will maximize the potential learnings resulting from the Pilot Projects.

127. ED states that Enbridge Gas should be using interruptible rates to avoid capital projects.[133] As part of the IRP Decision, the OEB directed Enbridge Gas to study its interruptible rates to determine how they might be modified to increase customer adoption of this alternative service. Enbridge Gas filed this study at Exhibit 8, Tab 4, Schedule 7 and this is an issue for Phase 3 of this proceeding. In addition, as part of the ongoing review and assessments of all viable IRP alternatives Enbridge Gas is asking customers about a geotargeted interruptible rate during the expression of interest process.

128. GEC submits that IRPAs should be assessed under multiple future load forecasts to determine the optimal solution given the range of potential futures to allow for a

[131] EB-2020-0091, OEB Decision and Order, July 22, 2021, page 35.
[132] EB-2023-0335, Exhibit D, Tab 1, Schedule 1, page 24.
[133] ED Submission, page 45.

quantification of the "option value" that can be obtained by repair versus replace deferrals in capital planning.[134] Enbridge Gas has already begun to consider how demand forecast sensitivities could affect the feasibility of an IRP plan and agrees that considering different future load forecasts could help to quantify the option value that could be obtained by implementing an alternative. Enbridge Gas intends that future IRP assessments included with an LTC or within an IRP plan filed with the OEB will incorporate the assessment of demand forecast sensitivities. Enbridge Gas submits that this will address OEB staff's recommendation that Enbridge Gas include a proposal on ways to determine forecast risk/stranded asset risk as part of the DCF+ test it files for approval as part of its first non-pilot IRP application.[135]

129. Enbridge Gas notes, however, that incorporating demand forecast sensitivities is different than developing pathway scenarios for a specific geographic region, as recommended by Mr. Neme[136]. Mr. Neme noted in the Oral Hearing that he didn't "…think it would require, like, super-extensive analysis or data collection to develop alternatives."[137] And that "[y]ou could have a kind of a generic set of alternatives that apply system wide, and have some way of customizing them, then, for an individual geography"[138]. Enbridge Gas maintains that developing a "generic set of alternatives" or pathways results only in the creation of illustrative plausible futures that do not provide the OEB with any additional concrete context with which to make project approval decisions. Mr. Neme noted himself that "[t]o be fair, Enbridge needs to ensure that its customers' peak hour energy needs are met, so it cannot rely on uncertain estimates of when gas demand will begin to decline in identifying potential capacity needs that must be addressed."[139] Customizing these generic pathways by region in a way that is meaningful requires developing, stakeholdering, modelling and

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[134] GEC Submission, page 34.
[135] OEB staff Submission, page 42.
[136] Exhibit M9, page 51.
[137] 6 Tr.105.
[138] Ibid.
[139] Exhibit M9, page 48.

considering if and how a probability could be assigned, all of which is time-intensive; therefore, as noted above, Enbridge Gas will conduct this regional analysis as part of its “Future Steps on Energy Transition” rather than for each individual IRP analysis.

130. Enbridge Gas reiterates that assessing demand forecast sensitivities within its IRP analysis to account for uncertainties will assist the OEB in understanding how much Enbridge Gas’s demand forecast would need to change before an IRP alternative becomes technically and/or economically feasible, as well as any associated risks that need to be mitigated. This approach allows Enbridge Gas to propose, and the OEB to review and consider, what the optimal solution is given a range of potential future demand forecasts and given what the associated opportunity cost could be.

131. It is also important to note that the AMP is not a static document; it is refreshed annually. Therefore, for instance, if the IRP Framework changes or if policy changes impact the future load forecasts, any associated impacts will be reflected in the AMP and the subsequent IRP analyses.

<u>ETSA & P2NZ Studies</u>

132. As set out above, the studies were another initiative undertaken by Enbridge Gas, in part, to help determine and address the potential for stranded asset risk in the future. Some intervenors had several criticisms of the ETSA and P2NZ studies.[140] Notably, these studies represent only one input of many to the development of Enbridge Gas’s plans for addressing energy transition[141], and the nature of such studies is that they are only a snapshot in time of the scenarios modeled. This is also true of other studies that have been referenced in this proceeding (CER Canada’s Energy Future scenario analysis, IESO P2D, Ministry of Energy’s Cost Effective Pathways Study). Many other scenarios can and likely will be modelled in future by Enbridge Gas and other parties.

[140] Most notably, see GEC, PP, ED and SEC Submissions.
[141] 1 Tr.83.

For instance, the government's Cost Effective Pathways Study planned to follow the EETP report should provide more current data points to inform the future Enbridge Gas ETP analyses.

133. The purpose of the ETSA was to understand the potential impact to the gas system in different future scenarios, and the purpose of the P2NZ Study was to understand the economy-wide potential cost of these scenarios. Both scenarios contain uncertainty with respect to government policies, consumer preferences and technology, amongst other things, which is also true of other pathways studies. The OEB is not being asked to select a pathway or endorse the studies in this proceeding and in fact, it would be beyond the OEB's mandate and jurisdiction to do so. These studies demonstrate that an alternative to electrification exists at a comparable cost and the gas system will continue to play an important role in either scenario. Notably, the resiliency and reliability benefits offered by the Diversified scenario have not been quantified or included in the scenario cost comparison.[142]

134. Some of the same intervenors characterize the studies as biased and suggest that Enbridge Gas directed the results of the studies.[143] This is simply not true. Enbridge Gas worked collaboratively with Posterity and Guidehouse to define scenarios and determine appropriate assumptions. The study results came from the models used by the consultants and Enbridge Gas did not know what the results would be until the modelling was completed.

135. In their submission, GEC quotes Enbridge Gas's expert Mr. Coyne: "Energy transition is a fact."[144] It will involve significant reduction in the energy delivered by the gas grid, particularly for general service customers. Enbridge Gas agrees that energy transition

[142] Exhibit 1, Tab 10, Schedule 5, Attachment 2, page 47.
[143] For example, see SEC Submission, page 24.
[144] GEC Submission, page 6.

is a fact, but it is evident from the record in this proceeding that we are far from any consensus on the definition of energy transition, how it will be achieved and, beyond emissions reductions, what the ultimate objectives are.

136. With respect to the pathways described in the P2NZ Study, GEC notes that the Diversified scenario has a 53% drop in energy for general service and the Electrification scenario sees an 88% drop, and that this will mean at least a doubling and possibly an order of magnitude increase of delivery costs per unit of energy if costs are not reduced in step.[145] However, even though the Diversified scenario shows a decline on an energy basis, on a volumetric basis the volumes could increase in a future scenario with a significant level of hydrogen. The assumption that delivery cost would double or increase by a similar order of magnitude is not grounded in fact or data.

137. GEC's expert Mr. Neme presents other concerns about the assumptions and methodologies employed by the P2NZ Study in Table 9 of his evidence.[146] Enbridge Gas has responded to and resolved these concerns on the record through interrogatory responses, during the Oral Hearing and/or in AIC. Some of Enbridge Gas's responses bear repeating to dispel some key misunderstandings:

- *Concern:* On the cost of CO_2e Emissions, Guidehouse improperly treats carbon taxes as a social cost and assumes a much higher cost of emissions for electrification scenario.
    - *Response:* The P2NZ Study does not take a societal view in its analysis; rather it presents costs to consumers for each tonne of GHG emissions, which will drive energy-related decision making.[147] The prospect of some sort of refund down the road is not assumed to influence the customer at the time of their energy-related decision or purchase. The higher carbon price used in the Electrification scenario is based on what would be

[145] GEC Submission, page 6.
[146] Exhibit M9, page 41.
[147] 2 Tr.43.

required to effectively incent enough customers away from gas to drive the aggressive levels of electrification required in that scenario.[148]

- *Concern:* On RNG availability, Guidehouse assumes that the entire "technical potential" for RNG in Ontario would be available, even though the expert report it references suggests it would be feasible to access less than one-quarter of that amount.
    - *Response:* The rapid growth in RNG production in North America and around the globe will undoubtedly accelerate technological innovation,[149] enhancing feasibility. And, the supply market that Enbridge Gas has access to is not constrained by Ontario's borders.[150]

- *Concern:* On GHG emission reductions from RNG, Guidehouse's analysis does not address the full lifecycle emissions of biomethane. Thus, it overstates the amount of emission reductions RNG provides.
    - *Response:* The P2NZ is not a life-cycle emissions study, and using life-cycle emissions for one fuel type and not others would not be appropriate and would skew results.[151]

- *Concern:* On GHG emission reductions from blue hydrogen, Mr. Neme relies on the evidence of Professors Howarth and Jacobson which suggests that lifecycle emissions from blue hydrogen are "quite high."
    - *Response:* The P2NZ is not a life-cycle emissions study, and using life-cycle emissions for one fuel type and not others would not be appropriate and would skew results. In any event, Guidehouse re-ran the model as requested with a variety of emission factors for blue hydrogen and while the cost differential narrowed between the two pathways, "the results do not substantively change any conclusions in the P2NZ Study."[152]

- *Concern:* On gas heat pump costs, Guidehouse used an informal estimate from a gas heat pump manufacturer rather than a much higher recent Enbridge estimate. Worse, it failed to recognize that the estimate it used was expressed in U.S. rather than Canadian dollars.

[148] This is consistent with the approach used by the IESO P2D study, where different carbon pricing was used for different scenarios. IESO Pathways to Decarbonization Report, December 15, 2022, page 11; filed at Exhibit I.1.10-EP-7.
[149] 1 TC Tr.123.
[150] RNG Coalition Submission, page 4.
[151] 1 TC Tr.140.
[152] Exhibit J9.16

- *Response*: Guidehouse explained in detail that the cost estimate was in fact converted from a US$ value of $8,000 to a CAD$ value of $10,800, accompanied by multiple room air conditioning units for a total cost of CAD$12,200.[153]

- *Concern:* On utility distribution system costs, Guidehouse excluded the cost of converting the distribution system to 100% hydrogen and all other incremental gas and electric distribution system costs.
  - *Response:* Including distribution costs for both the gas and electric systems were out of scope for the P2NZ Study, and in any event, one cannot simply assume that their inclusion would solely disadvantage the diversified scenario. It is possible that due to the number of investments needed on the electricity side to adequately ramp up the distribution system to support deep electrification that the cost gap between scenarios may end up being even wider as a result of including these costs.[154]

138. Just as GEC claims that the P2NZ model results can swing based on "correcting Guidehouse's errors and biases"[155] (which are addressed as described above), GEC's own model[156] can show variable outputs based on objective adjustments to inputs. Therefore, the electrification savings outputs of Mr. Neme's model should not be relied upon as proof that "full electrification of homes is already highly cost-effective."[157]

139. The following updates/corrections to Mr. Neme's input assumptions are examples of hypothetical adjustments that could result in a significant shift in the NPV of the savings associated with electrification:
   - Including electric utility fixed monthly charges, as they were excluded, resulting in an exaggerated difference in total energy bill savings.
   - Updating the price of natural gas to that from the April 2023 QRAM instead of the January 2023 QRAM (the analysis was provided by GEC in May, and the

153 Exhibit I.1.10-ED-68.
154 2 Tr.2.
155 Exhibit M9, page 40.
156 Excel version of Mr. Neme's model is found at the attachment to Exhibit N.M9.EGI-90.
157 Exhibit M9, page 8.

April cost of gas was the best available information at the time. Using the unusually high January pricing distorts the comparison).

- Updating the carbon pricing to reflect the Environment and Climate Change Canada calendar year.
- Updating the average electricity pricing based on 8760 hours.
- Changing the ccASHP seasonal energy efficiency ratio (SEER) to match what was in the P2NZ Study, since it would be inconsistent to use a different SEER as the rest of the analysis is based on the figures from the P2NZ Study.
- Removing the availability of the rebates for 2030 and beyond. The Canada Greener Homes grant program has a 7-year timeframe. It was launched in May 2021 and would expire sometime in 2027. For the 2030 electrification scenario it should not be assumed that the Greener Homes grant will be available as an incentive.

140. While Enbridge Gas did not re-run Mr. Neme's analysis with his model with updated assumptions as part of the record in this proceeding due to limited time and resourcing, directionally it is clear that these changes to input variables could reduce the potential savings from electrification significantly, thereby demonstrating that Mr. Neme's cost-effectiveness conclusion should not be taken as definitive.

141. An additional concern is that Mr. Neme's cost effectiveness analysis applies to a single building that electrifies today in isolation from the rest of the building population, that has minimal barriers to conversion at the building level. This does not account for the costs and complexity of a situation where millions of buildings electrify at or around the same time, which would result in significant societal costs associated with building the energy system to support the new demands. Early adopters would benefit; however, the benefits of conversion would diminish as more households convert and electricity prices increase, or grants are no longer available. The analysis presented by Mr. Neme also does not account for individual characteristics of each building that

may require upgrades such as panel or service line upgrades, internal wiring upgrades (gas to electric range), and building envelope improvements.

142. EP pointed out a number of the same and some additional flaws in Mr. Neme's analysis and conclusions about heat pump cost effectiveness and electrification in general. These include a lack of information on various costs including the cost of operating a heat pump with electric resistance heating, air handler costs, costs of disconnecting from gas, and additional home insulation costs. EP also pointed out that Mr. Neme (and Dr. Hopkins) did not take into account the high population growth rate in Ontario and how that might impact energy use, and the impact of the growing rate of EV charging on the electricity distribution grid and electricity distribution rates.[158]

B. Rate Base (Exhibit 2)

<u>Rate Base</u>

143. Issue 6 – Is the 2024 proposed rate base appropriate?

<u>*Summary and Relief Sought*</u>

144. Enbridge Gas requests approval of its as-filed 2024 proposed rate base, including the impacts of the Capital Update, subject to three adjustments.[159]

145. The three differences between what is filed in the Capital Update and what is requested for approval in Phase 1 of this proceeding are:

[158] EP Submission, pages 7-8.
[159] See AIC, pages 76-77 and associated references. In AIC (pages 77-78), Enbridge Gas explained that the Capital Update (which is not reflected in the Settlement Proposal) differs from the original filing, because it uses actual 2022 closing rate base value, rather than an estimate. As described in AIC, this adjustment results in a reduction in 2024 rate base versus the original filing. No party objects to this approach, and it is supported by OEB staff (OEB staff Submission, page 55) and LPMA (LPMA Submission, pages 9-10).

a) Changes made to 2024 opening rate base to reflect the agreement in the Settlement Proposal to remove approximately $41 million related to WAMS and GTA project overspend;[160]

b) The rate base value of the Dawn to Corunna project has been removed (on an interim basis), as this is being determined in Phase 2 of the proceeding (after which time all or some of the value will be added back into 2024 rate base, depending on the OEB's determination); and

c) The land purchased for the GTA West REWS project ($24.5 million) is removed from 2024 rate base for rate making purposes.[161]

146. As explained in AIC[162], there are four unsettled aspects to this issue:

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; and

d) Consequential changes to 2024 rate base from other determinations made by the OEB in this proceeding.

In this section of this Reply Argument, Enbridge Gas addresses items a) and b).

147. For the reasons already set out in AIC, Enbridge Gas submits that no further adjustments are required to the 2024 opening rate base beyond what is described above in paragraph 145.[163]

148. Enbridge Gas submits that it is appropriate to include integration capital amounts in 2024 rate base. The total undepreciated integration capital amounts that Enbridge Gas proposes to include in 2024 rate base is $119 million. Under the OEB's general principle of "benefits follow costs", it is appropriate that customers pay the ongoing costs of technology assets, in the form of depreciation, that will continue to benefit

[160] Settlement Proposal, Issue 6, pages 24-25 – filed at Exhibit O1, Tab 1, Schedule 1.
[161] Exhibit J14.13.
[162] AIC, page 76.
[163] See AIC, pages 75-95.

them after rebasing. This also fits with the OEB's "beneficiary pays" principle that applies to infrastructure projects.

149. The evidence establishes that important integration activities were swiftly implemented, and costs were prudently incurred, leading to sustained savings that Enbridge Gas is passing onto customers at rebasing. Importantly, many of these integration activities were projects that would have to be done individually by EGD and/or Union in the absence of amalgamation. However, because the projects were designed for the amalgamated utility, they are called "integration". These projects continue to be in service and will benefit customers well beyond rebasing. Enbridge Gas funded the projects using integration savings during the deferred rebasing term, and it is appropriate that customers fund the remaining costs of the projects using integration savings after rebasing.

150. The OEB's MAADs policy does not specifically state that a utility must absorb all capital costs that are even loosely related to a merger for all time. That outcome would imply that the MAADs policy actually changes how capital costs are recognized from a regulatory accounting perspective, such that they become a fixed period charge rather than costs recovered over the period when the associated assets provide service. If the MAADs policy intended such a different treatment, one would expect that to be stated clearly, whereas it is not mentioned at all. Such an outcome would be unfair in this case, resulting in a windfall to customers such that assets supporting ongoing service to customers are provided for free at the same time as customers receive the ongoing $86 million integration benefits reflected in the Company's cost base through this rebasing case.

151. An implication of interpreting the MAADs policy as requiring utilities to bear all capital costs of integration projects for all time is that utilities will not invest in such projects in the future during a deferred rebasing term. Otherwise, they will not have time to

recover the costs before benefits are transferred to customers at rebasing. Given that a utility can only complete so much work in the early years after amalgamation, this may lead to important work being delayed for many years.

152. The intervenor argument that Enbridge Gas “over earned” and therefore can afford to fund the remaining capital costs of integration projects is misguided. During an IR term (including a deferred rebasing term), revenues and costs are decoupled such that it is not proper to attribute overearnings to particular items. Integration savings are intended to fund integration costs. The evidence from Enbridge Gas is that its integration costs and savings during the deferred rebasing term were almost exactly equal.[164] Additionally, as explained in the Overview, the total amount of costs that intervenors argue can be funded by “overearnings” exceeds the actual overearnings by more than $100 million.

153. Enbridge Gas disputes that there is a proper basis for the OEB staff proposal[165] (supported by some intervenors) where Enbridge Gas would include only 50% of the remaining undepreciated integration capital included in rate base, with the other 50% being disallowed. There is no principled basis for this. Customers are getting 100% of the sustainable efficiency savings. Customers are getting 100% of the ongoing benefit of the investments. It is appropriate that 100% of the undepreciated costs be included in rate base.

154. Very few parties raised concerns with the Company’s proposed 2023 rate base additions. Presumably, this signals that there is no strong and/or specific opposition. While some parties commented on the size of the 2023 capital forecast, the only specific item of concern noted is the $26.8 million forecast revenue shortfall

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[164] See Exhibit J14.11.
[165] OEB staff Submission, pages 56-57.

associated with 2023 customer additions having a profitability index (PI) of less than 1.0.[166]

155. Enbridge Gas submits that it would be unfairly punitive to disallow a portion of 2023 customer attachment capital expenditures from being added to rate base in circumstances where the overall customer attachment capital being added to rate base benefits customers by many millions of dollars. Enbridge Gas provided explanation for its challenges in customer additions costs for 2023, including the fact that the Company was not permitted to update its cost recovery from infill customers.[167] The evidence establishes that the costs incurred were prudent and reasonable in the circumstances, and should be recoverable.

156. More generally, Enbridge Gas submits that the exercise of determining 2024 opening rate base is not aimed at evaluating the Company's 2023 budget as in a cost of service review, but rather it is a prudence review of the actual and forecast assets and projects being added to rate base. Other than in relation to customer additions capital, no party has raised any questions or concerns about particular 2023 expenditure items. There is no basis for an overall reduction to opening rate base, as argued by some parties.

157. Finally, Enbridge Gas acknowledges that its actual capital expenditures in recent years have varied from forecasts from time to time. Enbridge Gas agrees that 2024 opening rate base should reflect actual results. Therefore, the Company proposes that as part of the Phase 2 Rate Order process, it will report on and reflect the impact of changes between forecast and actual 2023 capital additions, and associated changes that impact rate base. Effectively, the update would be the same as performed for

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[166] ED and SEC refer to a $26.5 million shortfall, which is the number that Mr. Elson suggested in cross-examination (13 Tr.17) – the actual number is $26.8 million, as set out in the updated response to SEC interrogatory 118, part a) – see Exhibit I.2.6-SEC-118, part a).
[167] See, for example, 11 Tr.100-103.

2022, as described in AIC.[168] This can be done at the same time as the approved rate base value of the Dawn to Corunna project is being reflected in rate base (and revenue requirement).

Submissions by Other Parties

158. On the topic of integration capital, OEB staff and many intervenors made submissions.

159. APPrO supports Enbridge Gas including the remaining undepreciated capital costs for integration-titled projects in rate base. Two main points are advanced. Enbridge Gas agrees with both.

160. First, APPrO points out that Enbridge Gas received a deferred rebasing term (5 years) that was only half of what was requested and what was required to recover capital costs of integration. On this point, APPrO notes as follows:

> If the OEB had approved a ten-year rebasing period, Enbridge would have fully recovered – in fact it would have more than recovered – these costs through operational savings that would not have gone to ratepayers. Instead, ratepayers are now receiving $86 million in annual savings as a result of capital expenditures that Enbridge has not been allowed to recover.[169]

161. Second, APPrO highlights that it is a red herring to say that Enbridge Gas earned above allowed ROE, and therefore can fund the remaining integration costs. As explained by APPrO, integration costs and ROE are two separate matters, noting that "[c]onflating Enbridge's ROE with its integration related capital spending – and the benefits this accrues for ratepayers – undermines basic regulatory principles."[170]

[168] See AIC, pages 77-78, and associated references from the Capital Update evidence.
[169] APPrO Submission, pages 25-26.
[170] Ibid, page 26.

162. OEB staff[171], along with EP[172], LPMA[173], QMA[174], and PP[175], support the OEB taking a middle-ground approach, under which Enbridge Gas would see 50% of the remaining undepreciated integration capital included in rate base, with the other 50% being disallowed. The rationale for this position is explained by OEB staff as being linked to the fact that Enbridge Gas received a 5 year deferred rebasing term, which is only half of the typical 10 year term that is contemplated in the OEB's MAADs policy.[176] In addition, EP and LPMA point to the fact that the integration capital projects are items that the legacy utilities would have had to complete in any event, and the resulting assets are continuing to provide benefit to customers.[177]

163. Six parties (CCC[178], CME[179], FRPO[180], OGVG[181], SEC[182] and VECC[183]) argue that none of the integration capital projects and undepreciated costs should be included in rate base. Two main arguments are advanced.

164. The first main argument is that the OEB's MAADs policy says that integration costs are not recoverable from ratepayers.[184] These parties argue that this policy is absolute and that it applies to capital expenditures (regardless of their nature) and that it applies even where the OEB orders a shortened deferred rebasing term. VECC and

[171] OEB staff Submission, pages 56-57.
[172] EP Submission, page 18.
[173] LPMA Submission, page 15.
[174] QMA Submission, page 3 (supportive of Enbridge Gas integration efforts) and page 7 (supportive of OEB staff Submission).
[175] PP Submission, page 43 – PP also argues for a "stretch efficiency amount" to be included if Enbridge Gas includes integration capital in rate base.
[176] OEB staff Submission, page 57.
[177] EP Submission, page 18; and LPMA Submission, page 15.
[178] CCC Submission, pages 22-23.
[179] CME Submission, pages 16-18.
[180] FRPO Submission, page 22.
[181] OGVG Submission, pages 14-15.
[182] SEC Submission, pages 52-58.
[183] VECC Submission, pages 15-17.
[184] See, for example, CME Submission, page 17.

SEC also indicate that the MAADs Decision makes clear that none of the integration costs are recoverable.[185]

165. The second main argument is that Enbridge Gas "over earned" during the deferred rebasing term, and that the remaining undepreciated capital costs can be funded from the overearnings.[186]

166. Three of these parties (CCC, SEC and VECC) go even further, and argue that where Enbridge Gas undertakes future projects that could be classified as "integration", then the Company should also fund those projects with no inclusion in rate base.[187]

167. A few other submissions were advanced by intervenors on the topic of integration capital. LPMA argues that Enbridge Gas could have set a depreciation approach for the integration capital that would result in it being fully depreciated at the end of the deferred rebasing term.[188] Several parties question whether Enbridge Gas is actually crediting customers with $86 million in integration savings on a go-forward basis.[189] SEC takes issue with whether Enbridge Gas bore the integration capital costs during the deferred rebasing term.[190]

168. Each of these items is addressed below.

169. All parties agree that the party who pays for integration capital projects (customers or the Company) should get the associated CCA benefit for the projects that is currently recorded in the TVDA. Parties further agree that this principle would apply

[185] VECC Submission, pages 16-17.
[186] See, for example, CCC Submission, page 22.
[187] CCC Submission, page 23; SEC Submission, pages 57-58; and VECC Submission, pages 16-17.
[188] LPMA Submission, page 15.
[189] See, for example, VECC Submission, page 15.
[190] SEC Submission, pages 56-57.

proportionally in the event that the OEB decided to include some but not all of the undepreciated integration capital in 2024 opening rate base. Enbridge Gas agrees.

170. Moving on from integration capital, only four parties made substantive submissions on any other aspect of 2023 capital additions.

171. ED and SEC argue that the 2023 customer connections capital proposed for 2024 opening rate base should be reduced by the forecast revenue shortfall for the 2023 customer additions portfolio ($26.8 million).[191] Those parties argue that Enbridge Gas could have avoided or mitigated this forecast shortfall by rerunning customer attachment feasibility analyses and seeking additional contributions from customers.

172. Each of CCC, LPMA and SEC raise questions about the overall size of the Company's 2023 capital forecast and argue that the OEB should take this into account when determining the amount of rate base additions for 2024 opening rate base.[192] Notably, no party points to any specific additional items that should be disallowed from being included in opening rate base. This is different from the specific items of disallowance from opening rate base noted in the Settlement Proposal (GTA project and WAMS), and in the ED/SEC Submission that some of the customer attachment capital should be disallowed.

173. Finally, CCC, LPMA and SEC each note that Enbridge Gas has been spending less on capital than forecast in some recent years. These parties point to 2023 as an example, noting that the Company is not on track to meet its forecast.[193] LPMA proposes that the OEB "should approve an asymmetric variance account to protect

[191] ED Submission, pages 39-41; and SEC Submission, pages 81-82. The $26.8 million number is found at the updated Exhibit I.2.6-SEC-118(a).
[192] CCC Submission, pages 24 and 30; LPMA Submission, page 16; and SEC Submission, page 52.
[193] CCC Submission, page 28; LPMA Submission, page 16; and SEC Submission, page 64.

ratepayers from paying for in-service capital additions that are forecast to take place in 2023 but do not actually occur."[194]

Enbridge Gas Response to Other Parties' Submissions

174. As noted, in this section of this Reply Argument, Enbridge Gas is addressing:
    a) Inclusion of integration capital in 2024 rate base; and
    b) 2024 opening rate base amounts resulting from 2023 rate base additions.

Inclusion of integration capital in 2024 rate base

175. While Enbridge Gas appreciates that many of the participants who filed submissions are supportive of Enbridge Gas including at least half of the undepreciated capital costs for integration capital in rate base, the Company maintains its position that all such costs are properly included in 2024 opening rate base.

176. Many parties seem to argue that the OEB's MAADs Handbook is prescriptive on this point. It is not.

177. The MAADs Handbook states, among other things, that "[i]ncremental transaction and integration costs are not generally recoverable through rates".[195] The inclusion of the word "generally" shows that there is discretion in the matter.

178. On a broader basis, the fact that the MAADs policy is not prescriptive can be seen in other ways.

[194] LPMA Submission, page 16.
[195] https://www.oeb.ca/oeb/_Documents/Regulatory/OEB_Handbook_Consolidation.pdf, January 19, 2016, (MAADs Handbook), page 8.

179. First, as an OEB policy, the MAADs Handbook is a guidance tool[196] rather than a hard and fast rule like a statute (such as the OEB Act) or regulation (such as the *Energy Consumer Protection Act* General Regulation[197]) or rule (such as GDAR) that must be strictly followed.

180. Second, the MAADs Handbook is very clear that a distributor is able to choose the length of the deferred rebasing term that it wishes, up to ten years:

> The extent of the deferred rebasing period is at the option of the distributor and no supporting evidence is required to justify the selection of the deferred rebasing period subject to the minimum requirements set out below. ….. The OEB will therefore require consolidating distributors to identify in their consolidation application the specific number of years for which they choose to defer.[198]

181. If the MAADs Handbook (or MAADs policy to the extent that is distinct) is prescriptive, then the OEB would not have had the ability to order that Enbridge Gas have only a five-year deferred rebasing term, despite having applied for ten years.

182. This is the first time that the OEB has considered rebasing of an amalgamated utility that incurred substantial capital costs classified as integration costs. The MAADs Handbook does not specifically address capital costs. No discussion is included around the fact that capital costs, unlike operating costs, are not expensed in the year incurred. Requiring a utility to absorb undepreciated capital costs of integration projects at the end of a deferred rebasing term changes how capital costs are recognized from a regulatory accounting perspective, such that they become a fixed period charge rather than costs recovered over the period when the associated assets

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[196] The MAADs Handbook states in the very first line (page 1) that "The Ontario Energy Board (OEB) has developed this Handbook to provide guidance to applicants and stakeholders on applications to the OEB for approval of distributor and transmitter consolidations and subsequent rate applications".
[197] Government of Ontario. (2022 July 1). O. Reg. 389/10: GENERAL. Energy Consumer Protection Act, 2010. https://www.ontario.ca/laws/regulation/100389
[198] MAADs Handbook, page 12.

provide service. If the MAADs policy intended such a different treatment, one would expect that to be stated clearly. Instead, this is not mentioned at all.

183. Enbridge Gas submits that the facts of this case support the inclusion of the remaining undepreciated capital costs described in evidence and summarized in AIC.[199] This is a scenario where it is appropriate for the OEB to depart from its guidance about what might "generally" happen.

184. The integration capital expenditures in question are not related to assets that are required only because of integration. Rather the assets are applications and facilities required for the Company's ordinary operations. The biggest of these assets are a Customer Information System and an Asset and Work Management System. Each is fundamentally important to Enbridge Gas serving its customers. They are referred to as "integration" related assets because the nature of the assets has been impacted by the fact that they will serve the amalgamated utility rather than the individual predecessor utilities. Importantly, these investments were included in previous Union Asset Plans as normal course of business operations investments that would have to be made.[200] As explained by Ms. Lindley: "[t]hey were targeted for end-of-life replacement or technology obsolescence at that time".[201]

185. Enbridge Gas's evidence is that the actual replacement costs for the TIS systems were lower than had been forecast, and the decision to upgrade and migrate to a combined system was less expensive than a replacement of the Union system.[202]

186. SEC suggests that the Company's statements that the integration projects are comprised of work and assets required regardless of amalgamation was advanced for

[199] See AIC, pages 83-89, and associated references.
[200] See Exhibit K14.2, pages 3-5. See also 14 Tr.147-148.
[201] 14 Tr.147.
[202] 14 Tr.148, and Exhibit 1, Tab 9, Schedule 1, page 22.

the first time at the Oral Hearing.[203] That is not the case – this is noted in pre-filed evidence[204]. The same facts were highlighted by Enbridge Gas in the 2020 DVA proceeding, when clearance of the TVDA balance related to integration projects was considered.[205] In any case, the evidence on this topic was highlighted at the outset of the integration capital panel's testimony[206], such that it could be tested and discussed through cross-examination.

187. Enbridge Gas does not agree with the submission from VECC and others that the MAADs Decision is determinative that integration capital costs are not recoverable at rebasing.[207] In the MAADs Decision, the OEB simply stated that "five years provides a reasonable opportunity for the applicants to recover their transition costs."[208] No definition was provided around "transition costs", and whether that included long-lived replacement assets. There was no specific consideration of the capital costs required for systems and assets that continue to be required but are being replaced on a consolidated basis (and thus referred to as "integration" projects). There was also no consideration of the evidence in the MAADs case that Enbridge Gas would require 10 years to recover all capital costs[209] – five years would not be enough. This is what APPrO describes in its submission.[210]

188. In other parts of their submissions, intervenors accuse Enbridge Gas of seeking a "windfall" in aspects of the Company's requested relief in this case.[211] The Company

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[203] SEC Submission, page 54.
[204] Exhibit 1, Tab 9, Schedule 9, pages 21-22 and Exhibit 1, Tab 9, Schedule 9, Attachment 1.
[205] EB-2021-0149 Reply Argument, December 6, 2021, pages 3-4.
[206] 14 Tr.146-148.
[207] See, for example, VECC Submission, page 16.
[208] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, page 22.
[209] EB-2017-0306/EB-2017-0307, Exhibit C.STAFF.4.
[210] APPrO Submission, pages 25-26.
[211] See, for example, CME Submission, page 48; OGVG Submission, page 16; and SEC Submission, page 106.

submits customers would receive a windfall if the undepreciated capital costs for integration-related projects are disallowed from inclusion in 2024 rate base.

189. Enbridge Gas will have funded the cost of the integration-related projects from 2019 to 2023 (it is not disputed that the Company spent $189 million and only seeks to include $119 million in 2024 rate base, nor is it disputed that Enbridge Gas did not receive any incremental funding for these projects). Then, the Company will have passed on sustainable integration-related benefits of $86 million per year to customers starting in 2024.[212] In return, Enbridge Gas says that it is reasonable for customers to pay for the remaining cost of the integration capital assets on a go-forward basis. There is no dispute that customers will continue to benefit from those assets, given their central importance to the Company's operations.

190. The position of intervenors that no amount should be included in rate base for integration capital projects would see customers receive the use of those assets for free, at the same time as customers receive all the future benefits accruing from integration. That is a windfall gain. It is an inappropriate departure from the OEB's "benefits follow costs" and "beneficiary pays" principles.

191. As described in AIC, Enbridge Gas acted responsibly during the deferred rebasing term to pursue projects that would benefit operations and customers.[213] The evidence establishes that important integration activities were swiftly implemented, and costs were prudently incurred, leading to sustained savings that Enbridge Gas is passing onto customers at rebasing. That being said, Enbridge Gas could not implement all integration capital projects in the first year of deferred rebasing, which would be

[212] While it is true that this sustainable integration benefit number has not been tested, that is because all parties were able to agree that an O&M budget reflecting integration benefits was reasonable. If there were great concerns that Enbridge Gas had failed to pass along appropriate integration benefits then presumably O&M would not have been settled.
[213] AIC, page 81.

required if the goal was to depreciate the projects as much as possible before rebasing. Investments in complex projects were made quickly but had to accommodate the required time to plan for such investments, and the capacity of the organization to accommodate a finite amount of change to interwoven foundational systems and processes. There is also a limit on the amount of change that the Company's customers can absorb in a short period of time.

192. By integrating technology platforms, Enbridge Gas was able to reduce costs, increase efficiency and as a result, deliver value to customers through the deferred rebasing term and beyond. Enbridge Gas believed that the regulatory principle of benefits follow costs would be maintained at rebasing and made necessary investments quickly, in the expectation that while it would shoulder the associated costs during the shorter deferred rebasing term, the remaining undepreciated capital costs would be recovered from ongoing integration savings credited to customers at rebasing.

193. The Company could have delayed investments until after the deferred rebasing term and might have done so if it knew that remaining costs would become unrecoverable, but that would not have met the expectations of the OEB and customers. As mentioned in AIC, a finding that a utility is responsible for the undepreciated costs of integration capital spending after a reduced deferred rebasing term could have a "chilling effect".[214] Presumably, that will stop other utilities from voluntarily electing any deferred rebasing term less than 10 years. Additionally, it could lead to amalgamated utilities deferring or avoiding capital spending that might be classified as "integration", notwithstanding that such spending would benefit customers.

194. Enbridge Gas disputes that there is a proper basis for the OEB staff proposal (supported by several intervenors) where Enbridge Gas would include only 50% of the

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[214] AIC, page 88.

remaining undepreciated integration capital included in rate base, with the other 50% being disallowed. There is no principled basis for this.

195. All of the integration savings to date have been used to fund the integration costs to date. As of January 1, 2024, customers are getting 100% of the sustainable efficiency savings on a go-forward basis. Enbridge Gas is not retaining 50% of the savings from the amalgamation. It should not absorb 50% of the remaining costs. Customers are getting 100% of the ongoing benefit of the integration investments. It is appropriate that 100% of the undepreciated costs be included in rate base.

196. The suggestion from SEC that there is no direct link between integration capital spending and integration savings now being credited to customers[215] is misguided. The updates to processes and systems enabled the workforce reductions that were a main driver of integration savings. In any case, no party argues that the integration capital spending or projects were unnecessary. Enbridge Gas submits that fairness dictates that where customers get the enduring benefit of savings from integration, then customers should also pay for the post-rebasing portion of costs that supported that outcome. That is the OEB's benefits follow costs principle.

197. As noted above, several parties argue that Enbridge Gas can fund the undepreciated integration capital from "overearnings" during the deferred rebasing term. Enbridge Gas addressed this in AIC.[216] The Company funded integration costs from integration savings during the deferred rebasing term[217] – that is what the OEB expects. Also, contrary to the assertions from SEC, the "overearnings" during the deferred rebasing term referenced by parties in argument do include the impacts of integration spending

[215] SEC Submission, page 55.
[216] AIC, page 89.
[217] Exhibit J14.11.

and savings.[218] All such items were part of the annual utility results and related ESM calculations.

198. There is no principled reason for finding that because Enbridge Gas earned more than allowed ROE during the deferred rebasing term, customers can avoid having to pay the ongoing costs of assets required to provide ongoing service. Enbridge Gas might have underearned (making this argument inapplicable), but due to efficient operations it did not. In any event, the regulatory treatment and customer protection related to overearnings established by the OEB is the ESM that was in place during the deferred rebasing term. Enbridge Gas did not earn above the ESM threshold in any year of the deferred rebasing term. Moreover, as explained in the Overview, the total amount of costs that intervenors argue can be funded by "overearnings" exceeds the overearnings by more than $100 million.

199. In response to LPMA's Submission that Enbridge Gas could have depreciated the integration capital assets more quickly, the Company has two responses.

200. First, this is not permitted under applicable accounting rules. During the deferred rebasing term, Enbridge Gas adopted, where it could, harmonized accounting policies related to depreciation; however, this did not include harmonization of depreciation/amortization rates. Updates to these rates required OEB approval – that is what is being advanced in this proceeding[219]. If Enbridge Gas had depreciated its in-service assets in a manner that deviated from its policies, this would have required the impacts of such to flow through the Accounting Policy Changes Deferral Account (APCDA). This is counterintuitive to LPMA's suggestion.

[218] This is confirmed in an exchange between Mr. Rubenstein and Ms. Ferguson at 14 Tr.169.
[219] See Exhibit 4, Tab 5, Schedule 1.

201. Second, even if this approach was permitted, it would not fit with the timing or nature of investments. Some of the integration capital was spent in 2023[220] – that would imply a one-year depreciation term, or simply expensing the cost. More importantly though, all the assets associated with the integration capital continue to be used and useful in providing service to customers. The Company would be ignoring that reality if it was to write the assets down to zero prematurely.[221]

202. Enbridge Gas takes great exception to the argument that future projects that could be considered to be "integration" should also be funded by its shareholder. That argument posits that even after the Company has passed on the sustainable efficiency gains from integration to customers, future projects are the Company's financial obligation. This is clearly offside of the OEB's benefits follow costs principle. It is also not addressed in the MAADs Handbook. And it would certainly have a chilling effect on future amalgamations if it was found that a utility's cost obligations for anything referred to as "integration" continue indefinitely.

203. In any event, Enbridge Gas submits that it is not necessary, or even appropriate, for the OEB in this case to give direction to (or speculate) about the future treatment of future projects that will not be part of rate base until 2029.[222] No determination on this point is relevant to the setting of 2024 rates. Indeed, without knowing the timing, costs, and details of future projects, it would not be appropriate or reasonable to make any findings.

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[220] See AIC, Table 3, page 83.
[221] Enbridge Gas notes that the question of whether integration capital projects would be funded by customers or the Company after rebasing was considered in the 2020 DVA proceeding (EB-2021-0149) – in the decision in that case, the OEB deferred any determination, stating that "Any interpretation of the MAADs policy by the OEB can be dealt with in the rebasing proceeding" (Decision and Order, January 27, 2022, page 10). Given this direction, it would make no sense for Enbridge Gas to pre-emptively determine that assets would not be included in 2024 rate base.
[222] Enbridge Gas notes that one of the projects mentioned by CCC and SEC is a consolidation of properties in London. Given that London is nowhere close to the boundary of the Union and EGD rate zones, the Company does not understand how this could be seen as integration-related, under any definition. Ms. Dreveny clarified in her testimony that this project would never be classified as "integration" – 14 Tr.182.

204. In conclusion on the topic of integration capital, Enbridge Gas submits that it is fair and appropriate that all remaining undepreciated costs be included in 2024 opening rate base.

2024 opening rate base amounts resulting from 2023 rate base additions

205. Enbridge Gas submits that no adjustments are necessary or appropriate for 2024 opening rate base, to address the unsettled issue of 2023 capital additions (beyond integration capital).

206. In AIC, Enbridge Gas anticipated that some parties might note that the PI for 2023 customer additions is below 1.0 and argue for a disallowance of some costs. The Company set out its preliminary submissions as to why no disallowance of 2023 customer additions rate base is appropriate or necessary.[223] Despite Enbridge Gas having specifically raised this item as a potential issue, only two parties (ED and SEC) made any submissions in response. Those two parties argue that the 2024 rate base additions associated with 2023 customer connections capital should be reduced by the forecast revenue shortfall for the 2023 customer additions portfolio ($26.8 million). No other party, or OEB staff, made any mention of this item or argued for any disallowance.

207. In evidence, including testimony at the Oral Hearing, Enbridge Gas provided explanation for its challenges in customer additions costs for 2023.[224] A main challenge is the recent increases to a wide array of costs associated with customer connections, including labour, municipal and conservation authority permitting, materials, supply chain disruptions, enhanced sewer safety program costs, municipal

[223] AIC, pages 90-95.
[224] The Company's evidence is summarized at pages 90-93 of AIC – the supporting evidentiary reference provide more detail.

changes to restoration requirements and impacts of new soil handling regulations. Additionally, inflation was much higher than expected in recent years. A particular challenge arises from the fact that the Company was not permitted to update its cost recovery from infill customers.

208. Enbridge Gas acknowledges that in E.B.O. 188, the OEB indicated that:

> The Board will treat variances between actual and forecast portfolio NPVs in the same manner as for other forecast test year variables. The utilities will provide explanations of the reasons for the variations and the corrective actions taken or proposed. The Board will judge the degree to which the cost impacts should be apportioned between the shareholder and the ratepayers.[225]

209. A fair reading of the OEB's direction from E.B.O. 188 is that the OEB will perform a prudence review of customer attachment expenditures when determining whether variances should be included in rate base. The OEB is clear that it may choose to allocate some of the cost impacts between customers and the applicant.

210. ED and SEC argue that Enbridge Gas should have adjusted its estimating procedures and obtained larger contributions from new customers in 2023.[226] The evidence shows that Enbridge Gas has been taking steps to improve its customer connection activities. The Company has renegotiated its construction services contract and has diversified its supply chain options.

211. It is not as easy as ED and SEC claim to renegotiate and reset customer contributions. That is not the Company's practice, unless a project changes. Enbridge Gas explained that there is a one- or two-year time gap between when projects are estimated and feasibility calculations are run, versus when the costs are incurred or construction begins.[227] Enbridge Gas commonly faces complaints from customers

[225] E.B.O. 188, section 6.3.9.
[226] ED Submission, pages 39-40; and SEC Submission, page 82.
[227] 14 Tr.102.

related to connection costs. [228] Enbridge Gas knows that builders plan capital investments and pricing based on information provided about contributions. As seen by the OEB's Decision in the 2019 rate case related to customer connection practices for infill customers[229], the OEB (or OEB compliance staff, in informal discussions) often sides with customers and cautions against adjusting customer contribution amounts. Thus, while it may be technically possible to reset contribution amounts, this is more challenging in practice.

212. Additionally, at least part of the challenges encountered by Enbridge Gas arise from the OEB's direction in the 2019 rate case indicating that EGD could not change its charges for infill customers even though costs had increased.[230] Enbridge Gas has not been able to specifically quantify these impacts (to do so, the Company would need to retroactively assess the feasibility of approximately 4,000 individual infill accounts).[231] The Company's evidence is clear, however, that the cost challenges for infill customers are a significant contributor to the customer attachment portfolio PI being less than 1.0 in 2023.[232]

213. Finally, Enbridge Gas disputes the suggestion from ED that it should have designed its customer connection portfolio to recover a higher PI of 1.1, to allow for cost changes.[233] That approach would see the Company denying connections to customers who appeared, at the time of application, to be feasible. Enbridge Gas is obliged to connect new customers who lie along its lines, subject to the connection

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[228] While specific complaints made to the OEB are confidential (not published), it is clear from a review of the OEB's annual reporting on compliance activity that connection costs are a common area of inquiry and complaint - see Holding Utilities to Account April 2021 - September 2021 (oeb.ca), page 14; Compliance Report Fiscal - English (oeb.ca), page 9; Compliance Report April - September 2022 (oeb.ca), page 17.
[229] EB-2018-0305, Decision and Order, September 12, 2019, pages 34-36.
[230] Ibid.
[231] Exhibit J13.3.
[232] See, for example, 13 Tr.18.
[233] ED Submission, page 40.

being feasible.[234] Therefore, Enbridge Gas cannot “cherry pick” the most economic connections and deny connection to otherwise qualifying new customers.

214. Enbridge Gas submits that it would be unfairly punitive to disallow a portion of 2023 customer attachment capital expenditures from being added to rate base in circumstances where the overall customer attachment capital being added to rate base benefits customers by many millions of dollars.[235] The evidence establishes that the costs incurred were prudent and reasonable in the circumstances and should be recoverable.

215. As explained in detail above, it would not be fair or appropriate to disallow any of the Company’s 2023 customer attachment capital additions. However, if the OEB does not agree and determines that some portion of the 2023 customer additions costs be disallowed, Enbridge Gas submits that it would be appropriate to apportion the rate base implications of the revenue shortfall between customers and the Company. That is what is contemplated by E.B.O 188, as noted earlier.

216. As noted already, while some parties (CCC, LPMA and SEC) argue for an overall reduction in 2023 capital additions, no details are given as to what items should be excluded. Essentially, these parties are arguing that there should be disallowances of capital additions from 2023, without saying what associated projects or costs are imprudent and/or unrecoverable.[236]

217. Enbridge Gas submits that the exercise of determining 2024 opening rate base is not aimed at evaluating the Company’s 2023 budget as in a cost of service review, but rather it is a prudence review of the actual assets and projects being added (or

[234] See GDAR, section 2.2.1 and *OEB Act*, section 42(2).
[235] See AIC, pages 93-95, including supporting references.
[236] CCC Submission, pages 24 and 30; LPMA Submission, page 16; and SEC Submission, page 52.

forecast to be added) to rate base. This is different from the budget-review process being undertaken to establish 2024 revenue requirement, which is being done on a forecast basis. One main difference is that the 2023 costs are committed (and in many cases already spent). The 2024 budget is comprised of costs that have not yet been spent and could, where appropriate, be adjusted. That is a fundamental difference between approving a forecast budget for the test year versus evaluating past (or in process) expenditures from the bridge year to determine if those should be included in opening rate base.

218. Enbridge Gas further submits that proposing an overall non-specific reduction to 2023 capital additions/2024 opening rate base does not fit with the exercise that the OEB must undertake when determining rate base. The question to be asked is project specific, to look at the particular items proposed to be added to rate base. That exercise involves asking whether the costs of a project are prudent – if so, then the associated assets should be included in rate base based on the current depreciated costs. While there may be some recent debate about whether the prudence test should employ "hindsight"[237], there is no debate that the approach is rooted in looking at a particular project and/or costs and deciding whether the costs were prudently incurred, taking into account all relevant circumstances. A finding that particular costs / projects should not be included in rate base must be specific to what is being disallowed and why.[238]

219. Taking all of this into account, Enbridge Gas submits that there is no basis for non-specific adjustments to 2023 capital additions / 2024 opening rate base.

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[237] See *Ontario (Energy Board) v. Ontario Power Generation Inc*., [2015] SCR 147.
[238] For an example of a case where the OEB disallowed a portion of capital costs related to a project from rate base, see the December 13, 2012 EB-2012-0033 Decision and Order for Enersource Hydro Mississauga, which looked at the costs of a property project and disallowed a portion of such costs based on specific evidence and argument about the Derry Road Project (see pages 13-18 of the Decision).

220. Finally, Enbridge Gas acknowledges that its actual capital expenditures in recent years have varied from forecasts from time to time. While the Company is on track to spend at or above its forecast for 2023, that cannot be said for certain until the year is complete. There are a large number of projects underway, and the timing and final costs and rate base impacts may vary modestly from what was forecast earlier this year.

221. Enbridge Gas does not seek to include different amounts in 2024 opening rate base from what will be seen in final results at the end of the year. As was seen with 2022 results, year end rate base amounts are impacted not only by the amount of capital spending, but also by the timing of when assets are placed into service and the impacts of retirements.[239] Therefore, the Company proposes that as part of the Phase 2 Rate Order process, it will report on and reflect the rate base and revenue requirement impact of changes between forecast and actual 2023 net capital additions. Effectively, the update would be the same as performed for 2022, as described in AIC.[240] This can be done at the same time as the approved rate base value of the Dawn to Corunna project is being reflected in rate base (and revenue requirement). There is, therefore, no need for variance account treatment for this item, as proposed by LPMA.

Customer Attachment Policy

222. Enbridge Gas observes that while there is no specific issue in Phase 1 directed at customer attachment policy, the topic is relevant to three issues on the Issues List: Issue 3 (Consideration of Energy Transition), Issue 6 (Rate Base) and Issue 7 (Capital Budget). As part of this item, Enbridge Gas requests approval of its proposed updated extra length charge (ELC), which is the only unsettled part of Issue 29 (Miscellaneous Service Charges).

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[239] See AIC, pages 77-78.
[240] Ibid, and associated references from the Capital Update evidence.

Summary and Relief Sought

223. Enbridge Gas requests approval of its harmonized customer attachment policies. The harmonized customer attachment policies will be effective January 1, 2024, except for the inclusion of a 30-year customer attachment revenue horizon which will be implemented starting January 1, 2025. Enbridge Gas also requests approval of its proposed updated ELC.

224. Having considered the submissions received from OEB staff and intervenors, Enbridge Gas is updating its proposal from what is in evidence and AIC, so that the Company's harmonized customer attachment policies will incorporate a 30-year customer attachment revenue horizon, on an interim basis. This would require corresponding changes to the ELC. The remaining aspects of the Company's proposed harmonized customer attachment policies remain unchanged.

225. Enbridge Gas proposes that it would implement updated customer attachment policies, incorporating a 30-year customer revenue horizon and corresponding changes to additional charges for infill customers (which may be an ELC), as of January 1, 2025. The Company proposes that the Commissioners in this case could recommend a generic proceeding (or rulemaking process) to complete a fuller review of whether further changes to gas distributor customer connection policies are appropriate, taking into account energy transition. That generic proceeding would be held in the next year or two. Any further changes could potentially be implemented during the 2025 to 2028 IR term. That is what would make the approval of the 30-year revenue horizon in this case "interim".

226. Enbridge Gas submits that this measured approach is appropriate for a number of reasons, including the following:

- Energy transition is happening, but there is much uncertainty. While it may not be appropriate to “do nothing”, that does not mean that there is enough clarity to move immediately to an outcome that assumes that all customers will be leaving the gas system. The Company’s proposal takes account of these considerations.

- There is no question that there is a continuing current demand for gas service, and that demand may increase with the pressure to add housing. It would be a step too far to immediately cut the customer revenue horizon to zero, or even to cut it in half.

- Enbridge Gas’s proposed approach allows for near-term changes to the customer revenue horizon, followed by a deeper review, and perhaps further changes to the customer attachment policies. The fact that this approach is appropriate, which envisages a generic proceeding in the relatively near future, is seen from the facts that:

  i. It is clear from this proceeding that there is a broad range of views about customer attachment policy changes, with almost no consensus.

  ii. There is no evidence in this case about the range of options available to change the customer attachment policies, and the implications of such changes, and the steps being taken by regulators in other jurisdictions. Instead, there is simply a lot of argument.

  iii. There are likely other parties who are interested and would participate in a generic proceeding, and there are certainly other perspectives that the OEB would benefit from hearing, including municipalities, builders, EPCOR, municipal gas utilities (Kitchener, Kingston), IESO and electric LDCs.

  iv. Almost all ratepayer groups support a measured approach and generic hearing (CCC, LPMA, OGVG, VECC) – the only exception among ratepayer groups is SEC.

  v. The fundamental questions at issue, around whether E.B.O. 188 and GDAR should be changed, are more in the nature of rulemaking or generic issues. These are better addressed in a generic proceeding (or rulemaking process), where the outcomes are binding in future rate cases.

227. As explained in AIC, and expanded upon below, there is a strong basis for the OEB to conclude that a 30-year customer attachment revenue horizon is reasonable. This makes good sense as, at very least, an interim step pending a fuller review.

228. On the other hand, the evidence does not support moving immediately to a shorter customer attachment revenue horizon (or to a full contribution in aid of construction (CIAC) requirement as proposed by ED and GEC). A revenue horizon of 15 or 20 years presupposes that every new customer will exit the gas system when their furnace fails. There is no basis to reach that conclusion at this time. A full CIAC requirement would see new customers immediately over-pay as compared to every customer that has been added to the system in the past.

229. As mentioned, Enbridge Gas proposes to implement the new customer attachment policy with a 30-year customer attachment revenue horizon as of January 1, 2025. The Company requires substantial lead time to update systems and processes and ensure that appropriate notice is given to customers. An ELC of $159 per metre beyond the first 20 metres would be implemented in 2024 (to be replaced in 2025 aligned with the implementation of the 30-year customer attachment revenue horizon).

230. Enbridge Gas proposes that customers who have already received commitments for connections with CIAC amounts set (or confirmation that no CIAC is applicable) based on the current customer attachment policy would not be subject to the new policy even if their new connection is not completed until after January 1, 2025. Enbridge Gas further proposes that the updated customer attachment revenue horizon would not apply to Phase 2 community expansion projects.

231. As the Company's updated proposed customer attachment policies with a 30-year revenue horizon will not be implemented until 2025, there is no impact on the 2024

capital budget and revenue requirement. This is discussed in this Reply Argument under Issue 7.[241]

232. As mentioned, Enbridge Gas believes that it is appropriate for the Commissioners in this case to recommend a future generic proceeding (or rulemaking process), to consider whether further changes to gas distributor customer connection policies are appropriate, taking into account energy transition. The Company suggests that it makes sense for that process to take place after the findings of the EETP are published. The Company believes that any further changes to the Company's customer attachment policy (and resulting revenue requirement implications) could be implemented during the 2025 to 2028 IR term.

Submissions by Other Parties

233. Notwithstanding that customer attachment policy is not a standalone issue on the Issues List, this item received a lot of attention in submissions from OEB staff and intervenors. Substantive submissions were provided by OEB staff and 10 intervenors, totaling around 60 pages on this item.

234. Rather than summarizing the submissions on a party-by-party basis, Enbridge Gas believes that it is more helpful and efficient to summarize the submissions by topic. Enbridge Gas will then set out its response, using the same topic headings.

a) *Is the OEB permitted to change the revenue horizon in this case?*

235. A preliminary question to ask is whether the OEB can make changes to the 40-year revenue horizon set out in E.B.O. 188 and prescribed by GDAR. Parties have different views.

[241] See paragraph 406.

236. VECC argues that requiring Enbridge Gas to adopt a shorter revenue horizon amounts to taking away the flexibility conferred by E.B.O. 188. Because GDAR directs Enbridge Gas to meet the requirements of E.B.O. 188, requiring Enbridge Gas to use a shorter revenue horizon amounts to, in VECC's Submission, a rule change. VECC submits that a panel of Commissioners is not empowered to change an OEB rule such as GDAR.[242]

237. OEB staff submits that changing the revenue horizon does not conflict with the fundamental principles of the economic feasibility approach in E.B.O. 188. OEB staff further submits that the OEB has already added mechanisms such as Temporary Connection Surcharge (TCS) and System Expansion Surcharge (SES) not contemplated by E.B.O. 188, and that this did not require any update to GDAR. OEB staff concludes by noting that, in any event, the OEB can provide exemptions from GDAR provisions.[243]

238. Other parties who support the position that the OEB may make changes to the customer attachment revenue horizon in this case argue that the 40-year revenue horizon in E.B.O. 188 is a maximum value, and departures from that maximum can still be consistent with E.B.O. 188 and GDAR.[244] A further argument is made by ED that the OEB is engaging in ratemaking in this case and can consider appropriate customer connection costs in that exercise.[245]

b) *Should the OEB change the revenue horizon in this case?*

239. The question that is related to whether the OEB <u>can</u> change the customer attachment revenue horizon in this case is whether the OEB <u>should</u> make such a change.

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[242] VECC Submission, pages 13-14.
[243] OEB staff Submission, page 25.
[244] ED Submission, pages 33-34; GEC Submission, page 33; SEC Submission, pages 77-79.
[245] ED Submission, page 34

240. While all parties agree that the question of what changes should be made to the customer attachment revenue horizon is important and should be addressed soon, many parties argue that this should be done in a separate generic proceeding to review GDAR (and E.B.O. 188, and potentially the DSC) that would be ordered by the OEB's CEO at the recommendation of the Commissioners in this case. The submissions in favour of this position are that:

a) It has been 25 years since E.B.O. 188, and it is time for a full review, especially in light of energy transition.[246]

b) The submissions in this proceeding are focused on only part of E.B.O. 188.[247]

c) There is insufficient evidence on the record to make a change to E.B.O. 188 parameters[248] and/or it would be helpful to have more information about impacts of changes[249] and/or it would be helpful to consider the impact of changing the revenue horizon on affordability of new connections and whether this could have discriminatory impacts.[250]

d) Not all interested parties are involved in this proceeding, and there has been insufficient notice provided to those who may be impacted.[251]

e) Any generic proceeding should await further policy direction from the government (including the completion of the EETP).[252]

f) Both gas and electricity connection policies should be considered at the same time.[253]

g) There has been no customer engagement conducted in relation to changes to the customer attachment policy and its impacts on customers.[254]

h) Changes to E.B.O. 188 should be made as rulemaking changes, because they involve changing GDAR.[255]

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[246] CCC Submission, page 15.
[247] CCC Submission, page 15; LPMA Submission, page 17; and VECC Submission, pages 11 and 13.
[248] EP Submission, page 15; and VECC Submission, page 12.
[249] OGVG Submission, page 9.
[250] CCC Submission, page 16.
[251] VECC Submission, pages 9-10.
[252] LPMA Submission, pages 18-19.
[253] CCC Submission, page 15; EP Submission, page 15; and LPMA Submission, page 17.
[254] VECC Submission, pages 12-13.
[255] CCC Submission, pages 15-16; and VECC Submission, pages 13-14.

i) Changes to E.B.O. 188 should not be made as one-off items in a rate case that can be revisited in each subsequent case, but rather should be made as OEB rule changes that are binding on future OEB panels. This will promote consistency and certainty.[256]

241. LPMA submits that the OEB could direct a 30-year revenue horizon in this case as an interim measure until a determination is made through the generic proceeding.[257]

242. No party expressly argues against a generic proceeding to consider changes to E.B.O. 188 and GDAR, though OEB staff and some intervenors argue for their proposed changes to the customer attachment revenue horizon be implemented immediately in 2024.

c) *What changes should be made to the current 40-year revenue horizon, and why?*

243. There is a broad range of positions on this item.

244. At one end of the spectrum, EP[258] and VECC[259] submit that the OEB should make no changes to the customer attachment revenue horizon until after direction is provided through a generic proceeding. CCC submits that a change should be made through a generic proceeding, but if there is no such proceeding then a 20-year revenue horizon should be adopted.[260] LPMA proposes interim use of 30-year revenue horizon until review through a generic proceeding.[261]

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256 VECC Submission, page 14.
257 LPMA Submission, page 18.
258 EP Submission, page 15.
259 VECC Submission, page 14.
260 CCC Submission, page 16.
261 LPMA Submission, page 18.

245. At the other end of the spectrum, ED[262] and GEC[263] argue that there should be no customer attachment revenue horizon and that new customers should pay the full cost of connection through a CIAC. Those parties take this position despite the fact that their own expert (Mr. Neme), filed a report recommending a 15-year revenue horizon, to align with the expected life of a new furnace.[264] Thus, the parties sponsoring the only evidence about what options exist and should be pursued to amend the 40-year revenue horizon do not even support that evidence. Those parties (who castigate Guidehouse for changing its evidence) will say that Mr. Neme also said in testimony that no customer revenue horizon is a good idea, but that is not what his report says.

246. In between the positions at each end of the spectrum, OEB staff[265] and Kitchener[266] propose a 20-year customer attachment revenue horizon, and PP[267] and SEC[268] propose 15 years.

247. The following rationale is advanced to support shorter (or eliminated) customer attachment revenue horizons:

a) Shortening the revenue horizon will reduce stranded asset risk.[269] OEB staff argues that a relatively high proportion of new customers will electrify and exit the gas system after the initial life of their space heating equipment.[270] SEC makes a similar submission.[271] This is the same rationale as advanced by Mr. Neme[272] (but not by his clients).

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262 ED Submission, pages 25-26 – alternately, ED argues for a 10-year revenue horizon.
263 GEC Submission, page 32.
264 Exhibit M9, page 4 and 42-44, Recommendations 1 and 2.
265 OEB staff Submission, pages 25-26.
266 Kitchener Submission, page 7 (arguing for a maximum 20-year customer revenue horizon).
267 PP Submission, page 28.
268 SEC Submission, pages 75-76.
269 OEB staff Submission, page 25; ED Submission, page 30; and GEC Submission, pages 28-29.
270 OEB staff submission, pages 25-26.
271 SEC Submission, page 75.
272 Exhibit M9, page 4 and 42-44, Recommendations 1 and 2.

b) The current revenue horizon results in a cross-subsidy from existing customers to new customers.[273] The general premise is that the rates paid by new customers must cover their costs. Curiously, while this item was noted frequently during the Oral Hearing, it plays only a minor role in submissions from OEB staff and intervenors. In general, there seems to be agreement (subject to the items noted in the next subparagraph) that if the revenue horizon is set accurately, then cross-subsidization concerns are low. OGVG notes that where the revenue horizon is set too low, compared to the time when customers remain on the system and the asset lives for their connection assets, then those new customers will actually pay too much and cross-subsidize existing customers.[274] Of course, this will happen from day one where new customers are required to pay the full costs of connection up-front.

c) New customers do not pay their full costs, because their rates only recover their connection costs, and not the other system costs from which they benefit, and not their ultimate exit costs.[275] This argument is advanced in support of requiring full CIAC, rather than as an explanation for why a different revenue horizon is appropriate. OEB staff anticipates this argument and points out that rates paid by new customers pay for more than just connection costs.[276] This argument appears to raise the types of questions that would be addressed in a generic proceeding, where all aspects of customer attachment policy are addressed (rather than solely revenue horizon).

d) Shortening the revenue horizon to 20 years aligns with Kitchener's municipal energy plan.[277] Importantly, though, Kitchener (which is a gas utility itself) presents no evidence to show that it has shortened its own customer attachment revenue horizon for the feasibility analysis that it uses for its own new customers.

e) Requiring new customers to pay the full connection costs as a CIAC (or something close to that) will lower customer bills by reducing the utility's capital expenditures and revenue requirement, and by encouraging customers to adopt heat pumps with lower lifetime energy costs (though higher upfront costs).[278] It should be noted, though, that the reduction in capital expenditures will have very minor bill impacts in the short term, and will be matched in the

[273] The notion of cross-subsidization is noted by OEB staff (page 25); ED (page 26); GEC (pages 30, 31 and 32); EP (page 15), OGVG (pages 9 and 10) and PP (pages 26 and 27).
[274] OGVG Submission, page 8.
[275] ED Submission, pages 28-29; and GEC Submission, pages 29-31.
[276] OEB staff Submission, page 26.
[277] Kitchener Submission, page 7.
[278] ED Submission, pages 26-27; and GEC Submission, pages 26-27.

long term by revenues from the new customers (assuming that the revenue horizon matches the time that the average customer remains connected).

f) Requiring developers to pay the full connection costs will eliminate or reduce the "split incentive" problem, where developers choose the lower cost up-front approach (gas furnace), rather than the longer-term lower cost choice (electric ASHP).[279] OEB staff anticipates this argument and submits in response that this is an issue that can be addressed through customer education and a shorter revenue horizon.[280]

g) Requiring developers to pay the full connection costs will lower the number of new connections, which will lower GHG emissions.[281] This is a new justification for changes to customer attachment policies, unconnected to the OEB's current mandate.

248. Each of these items is addressed in the Enbridge Gas response below.

d) *Proper approach for infill customer additions, including ELC*

249. Enbridge Gas has proposed an updated ELC that would apply for infill customers. It is based on the continuing applicability of a 40-year customer attachment revenue horizon. In AIC, the Company explained that if there are changes to the revenue horizon then an alternate approach to recovering connection costs from infill customers may be necessary.[282]

250. OEB staff submits that the infill customer portfolio should achieve a PI of greater than 1.0 based on a revenue horizon of 20 years, and that this could be done through changing the ELC or by some other method.[283] OEB staff suggests that Enbridge Gas could develop and file an updated proposal for treatment of infill customers as part of Phase 3 of this proceeding.[284] In the interim, OEB staff submit that the OEB should

[279] ED Submission, page 31; and GEC Submission, pages 26-27.
[280] OEB staff Submission, pages 26-27.
[281] GEC Submission, page 28.
[282] AIC, pages 113-114.
[283] OEB staff Submission, page 27.
[284] Ibid, page 28.

approve the Company's original proposal for an ELC of $159 per metre above the initial (free of charge) 20 metres.[285] FRPO agrees.[286]

251. ED submits that infill customers should pay the full cost of connection. Alternately, if the OEB orders a new shorter customer attachment revenue horizon, ED submits that Enbridge Gas should file a new infill customer attachment proposal "within a short period".[287]

252. VECC submits that the proposed ELC should not be approved, and instead a lower amount ($100 per extra metre) should be approved pending a generic proceeding on customer attachment rules.[288]

253. No other party makes submissions as to the development and implementation of an approach for infill customers that would reflect a customer attachment revenue horizon of less than 40 years.

e) *Applicability of TCS*

254. ED notes that Enbridge Gas has an "unwritten policy" of not offering the TCS to developers of new subdivisions. ED asks the OEB to require Enbridge Gas to maintain this policy "to protect future gas customers" from a new form of "split incentive" where developers find a different way to avoid paying connection costs.[289] GEC makes a similar submission.[290]

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[285] OEB staff Submission, page 32.
[286] FRPO Submission, page 20.
[287] ED Submission, pages 36-37.
[288] VECC Submission, page 15.
[289] ED Submission, page 37.
[290] GEC Submission, page 27.

255. OEB staff submit that the use of CIAC, rather than SES/TCS, for new developments should be the "preferred approach" and this should be incorporated into the Company's customer attachment policy.[291]

256. No other party addresses this item.

f) *Treatment of Community Expansion*

257. OEB staff agree with Enbridge Gas that community expansion projects already selected for government funding in Phase 2 of the Natural Gas Expansion Program (NGEP) should be subject to the previous (40-year) revenue horizon, as projects were selected and government funding was provided on this basis.[292] However, OEB staff argues that, absent direction from the Government of Ontario, future phases of the NGEP could be assessed using the new revenue horizon (if any) determined by the OEB in this case. [293]

258. ED proposes that any exceptions for community expansion should be limited, and that Enbridge Gas should be required to fit such projects into a portfolio with a PI of 1.0, even with a different revenue horizon applying to other projects.[294]

g) *Implementation of changes to customer attachment policy*

259. In AIC, Enbridge Gas explained that it will need time to implement changes to its customer attachment policy, if those include significant changes to customer attachment revenue horizon. The Company set out a proposal as to how this can be done, proposing an implementation date of January 1, 2025.[295]

[291] OEB staff Submission, page 28.
[292] SEC takes a similar position - SEC Submission, page 80.
[293] OEB staff Submission, page 27.
[294] ED Submission, pages 35-36.
[295] AIC, pages 115-117.

260. OEB staff submits that any customers who approach Enbridge Gas for a new connection as of January 1, 2024 should be subject to the new customer attachment policy proposed by OEB staff.[296] 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.”[297]

261. ED and GEC submit that Enbridge Gas should implement changes to customer attachment policy immediately.[298] No consideration is given to the fact that their proposals are fundamental departures from current practice and would require very meaningful systems and process changes. ED and GEC accept that customers who have received a “binding” commitment to connections under the previous rules should not be subject to a new customer attachment policy.

h) *Other Items*

262. There are a number of additional items addressed in the submissions from OEB staff and intervenors.

i. Customer connection horizon

263. In addition to changing the customer attachment revenue horizon, SEC argues that the customer connection horizon used by Enbridge Gas should be reduced to 5 years. This would align with the rules for electricity distributors in the DSC.[299]

264. Neither OEB staff, nor any other party, commented on this item.

[296] OEB staff Submission, page 31. SEC takes a similar position – it argues for reduction in 2024 capital expenditures based on a 15-year customer attachment revenue horizon (SEC Submission, page 79).
[297] OEB staff Submission, pages 31-32.
[298] ED Submission, page 35; and GEC Submission, page 33.
[299] SEC Submission, page 74

ii. E.B.O. 134

265. Enbridge Gas did not make any comment, or provide any evidence, about the application of E.B.O. 134 in this proceeding. It does not fit with the Company's customer attachment policies for attaching new customers.

266. In its submission, GEC argues that the OEB should alter the "revenue period" in E.B.O. 134 to 15 years to reflect the likelihood of declining energy delivery via the gas system to all classes of customers.[300] This was not discussed during the Oral Hearing and is not addressed anywhere in evidence.

iii. Alignment with electricity distributors

267. A topic that was raised by Mr. Neme, and that was discussed through the discovery and hearing process, is whether there should be alignment between electricity and gas distributors in their customer connection policies.

268. No party argues for immediate alignment between electricity and gas customer connection policies, at least in relation to customer attachment revenue horizon, but some parties do argue that review of connection policies should include both electric and gas distributors, in part to explore harmonization potential.[301]

iv. Information packages for prospective new customers

269. OEB staff suggest that Enbridge Gas should be required to provide information about energy options to prospective customers.[302] In the view of OEB staff, the factsheet would be a fuel-neutral factsheet that both natural gas and electricity distributors would agree is accurate and Enbridge Gas may benefit from working with one or more

[300] GEC Submission, page 34.
[301] CCC Submission, pages 15-16; and EP Submission, page 15. ED, GEC and SEC argue that there is no need for symmetry – ED Submission, page 32; GEC Submission, page 32; and SEC Submission, page 75.
[302] OEB staff Submission, pages 29-31.

electricity distributors in developing this factsheet. OEB staff provided a list of the types of information that could be provided. ED makes a similar suggestion.[303]

270. These suggestions are addressed below with “other items” under heading h).

v. Large volume customers

271. Enbridge Gas has not proposed changes to its connection policy for large volume customers. Parties commenting on this item agree that there is no evidentiary basis for the OEB to make any such changes in this case.[304] ED notes that the Company should ensure that it obtains adequate security from large volume customers but admits that it has no evidence that this is not happening.[305]

vi. Exit fees

272. Enbridge Gas has not made any proposal to impose exit fees on customers who opt to leave the gas system. In fact, no party objected to the Company’s proposal to discontinue charging the “cut off at main” charge[306] – the rationale for this change is that Enbridge Gas does not want to discourage safe disconnections.[307]

273. 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.[308] EP also submits that exit fees may be appropriate in the future.[309]

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[303] ED Submission, pages 38-39.
[304] ED Submission, page 36; and OGVG Submission, page 7.
[305] ED Submission, page 36.
[306] Settlement Proposal, Issue 29 – Exhibit O1, Tab 1, Schedule 1, pages 51-52.
[307] Exhibit 8, Tab 3, Schedule 1, pages 34-35.
[308] OEB staff Submission, page 33.
[309] EP Submission, page 15.

vii. Linkage with depreciation

274. In AIC, Enbridge Gas pointed out that if there are substantial changes to the customer attachment revenue horizon, then it may be necessary to make changes to the Company's current depreciation proposal. Otherwise, there is a mismatch between asset lives and expected recoveries.

275. OGVG and PP acknowledge this issue. PP indicates that it proposes a 15-year depreciation period for new capital, and a corresponding 15-year customer attachment revenue horizon.[310] OGVG points to a concern that if the customer attachment revenue horizon (or the expected time that a customer remains on the system) is different than the asset lives for connection assets, then customers may overpay (or underpay) for their costs.[311]

i) *Examples of pure argument*

276. In reviewing the intervenor submissions, Enbridge Gas notes that much of what was provided is pure argument, based on assumptions and observations rather than on any evidence presented or tested in this proceeding.

277. A few examples are set out below:

    a) Kitchener points, for the first time, to its municipal energy strategy document, as justification for a shorter revenue horizon.[312]

    b) ED and GEC present scenarios for what they say will happen with developers if CIAC is required for the full amount of connection costs.[313] This is particularly notable, given that these are the only parties who presented expert evidence on the topic of customer attachments, yet that evidence did not address this item, given that Mr. Neme made a different recommendation (for a 15-year revenue horizon).

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[310] PP Submission, page 28.
[311] OGVG Submission, page 8.
[312] Kitchener Submission, page 7.
[313] ED Submission, page 27; GEC Submission, pages 26-27.

c) GEC argues that there is no concern that the electric distribution system will have capacity for all new customers, because there will already be 200-amp service to most new houses.[314] There is no evidence on this point, and it completely ignores the question of upstream capacity on the distribution system to supply not only typical existing loads, but also heating and vehicle load.

d) As noted above, GEC also argues that the OEB should change the parameters of E.B.O. 134.[315] That was never discussed during the Oral Hearing.

e) SEC sets out its view of how builders will react in the event that a different customer attachment revenue horizon is implemented.[316] SEC also goes further and speculates about how customers will respond.[317]

278. Without commenting on whether the particular items of argument noted above are fair, the Company submits that the number of items of argument provided for the first time in intervenor submissions, without evidence or discussion at the Oral Hearing, underlines the need for further process if significant changes are to be made to the Company's customer attachment policy.

j) *Items not discussed in evidence*

279. Before concluding this summary of the submissions from OEB staff and intervenors, Enbridge Gas believes that it is instructive to review and list items that are not included in evidence. On this point, Enbridge Gas agrees with VECC[318] that questions and propositions advanced in cross-examination, and related argument on the same propositions are not evidence. The following is a partial list of items that the Company expects would be important for the OEB to consider before making a very significant change to customer attachment policy.

a) There is very limited expert evidence on the question of customer attachment policy, and the implications to consider when making changes.

[314] GEC Submission, page 27.
[315] Ibid, page 34.
[316] SEC Submission, page 76.
[317] Ibid, page 77.
[318] VECC Submission, page 12.

b) There is no evidence from any expert or other witness to support the positions taken by any party advocating for a lower customer attachment revenue horizon.

c) There is no evidence about how regulators in other jurisdictions are addressing customer attachment rules in the context of energy transition.

d) There is no participation from parties who one would expect to be interested in this issue, including municipalities, the provincial government, builders, trade organizations, EPCOR, IESO, LDCs and chambers of commerce.

   BOMA and FRPO, the two parties who do represent building owners (who are the participants most directly impacted by customer attachment rules), provide no submissions on this issue.

e) There has been no customer engagement on the question of different customer attachment policies because that was not something being proposed by Enbridge Gas.

f) There is no case-specific information or participation from IESO, and no information from electricity distributors, about the capacity of the provincial system and local distribution systems to accommodate significant load growth.

280. In their submissions, ED[319] and GEC[320] blame Enbridge Gas for the lack of evidence on this topic. That is entirely unfair and misguided.

281. The Application filed by Enbridge Gas did not propose any change to the customer attachment revenue horizon, or other major components of the customer attachment policy. As noted by VECC, this was not on the Issues List, and was only brought into focus in the OEB's Procedural Order No. 6, issued on June 23, 2023 (not June 6 as noted by VECC). It was only at that time that the OEB identified "whether Enbridge Gas's application of the revenue horizon parameter established in E.B.O. 188 continues to be appropriate in light of energy transition" as a "matter of particular interest".[321] Enbridge Gas has always maintained the importance of having this

[319] ED Submission, pages 32-33.
[320] GEC Submission, page 33.
[321] Procedural Order No. 6, June 23, 2023, page 5.

proceeding completed in a manner that allows for rates to be implemented as close as possible to January 1, 2024. In these circumstances, it is understandable and reasonable that Enbridge Gas did not file additional evidence to support its position.

282. On the other hand, not a single party arguing for changes to the customer attachment revenue horizon has filed evidence supporting their position. To say that it is Enbridge Gas's fault that the evidence is "too thin" is unfair. The simple fact is that the OEB does not have the benefit of evidence (as opposed to argument) as to the options advanced by other parties to be considered and the implications of those options.

Enbridge Gas Response to Other Parties' Submissions

283. Enbridge Gas submits that the OEB should approve the harmonized customer attachment policy as filed, with several changes related to the customer attachment revenue horizon. Enbridge Gas repeats and relies upon its detailed AIC submissions on the topic of customer attachment policy.[322] This Reply Argument should be read in conjunction with the AIC.

284. The Company's updated proposal is described in the Overview section above.

285. To recap, Enbridge Gas submits that it is appropriate, in light of the evolving energy transition, to reduce the customer attachment revenue horizon to 30 years on an interim basis. Assuming that the OEB agrees, then sometime after this case is complete a generic proceeding or rule-making process would be held to determine what further changes, if any should be made to the gas distributor customer connection policies prescribed by GDAR and E.B.O. 188.

[322] AIC, pages 96-117.

286. This approach provides stability for the Company to operate with certainty pending the outcomes of any generic proceeding (or rulemaking process) that may be undertaken by the OEB. This measured approach strikes a reasonable balance between new and existing customers.

287. The reasons for this proposal can be seen below, in the Company's response to the submissions received, which are organized under equivalent headings as the summary of those submissions in the previous section of this Reply Argument.

a) *The OEB may change the revenue horizon in this case*

288. Enbridge Gas continues to take the position that E.B.O. 188 is mandatory in its requirement for a 40-year revenue horizon for customer attachments. That is what the Guidelines set out in Appendix B of E.B.O. 188 indicate. All of this is set out in more detail in AIC.[323]

289. However, as indicated in AIC, this question about whether the 40-year revenue horizon is "mandatory" is not something that the OEB needs to determine here. Enbridge Gas accepts the OEB can order exemptions from GDAR provisions, including section 2.2.2 which requires adherence to the E.B.O. 188 Guidelines.

b) *This is not the proper venue to make fundamental and permanent changes to GDAR and E.B.O. 188*

290. Enbridge Gas submits that the question of whether the OEB can order changes to the customer attachment revenue horizon is different from whether the OEB <u>should</u> order such changes.

291. Enbridge Gas submits that the OEB should not make a fundamental and permanent change to the customer attachment revenue horizon rules in this case. Instead, it is

[323] AIC, pages 104-107.

much more appropriate to make a measured interim change from 40 years to 30 years, along with a recommendation that the OEB convene a generic proceeding (or rulemaking process) to fully consider whether further and/or broader changes to gas distributor customer attachment policies should be made, taking into account what is known about energy transition.

292. In the recent proceeding where the OEB approved Enbridge Gas's proposal for a harmonized SES and TCS, the OEB declined to initiate a review of E.B.O. 188, noting that this was "outside the scope of this panel's review".[324] That case, unlike this proceeding, was specially focused on customer attachment mechanisms. Enbridge Gas submits that the same conclusion can and should be made here, and that the OEB should decline to take steps that amount, in effect, to a review of E.B.O. 188.

293. In AIC, Enbridge Gas explained the reasons why this proceeding is not the appropriate forum to make substantial changes to OEB policy prescribing gas distributor connection rules. Among other things, Enbridge Gas pointed to the relative lack of evidence presented and the fact that what is at issue is really a rulemaking change that is appropriately addressed by the OEB through a generic proceeding or rulemaking process.[325]

294. In AIC, Enbridge Gas also noted that any reduction in the revenue horizon should balance the interests of existing customers and new customers. The Company also underlined that any changes made should be done in the context of the Government's policies, such as the NGEP, the *More Homes Built Faster Act,* and the affordability concerns that have been raised both in the Powering Ontario's Growth Report as well

[324] EB-2020-0094, Decision and Order, November 5, 2020, page 24.
[325] AIC, pages 105-108.

as the Minister of Energy's response letter to Ms. Harradence.[326] Very few, if any, of these considerations are addressed in any detail in intervenor submissions.

295. In the summary of intervenor submissions above (see paragraph 240), Enbridge Gas highlighted examples of evidence and participation that are not included in this proceeding, but which the OEB would presumably want to consider before making a fundamental change to gas distributor connection rules. Enbridge Gas submits that this is an important factor weighing in favour of the measured approach proposed by the Company.

296. Almost every ratepayer group filing submissions on this topic agrees with Enbridge Gas. The submissions in support from CCC, LPMA, OGVG and VECC all support having the OEB review gas distributor customer connection policy through a generic proceeding. The rationale presented by those parties is compelling. Enbridge Gas encourages the OEB to consider the full list of reasons in support from those parties, as summarized in paragraph 240 above.

297. While all of the rationale presented is important, Enbridge Gas wishes to emphasize VECC's Submission that there is a fundamental difference between a rulemaking process and a rates proceeding. Rules issued by the OEB are binding, not only on regulated parties but also on OEB Commissioners considering new fact scenarios. This promotes certainty and consistency. The same can be said of generic proceedings. In the OEB's recent Generic Hearings Protocol, the OEB noted that "the outcome of a generic hearing is binding on the regulated entities that are the subject of any ensuing order".[327] Conversely, decisions of OEB Commissioners in rate cases are fact-specific and can be revisited and, in appropriate cases, reversed or

[326] AIC, page 108 (including references).
[327] OEB Generic Hearing Protocol, December 13, 2022, page 1.

distinguished or disregarded.[328] Enbridge Gas submits that something as important as customer attachment policy, which is already part of OEB rules, is appropriately reviewed and (if necessary) amended through a generic proceeding or rulemaking process.

298. A review of the OEB's recent Generic Hearings Protocol confirms that the consideration of an updated gas distributor connection policy is an appropriate matter to be considered through a generic proceeding. The following observations fit with the factors that the OEB states that it will consider in assessing whether an issue should be considered in a generic proceeding[329]: (i) this is a significant issue; (ii) the outcome will apply to more than one regulated utility; (iii) there is benefit from broader stakeholder participation as compared to what has been experienced in the current case; and (iv) there is no negative impact on the current proceeding from making an appropriate interim determination pending a later generic proceeding.

299. Enbridge Gas recognizes that the Commissioners in this case have signaled a particular interest in the question of what is the appropriate customer attachment revenue horizon in light of energy transition. Enbridge Gas also acknowledges that it may not be acceptable to "do nothing" in the face of the acknowledgement of all parties (including Enbridge Gas) that energy transition is happening. Taking that into account, Enbridge Gas submits that a reasonable and appropriate balance is achieved by its proposal that the OEB approve an updated customer attachment policy including a 30-year customer attachment revenue horizon on an interim basis, with a recommendation that the OEB convene a generic proceeding (or rulemaking process) to consider gas distributor customer attachment policy more broadly. That generic

[328] That the OEB believes that it can revisit or reverse prior rates decisions can be seen in the OEB's Decision on the Issues List in this case, where the OEB included Issue 47 (amount of cost-based storage), even though it contradicts an earlier OEB decision – see Decision on Issues List & Expert Evidence and Procedural Order No. 2, January 23, 2023, pages 5-7.
[329] OEB Generic Hearing Protocol, December 13, 2022, pages 2-3.

proceeding can include all interested and impacted parties, and the decision-makers can have the benefit of more evidence (including expert evidence) compared to what is on the record in this proceeding.

c) *The revenue horizon should not be reduced below 30 years at this time*

300. Enbridge Gas believes that if there is to be a change to the customer attachment revenue horizon, then 30 years is appropriate. The reasons for this position are set out in AIC.[330] Enbridge Gas will not repeat its detailed submissions but continues to rely upon them.

301. One thing that is not noted in AIC, but which supports the adoption of a 30-year customer attachment revenue horizon, is that 30 years is roughly equivalent to the period of time that it takes for a typical residential customer to recover the capital cost to connect with the distribution system.[331]

302. Enbridge Gas submits that its position stands up in the face of the arguments advanced by other parties for shorter customer attachment revenue horizons.

303. Most parties who provide submissions on this question, as well as Mr. Neme[332], indicate that the appropriate way to determine a customer attachment revenue horizon is to evaluate how long a new customer is likely to remain attached to the gas system. These same parties agree that the time that a new customer will remain attached is closely related to the lifespan of the customer's gas furnace. It is at that time that the customer will decide whether to replace the gas furnace with a new gas appliance, or to convert to electric heating.

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330 AIC, pages 108-112.
331 Exhibit JT3.11.
332 6 Tr.42-43.

304. Enbridge Gas largely agrees with the position above, but notes that even where customers choose to convert to electric heating, they may retain their gas connection for hybrid heating or for other appliances.

305. There are two key differences between the way that Enbridge Gas and others approach this question.

306. First, there is the question of the average lifespan of a new furnace. Enbridge Gas says it is around 20 years, taking into account technological improvements. The standards that are applied for DSM measures say the lifespan is 18 years.[333] Other parties seem to "round down" to 15 years.

307. A starting point assumption that the lifespan of a new furnace is 15 years is not supported by any evidence. An assumption of a 20-year lifespan is much more reasonable.[334]

308. Second, there is a question about what a customer will do at the end of the lifespan of their furnace. Enbridge Gas says that at this early stage of energy transition, it is fair to assume that half of customers will retain a gas connection when their furnace fails. There is no evidence to date of large numbers of customers exiting the system and making the choice to electrify.[335] When the time comes for a customer to consider furnace replacement, they may choose to pursue hybrid heating and/or may continue with gaseous heating using RNG or hydrogen mix or abated natural gas.[336] Some customers may choose to retain a gas connection for other appliances (or at very least until the end of the operating life of those appliances).

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[333] Correspondence of the Board, Natural Gas Demand Side Management Technical Resource Manual version 7.0, EB-2015-0245, November 30, 2022, pages 26 and 273.
[334] 11 Tr.18.
[335] 11 Tr.25-26.
[336] AIC, pages 109-110, and associated references.

309. Some intervenors (and OEB staff) seem to assume that <u>every</u> customer will electrify immediately when their furnace fails. Enbridge Gas submits this position is untenable. It is not reasonable to assume that every new customer will leave the gas system in 15 years (PP and SEC) or 20 years (OEB staff and Kitchener). There is no evidence to support that conclusion.

310. As Enbridge Gas set out in Table 5 of AIC[337], there are big impacts on the revenue horizon depending on replacement assumptions. The Company submits that it is reasonable, particularly in the context of the interim solution that Enbridge Gas proposes, to assume that half of new customers will remain on the gas system in 20 years (in the year 2044).

311. Enbridge Gas agrees with LPMA's Submission that impacts of an amended customer attachment revenue horizon on potential new customers needs to be taken into account. LPMA notes that:

> …the increase in the contribution in aid of construction ("CIAC") from moving from 40 to 20 years of revenue is an increase of $1,140 per customer (exhibit J11.1). Such a significant increase or even larger increase associated with shorter revenue horizons cannot, in the view of LPMA, be justified at this time given the lack of any concrete government policy that signals a significant change in energy policy within the province.[338]

312. As explained in AIC, Enbridge Gas does not agree that customer attachments cause cross-subsidies.[339] Assuming that the new customer remains on the system for the assumed revenue horizon, then the rates paid by the customer cover the cost of connection, as well as the costs of serving the customer. The inclusion of normalized

[337] AIC, page 110.
[338] LPMA Submission, page 19.
[339] AIC, pages 102-103.

system reinforcement costs in the economic evaluation ensures that the customer is also paying for system upgrade costs to accommodate new customers.[340]

313. Enbridge Gas submits that setting the correct revenue horizon is important to ensuring that there is no cross-subsidy. However, that is a symmetrical issue. As OGVG explains, if the customer revenue horizon is too short (and if there is a full CIAC), then the new customer will effectively cross-subsidize existing customers by paying the CIAC and then paying rates for longer than is needed to pay for their connection.

314. Some might argue that paying full CIAC is fair, since everyone pays the same rates, but that ignores the fact that all existing customers were also a new customer at one point, with their own costs recovered over time. It has always been the case that the initial cash flow deficiencies caused by the portfolio of new customers is temporary (short-term) and will follow a revenue sufficiency in the later years to benefit existing customers through a revenue stream generated by these customers.

315. Customers attached decades ago accrue significant benefits to existing customers as their assets are fully depreciated and the revenue they generate over and above their ongoing cost help reduce rates for everyone. This is an enduring principle of E.B.O. 188, and of the regulatory approach used for gas distributors in Ontario. Never have new customers been required to pay their full cost of attachment up front. Instead, the new customers pay back the costs of their connection, and contribute to system costs, over time. The growing customer base then spreads fixed costs among a larger group of ratepayers, with benefits therefore passed along to the existing customers. This has helped mitigate rates for all customers for many decades. Enbridge Gas submits that if the OEB is inclined to depart from its historical approach, this is best considered in a

[340] 11 Tr.27.

generic proceeding, with full evidence and precedential value, rather than through a subsidiary issue in a large utility rate case.

316. ED and GEC support their proposal that new customers should pay <u>all</u> connection costs in the form of a CIAC with several arguments that engage factors going beyond what is properly considered by the OEB in this case.

317. In any case, though, Enbridge Gas submits that there is no evidence setting out the consequences of such an approach, nor around how it would be implemented, and whether other parties and stakeholders would support. Requiring full CIAC is the type of fundamental change that should not be made in this case – it amounts to a structural change to the way that utilities would approach customer connections. No doubt it would lead to questions about how electricity distributor connections should be treated. This structural change is not something to be approved and implemented in a utility-specific rate case with no evidence. Of course, if there is a generic proceeding on the topic of gas utility customer connections, then ED and GEC can advance this same position there, with supporting evidence, and other interested parties can respond.

318. One main reason advanced by ED and GEC for their proposal is that it would eliminate the "split incentive" that they say occurs where a developer prefers a gas connection (with limited or no CIAC) while an informed consumer would choose an electric heat pump. ED asserts that having a full CIAC requirement would make a developer more likely to choose electrification. There are several problems with this argument. First, it goes beyond the OEB's mandate. The OEB is not charged with encouraging electrification. Second, it gives too little credit to customers being able to make their own informed decisions. If the advantages of heat pumps are as obvious as ED, GEC and Mr. Neme assert, then customers may make clear that is their preference, which will drive developers to make different decisions. OEB staff points to

the importance of customer education in this regard. Additionally, it should not be forgotten that there may be different up-front costs associated with gas and electric heating solutions. Even if a customer sees potential for long-term savings through electrification they may choose the relative affordability of a gas solution in the shorter term.

319. As already stated, GEC's Submission that requiring full CIAC is appropriate because it will lower GHG emissions goes beyond the OEB's mandate. Using that as a justification for requiring full CIAC would be a fundamental policy change that is not appropriately determined in a utility-specific rate case. Also, as noted in Exhibit J11.6, the relationship between GHG reductions and electrification is influenced by the number of hours that gas-fired generation is used.[341]

d) *Proper approach for infill customer additions, including ELC*

320. As Enbridge Gas explained in AIC, its proposal for an updated ELC was premised on a 40-year customer attachment revenue horizon. Enbridge Gas has explained that it may take a different approach, potentially using a fixed fee amount, where a different revenue horizon is applied.[342] 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. As an example of the alternate approach that Enbridge Gas might propose, the Company calculated an estimate of the fixed charge approach for each revenue horizon which was filed at Exhibit J10.7, Table 1.

321. Parties generally agree that it would be appropriate for Enbridge Gas to determine and propose a new approach for an ELC or other cost recovery from infill customers, assuming that a different revenue horizon is directed.

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[341] Exhibit J11.6, Attachment 1.
[342] AIC, pages 113-114.

322. Enbridge Gas is open to providing an updated proposal in Phase 3 of this proceeding. If the OEB agrees with the Company's overall implementation proposal, then all aspects of the interim 30-year revenue horizon, including the updated approach for infill customers, could be implemented as of January 1, 2025.

323. If OEB staff's proposal that there should be a PI of more than 1.0 for infill customers is intended to mean that the infill customer portfolio should be assessed separately from other customer additions, then Enbridge Gas disagrees. That is not what is directed by E.B.O. 188. It directs that the customer attachment portfolio is to be assessed on an overall basis.

324. For 2024, Enbridge Gas agrees with OEB staff and FRPO that it would be reasonable to implement the $159 per metre ELC (beyond 20 metres) included in evidence for this proceeding. There is no evidence or basis to adopt VECC's alternative proposal of applying inflation to the prior ELC, to set a new interim charge.

e) *Applicability of TCS*

325. Enbridge Gas has explained that its practice is to generally not use the TCS for new residential developments. However, Enbridge Gas has also explained that it will have to consider all available tools in order to accommodate significant changes to the customer attachment revenue horizon.[343]

326. Enbridge Gas does not agree that it will or should commit to never using the TCS for new residential developments or other new customer attachments. The costs of CIAC could be very high under proposals from ED and GEC. The parties connecting to the

[343] 10 Tr.128-129.

gas system will expect to be connected for many years, so there is logic in permitting their connection costs to be paid over time, where permissible.

327. Again, like with so many aspects of the Company's customer attachment policy that other parties seek to amend, there has been very little discussion of this item. There is certainly no discussion of how the Company's harmonized customer attachment policy and the OEB's EB-2020-0094 Decision and Order setting out the terms and applicability of the TCS[344] should fit together.

328. Enbridge Gas proposes that the applicability of the TCS to new connections would be an appropriate item to address in a generic proceeding.

329. In the meantime, if the OEB agrees with the Company's proposal for interim implementation of a 30-year customer attachment revenue horizon, then Enbridge Gas can agree to refrain, on a similar interim basis from offering the TCS to developers of eligible new residential subdivisions. The matter can then be addressed in the generic rulemaking proceeding.

330. If the OEB decides to require a shorter revenue horizon, then Enbridge Gas cannot make that commitment. It may be appropriate to use the TCS in some circumstances. Enbridge Gas submits that there is insufficient evidence or basis for the OEB to effectively over-rule, or at least re-write, the recent EB-2020-0094 Decision and Orders (original decision[345], and rate order[346]) that set out the terms under which TCS can be offered. An allegation that the TCS would create a "split incentive" is insufficient grounds for such a change.

[344] EB-2020-0094, Decision and Order, November 5, 2020.
[345] Ibid, with further Decision and Order dated December 4, 2020.
[346] EB-2020-0094, Rate Order, January 7, 2021.

331. Additionally, for clarity, Enbridge Gas notes that it plans to offer SES/TCS where applicable for community expansion projects (based on the existing 40-year revenue horizon).

f) *Community Expansion*

332. There is broad consensus that any new customer attachment revenue horizon would not apply to community expansion projects that have already been selected for Phase 2 NGEP grant funding. OEB staff notes that any new customer attachment revenue horizon could apply to future phases of the NGEP unless the Government directs otherwise.

333. Enbridge Gas submits that this approach is appropriate. It is consistent with the position that the Company advanced in AIC.[347] Phase 2 NGEP projects should be subject to existing customer attachment rules, including a 40-year revenue horizon and a 10-year customer connection horizon, as well as the updated ELC calculated based on those parameters. The OEB can determine if any GDAR exemption is required, for example in relation to the requirement in section 2.1.1 that a gas distributor shall provide gas distribution services in a non-discriminatory manner.

334. Enbridge Gas does not agree with the proposal by GEC that community expansion projects must be considered in a customer attachment portfolio as if they were subject to the same customer attachment revenue horizon as other projects. This is unfair. It penalizes Enbridge Gas for complying with the terms of the Government's NGEP. It also penalizes otherwise eligible new customers (those with a PI of >1 but who are less profitable than other eligible new customers) who will be denied a connection in order for Enbridge Gas to maintain an overall portfolio with a PI of 1.0.

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[347] AIC, pages 112-113.

g) *Implementation of changes to customer attachment policy*

335. As explained in AIC, Enbridge Gas will require some time to fully implement a change to a shorter revenue horizon.[348] This is not a simple process – systems and training and customer information materials will have to be updated and implemented to reflect a new revenue horizon approach into the Company's customer feasibility calculations and determinations. These are described in detail at Exhibit J10.13. Time will be required for system changes to implement new feasibility determinations.

336. The suggestion from OEB staff, and from ED and GEC, that implementation can happen immediately is not feasible. No consideration is given to the Company's business, processes, systems, and communications materials that will be impacted by such a change. Enbridge Gas respectfully submits that these parties underestimate the complexity of the change management process involved in making such a change including, for example, system changes that involves TIS work, testing and training. In addition, new complexity arises from the process of monitoring and tracking customers who have requested service before and after implementation of such a change. No reference is made in intervenor submissions to the five pages of details of the process and system changes that Enbridge Gas will have to implement, as set out in Exhibit J10.13. Enbridge Gas urges the OEB to review those requirements when assessing a reasonable implementation timeframe.

337. In AIC, Enbridge Gas should have also described the E.B.O. 188 and GDAR provisions with which it must comply when changing the customer attachment policy. These items also make immediate implementation of customer attachment policy changes unachievable.

[348] AIC, pages 115-117.

338. Under section 4 of E.B.O. 188, Enbridge Gas is required to have a “clear set of common Board-approved Customer Connection and Contribution in Aid Policies.” These policies must include information on the “specific criteria and the quantum of, or formula for calculating, the total excess service line fees and other charges”. It will take time to develop to reflect any changes arising from this proceeding.

339. More importantly, notice will have to be provided to customers about the changes to the customer attachment policy. This means that implementation cannot be immediate.

340. Some of the changes that may be required will have to be reflected in the Company’s Conditions of Service. Under section 8.5.1 of GDAR, Enbridge Gas is required to provide advance public notice of any revisions to Customer Service Policies related to residential customers. In past changes to GDAR, the OEB has set out a range of notice periods from as low as 4 months to as high as one year.[349]

341. Enbridge Gas acknowledges that the customer attachment revenue horizon associated with the Company’s customer attachment policies is not described in its Conditions of Service. However, making a change to the customer attachment revenue horizon will be expected to have significant impact on some prospective new customers. Enbridge Gas submits that implementing such a change without providing consumers, businesses and other affected stakeholders reasonable notice is unreasonable and not in keeping with the best practices of the OEB in the discharge of their statutory objective to inform consumers and protect their interests with respect to prices and the reliability and quality of gas service.[350] It is also not consistent with the OEB’s practices when its own Rules (such as the DSC or GDAR) are amended –

[349] For example, the Customer Service Rule Amendments set out in the OEB’s EB-2017-0183 Notice of Amendments to Codes and a Rule (March 14, 2019) allowed for implementation intervals of one year for some items, and four months for other items, depending on the implementation complexity.
[350] *OEB Act*, section 2(2).

in those cases, ample notice is typically provided in order to give warning to affected parties and in order to give utilities lead-time for implementation.

342. Taking all of this into account, Enbridge Gas maintains its proposal 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 should be exempt from the new rules.

343. There seems to be general agreement that commitments already made by Enbridge Gas to prospective customers for new connections should be honoured, even after any connection policy comes into effect. The reasons why this is appropriate are set out in AIC.[351]

344. There will be a high number of existing commitments to be honoured after any new connection policy is implemented. Enbridge Gas connects more than 40,000 customers annually and at any given moment is reviewing and then committing to connections for development projects and other new connections that are in some cases two to three years in the future.[352]

h) *Enbridge Gas response to other items*

345. As noted above, there are a number of items noted by OEB staff and other parties that do not fit neatly with the Company's proposal. Enbridge Gas's response is set out below.

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[351] AIC, pages 116-117.
[352] Exhibit I.3.2-LPMA-22, Attachment 1; see also 12 Tr.2-3.

i. Customer connection horizon

346. The question of whether Enbridge Gas should maintain the 10-year customer connection horizon set out in E.B.O. 188 received almost no attention in intervenor submissions.

347. Enbridge Gas submits that SEC's proposal to reduce the connection horizon from 10 to 5 years will introduce an unnecessary limitation on accurately reflecting customer attachments expected beyond five years. Enbridge Gas notes that SEC relies almost exclusively on wanting to achieve symmetry with the Distribution System Code (DSC) but fails to note that the DSC allows electricity distributors to use a connection horizon of more than 5 years, noting that in such cases an explanation will be provided to the OEB.[353]

348. No party has brought forward evidence that Enbridge Gas has inappropriately applied the customer attachment horizon and there is no evidence about the impact of such a change on customers or customer connections capital expenses.

349. In setting the connection horizon for a project, Enbridge Gas applies its discretion in a consistent manner using best available information including customer surveys, direct customer engagement and other best practices to establish appropriate forecasts.[354] In most cases, Enbridge Gas does not employ a connection horizon beyond 5 years. A longer period is necessary for short main extensions and community expansion projects, because this recognizes that as gas service is brought into a new area, conversions to natural gas occur over time often based on the replacement of the customer's space heating equipment.

[353] See Distribution System Code, Appendix B, page 4, footnote 1.
[354] 10 Tr.80-81 and 94.

350. Enbridge Gas submits that if the OEB believes that the customer connection horizon should be reconsidered, that is best done through a generic proceeding, not in this case where only one party has made submissions on the topic.

ii. E.B.O. 134

351. Enbridge Gas submits that there is no basis for the OEB to adopt GEC's proposal that the OEB should alter the "revenue period" in E.B.O. 134 to 15 years to reflect the likelihood of declining energy delivery via the gas system to all classes of customers. There is no evidence on this item. It was not discussed during the Oral Hearing. It is not part of the Issues List. It is not a necessary item for the determination of the Company's 2024 revenue requirement.

352. Should the OEB decide that it is interested in reviewing E.B.O. 134, this could be part of the recommendation to the OEB for a generic proceeding (or rulemaking process).

iii. Alignment with electricity distributors

353. As explained, no party argues that for immediate alignment between electricity and gas customer connection policies. However, some parties do argue that review of connection policies should include both electric and gas distributors, in part to explore harmonization potential.[355]

354. Enbridge Gas questions whether it is appropriate for both electric and gas connection policies to be reviewed in the same generic proceeding, noting that this may distract from the task (which parties have identified as being very important) of conducting a full review of gas distributor connection policies in light of energy transition. That being said, Enbridge Gas agrees that it would be relevant and useful to have participation from electricity sector participants, to ensure that full range of views are provided and

[355] CCC Submission, pages 15-16; and EP Submission, page 15. ED, GEC and SEC argue that there is no need for symmetry – ED Submission, page 32; GEC Submission, page 32; and SEC Submission, page 75.

that a new customer connection policy does not have unintended consequences (such as directing new customers to an electricity distribution system without local capacity to accommodate them).

iv. Information packages for prospective new customers

355. In response to OEB staff's proposal that Enbridge Gas provide information packages to new customers, the Company notes that it currently provides similar such information to consumers, both as part of marketing for community expansion projects and through its website, and reviews and updates this information on a regular basis. For instance, Enbridge Gas has updated its marketing materials to ensure that information provided about cost savings relative to electricity indicate that air source heat pumps are available and are not factored into the existing savings calculators (given the many variables associated with heat pump models, installation costs, etc.).

356. Enbridge Gas believes that the information it provides currently, with a few modifications as set out below, meets the spirit and intent of the OEB staff's recommendations while avoiding duplication with existing and better sources for such information:

a) *Space heating options for buildings:* As there are many potential options available and Enbridge Gas does not maintain a comprehensive database of such information, the Company's marketing materials state, "There are many alternatives to serve your energy needs. Visit Natural Resources Canada at tinyurl.com/y3k2nh8b to learn more about alternative technologies such as heat pumps."

b) *HVAC service providers:* Enbridge Gas will add a statement to its marketing materials directing customers to consult an HVAC service provider regarding specific energy options, building considerations and cost estimates that will be appropriate for their specific needs. HVAC service providers can also inform consumers about electric LDC related costs.

c) *Reference to OEB website:* Enbridge Gas already provides a reference and link to the OEB Consumer Information and Protection website on the Enbridge Gas website available to all members of the public. As web links may change, Enbridge Gas prefers to minimize the links provided in any printed materials.

d) *Federal carbon charge:* Enbridge Gas also already provides information on its website about the federal carbon charge through 2030 and how the charge may impact natural gas bills.

e) *Incentives and energy efficiency measures:* Enbridge Gas provides information on its website about the DSM programs it administers, including the HER+ program. Enbridge Gas does not maintain a comprehensive database of information about other incentives for space heating technologies or energy efficiency measures and is not in a position to include such information in its marketing materials.

357. Enbridge Gas submits that it would be extraordinary for the OEB to require the Company to provide information about alternative technologies and programs it does not administer, at the cost of gas ratepayers. The OEB has agreed with this position in the past. In the generic community expansion proceeding, the OEB stated the following:

> The environmental groups have submitted that the utilities should be required to assess sustainable energy technologies for all community expansion projects. The OEB agrees with the position of OEB staff that utilities are primarily in the business of gas distribution and should not be required to provide detailed assessments of alternative technologies such as solar and geothermal as part of the community expansion applications.[356]

358. Regarding filing the Enbridge Gas marketing materials with the OEB as part of Phase 3 of this proceeding or otherwise, Enbridge Gas does not believe this is necessary because these marketing materials are publicly available (primarily on the Enbridge Gas website), the OEB can request any of this information directly from Enbridge Gas whenever desired and as noted, the information is updated relatively frequently.

[356] EB 2016-0004, Decision and Order, November 17, 2016, page 29.

v. Large volume customers

359. No changes are proposed by Enbridge Gas, or any other party, related to the Company's connection policy for large volume customers.

vi. Exit fees

360. Enbridge Gas accepts the spirit of OEB staff's recommendation that Enbridge Gas make a proposal on exit fees (including how exits from the distribution system could be tracked) in its next rebasing application. However, Enbridge Gas wishes to emphasize that its proposal may not endorse exit fees, in which case an explanation for that position would be provided.

vii. Linkage with depreciation

361. In AIC, Enbridge Gas pointed out that it may be necessary to make changes to the Company's depreciation approach, in the event that a significantly different customer attachment revenue horizon is directed.[357] As set out at Exhibit J13.6, the plant accounts (assets) associated with customer connections have asset lives that are generally 40 years or more. It does not make sense to assume that new customers will remain for substantially less time than the asset lives associated with the connection assets. Implications of this issue are described in Exhibit J18.5.

362. Enbridge Gas believes that a change to a 30-year customer attachment revenue horizon makes it even more clear that the use of the ELG depreciation methodology and asset lives proposed by Concentric for the customer connection accounts[358] is appropriate. This approach is better suited to address the inter-generational equity issues and future rate impacts of a change in revenue horizon than what is being proposed by InterGroup and Emrydia.

[357] AIC, page 115.
[358] Exhibit J13.6, Table 1.

363. It may be the case that Enbridge Gas will make a different depreciation proposal in the next rebasing case, such as an EPH, even if the 30-year customer attachment revenue horizon remains.

364. In the event, however, that the OEB directs a customer attachment revenue horizon that is shorter than 30 years, either in this case or in a subsequent generic proceeding, then Enbridge Gas will need to consider the implications on depreciation because there will be a substantial mismatch in customer attachment and depreciation assumptions related to customer connection accounts. Enbridge Gas believes that an EPH for affected accounts is more appropriate in that context, and submits that it is appropriate that the Company be permitted to address available and proper approaches at that time. Enbridge Gas submits that where the OEB orders a customer attachment revenue horizon of less than 30 years, then the OEB should approve depreciation rates based on the ELG methodology and Concentric's recommended asset lives on an interim basis, until such time as the matter can be more fully addressed. All of this is discussed in more detail in the Depreciation section of this Reply Argument.

<u>Overhead Capitalization</u>

365. Issue 8 – Are the proposed harmonized indirect overhead capitalization methodology and proposed 2024 overhead amounts appropriate?

<u>*Summary and Relief Sought*</u>

366. Enbridge Gas requests approval of its overhead capitalization methodology (O/H Methodology) and resulting capitalized overhead amounts for the 2024 Test Year. As the O/H Methodology was implemented January 1, 2020, the resulting impacts of the use of the harmonized methodology through 2023, in comparison to the overhead capitalization methodologies employed by EGD and Union, have been recorded in the APCDA which was approved in the MAADs proceeding. The amounts recorded in the

APCDA arising from the implementation of the O/H Methodology are dealt with under Issue 33 which deals with the proposal to dispose of balances in certain deferral and variance accounts.

367. Enbridge Gas also requests approval for the inclusion of $292 million of overhead capitalized amounts in the OEB-approved capital budget for the test year. With OEB approval for this amount being included in the capital budget, there would be no need to change net O&M which is settled at $821 million, excluding DSM. If, however, the full $292 million of proposed overhead capitalized amounts is not approved for inclusion in the approved capital budget, the difference will need to be added to the net O&M total of $821 million, net of DSM.[359]

Submissions by Other Parties

368. Several parties expressed support, subject to certain recommendations, for the proposed harmonized O/H Methodology. Notably, OEB staff support the O/H Methodology subject to two recommendations. LPMA similarly supports the O/H Methodology but only one of OEB staff's recommendations. CCC and VECC also support the O/H Methodology with several recommendations of their own.

369. EP, SEC, FRPO and PP do not support the O/H Methodology as proposed in whole or in part.

Enbridge Gas's Response to Other Parties' Submissions

370. OEB staff state in their submission that:

> Enbridge Gas's argument-in-chief lays out a principled case for capitalization where it says:

[359] Note that the Capital Update did not reflect the adjustment that needs to be made to the capitalized overhead ($18 reduction, to a total of $292 million) based on the agreed upon O&M budget envelope under the Settlement Proposal and the application of Enbridge Gas's proposed overhead capitalization methodology.

> 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.[360]

371. OEB staff therefore do not object to the continued capitalization of indirect overheads in this proceeding and they do not object to the proposed harmonized methodology developed with the assistance of Ernst and Young. OEB staff propose one change to an aspect of the O/H Methodology and they further submit that at the next rebasing application, Enbridge Gas should quantify, on a best efforts basis, indirect costs that would not be eligible for capitalization without regulatory approval. Before turning to these two specific recommendations, the Company will first address some of the general submissions made by OEB staff.

372. First, OEB staff reference the Company's response to an interrogatory[361] which states that there is a portion of Enbridge Gas's overheads that are direct in nature but are capitalized as indirect because the Company's current processes are not designed for these costs to be directly capitalized to specific capital projects. The same interrogatory response notes that these direct in nature costs could be capitalized under US GAAP by applying the guidance of ASC 360. As the response notes, this is done simply because of the difficulty in identifying such costs for the purposes of directly allocating them to capital projects. While the interrogatory response is correct, Enbridge Gas would also like to highlight that there are material overhead costs that are indirect in nature which are being appropriately capitalized as indirect through the O/H Methodology. Central functions is a good example of such costs. It was never the

[360] OEB staff Submission, page 68.
[361] Exhibit I.2.4-STAFF-52 parts a) and b).

intention of the interrogatory response to indicate that the majority of overhead costs would be direct capital in nature. It should further be noted that removing these costs from the overhead capitalization figure will result in O&M impacts as well.

373. OEB staff also referred to the exemption the Company received from the Ontario and Alberta Securities Commissions to report under US GAAP until the earlier of January 1, 2027, or when there is a rate-regulated standard issued by the International Accounting Standards Board[362]. It is the expectation of the Company that if the International Accounting Standards Board has not issued a rate regulated standard on a timely basis, that a further exemption will be requested extending the Company's permission to report under US GAAP beyond January 1, 2027. For the principled reasons given in Enbridge Gas's AIC in support of the capitalization of indirect overheads, which OEB staff accepted,[363] Enbridge Gas is of the view that the practice should continue and that any necessary exemptions or approvals are likely to be received.

Operations Cost Category Capitalization Rate

374. OEB staff correctly note that the Company has proposed to use 2021 actuals for the purposes of setting the capitalization rate for the operation costs component of the O/H Methodology for the test year. This generated a capitalization rate for operations costs of 35%. This is in fact a decrease over the capitalization rate generated by the historical methods.[364] OEB staff have recommended that the capitalization rate for operations costs be determined using a three-year rolling average consisting of 2022 actuals, 2023 actuals up to Q2 and a forecast for the remainder of 2023 and all of 2024. SEC recommended overhead capitalization rates should be based on forecast capital work.[365] OEB staff also recommend that the three-year rolling average be used

[362] OEB staff Submission, page 67, footnote 163; Exhibit 1, Tab 8, Schedule 2, Attachment 1.
[363] OEB staff Submission, page 68.
[364] OEB staff Submission; and Exhibit 2, Tab 4, Schedule 2, pages 9, 10 and 17.
[365] SEC Submission, page 89.

for the purposes of determining the operation costs capitalization rates for each of the years 2020 through 2023. OEB staff propose that changes as a result of using this amended harmonized methodology would then be recorded in the APCDA balance requested for disposition in this proceeding. More is stated about the appropriateness of changing this deferral account's parameters under the deferral and variance account issue.

375. It is important to note that neither OEB staff's nor SEC's proposals were raised during the proceeding. There is therefore no evidence of the practicability nor of the impact of these proposals. These proposals should have been raised in an interrogatory or at the Technical Conference so that the Company could advise of the advantages and disadvantages and the estimated impact on the capitalization rate. Enbridge Gas submits that there is an insufficient evidentiary record for the OEB to consider and approve OEB staff's suggestion.

376. This said, while Enbridge Gas understands the objective of what OEB staff hope to achieve using the three year rolling average, namely that it will make the methodology somewhat more responsive to changes to the capital budget, for the following reasons, the Company does not believe that the proposed changes generate a capitalization rate for the operations costs component of the O/H Methodology that is any more responsive or credible than what the Company has proposed.

377. As noted in evidence,[366] a large component of the forecasts include smaller projects like customer additions. These forecasts are not based on a bottom-up project by project estimation but rather they are based on average net costs for attachments in prior years. More specifically they are based upon historical average net connection costs and the forecasted connections for each year. As well, capital contributions will

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[366] Exhibit I.1.2-STAFF-2; Exhibits J10.5 and J10.6.

vary by project which adds additional uncertainty. In the end, the Company submits that because the forecasts that OEB staff propose to be used in the rolling average are to a large extent based upon historical averages rather than project by project estimated costs, the goal of making the methodology more reflective of future capital project costs is not achieved.

378. The Company used 2021 actuals as they were the most current figures available at the time that the Application was filed. It is true that 2022 actuals are now available and these could be used in place of 2021 or an average of the two years could be used but the question that this invites is whether the impact is material. The Company has done the calculations and the impact using either scenario is less than $1 million which suggests that there is no real benefit in making the change. As well, Enbridge Gas does not believe that this change improves the O/H Methodology over what has been proposed in terms of making it more sensitive to changes to the capital budget.

379. It should also be noted that prior to 2020, EGD and Union used different methodologies which were not compatible. This means that reliable comparable data for the years prior to 2020 does not exist. It would be a monumental exercise to review and separate out comparable operations costs data from EGD and Union for the purposes of establishing a capitalization rate for operations costs in 2020 through 2022. Accordingly, the Company does not believe applying a three-year rolling average for the years 2020 through 2023 makes sense.

380. The difference between the O/H Methodology used in the years 2020 to 2023 and the historical methodologies is relatively modest in each year.[367] Even if the Company spent all of the time necessary to compile the data required in support of using a three-year rolling average for these years, as is the case with a two-year average as

[367] Exhibit 2, Tab 4, Schedule 2, page 19, Table 4.

noted above, it is unlikely that the three-year rolling average will reduce the difference by any material amount. Indeed, the opposite may be the case. Enbridge Gas therefore questions the value of this exercise particularly given that should this work to reduce the O/H Capitalization amount in any of these years, the revenue requirement impact of the reduction to the amount capitalized, and corresponding increase to the amount recognized as O&M, would reduce the payable currently captured in the APCDA (and or possibly result in a receivable balance being recorded). Should the OEB determine it necessary to change the overhead capitalization methodology, Enbridge Gas submits that as a practical matter it should only be undertaken on a prospective basis which would allow the Company an opportunity to determine and understand the impact of such changes.

381. Enbridge Gas continues to believe that the O/H Methodology, which relies on the immediate prior year's actuals of direct capital amounts, offers the highest degree of historical accuracy. It utilizes the latest verified information available ensuring that capitalization rate calculations are based on real, proven data rather than forecasts or estimates, which at times can be subjective. Additionally, the capitalized overhead is trued up based on actual O&M costs each month.[368]

382. Enbridge Gas also believes that using prior year actuals makes the rate setting responsive to fluctuations and changes in capital expenditures. This will result in prompt adjustments in response to financial shifts or operational changes.

383. By excluding forecast figures, the O/H Methodology eliminates uncertainties associated with future projections. This promotes confidence in the stability and fairness of overhead capitalization rates because they are grounded on historic actuals rather than forecast amounts. Using historical actuals also means that they are

[368] Exhibit I.2.4-STAFF-54 part a).

readily available and simple to validate. Using actuals therefore adds to the integrity of the O/H Methodology.

384. Turning specifically to SEC's recommendation that it should update capitalization rates throughout the year similar to Hydro One's policy, it was noted during the Oral Hearing, by Company witness Mr. Healey, that Enbridge Gas is unable to determine what Hydro One's process actually is.[369] However, as noted in evidence, Enbridge Gas applies calculated capitalization rates to actual incurred expenses. It then performs a monthly variance analysis on all applicable accounts. This monthly variance analysis allows for a reasonableness assessment in comparison to budget which considers the capitalization rate applied. If Hydro One does the same monthly review as Enbridge Gas, the Company submits that the O/H methodology already achieves the purported benefits of what SEC proposes.

Benchmarking/Independent Third-Party Assessment

385. Several parties have recommended that the Company be directed to undertake a benchmarking study of the indirect overhead capitalization methodologies used by other utilities for the purposes of comparing these in the future with the proposed O/H Methodology[370]. Other parties have recommended that Enbridge Gas be directed to complete a third-party assessment of its O/H Methodology to be submitted at the next rebasing application[371].

386. While the Company is prepared to engage an independent third-party expert for the purposes of undertaking an assessment of the O/H Methodology by the next rebasing

[369] 15 Tr. 145-146.
[370] SEC Submission, page 91; FRPO Submission, page 8; LPMA Submission, page 23; and VECC Submission, page 20.
[371] SEC Submission, page 90; FRPO Submission, page 8; and CCC Submission, page 17.

application[372], for the reasons stated during the Oral Hearing,[373] and in the Company's AIC,[374] Enbridge Gas does not believe there is any value in undertaking a benchmarking study. To be clear, the Company is not opposed to engaging a duly qualified firm to undertake such a study. The Company's concerns relate to its understanding that the details and mechanics of the overhead capitalization methodologies used by other utilities are not generally publicly available and even if they are, enquiries with each of the utilities in question would be necessary to understand the specifics and operating characteristics of the methodologies. Whether such utilities would sufficiently cooperate is unknown.

Impact of OEB Ordered Reductions to Overhead Capitalization Amounts

387. Several parties argue that in the event that the OEB orders a material reduction to the capital budget proposed by Enbridge Gas for the test year, there should be a reduction also ordered to the overhead capitalization amount and that all of this reduction, or some portion thereof, should not then be added to the net O&M which is the subject of the Settlement Proposal.[375] The Company notes that SEC in its submission stated:

> SEC does not dispute that "annual fluctuations in the level of invested capital or the quantum of projects" may not result in material changes to the gross O&M budgets that support, in addition to its own activities, its capital work.
>
> The relationship may not be perfectly linear, but it simply cannot be said that there was no relationship.[376]

388. The reason why Enbridge Gas noted that a change to the capital budget does not translate into a similar, or perhaps any, reduction in O&M are set out in detail in its

[372] Subject to the OEB approving a deferral account to record the anticipated material costs that will be incurred by the Company undertaking all of the various studies that have been proposed.
[373] 16 Tr.59-60.
[374] AIC, pages 129 and 130.
[375] SEC Submission, pages 91-92; PP Submission, page 45; and LPMA Submission, page 26.
[376] SEC Submission, pages 91-92.

AIC.[377] The fact is that the sheer volume of projects undertaken each year and the multi-year activities related to predevelopment, planning, execution of these projects must necessarily continue. This means that the work is driven less by the dollar value of capital projects and more by the breadth and scale of the Company's operations and capital activity. In addition, it is a matter of common sense as explained below.

389. Enbridge Gas does not take the position that there is no relationship between the capital budget and overhead capitalization amounts as SEC suggests. During the Oral Hearing, Company witness Mr. Healey acknowledged that the O/H Methodology would in time reflect material changes in the capital budget.[378] In respect of 2024, even assuming a final decision by the OEB in this proceeding is issued before year end, Enbridge Gas already has its existing complement of management and employees in place. It has set its O&M budgets for 2024 based upon the current complement of staff. While a material reduction in the capital budget for 2024 would likely lead to the cancellation of certain projects in 2024, this reduction would primarily be implemented by the avoidance (or cancellation) of third-party contractor expenses. If these cancelled projects involved the planned replacement of existing pipe, then common sense dictates that it would become incumbent on the Company to undertake the work necessary internally to develop an alternative to the replacement to ensure the continued safe and reliable delivery of natural gas. In other words, it is foreseeable that a material decrease in the capital budget could correspondingly increase the demands for maintenance related activities that need to be undertaken by Enbridge Gas using internal resources that would be expensed as opposed to capitalized. This supports the need to retain current staffing levels or perhaps even increase staffing levels.

[377] AIC, pages 130-135.
[378] 16 Tr.11-12.

390. Should the Company determine that it no longer requires the same complement of staff to support its capital activities, the reduction in staff will occur over time and will necessarily result in severance and reorganizational costs. These costs are not currently included in the O&M budget so there will be an offset between savings in staff salaries and benefits and the severance costs incurred to effect such savings. When O&M costs decline as a result, the actual amounts incurred will be used for the purposes of the annual updates so that the overhead amounts that are recorded and allocated to rate base reflect the most up to date information.[379]

391. The fact is that no party presented even a hypothetical scenario where in 2024, the gross O&M budget should be reduced due to a reduction in the proposed capital budget. Enbridge Gas submits that parties are unable to find fault with the above because is it a matter of common sense. While Enbridge Gas acknowledges that parties have the right under the Settlement Proposal to argue that a different overhead capitalized amount would be appropriate if a different capital budget is ultimately approved by the OEB, to argue that any reduction in the overhead capitalization amount should not be recovered through O&M simply results in a further reduction to the O&M for 2024 beyond the significant discount agreed upon for the purposes of the Settlement Proposal.

392. EP notes that the O/H Methodology generates a $15.4 million higher overhead capitalization amount in 2024 than using the historical methodologies. EP recommends that the OEB deny this $15.4 million increase in capitalization of indirect overheads.[380] Enbridge Gas understands that EP's Submission is not linked to any change in the capital budget but is merely a reflection of the fact that it still has a number of questions about the O/H Methodology.[381]

[379] AIC, page 133.
[380] EP Submission, page 17.
[381] Ibid, page 16.

393. Enbridge Gas notes that EP had every opportunity to ask each of the five questions posed in its submission at page 16 during the interrogatory, Technical Conference and Oral Hearing phases of this proceeding. Enbridge Gas believes it is inappropriate at this stage to state that the Company has failed to address such questions and, as a result, to deny the recovery of this amount.

394. As noted by LPMA[382], no other methodology has been sufficiently tested as part of this proceeding and the historic methodologies are not feasible given that Enbridge Gas has undergone multiple organizational changes since the amalgamation with significant changes to the cost structures that were in place at EGD and Union. This undoubtedly is one of the reasons that led OEB staff to accept the O/H Methodology (subject to its proposed refinement as discussed earlier).

Overhead Capitalization and ICMs

395. Several parties raise in their submissions questions about applying capitalized overhead amounts to Incremental Capital Module (ICM) projects.[383]

396. The Settlement Proposal under Issue 6 states that all parties agree that the acceptance of overhead capitalized amounts in ICM projects being included in 2024 opening rate base is without prejudice to the rights of parties to argue in future, including Phase 2, when the proposed IRM Plan is reviewed and in future LTC proceedings, that overhead capital amounts should not be included in ICM amounts. Accordingly, the submissions made by parties in respect of the inclusion of overhead capital amounts in ICM projects is out of scope in this phase of the proceeding.

[382] LPMA Submission, page 23.
[383] EP Submission, page 17; CCC Submission, page 17; and VECC Submission, page 21.

Commissioner Moran confirmed this during the Oral Hearing.[384] These are issues for Phase 2.

Quantifying Indirect Costs

397. While OEB staff frame their request that the Company be asked to quantify on a best efforts basis at the next rebasing application indirect costs that would not be eligible for capitalization, what it is really requesting is that the Company attempt to quantify the direct costs that are currently being included in overhead capitalization which would continue to be capitalized if indirect costs are no longer permitted to be capitalized. OEB staff specifically acknowledge that this will be a challenging undertaking.[385] It is for this reason that they recommend that this quantification be undertaken on a “best efforts basis”.

398. While the Company is prepared to attempt, on a best efforts basis, to provide a high level estimate of costs which are direct in nature, which are included in the indirect overhead capitalization figure, as noted earlier, the Company and OEB staff believe that the effort to perform this analysis will be significant and it may not identify an amount that is sufficiently material to warrant the exercise. The fact is that Enbridge Gas strives to allocate all directly associated costs to specific capital projects as much as is practically possible. The exercise that OEB staff propose will likely reveal that a portion of the costs which are capitalized using the O/H Methodology are indirect which means that if necessary, approvals to continue capitalizing these amounts are not received, there will be a significant increase in the revenue requirement because such costs must necessarily be added to O&M. This appears to be recognized by OEB staff as they indicate at page 68 of their submission that it might, in such circumstances, be necessary to consider bill mitigation measures. The Company however continues to believe that by the nature of the work required to plan and

[384] 15 Tr.190-191.
[385] OEB staff Submission, page 66.

construct capital projects, a good portion of which is indirectly supported, capitalization of overhead remains appropriate.

<u>2024 Capital</u>

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

<u>Summary and Relief Sought</u>

400. Enbridge Gas requests approval of its as-filed 2024 Test Year capital expenditures (as underpinned by the AMP) and resulting in-service additions, including the impacts of the Capital Update.[386]

401. The Capital Update excluded forecast expenditures and in-service additions related to PREP, for which Enbridge Gas is requesting approval of a separate levelized recovery mechanism (as well as an associated variance account under Issue 32) to include the project's revenue requirement impacts in a rate rider that will be in effect upon approval of the LTC and ultimate in-servicing.[387]

402. For the reasons outlined in AIC[388], and subject to the specific areas of capital reductions that Enbridge Gas is prepared to make (outlined below), Enbridge Gas maintains its submission that its forecast 2024 capital expenditures and in-service additions are appropriate. Enbridge Gas has presented considerable evidence in this proceeding to demonstrate that its forecasted capital expenditures are required to maintain a safe, secure and reliable gas delivery system, while meeting compliance obligations, continuing to supply the province's growing energy demands, maintaining customer service levels, and working towards emissions reduction targets.

[386] Exhibit 2, Tab 1, Schedule 1, pages 5 and 6.
[387] Exhibit 2, Tab 5, Schedule 4, Section 4.1.
[388] AIC, pages 135-174.

403. Enbridge Gas has also explained in this proceeding the unprecedented cost pressures it has recently faced, resulting from changing market conditions, supply chain issues during and following COVID-19, heightened awareness of newly identified pipeline hazards, and an increasingly complex construction environment.[389] In combination, these pressures necessitated a substantial level of investment reprioritization in short order (in some cases resulting in significant deferrals of projects into the 2024 Test Year and beyond), by way of a Capital Update during this proceeding. This reprioritization along with proactive steps to address cost pressures[390] help ensure that the Company can continue to effectively operate within its capital budget. Enbridge Gas recognizes that these deferrals, compounded by market demands for large pipeline expansions, led to a capital expenditures profile for 2024 to 2028 that is necessarily higher in the early part of the 5-year term.

404. In addition, Enbridge Gas also recognizes the need (and the OEB's increased expectation, which has become evident in this proceeding) to incorporate energy transition considerations into the Company's capital planning and believes it has done so to the extent possible based on available information.

405. With these factors in mind, and having considered the capital reductions proposed by OEB staff and other parties, Enbridge Gas has identified and is prepared to make the following adjustments to its most recent 2024 capital expenditures forecast: (i) levelized approach for the St. Laurent Pipeline Replacement project Phases 3 and 4 to spread the recovery of project costs (which include $75.7 million for 2024) over 2024 to 2028, consistent with OEB staff's proposal and similar to the Company's requested

[389] 11 Tr.101-103.
[390] In addition to re-prioritizing investments, Enbridge Gas has pursued efficiency and cost saving measures to mitigate rising costs, diversify the supply chain for procurement, and negotiate new contracts with construction partners (referred to as Alliance Partners) that drive value and greater price certainty for the utility and ratepayers (14 Tr.79-80; 11 Tr.103).

rate treatment for PREP; and (ii) $1.5 million reduction in relation to the Selwyn Community Expansion Project.

406. As detailed in the Customer Attachment Policy section of this Reply Argument, Enbridge Gas proposes 30 years as the appropriate revenue horizon under E.B.O. 188 and GDAR, on an interim basis effective January 1, 2025 (subject to final determination in a generic hearing as suggested by the Company and several other parties). If the OEB adopts this change and effective date, there would be impact to the Customer Connections budget in 2025 and beyond, but no impact to the 2024 capital budget and revenue requirement.[391]

407. Notwithstanding the capital cuts proposed by various parties, they generally accept the importance of, first and foremost, ensuring safety, reliability and compliance. In evaluating any potential reductions to the capital budget, Enbridge Gas must consider impacts to its primary objective of safe, reliable and compliant operations. Enbridge Gas submits, and evidence in this proceeding shows, that its capital budget has been subjected to rigorous evaluation, prioritization, constraints, and ongoing refresh using the latest information so as to meet this objective, and that any further capital cuts would be inconsistent with this objective and unsupported by the evidence. As APPrO correctly pointed out in its submission:

> The evidentiary record, as it stands today, lacks evidence that directly contradicts Enbridge's capital spending program. Notably, there is a lack of evidence that the current reliability and safety of the gas delivery network can be maintained through an *alternative* capital budget. Additionally, there is no evidence to suggest an alternative method of maintaining existing assets other than what Enbridge has proposed as part of its asset management planning.
>
> While a number of parties are likely to question various elements of the capital budget, a large portion of the spending is related to maintaining the

[391] As discussed later in this section, if the OEB requires the change from a 40-year to 30-year revenue horizon starting immediately in 2024 (which Enbridge Gas notes is not sufficient lead time for implementation), the 2024 Customer Connections budget is expected to be $42.5 million lower. The impact is expected to be similar in 2025 based on Enbridge Gas's proposed effective date of January 1, 2025.

> current gas delivery network, connecting new customers or expanding connections for existing customers…[392]

408. Under Issue 7, Enbridge Gas responds to the capital cuts proposed by OEB staff and other parties and explains point by point where the proposals are inconsistent with, or unsupported by, the evidence in this proceeding. Further reductions to the capital forecast, if imposed by the OEB, cannot be implemented without material consequences and potential long-term repercussions to the natural gas system and customers. Depending on the extent of reductions, the following outcomes/risks are likely to materialize:

System Operation:

- Pressure reductions or shut down of pipelines for which Integrity Management activities cannot be funded. This would result in loss of service to some or all customers downstream of the affected pipeline.
- Increased risk of system minimum pressures being breached due to capital constraints applied to Distribution System reinforcement projects. The result could be customer outages during peak demand periods.
- Increased risk of security breaches, putting staff, system operation, confidential information, and finances at risk.
- Increased unplanned leaks driving up emergency response, unplanned customer outages, and potentially evacuations, property damage and harm to the public.
- Increased incidences of non-compliance and penalties which would require O&M funding not currently forecasted.

Higher Future Costs

- Increases in O&M-funded reactive emergency leak response, investigation and repairs as a result of cancelling planned replacement projects. Additionally,

[392] APPrO Submission, page 27.

there are likely to be increased O&M costs associated with Fleet vehicles and production equipment maintenance and repairs.

- Reductions to maintenance related investments including those intended to prevent corrosion or ensure reliable operation of equipment will result in premature failure and/or replacement of equipment.

- Deferral of investments intended to levelize longer term programs (and prevent the population of poor condition assets from growing to unmanageable levels) will lead to higher future investment needs, driving up capital costs for a future rebasing term.

- Some investments would be split into smaller components/phases to address the most immediate risks/issues, but this means ignoring longer-term issues and losing the benefits of cost efficiency through bundling of projects.

Increased Current and Future Emissions

- Deferring or foregoing planned pipe replacements may lead to higher rates of unplanned leaks requiring reactive intervention as well as higher methane emissions.

- Cancellation or delay of planned main replacement may delay hydrogen readiness for parts of the system where older steel pipelines are being renewed.

- Investment in projects to reduce GHG emissions would likely have to be reduced or canceled to operate within reduced capital constraints.

Reduced Customer Satisfaction and Ability to Serve Customers

- Reducing the number of customer attachments that can be funded each year will result in costs being allocated to comparatively fewer customers, potential delays to home construction (as builders are forced to source alternative appliances), possible impacts to electric LDCs that are not prepared to support incremental demands if developments continue, and increased heating costs for occupants of new buildings.[393]

[393] See *Powering Ontario's Growth – Ontario's Plan for a Clean Energy Future,* page 26, which states "for areas with existing natural gas access, in most cases natural gas remains the most cost-effective home heating source".

- Lower customer satisfaction may result from the cancellation or delay of Information Technology investments that are designed to enhance customer experience and renew antiquated/obsolete technology no longer able to meet system demands.

Submissions by Other Parties

409. OEB staff and various intervenors made submissions regarding Enbridge Gas's 2024 capital expenditures and in-service additions.

410. APPrO and OGVG generally accept Enbridge Gas's capital spending for 2024 rate-making purposes. The reasons for their acceptance include the following, which Enbridge Gas agrees with:

- APPrO notes that maintaining a reliable and safe gas delivery network is vital to the reliability of the province's electricity grid – given the importance of gas-fired generation particularly on peak demand days, and that Enbridge Gas's evidence regarding capital requirements to ensure safety and reliability has not been contradicted in this proceeding.[394]
- APPrO notes that over half of the 2024 capital budget is directly related to what it describes as largely "non-negotiable" spending and that more than 80% of the budget relates to projects required for safety and reliability, customer connections or long-term cost-effectiveness for ratepayers.[395]
- OGVG notes that the 2024 budget is in line with historical spending over the 2014 to 2023 period, given that – once capitalized overheads and LTC investments are separately accounted for – the material differences between 2024 and the preceding 10 years are largely due to new RNG and CNG investments (which are directly recoverable from customers), sustained cost increases for meters and customer connections, and inflationary pressures over time.[396]

411. Other intervenors and OEB staff support varying levels of reductions to Enbridge Gas's 2024 capital budget – either on an envelope basis or in relation to specific items. OEB staff propose investment area-specific reductions that total $271.5 million,

[394] APPrO Submission, pages 27-28.
[395] Ibid, page 28.
[396] OGVG Submission, page 10.

including $116.1 million in reductions to customer connections (based on OEB staff's proposal of a 20-year revenue horizon), $15.1 million to system reinforcement, $75.7 million related to St. Laurent Phases 3 and 4 (based on OEB staff's proposed levelized rate recovery for the project), $54.6 million to integrity digs, $8.5 million to compressor stations, and $1.5 million to NGEP spending.[397]

412. LPMA submits that total reductions of $143.7 million are appropriate, which consist of the same reductions identified by OEB staff for compressor stations and NGEP as well as other reductions identified by LPMA consisting of $75 million to customer connections (based on its support for a 30-year revenue horizon), $9.5 million to system reinforcement, and $49.2 million to integrity digs.[398]

413. GEC identifies one main area of capital cuts, which is to eliminate all system access expenditures (i.e., customer connections, including the cost of meters but excluding NGEP costs) totalling $1.579 billion over the 2024 to 2028 period based on its proposed 100% CIAC policy (or alternatively, reductions of $853 million over 2024 to 2028 based on a 10-year revenue horizon).[399]

414. Several intervenors argue for capital reductions on an envelope basis. SEC proposes reducing capital in-service additions to match depreciation expense (i.e., lowering 2024 in-service additions by $422 million to $879 million).[400] ED similarly argues for capital reductions (coupled with accelerated depreciation) to achieve a declining rate base, though it did not propose any specific reductions.[401] CCC, CME and PP recommend 2024 capital expenditure reductions of $254 million, $400 million, and $367.6 million, respectively.[402]

[397] OEB staff Submission, page 55.
[398] LPMA Submission, page 22.
[399] GEC Submission, page 24.
[400] SEC Submission, page 42.
[401] ED Submission, page 25.
[402] CCC Submission, pages 29-30; CME Submission, page 11; PP Submission, page 37.

415. With respect to the rate treatment of PREP, OEB staff supports Enbridge Gas's levelized recovery proposal and the associated PREP variance account.[403] SEC argues that PREP should be reflected in 2024 rate base, with a variance account in place solely to capture outcomes if the project is denied LTC or if the approved costs change from what has been proposed.[404] SEC's Submission was endorsed by CCC.[405] LPMA opposes the levelized approach for PREP and believes that the project should be treated as being in-service in 2024 (with the associated revenue sufficiency built into 2024 base rates).[406]

416. Further to the rate treatment of PREP, OEB staff submits that St. Laurent Phases 3 and 4 warrant the same levelized treatment as PREP – with a variance account in place to track actual revenue requirement versus revenues collected over 2024 to 2028 – and that the project's 2024 capital expenditures ($75.7 million) and in-service additions should be excluded in setting 2024 base rates.[407] LPMA and OGVG both argue that levelized treatment for St. Laurent is not necessary.[408]

417. OEB staff and intervenors also made submissions regarding the assumptions and processes that underpin (or they argue, ought to underpin) Enbridge Gas's capital plan, including: their preferred approach to incorporate energy transition impacts and IRPAs (including the assessment of repair options) in capital planning; perceived inadequacies with certain features of Enbridge Gas's planning framework (such as incentive objectives and investment value scoring and prioritization); and proposed inclusion of capital savings that they believe should result from undefined productivity and/or the implementation of EDIMP.

[403] OEB staff Submission, page 63.
[404] SEC Submission, pages 87-88.
[405] CCC Submission, page 22.
[406] LPMA Submission, page 14.
[407] OEB staff Submission, page 64.
[408] LPMA Submission, pages 21-22; OGVG Submission, page 11.

418. The rest of this section sets out Enbridge Gas's response to the submissions of OEB staff and intervenors regarding Issue 7. Given the overlap between Issue 7 and other topics (particularly energy transition and customer attachment policy), references are made to other sections of this Reply Argument as applicable.

Enbridge Gas Response to Other Parties' Submissions

419. Enbridge Gas's detailed response is organized around the following topics:

- 2024 capital forecast, including the reasonableness of the overall budget relative to historical spending and investment needs, as well as responses to various parties' proposed reductions to the overall capital envelope or specific investment areas;
- Asset management and planning approach, including the process for valuing and prioritizing investments, asset condition assessment, and the recent Capital Update;
- Consideration of energy transition risks and IRPAs in capital planning, including parties' proposals regarding scenario/probabilistic planning and utilization tracking for new growth projects;
- The appropriate rate treatment of PREP and St. Laurent Phases 3 and 4; and
- Responses to two specific requests for clarifications raised by OEB staff.

2024 Capital Budget – Overall Envelope

420. Several parties proposed reductions to Enbridge Gas's overall capital envelope for 2024. As noted above, SEC recommends lowering 2024 in-service additions by $422 million to match depreciation expense, [409] and ED advocates for reductions to achieve a declining rate base.[410] CCC, CME and PP recommend reductions of $254 million, $400 million, and $367.6 million, respectively.[411]

[409] SEC Submission, page 42.
[410] ED Submission, page 25.
[411] CCC Submission, pages 29-30; CME Submission, page 11; PP Submission, page 37.

421. Generally speaking these parties favour drastic envelope-level reductions based on: (i) their perceived inadequacies in Enbridge Gas's investment planning framework and incorporation of energy transition considerations; (ii) proposed shortening of the E.B.O. 188 revenue horizon, and (iii) a general perception that the capital plan is excessive compared to historical levels and that Enbridge Gas does not require all of the proposed budget to address system and asset needs. Item (i) is addressed in the Energy Transition section of this Reply Argument and below in this Capital section. Item (ii) is addressed in the Customer Attachment Policy section and below in this Capital section. Item (iii) is the focus of this subsection.

422. APPrO and OGVG generally accept Enbridge Gas's capital spending for 2024 rate-making purposes. Relative to historical levels, Enbridge Gas agrees with OGVG's observation that the proposed 2024 budget is in line with historical spending over the 2014 to 2023 period once capitalized overheads and LTC investments are separately accounted for.[412] On that basis, OGVG points out that the material differences between 2024 and the preceding 10 years are largely due to new RNG and CNG investments (which are directly recoverable from customers), sustained cost increases for meters and customer connections, and inflationary pressures over time.

423. Enbridge Gas also agrees with the submissions made by APPrO regarding the appropriateness of the capital budget. Emphasizing the importance of gas-fired generation to the province's electricity supply particularly on peak days, APPrO submits that a reliable and safe gas system is vital to the reliability of the electricity grid and that Enbridge Gas's evidence regarding capital requirements to ensure safety and reliability has not been contradicted in this proceeding.[413] APPrO also correctly observes that over half of the 2024 capital budget is directly related to what it

[412] OGVG Submission, page 10.
[413] APPrO Submission, pages 27-28.

describes as largely “non-negotiable” spending and that more than 80% of the budget relates to projects required for safety and reliability, customer connections or long-term cost-effectiveness for ratepayers.[414] In addition to these points, below Enbridge Gas sets out its own responses to the proposed envelope-level reductions.

424. The cost pressures and supply chain issues that have arisen in recent years (exacerbated by COVID-19 and Russia’s invasion of Ukraine, among other factors) are well documented. In spite of efforts taken by Enbridge Gas to prioritize only the core activities necessary to sustain the business and maintain a safe and reliable gas system, the costs of executing these core activities have risen substantially over the past 5 years. In addition, market demands and system risks have driven the need for unusually high capital expenditures in 2023 and 2024. The evidence in this proceeding details various impacts to the costs of core business activities, as highlighted below:

- *Customer Connections* – Enbridge Gas has experienced about a $2,000 increase in costs to attach a customer from 2019 to 2024. Contributing factors include: higher costs for municipal and conservation authority permitting (20 to 50% higher or $200 to $500 impact per customer attachment); higher costs of materials (3% increase or $100 to $200 impact per customer); implementation of an enhanced sewer safety program for new installations ($500 impact per customer); and significant inflation on construction costs in general, with higher annual increases for contractors through that period. Other factors that are harder to quantify include municipal changes to restoration requirements, regulation changes such as the new soil handling regulations, and productivity losses due to supply chain complications through those years.[415]

- *Utilization* – The supply chain for meters has been dramatically impacted through COVID-19. Enbridge Gas has seen a loss of production of one third of its typical supply of diaphragm meters and has had to replace those with ultrasonic meters at a cost premium, increasing costs by about $65 million.[416]

- *Integrity Management* – With changes to the applicable criteria for assessing pipe anomalies, Enbridge Gas has experienced a higher number of identified anomalies that require integrity digs through in-line inspection activities. Over

[414] APPrO Submission, page 28.
[415] 11 Tr.101-102.
[416] 11 Tr.133.

the last several years, there have been advancements in technologies and tools that can find different types of pipeline anomalies and defects, therefore enabling findings that previous technologies did not allow.[417]

- *Compression* – $8.5 million of new compressor station-related investments have been driven by routine inspection findings, including leaks that must be resolved under the federal methane regulations. Many of the findings relate to leaking valves, where repairs are first attempted but irreparable valves must be replaced within a limited time window to ensure regulatory compliance.[418]

425. SEC's suggestion to drastically cut capital additions to match depreciation expense is without merit and shows a flawed understanding of Enbridge Gas's core business and operating context. Aside from the above-noted cost pressures, SEC seems to ignore the real and pressing needs to sustain Enbridge Gas's core business functions while continuing to meet growing gas demand in Ontario. The Company has an obligation to maintain the safety and reliability of a critical component of Ontario's energy delivery system, delivering 30% of the province's annual energy requirements and supplying peak energy requirements equivalent to 3 to 5 times the peak of the provincial electricity grid.[419] If SEC's proposed cuts were to be implemented, Enbridge Gas would essentially have to curtail all investments under Gas Infrastructure - Growth, Emission Reduction, Energy Transition, as well as Proactive Replacements targeting future resource balancing and cost-effectiveness in the long run.[420] This means thwarted emissions reduction efforts, long-term cost escalations related to asset renewal or lifecycle extension, and inability to provide the additional energy needed by Ontario's growing communities.

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[417] 13 Tr.190. Integrity management related costs are also discussed below in relation to parties' proposed reductions for specific investment areas.
[418] 13 Tr.186. Note that the witness during the Ora Hearing had referenced the MSAPR while the correct reference should have been the federal methane regulations. This is also clarified below where Enbridge Gas responds to proposed reductions for compressor stations.
[419] Exhibit 1, Tab 10, Schedule 2, page 2.
[420] Based on the investment categories outlined in Exhibit 2, Tab 5, Schedule 1, Table 1.

426. SEC asserts that Enbridge Gas added investments to 2023 to fill the gap left by projects deferred out of 2023.[421] Contrary to that assertion, the fact is that Enbridge Gas had to shift a number of projects into 2023 (and beyond) so that it can manage in-service additions in light of the deferrals of certain projects out of 2022. During Mr. Rubenstein's cross-examination on this topic at the Oral Hearing, Mr. Wellington explained that the Company had to take action to manage its capital budget in the face of mounting cost pressures in 2022 and 2023, and that decisions were made to focus on the highest priority investments (based on value risk) while pushing some investments into 2023 and beyond.[422] This contributed to a relatively large number of projects that saw funding or timing adjustments. Additionally, some of the projects that appear to be new are a result of blanket accounts – which are used to fund emergent work each year – being written down into discrete investments.[423]

427. Despite the multitude of cost pressures and construction/procurement challenges, the Company was able to effectively adjust and manage capital at the portfolio level, as the Capital Update budget for 2023 ($1,427.2 million) is only 1.2% higher than the earlier AMP forecast excluding PREP ($1,410.8 million). For 2024[424], the Capital Update budget ($1,470.3 million) is again very close to the earlier AMP forecast ($1,491.3 million) excluding PREP.[425]

428. SEC argues that Enbridge Gas has not presented any evidence on capital productivity and that inclusion of embedded capital productivity is warranted for 2023 and 2024

[421] SEC Submission, page 59.
[422] 11 Tr.121.
[423] 11 Tr.124.
[424] Exhibit 2, Tab 5, Schedule 4, Table 8.
[425] When considering the treatment of PREP as supported by OEB staff, these amounts represent a more appropriate reflection of the changes to 2024 budget as a result of the Capital Update, than what CCC had noted in its submission (see CCC Submission, page 24, where CCC asserted that the Capital Update resulted in a 2024 forecast that was 12% higher).

budgets.[426] CCC takes a similar position.[427] Enbridge Gas disagrees. It is important to understand that productivity savings are already captured within the O&M budget, which translate into capital savings in the form of lower overhead allocations or lower direct-to-capital charging. Further, Enbridge Gas has negotiated renewed contracts with its Alliance Partners and incorporated expected productivity savings (about 1% of contract value) starting in 2024.[428]

429. While APPrO generally supports Enbridge Gas's capital budget, it makes two specific suggestions: (i) the OEB could "smooth" the capital spending over the 5-year term, given that the APPrO views the capital budget as being "front-loaded" in 2024 and 2025, and (ii) the OEB may consider a variance account or specific tracking mechanism for EDIMP, so savings can be shared with ratepayers.[429] Enbridge Gas disagrees with both suggestions.

430. On item (i), Enbridge Gas agrees in concept that the outcome of an optimized plan is in part to strive for a more levelized spend profile. However, the reality is that 2024 has been heavily impacted by the deferral of and cost increase to PREP, deferral of the St. Laurent project, increased RNG projects, timing of major real estate projects currently under construction, and TIS investments required to support rate harmonization. Moreover, 2025 has been impacted by the deferral of St. Laurent, delay to the Wilson Avenue Project to allow for EDIMP inspections, and the Hamilton Reinforcement Project which is a significant investment driven by demands from a single industrial customer. Given these year-specific impacts and investment needs, Enbridge Gas cannot support a proposal to average or levelize capital expenditures over the 5-year period. It should also be noted that even if the OEB were to make

[426] SEC Submission, pages 73-74.
[427] CCC Submission, page 28.
[428] 11 Tr.183.
[429] APPrO Submission, pages 33-34.

adjustments to the 2024 capital budget in an attempt to levelize, the resulting impact on the proposed 2024 revenue requirement would be minimal.[430]

431. On item (ii) raised by APPrO, Enbridge Gas does not support the proposed variance account to track EDIMP savings. ED makes a similar suggestion that full implementation of EDIMP should result in further deferrals and reductions in capital spending.[431] For clarity, there is an immaterial amount of revenue requirement in 2024 rate base related to pipelines in scope for the EDIMP. The EDIMP work may determine that a full replacement is not warranted based on enhanced asset health findings. However, it could also find significant unexpected issues requiring planned capital investments or urgent intervention (e.g., crawler tool inspection and integrity digs on the St Laurent pipeline already led to the emergency replacement of a high-risk pipe section in the fall of 2022)[432], and there could still be capital maintenance costs incurred related to digs as a result of in-line inspection work.

432. In addition, the variance tracking proposed by APPrO would add significant complexity to the ICM under price cap, be very complicated to implement and track, and does not affect the base capital upon which rates are being set in Phase 1. Even if the savings from EDIMP were to be tracked, the difficulty lies in being able to value avoided capital/revenue requirement. There is no obvious answer to a range of complications, including: (i) Is the proper baseline the amounts in the current budget/AMP or updated amounts in a subsequent budget/AMP? (ii) Are any of the amounts in the budget based on a detailed cost estimate, or would undertaking such an estimate be made unnecessary by the EDIMP findings? For the above reasons, Enbridge Gas opposes the proposed tracking mechanism.

[430] Enbridge Gas also refers to a similar point made in OGVG's submission, which on page 11 points out that "OEB's staff's proposed reductions will have little or no impact on the proposed 2024 revenue requirement, and in fact may increase the revenue requirement".
[431] ED Submission, page 49.
[432] 11 Tr.188-189.

433. VECC suggests that the OEB could keep the cost of adding customers in line with inflation (which in VECC's view would result in higher reductions than what OEB staff recommends) and that the average 2019 to 2022 capital spend is a reasonable alternative basis for cutting the 2024 budget.[433] Both of these suggestions are flawed.[434] First, the consumer price index (CPI), which VECC references in its submission,[435] is not a reasonable barometer to set expectations around inflationary pressures faced by a gas distribution utility in Ontario, especially during a time period that included unprecedented market disruptions and cost escalations. As noted above, a myriad of factors has contributed to the significant cost increases across the capital portfolio, including customer attachment and utilization. Using CPI would be to ignore the actual cost pressures faced by Enbridge Gas. Secondly, 2020 and 2021 capital expenditures were significantly impacted by COVID-19. Notably, constraints such as supply chain issues, cost escalations, and regulatory permitting challenges/costs all hindered the Company's ability to execute investments in those years. Had capital amounts been spent as planned, average spending would amount to $1,198 million across 2019 to 2021.[436]

434. Moreover, expenditures on RNG and CNG averaged $3.6 million over the three years as opposed to $124.6 million in the 2024 Test Year.[437] These projects are funded through special rates charged to producers (where projects have a PI >=1.0) or 100% CIAC, and therefore do not impact general rates. Additionally, customer connection costs during 2019 to 2021 averaged $209.9 million, compared to $302.3 million

[433] VECC Submission, page 18.
[434] CCC makes a similar point as VECC, arguing that 2018 to 2022 average spend represents a reasonable basis for reducing 2023 and 2024 budgets (CCC Submission, page 29). For the same reasons set out below, this is also an untenable proposal and should not be accepted by the OEB.
[435] VECC Submission, page 3, footnote 4.
[436] Exhibit I.2.5-CCC-43 part e).
[437] Determined using average for the "Other" line item from Exhibit I.2.6-SEC-107 and comparing against the same from Exhibit 2, Tab 5, Schedule 2, page 2, Table 1.

forecast for 2024 due to the cost pressures described above and detailed during the Oral Hearing.[438] Finally, supply chain impacts relating to meters have materially affected Utilization costs.[439] Due to the productivity impact on the meter exchange program during COVID-19 that reduced associated spend,[440] 2019 provides the most reasonable basis for comparison at $99.3 million (compared to $146.3 million in 2024). It should be noted that this increase comes at a time when meter replacements in the EGD rate zone must accelerate to catch up on the forecasted volume of out-of-date meters in the next 5 years.[441] When factoring in these differences and adding them to the $1,198 million average mentioned above, the total is $1,458.4 million which is in line with the 2024 Test Year Forecast exclusive of PREP.

2024 Capital Budget – Specific Investment Areas

435. This subsection deals with the investment area-specific 2024 capital budget reductions proposed by OEB staff and LPMA, as well as the customer connection-related reductions that were included in the proposals from SEC, ED and GEC.

436. OEB staff proposes total reductions of $271.5 million to 2024 capital expenditures, consisting of $116.1 million in reductions to customer connections (based on adopting a 20-year revenue horizon as suggested by OEB staff), $15.1 million to system reinforcement, $75.7 million related to St. Laurent Phases 3 and 4 (based on OEB staff's proposal of levelized rate recovery for the project), $54.6 million to integrity digs, $8.5 million to compressor stations, and $1.5 million to NGEP spending.[442]

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[438] 11 Tr. 101-102. Note that the $302.4 million amount is inclusive of energy transition impact as shown in Exhibit J14.2.
[439] Exhibit 2, Tab 6, Schedule 2, page 145.
[440] 11 Tr.133; Exhibit 4, Tab 4, Schedule 3, page 33.
[441] See Exhibit 2, Tab 6, Schedule 2, page 153, Table 5.2.5-4; page 169, Table 5.2.5-7; and age demographics for 200 & 400 series regulator sets as illustrated in page 157, Figure 5.2-82, which shows a significant uptick in meters reaching the expected life of 18-24 years.
[442] OEB staff Submission, page 55.

437. LPMA proposes total reductions of $143.7 million, which consist of the same reductions identified by OEB staff for compressor stations and NGEP as well as other reductions put forward by LPMA of $75 million to customer connections (based on its support for a 30-year revenue horizon), $9.5 million to system reinforcement, and $49.2 million to integrity digs.[443]

438. Regarding customer connections, SEC recommends 2024 capital expenditure reductions of $158 million based on its preferred 15-year revenue horizon[444]; whereas ED and GEC each recommend disallowance of all 2024-2028 connection costs (based on their preferred 100% CIAC policy) or in the alternative, reductions based on a 10-year revenue horizon.[445]

439. As noted above, Enbridge Gas is prepared to accept a levelized treatment for St. Laurent (consistent with OEB staff's Submission and the Company's proposal for PREP) and reduce $1.5 million in relation to NGEP expenditures. As discussed in the Customer Attachment Policy section, the Company proposes that it is appropriate, in light of the evolving energy transition, to reduce the customer attachment revenue horizon to 30 years on an interim basis, which may impact the Customer Connections budget during the next rate term depending on whether the proposal is adopted by the OEB and when it is made effective (the Company submits that an effective date of January 1, 2025 is appropriate).

440. Other than the adjustments that Enbridge Gas is prepared to make, in the Company's view and based on the record of the proceeding, the other reductions put forward by OEB staff and other parties are not supported by the evidence and should be rejected by the OEB.

[443] LPMA Submission, page 22.
[444] SEC Submission, page 79.
[445] ED Submission, page 25; GEC Submission, page 24.

Customer Connections

441. Starting with customer connections, Enbridge Gas has detailed its response regarding potential adjustments to the E.B.O. 188 revenue horizon under the Customer Attachment Policy section of this Reply Argument. If the OEB decides to make such adjustments in this proceeding and accepts Enbridge Gas's proposal of 30 years as the appropriate interim number effective January 1, 2025 (subject to final determination in a generic hearing as suggested by the Company), there would be no impact to the 2024 capital budget or revenue requirement.

442. If a 30-year revenue horizon takes effect as of January 1, 2024 (which Enbridge Gas emphasizes is *not* sufficient lead time for implementation, as discussed in the Customer Attachment Policy section), the estimated impact to the Customer Connections budget will be a $42.5 million reduction in 2024.[446] This amount is calculated on the basis that: (i) 30% of the forecasted connections are already committed at the present 40-year revenue horizon and (ii) no reduction in capitalized overhead is included, on the basis that overhead would not be impacted by increasing CIAC payments with the same amount of work still being required. This is why the $42.5 million estimate[447] differs from the previous estimated reduction of $75 million outlined in Exhibit J11.1.[448] The impact is expected to be similar in 2025 based on a January 1, 2025 effective date.[449]

[446] See Exhibit J14.5, which shows a 2024 customer connections budget of $238.7 million without capitalized overheads. Excluding capitalized overheads, the updated estimate for 2024 customer connection budget would be $196.1 million based on a 30-year revenue horizon.
[447] If the change takes effect part way through 2024 (which, again, would not provide enough lead time for implementation), then the reduction to 2024 capital budget is estimated as follows: (i) reduction of $33.3M based on a April 1 effective date, (ii) $23.6 million reduction based on a July 1 effective date, and (iii) $14.4 million reduction based on a October 1 effective date.
[448] As shown in Exhibit J11.1, "2024" column": $304 million (based 40 year revenue horizon) minus $229 million (based on 30 year revenue horizon) equals $75 million.
[449] This assumes the same variables applied to the derivation of the estimated impact on 2024 capital budget are also valid for 2025.

System Reinforcement

443. Regarding OEB staff and LPMA's Submissions on System Reinforcement spend, Enbridge Gas submits that the proposed cuts are not reasonable for purposes of achieving emissions reduction goals and maintaining system reliability. This is because the System Reinforcement portfolio includes projects (amounting to $11.5 million in costs) that will help the Government of Ontario meet emissions reduction targets.[450] Other System Reinforcement projects include those directly tied to specific customer requests for supply. As outlined in evidence, the Distribution System Reinforcement capital forecast for 2024 to 2026 has already been reduced by $66 million (excluding overhead, relative to the previously filed AMP forecast) as a result of the harmonized design hour approach and the inclusion of energy transition factors in growth forecast.[451] Further reductions would result in elevated risk to the system and jeopardize emissions reductions efforts.

Integrity Digs

444. OEB staff and LPMA propose reducing 2024 integrity capital spending to $46.3 million (based on 2025 to 2028 program spend) and $51.7 million (based on 2024 to 2028 program spend), respectively.[452] As LPMA generally agreed with OEB staff's Submission on this program, Enbridge Gas's response focuses on submissions raised by OEB staff.

445. OEB staff argues that there is no reason integrity spend cannot be levelized, that planned integrity spending is not related to replacement of pipelines or major reinforcement where spending could be lumpy in nature, and that there is no basis for the proposed forecast.[453] Based on the evidence (including Oral Hearing testimony referenced by OEB staff, which was used to unfairly paint the entire integrity forecast

[450] Exhibit I.2.6-CCC-71, Table 5.1.10-1.
[451] Exhibit 1, Tab 10, Schedule 4, page 13.
[452] OEB staff Submission, pages 62; LPMA Submission, page 21.
[453] OEB staff Submission, pages 61-62.

as a “guessing game”), Enbridge Gas submits that OEB staff’s position is based on an inaccurate understanding of the evidence and should not be accepted by the OEB.

446. During the Oral Hearing, Enbridge Gas witnesses clarified that integrity spend is budgeted based on the expected number of digs as determined from history (where available) of past inspections/findings.[454] Specifically, Mr. Wellington stated:

> MR. WELLINGTON: It is basically an outcome of our inline inspection activities. And it is essentially determined by what we find in each case. So we set budgets based on the expected number of digs, which can be determined through the history we have with the pipeline, if we have inspected it previously. If we have not, then it may be assumptions that we have to take, based on its age and other factors. But it is a bit of a guessing game when it comes to establishing the right number.
>
> And then of course the cost for the digs themselves can be quite variable. In some cases, digs are – or I should say anomalies which need to be inspected are located in the centre of a watercourse crossing, and so we can’t physically inspect them. And we have to look at things like replacing, whereas others may be located in the centre of a farmer’s field, which is easily accessible and doesn’t cost a lot of money to get to.

447. Reading this testimony in context shows that the phrase “guessing game” was intended to describe circumstances where there is no history of inspections on a particular pipe. Of course, there is some degree of uncertainty involved, as is expected in all forecasting/estimation exercises. But to suggest the whole program forecast – which reasonably leverages available historical data to the extent possible – was somehow entirely based on a “guessing game” is unfair and inaccurate.

448. In the Oral Hearing, Mr. Wellington also clarified the drivers of increased digs and costs, i.e., changes in technology and code requirements relating to the assessment of identified anomalies:[455]

> There has been a couple of changes on the dig side over the last couple of years. There was a code change, I believe, that impacted how top-side dents are assessed. And when I code, I am referring to the CSA Z662.

[454] 13 Tr.189-190.
[455] 13 Tr.190.

> So their criteria for the assessment of those types of anomalies have changed which has led to an increased number that we are finding that get flagged for digs through inline inspection activities. And also, over the last several years, the types of tools that we have been using have been becoming increasingly advanced. They can find different types of pipeline anomalies and defects. And so we are finding things that previous technologies didn't allow us to find.

449. OEB staff's recommendation to reduce integrity spending in an attempt to levelize is arbitrary and not responsive to the forecasted needs for the assets. The actual specific outcomes of anomaly assessments are of course uncertain; however, as stated above the forecast is based on the best available information. Transmission Integrity Management Program (TIMP) pipeline inspection and maintenance activities are established based on a reliability-based process,[456] and are designed to manage risk of rupture-type failures which can lead to explosions if not effectively monitored and mitigated.[457] It is also important to note that Enbridge Gas must comply with applicable codes and standards related to pipeline integrity, design and operations, including CSA Z662 which is adopted by the Technical Standards and Safety Authority as the minimum standard in Ontario.[458] Arbitrarily reducing capital spend in this portfolio will increase the risk of failures that pose severe public safety and system reliability impacts.

450. Enbridge Gas recognizes that the capital expenditures under TIMP are higher in the earlier part of 2024 to 2028. However, the distribution of costs is responsive to potential hazards associated with these assets as well as improvements to programs and technologies that have been implemented in response to these hazards. The TIMP inspection program has traditionally employed various monitoring techniques, such as in-line inspections and external corrosion direct assessment, to look for corrosion or other geometric anomalies that pose the risk of failure.[459] Actionable

[456] Exhibit 2, Tab 6, Schedule 2, page 84.
[457] Ibid, page 82, Table 5.2.3-2.
[458] Exhibit I.1.13-FRPO-27.
[459] Exhibit 2, Tab 6, Schedule 2, page 82, Table 5.2.3-2.

features discovered through these activities are then prioritized for direct examination through the dig program. The number of digs discovered each year will depend on the number of inspections undertaken and anomalies discovered.

451. As the technology used for inspections has improved, so too has the number of features discovered through inspection and consequently, the number of digs. An example is the Sudbury Lateral Integrity Digs project for 2023.[460] This $10 million project is the last year of a dig program which resulted from an in-line inspection undertaken in 2021 for a pipeline that had been inspected multiple times since 2002. While some of the features identified were a result of worsening pipe condition since previous inspections, many features were newly discovered as a result of improved technology. This is also happening for other pipelines being inspected with new technologies, giving Enbridge Gas better information to drive appropriate response and ensure these critical pipelines remain safe and reliable.

452. In addition to in-line inspection and dig programs, Enbridge Gas continues to enhance its assessment programs[461] to ensure other hazards – which are causing pipeline failures within the pipeline industry but have not historically been monitored in Enbridge Gas's IMP – are now being addressed. These include geohazards (e.g., soil instability around a pipe), erosion of pipeline cover at water way crossings, and long seam weld anomalies which cannot be monitored with in-line technologies. These new programs have been developed in response to incidents and learnings occurring within the pipeline industry. Enbridge Gas is acting swiftly to identify and address these hazards. If accepted, OEB staff's proposal to significantly cut 2024 integrity dig spend means Enbridge Gas will have to delay identifying and resolving many of these threats, which would not be responsible in the context of ensuring safety and reliability. The OEB has previously held that Enbridge Gas's planning decisions should

[460] Exhibit 2, Tab 6, Schedule 2, Appendix A, page 18.
[461] Ibid, page 82, Table 5.2.3-2.

be based on the needs of the system.[462] The consequence of OEB staff's recommendation is to delay work that is otherwise necessary based on the needs of the system. Enbridge Gas does not agree that this is a prudent approach.

453. In its submission, OEB staff also notes that the $101 million integrity digs forecast for 2024 is high compared to the $46.3 million average for 2025 to 2028, citing Enbridge Gas witness statements that some of the increase relates to inspections for not only external corrosion, but also internal corrosion.[463] Drawing a comparison with the relatively flat spend profile for the Corrosion Prevention Program during the AMP period, OEB staff took the position that any inspection or prevention spending should similarly be levelized.[464] This position reflects an incorrect and incomplete understanding of corrosion inspections under Enbridge Gas's integrity management and corrosion prevention programs.

454. As explained in the AMP, the Corrosion Prevention Program is primarily focused on ensuring adequate cathodic protection for steel pipelines to prevent corrosion.[465] The program involves monitoring pipe-to-soil voltages and identifying required system upgrades as voltages decline, thereby allowing time to plan and budget investments to maintain these voltages and levelized spend over time. In contrast, TIMP investments are focused on spotting and remediating detectable pipeline hazards,[466] including internal or external corrosion which represents hazards requiring a much quicker response compared to declining voltages on a cathodic protection system. For these

[462] As part of the OEB's Decision on Enbridge Gas's 2019 rates (EB-2018-0305), in approving capital passthrough treatment of the integrity-driven project for Sudbury Lateral Replacement, the OEB stated that "system planning should be based on the needs of the system, not on the regulatory framework that is in place". See EB-2018-0305 Decision and Order (September 12, 2019), page 23.
[463] OEB staff Submission, page 62.
[464] Ibid.
[465] Exhibit 2, Tab 6, Schedule 2, page 108.
[466] Ibid, page 84.

reasons, Enbridge Gas submits that the comparison that OEB staff tries to draw in support of levelizing spend is not appropriate and should not be accepted by the OEB.

Compressor Stations

455. Regarding compressor stations, OEB staff argues that expenditures related to compliance with the Multi-Sector Air Pollutants Regulations (MSAPR) should have been identified prior to the creation of the capital plan and that the forecast for compressor stations should be reduced by $8.5 million.[467] LPMA supports this submission.[468] The basis for this submission is that the MSAPR have been in place since 2017 and Enbridge Gas should have included sufficient funding in the original capital plan.

456. Upon reviewing the relevant transcript references[469], Enbridge Gas discovered that the witness had inadvertently referenced the incorrect emissions regulation. Instead of the MSAPR, the correct reference should have been the federal methane regulations, which are addressed through Enbridge Gas's Direct Leak Inspection Program as outlined in the AMP.[470] While the methane regulations have been in effect since 2020, the associated investment forecast for the AMP would have been developed based on only 2 years of history of leak surveys. Some of the leaks identified resulted from failures of sealing elements in equipment, for which there are limited predictive inspection options to forecast expected failure for capital planning purposes. The federal methane regulations include specific timelines for completing corrective actions, thus limiting the Company's ability to shift or levelize the capital expenditures required for compliance.[471] For these reasons, Enbridge Gas does not agree with OEB staff's proposal on this point, in that it would not permit sufficient funding to

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[467] OEB staff Submission, page 60.
[468] LPMA Submission, page 21.
[469] 13 Tr.186.
[470] Exhibit 2, Tab 6, Schedule 2, Section 5.3.5.3.11.
[471] Ibid.

ensure regulatory compliance or to effectively manage emissions from leaks that are identified through this program.

Selwyn

457. OEB staff proposes a reduction of $1.5 million in relation to the Selwyn Community Expansion Project, so as to reflect the revised (lower) net capital cost estimate for the project.[472] LPMA supports the same reduction.[473] Enbridge Gas is prepared to make this reduction as noted above and will bring forward the actual project costs for review at the next rebasing following the 10-year rate stabilization period.

Asset Management and Planning Approach

458. Several parties raised concerns with certain aspects of the asset management and investment planning approach that underpinned Enbridge Gas's 2023 to 2032 AMP and capital forecast, including the framework for valuing and prioritizing investments, the implications of improved asset condition assessments, and the recent Capital Update, which are in turn addressed below.

Investment Value and Prioritization

459. Regarding the framework for valuing and prioritizing investments, some parties took issue with the inclusion of investments that have negative value scores and argue that there is significant flexibility within the capital plan to cancel or defer projects.

460. SEC claims that projects with negative value scores are imprudent and should not proceed, and that the OEB cannot rely on the Value Framework at all for purposes of supporting the proposed budget.[474] CCC makes a similar criticism regarding the perceived large proportion of projects with negative value scores.[475] These

[472] OEB staff Submission, pages 57-58.
[473] LPMA Submission, page 20.
[474] SEC Submission, pages 65-67.
[475] CCC Submission, page 27.

submissions reflect an incorrect expectation that only those investments with positive value scores warrant inclusion in the capital plan. The fact is that the value score is one of multiple factors for prioritization and, in some cases, it is necessary and reasonable to include investments with negative value scores (i.e., where the cost outweighs the risk reduction value) due to the health of the assets and associated safety and reliability risks that must be mitigated.

461. For instance, within Enbridge Gas's Bare and Unprotected Steel Replacement Program[476], several projects[477] relate to buried pre-1970 steel pipelines which have no coating and no cathodic protection and are therefore highly susceptible to corrosion leaks. Moreover, these pipelines are generally very difficult to repair due to the vintage and condition of the steel, often negating the ability to form positive mechanical seals with repair clamps or to undertake welded repairs. As a result, large scale replacements are necessary to limit widescale outages and to ensure new pipelines can be successfully installed to eliminate known and future leaks.

462. The reality is that while the risk reduction has a significant value and is necessary, it is outweighed by the very high cost of replacement on many of these projects. That does not mean, however, that Enbridge Gas should forego the necessary replacements on those sections of bare and unprotected steel pipeline (which would be the outcome based on SEC's suggestion), since the safety and reliability risks cannot be ignored. Assessing this program via the lens of value scores alone would also be inconsistent with past efforts to replace bare and unprotected steel pipe, which were underway at least since 2014[478] and have been included in prior iterations of the AMP filed with the OEB and supported through customer engagement results.[479] In addition, this

[476] Exhibit 2, Tab 6, Schedule 2, page 109.
[477] Exhibit I.2.6-CME-23 Attachment 1, pages 4 and 6; see projects with the initials "BU" in the investment names.
[478] Exhibit I.2.6-SEC-129, page 5.
[479] EB-2017-0306/EB-2017-0307, Exhibit C.STAFF.54, Attachment 2 (Union 2018-2027 AMP), page 55.

investment need is not unique to Enbridge Gas. For decades, it has been a broadly accepted risk mitigation practice for utilities across North America to replace bare and unprotected pipe, and presumably that long-standing practice would be deemed imprudent if SEC's Submission was to prevail.

463. Another factor that Enbridge Gas must consider in developing an optimized investment scenario is the asset class strategy. As discussed at the Technical Conference[480], projects which might have high immediate financial or operational efficiency benefit, such as TIS and REWS projects, can have value scores which outweigh the value scores of some safety and reliability driven investments, such as AMP fitting replacements.[481] This is simply due to a difference in the cost benefit ratios, and does not detract from the need to complete risk-driven work. In other words, value score is not always determinative. The applicable asset strategy, risk mitigation benefits, and other external factors as explained at the Technical Conference[482] all need to be considered in developing the capital plan.

464. As discussed in AIC, Enbridge Gas's AMP processes are part of a robust asset management framework that incorporates value-based decision making based on a holistic evaluation of cost, risk, and performance.[483] This framework was developed based on the Institute of Asset Management Conceptual Asset Management Model and aligns with ISO 5500X as well as the OEB's expectations as outlined by its Handbook for Utility Rate Applications, Filing Requirements for Natural Gas Rate Applications and Integrated Resource Planning Framework.[484] Through various iterations of the AMP filed by Enbridge Gas and its predecessor companies, continuous enhancements have been made over the years to drive effective asset

[480] 6 TC Tr.7-8.
[481] Exhibit 2, Tab 6, Schedule 2, page 117.
[482] 6 TC Tr.9-10.
[483] AIC, page 140.
[484] Exhibit 2, Tab 6, Schedule 2, pages 12 and 29.

management and investment planning based on sound inputs and methodologies.[485] This framework and the underlying processes are anything but arbitrary.

465. With respect to the Copperleaf Value Framework in particular, value scores are derived from a number of sources. For example, all pipeline replacements projects are scored using direct outputs from the DIMP Risk Model[486], which uses engineering principles to determine risks associated with distribution pipelines;[487] and the risks feed into Copperleaf value assessments. Enbridge Gas also relies on subject matter expertise to complete more qualitative risk assessments where failure data is not as abundant and reliability models are not sufficiently advanced. In these cases, the likelihood of failure and potential outcomes are estimated based on employee and industry experience as well as relevant engineering principles. In both cases, value scores are supported by data, though the quantity of data used to formulate assumptions may differ depending on the type of risk at issue. In addition to value scores, Enbridge Gas considers a range of factors when prioritizing work, such as the degree to which funds have been spent/committed towards an investment[488] and external constraints that may impact specific assets (e.g., future road construction projects). There may also be cases where decisions are required to shift time-constrained mandatory or compliance projects, but such decisions are typically made out of necessity to manage budgetary cost pressures, with the full understanding that any increased project execution risks due to timing shift must be carefully managed.

[485] Recent enhancements as reflected in the 2023-2032 AMP include energy transition-related adjustments, integrated resource planning, ongoing consolidation of asset data, updated understanding of asset condition and strategies, ongoing integration of asset standards, improved quality assurance behind investment value assessments (including the Copperleaf value framework), and continuous evaluation of facility emission reduction opportunities (Exhibit 2, Tab 6, Schedule 2, Section 3.2).
[486] Exhibit 2, Tab 6, Schedule 2, pages 95-96.
[487] Exhibit I.2.6-SEC-127, Attachments 1 and 2.
[488] 12 Tr. 48.

466. Naturally in each of the above scenarios, in addition to considering value scores, the utility needs to apply judgement (consistent with sound engineering principles) in assessing the full suite of relevant factors before arriving at a prudent decision. To suggest that the utilization of best available expertise and experiences somehow renders the entire planning process arbitrary or unreliable reflects a misconception of reasonable utility asset management practices.

467. SEC submits that the GHG emissions value measure should account for changes in emissions resulting from the investment, both from Enbridge Gas and downstream, to ensure the overall impact on GHG emissions is assessed. SEC refers to the example that “a new pipeline may require incremental compression, which would increase GHG emissions”.[489]

468. It is important to recognize that identifying and quantifying changes in emissions associated with each investment would be a very complex and resource intensive endeavour and involve a range of upfront challenges. In light of Enbridge Gas’s corporate commitments regarding Scope 1 emissions intensity reductions by 2030 and achieving net zero by 2050[490], in the Company’s view the appropriate way to address operational emissions is through a top-down approach that identifies the most significant opportunities for emission reductions, combined with continuous improvements in the design of new facilities as well as operating practices.

469. If the OEB were inclined to consider SEC’s proposal regarding the GHG emissions value measure, it must be noted that the Company cannot commit to such a proposal without first identifying and securing (including having in place a cost recovery mechanism for) the resources necessary to determine whether/how it can be pursued.

[489] SEC Submission, pages 68-69.
[490] Exhibit 1, Tab 10, Schedule 3, page 3.

470. A complicating factor with SEC's example is that the GHG emissions impact from compression activities for small growth projects is difficult to quantify. This is due to the intricate dynamics of the storage and transmission system, driven by fluctuations in storage inventories and demands at delivery points.[491] Regarding customer emissions, again SEC's proposal requires significant work based on numerous variables, including consideration of alternative energy sources and emissions across the value chain for all energy sources being compared (in addition to any end use tailpipe emissions). The Company would have to identify the requisite resources and secure a reasonable cost recovery mechanism before making any such commitments. For these reasons, Enbridge Gas favours the above-noted top-down approach for addressing operational emissions and disagrees with SEC's proposal.

Asset Condition Assessment

471. SEC claims that as Enbridge Gas obtains new or better asset condition information over time, "one would expect that the additional information would generally not point in only one direction – toward greater assets requiring replacements and higher risk… It seems that for Enbridge, time only results in things getting worse (i.e., increasing the proposed capital spending)".[492]

472. These claims are problematic for several reasons. First, SEC seems to assume that the only or primary factor influencing capital expenditures is the volume of work resulting from increased understanding of asset health. In fact, a myriad of factors drive capital spend, including asset condition. In many instances, findings from inspections do not result in additional capital spend. Examples include corrosion

[491] This complication is exacerbated by the performance characteristics of gas compressors and the turbines that drive them. With respect to compressor emissions in particular, Enbridge Gas will continue to evaluate Scope 1 emissions associated with storage and transmission investments, including when assessing electric vs engine driven compression, compression versus pipe alternatives, and potential benefits of removing system constraints which could reduce the need for compression.
[492] SEC Submission, pages 61-62.

surveys[493] and meter sampling programs[494]. Of course, sometimes inspections under these programs lead to new capital work. The intent of inspection programs is not to focus on reducing work but to identify and (if needed) address asset health issues to ensure safety, reliability and compliance.

473. Enbridge Gas has implemented new or enhanced inspection programs by leveraging more advanced technology, which improves understanding of asset health and increases awareness of failure modes. For each program, some inspection activities do not result in any additional work, such as bridge crossing inspection programs[495] and in-line inspections or external corrosion direct assessments under the Integrity Management Program (IMP)[496]. These programs could also lead to the discovery of poor condition assets and trigger new investments. It is simply incorrect for SEC to suggest that Enbridge Gas's asset management practices are somehow biased towards always increasing capital expenditures. It would be imprudent or even negligent if Enbridge Gas ignored the data and findings from its inspection programs.

Capital Update

474. Regarding the recent Capital Update, SEC says the capital evidence in this proceeding is "materially wrong", with its reasons being that the material changes made to the investment plan for 2023 and 2024 reflect "a capital planning process that clearly lacks a firm grasp of the project [Enbridge Gas] needs to undertake", and that the investment prioritization system was not re-run for the Capital Update.[497] CCC and CME also each comment on the Capital Update, taking issue with what they view as a

[493] Exhibit 2, Tab 6, Schedule 2, page 108, section 5.2.3.6.2.1. Cathodic protection systems that are deemed healthy would not require new investment to maintain pipe-to-soil voltages.
[494] Exhibit 2, Tab 6, Schedule 2, page 152, section 5.2.5.5.1. Meter populations that pass applicable sampling requirements would have their seal life extended.
[495] Exhibit 2, Tab 6, Schedule 2, page 108, Section 5.2.3.6.2.1. Outcomes of these inspections are limited to recoating or replacement of pipe hangers.
[496] Exhibit 2, Tab 6, Schedule 2, Table 5.2.3-2. In many cases, these programs help verify that pipelines in acceptable condition do not require additional investment.
[497] SEC Submission, page 60.

large number of project deferrals and cancellations as well as perceived lack of optimization to support the Capital Update.[498]

475. These arguments reflect an incomplete understanding of Enbridge Gas's capital planning processes and the relevant context for the Capital Update. Evidence shows that Enbridge Gas's investment portfolio is well supported through a robust Value Framework and rigorous reviews with stakeholders to account for external constraints and factors impacting timing.[499] With sound processes and methodologies in place, the key question is whether the inputs and assumptions feeding into planning are reasonable and grounded in best available information. While SEC, CCC and CME would have the OEB believe that Enbridge Gas lacked a firm understanding of investment needs and applied faulty methods with arbitrary assumptions in making the Capital Update, the evidence shows their claims are unfounded. Respectfully, this is arm-chair quarterbacking that unfairly impugns, through the lens of hindsight, past decisions made on information available at the time.

476. If Enbridge Gas could have reasonably foreseen the unprecedented cost and supply chain pressures that arose and persisted in recent years (including the lagging impact on 2023 and 2024 budgets) or the worse-than-expected asset condition findings from its ongoing inspection activities, then the Company could have avoided much of the changes made in the Capital Update. But the fact is that these unprecedented or unexpected developments were not reasonably foreseeable. As soon as Enbridge Gas recognized that its investment plan needs to change in response to these pressures and constraints, it updated the plan in a short amount of time based on known information to ensure spending is still prudently allocated and prioritized. Enbridge Gas noted during the Technical Conference that it would report on changes stemming from its 2024 budgeting process as soon as the information could be

[498] CCC Submission, page 26; CME Submission, page 15.
[499] 6 TC Tr.14, lines 8-22.

provided in advance of the Oral Hearing, which is exactly what the Company did through the Capital Update. When planning inputs and assumptions significantly change, it is not surprising that the prioritized investment portfolio would as well.

477. More specifically, the Capital Update used the AMP as a starting point and projects were moved on an exception-basis to accommodate the cost pressures from work carryover from 2022 and emerging business requirements identified for 2023 and 2024.[500] It is worth emphasizing that the corporate budgeting process involves all business units under Enbridge Inc. and encompasses all other budget components such as O&M and revenue. The typical process starts in the March to April timeframe, followed by business unit review in the summer, Enbridge Inc. approval in and around September, and Enbridge Inc. Board of Directors approval in and around November. However, the process was significantly accelerated so as to put the best available information on the record in this proceeding as soon as possible. In criticizing a perceived lack of optimization behind the Capital Update, SEC, CCC and CME appear to ignore the evidence that the adjustments to funding and/or investment timing were reviewed to be consistent with the strategies underlying asset management and planning decisions and did not change the initial portfolio optimization.[501]

478. As explained in the Oral Hearing,[502] investments that do not show up in the Capital Update have not been eliminated entirely. They still exist in Copperleaf and will be considered against other investments as the AMP is re-optimized in 2024. Additionally, as part of ongoing management of the utility's asset base and capital budget, emergent investments have to be considered against planned investments in the context of risk, value, execution status, and spent or committed costs. While the extent of changes made through the Capital Update may have been significant for the

[500] AIC, page 149.
[501] Exhibit 2, Tab 5, Schedule 2, paragraph 3; 11 Tr.125; AIC, page 149.
[502] 11 Tr.124; 11 Tr.94.

above reasons, the process that underpinned the Capital Update is sound and represents normal course management of utility capital programs.

479. CCC and CME argue that the Capital Update was not supported by customer engagement.[503] For much of the same reasons and context described above, Enbridge Gas does not believe that further customer engagement specific to the Capital Update was necessary or could feasibly have been implemented within he accelerated/shortened budgeting process to produce the Capital Update before the Oral Hearing. In relation to the development of the AMP and capital forecast, Enbridge Gas did conduct comprehensive customer engagement in two phases during 2021 and 2022, which allowed customer feedback to be integrated into key stages of business planning and overall investment focus/priorities to be aligned with customer values.[504] Notwithstanding the pacing/timing adjustments made through the Capital Update, Enbridge Gas has maintained the same overall programs and strategies. Lastly, additional customer engagement will occur in the immediate future as Enbridge Gas develops its next updated AMP which is expected to be filed in October 2024.

Energy Transition and IRP in Capital Planning

480. OEB staff and several intervenors made proposals regarding scenario planning and probabilistic analysis to account for energy transition risks related to future asset stranding or under-utilization.

Probabilistic Analysis and Stranded Asset Risk

481. OEB staff recommends that Enbridge Gas be required to, at the next rebasing, "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

[503] CCC Submission, page 28; CME Submission, page 10.
[504] AIC, page 141.

assets".[505] As a more immediate proposal, SEC states that Enbridge Gas should be required to "carry out a probabilistic assessment of future stranding/impairment for all assets brought into service in 2024 and thereafter, and file that assessment with the OEB annually until further notice".[506] ED proposes that Enbridge Gas should set out in an ETP at least three future scenarios with respect to gas demand, with the core of each scenario being a forecast of customer numbers and demand by customer class and at least one scenario reflecting a potential high-electrification future.[507]

482. As explained during the Phase 1 Oral Hearing, Enbridge Gas has considered energy transition in its AMP and capital budget through inclusion of energy transition impacts to the growth reinforcement forecast, ongoing consideration for IRPAs, implementation of EDIMP, inclusion of the hydrogen study, continued investment to support switching to lower carbon fuel, and investment in RNG projects.[508] Enbridge Gas recognizes the importance of continuing to assess and account for energy transition risks in its capital plan. At the same time, as Company witness Mr. Wellington noted during the Oral Hearing, it is important to realize that establishing direct linkages between energy transition and capital spending in all operating areas would require very specific information to anchor asset level decisions, including to identify which assets may become stranded, under-utilized or used differently in the future.[509]

483. Enbridge Gas is cognizant of the concerns expressed by the OEB and intervenors about the financial risks tied to stranded assets. The Company will continue to monitor for clear, discrete, geographically based disconnection or demand reduction signals to help support asset level decision making and ensure that the approach taken is clearly documented in the AMP filed with the next rebasing application. Having said that, it is

[505] OEB staff Submission, page 59.
[506] SEC Submission, page 38.
[507] ED Submission, pages 22-23.
[508] 11 Tr.104.
[509] 13 Tr.164.

neither feasible nor prudent to make speculative changes to capital investments that impact discrete assets and serve specific customers without clear indication about when and how the utilization of natural gas by those customers will change.

484. Enbridge Gas has significant concerns with the premise and proposals of OEB staff, SEC and ED on this point, and in particularly, strongly rejects SEC's Submission that the OEB should require a probabilistic assessment immediately for assets being brought into service in 2024. For reasons stated below, there is insufficient information to establish the probability that a specific asset requiring capital investment may become stranded or impaired by a certain date due to energy transition. Further, the composition of the 2024 capital forecast is largely directed towards system maintenance and renewal needs over the immediate to near term, and there is a small portion of the overall expenditures that is even possibly susceptible to energy transition impacts (if any), as discussed below:[510]

- Of the $1,665.2 million forecasted capital expenditures in 2024, $611.0 million or 37% is directed towards attaching new customers; $135.9 million or 8% relates to investments targeting emission reductions and energy transition; and the remaining 55% or $917.7 million is required for business sustainment and replacement of existing assets to ensure continued compliance, safety and reliability.[511]

- Regarding replacement work particular, the vast majority has a short-term or reactive focus, while $41.1 million is directed to balancing forecasted capital replacement demands across a 20+ year planning horizon and represents 2.4% of the replacement work in 2024. This 2.4% could potentially be impacted depending on how energy transition unfolds; however, the affected assets are still expected to require some capital intervention (i.e., to address short term needs of higher risk components and ensure safety, reliability and compliance) regardless of future energy transition impacts.

[510] All numbers are based on Exhibit 2, Tab 5, Schedule 1, Table 2.
[511] Of that $917.7 million, 78% or 721.9 million is required for gas infrastructure, including (i) $472.7 million to extend the life or maintain the current function of assets and to address safety, reliability or compliance issues; and (ii) $249.3 million for the reactive or planned replacement of assets to address actual failures or failure risks, of which 84% or $208.2 million is short term or reactive focused.

485. Looking across 2024 to 2028, 35% of the forecasted capital investment relates to new customer attachments, 4% relates to emission reductions and energy transition, and 61% relates to sustainment and replacement (of which only 11% is focused on longer term asset needs). In order to sustain ongoing safety, reliability and compliance and prevent a snowplough effect of unmanageable rate of asset health/performance issues in the long-run, Enbridge Gas requires the capital planned for replacement and sustainment and cannot speculatively scale back or eliminate expenditures directly tied to specific asset needs and service obligations.

486. Enbridge Gas notes that the probabilistic assessment of stranded assets was only a topic that arose in later stages of the Phase 1 proceeding. There was no evidence presented by either Enbridge Gas or other parties that would support this type of assessment or that shows such an assessment could have been undertaken in developing the 2023 to 2032 AMP. In order to develop a statistical model capable of estimating the likely date for an asset to become stranded (i.e., no longer used or useful), Enbridge Gas would require information to determine the probabilities of conversions at a customer level, so as to establish a statistical distribution of the most likely date for stranding based on such probabilities. Comparing this date with investment need timing (e.g., as determined through reliability modeling) can then help identify any assets likely to be stranded ahead of the investment need date, resulting in the associated investment being removed from forecast. The derivation of conversion probabilities at the customer level requires information that is not currently available to the Company.[512]

487. On a related note, Enbridge Gas would like to comment on OEB staff's statement that "one of the primary objectives [*of the AMP*] should be to reduce the risk of stranded

[512] In addition, a confidence level in these probabilities will need to be established based on the risk appetite/tolerance to incur unexpected costs from replacements that were not forecasted based on these assumptions. This means a cost recovery mechanism for such unexpected costs will be needed as well.

assets".[513] As described at the start of the AMP, one of the purposes of the AMP is to outline "asset class objectives and lifecycle management strategies".[514] A key input to lifecycle management is understanding the associated lifecycle duration. On this basis, Enbridge Gas agrees that as the timing of specific changes related to energy transition becomes clearer, this would help drive greater certainty in lifecycle management decisions. However, the fact is that there is more uncertainty in the timing and trajectory of energy transition impacts than there is in the timing and impacts of asset failures that may endanger public safety and disrupt energy supply to customers. This is because failure predictions are built on reliability models that use science-based data and sound engineering principles.[515]

488. It must be acknowledged that no data is yet available regarding the probabilities of stranded assets that could help quantify the financial risk from investing in assets with stranding potential. While OEB staff views stranded asset risk reduction to be a primary AMP objective, it has proposed untenable reductions to the Company's capital budget (including a $54 million reduction to integrity management based on an arbitrary interpretation of asset needs and future spending profiles, as discussed below). This seems to imply an outsized focus from OEB staff on financial risk relative to safety and reliability risks. Enbridge Gas takes very seriously the financial wellbeing of the business and rate impact on customers, but safety and reliability will always be the Company's paramount concern.

Incorporating Energy Transition Assumptions

489. OEB staff recommends that Enbridge Gas be required to review its energy transition assumptions in the load forecast on an annual basis and to document any changes as part of the annual AMP update.[516]

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[513] OEB staff Submission, page 59.
[514] Exhibit 2, Tab 6, Schedule 2, page 12.
[515] Ibid, pages 82-208; Exhibit I.2.6-SEC-110 Attachments 1 and 2; I.2.6-SEC-127 Attachments 1 and 2.
[516] OEB staff Submission, page 38.

490. For clarity, for this proposal Enbridge Gas interprets the forecasts of interest to be the peak day and peak hour demand forecast as well as customer connections forecast. In future iterations of the AMP and AMP addendum, Enbridge Gas agrees that it can capture updated customer connection forecasts based on updated energy transition assumptions and present these as forecasted adjustments to capital requirements for customer connections. Additionally, as Enbridge Gas annually updates its hydraulic models, it will take into consideration available and substantiated data regarding disconnections or confirmed demand reductions associated with energy transition.[517] In doing so, this could provide an opportunity to reduce short-term reinforcement needs. Going forward, as longer-term data becomes more available in respect of community energy transition activities that might signal full community fuel switching within certain timeframes, Enbridge Gas will factor in how such data might impact existing network utilization and reflect appropriate changes to long term system reinforcement plans, among other investments.

491. ED, SEC and GEC each suggest that Enbridge Gas has not appropriately considered energy transition in developing the capital plan.[518] IGUA asserts that the AMP was developed without any assessment of energy transition or stranded asset risk beyond the modest adjustments made to volume and customer growth forecasts.[519] While detailed responses regarding energy transition issues are set out in the Energy Transition section of this Reply Argument, Enbridge Gas wishes to reiterate what the evidence clearly demonstrates in relation to the AMP – i.e., the Company has pursued prudent steps to incorporate energy transition considerations into the AMP and is

[517] This is in addition to other data points to be considered, such as actual customer additions, customer usage and measured demand profiles from the prior season.
[518] ED Submission, page 41-44; SEC Submission, page 51; GEC Submission, page 22.
[519] IGUA Submission, page 8.

actively monitoring for clearer signals at a localized level as to how and when energy transition may impact asset utilization.[520]

492. Detailed explanation of how Enbridge Gas has factored energy transition into its system forecasts at both the system and local level is provided in the evidence.[521] To mitigate the risk of stranded assets within and beyond the next five years, the growth forecast underpinning the AMP already reflects energy transition adjustments, which were developed based on the ETSA Study,[522] current climate policies,[523] input from stakeholder engagement,[524] and understanding of market trends.

493. Energy transition adjustments have a relatively small impact on the growth forecast and capital plan in the next few years.[525] However, the impact beyond 2028 becomes greater.[526] Enbridge Gas is appropriately accounting for known energy transition factors to date, integrating changes as policy signals become clearer and building increased transparency into its forecasting and planning processes. Notably, actual customer attachments have exceeded the Company's forecast,[527] showing a trend of continued strong growth in gas connections. The reality is that the majority of the capital expenditures for replacement and capital maintenance work are focused on short term system needs to maintain safety, reliability and compliance, and will not be impacted by energy transition impacts within the timeframe in which the expenditures are required.

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[520] AIC, pages 163-164; 14 Tr. 115.
[521] Exhibit J14.9 and Exhibit I.1.10-SEC-31.
[522] Exhibit 1, Tab 10, Schedule 5, Section 1 and Attachment 1.
[523] Exhibit 1, Tab 10, Schedule 3, Section 2.
[524] Exhibit 1, Tab 10, Schedule 5, Section 2.
[525] Exhibit J14.2.
[526] For instance, by 2032 annual additions are reduced by 4,774 customers per year (Exhibit 1, Tab 10, Schedule 4, paragraph 39).
[527] Exhibit 2, Tab 5, Schedule 4, page 16, paragraph b).

494. ED argues that Enbridge Gas should be required to assess capital projects with reference to at least three demand forecast scenarios. It asserts that doing so would involve the largely mechanistic application of demand trajectory scenarios to the revenue forecast and discounted cash flow table and would not be onerous.[528] Enbridge Gas disagrees with this argument. ED appears to assume there are already systems in place to conduct DCF analysis for every single project in the AMP, with the implicit premise being either: (i) the investment in a particular asset should be no more than the revenue it generates, or (ii) alternatives which assume different asset lifecycle durations are being compared.

495. Both premises are problematic. On the first item, as stated in the Energy Transition section, Enbridge Gas does not have a cost allocation process to identify revenue streams with certain segments or components of its system that it determines requires replacement nor information to inform its probability analysis of revenue generation. ED's premise also entails the obvious consequence that customers who happen to be attached to a newer/less costly part of the system would continue to receive gas service, whereas those connected to older/more costly assets would be disconnected once those assets are no longer profitable to operate in a safe, reliable and compliant manner. On the second item, to the extent ED's proposal includes a DCF analysis (i.e., replacement versus increased maintenance options based on scenarios with an assumed asset stranding date), it is incorrect to assume that a maintenance alternative necessarily exists for all scenarios.[529] Moreover, it is problematic to assume that enhanced maintenance activities can be managed within the O&M envelope, when these activities were not in fact contemplated as part of the original O&M forecast submitted with the rebasing application nor the O&M budget set out in the

[528] ED Submission, pages 41-42.
[529] A number of investments have no feasible maintenance alternatives, including all investments related to growth, utilization, corrosion, mains relocation, service relays, compression station overhauls, and integrity management.

Settlement Proposal. For these reasons, the OEB should not accept ED's Submission regarding demand forecast scenario analysis.

496. ED also claims that Enbridge Gas is implicitly assuming, in its cost-effectiveness calculations, that the option value arising from deferrals is $0 and that "quantifying option value requires judgment and is not a science".[530] These claims are incorrect. Enbridge Gas's portfolio is largely made up of investments necessary to address short term safety and reliability risks and maintain compliance.[531] For growth investments, the perceived benefit of optionality in terms of potentially reducing future asset stranding or financial risk will in part be addressed implicitly through the OEB's decision (whether in this or a future proceeding) regarding the E.B.O. 188 revenue horizon. For safety and reliability focused investments, Enbridge Gas leverages fact-based data, engineering principles and sophisticated reliability models to determine the existence of risk and the appropriate mitigation strategies.[532]

497. To the extent "optionality" encompasses potential future savings/risk reductions by delaying or downsizing facility projects at the present, this inherently requires effective quantification (not just "judgement") of the probability that energy transition will unfold in a certain manner and that the potential savings/risk reductions in the future may or may not materialize. This brings us back to the challenges associated with the scenario-based probabilistic analysis, which is discussed in detail above and under the Energy Transition section.

Utilization Tracking for New Growth Assets

498. With regards to asset utilization, OEB staff proposes that Enbridge Gas track utilization of new growth-driven projects relative to forecast on an ongoing basis to

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[530] ED Submission, page 44.
[531] As illustrated by Exhibit 2, Tab 5, Schedule 1, Table 2.
[532] Exhibit 2, Tab 6, Schedule 2, pages 85-118; Exhibit I.2.6-SEC-127, Attachments 1 and 2.

improve forecasting accuracy and to assist in identifying stranded or under-utilized assets.[533] CCC submits that Enbridge Gas should formally incorporate an analysis of asset utilization in its capital planning process and report back on these efforts and lessons learned at the next rebasing.[534]

499. Enbridge Gas recognizes the importance of understanding the risk of under-utilization and initiating the development of methodologies/tools in this regard. However, it is crucial to note that a tremendous amount of work and cost would be required before this type of tracking can be reasonably defined/scoped and potentially implemented. Notably, the basis of the proposed tracking for new growth assets is not clear and would require extensive discussions (e.g., via a technical working group) to ensure common understanding of the limitations as to what is measurable for different assets and what is exactly meant by “utilization”. Aside from the potentially significant work/costs to install the requisite infrastructure to support measurement (e.g. measurement and telemetry assets), outlined below are some physical complexities that must be understood or resolved prior to implementation:

- *Simple system configuration* -- Growth-driven investments will include a range of projects for which utilization may be measurable to varying degrees. Where system configuration is relatively simple (e.g. each component serves as the sole feed to downstream customers), utilization can be measured as volume of gas delivered annually for the purposes of comparing to assumptions used to calculate profitability index. However, if utilization is to be measured for the purposes of determining system constraints, measurement of peak hourly flowrates would be necessary and require additional requisite infrastructure as described above.

- *Multiple feeds from upstream mains/stations* -- For gas mains with multiple feeds from upstream gas mains/stations or distribution stations that serve networks with multiple feeds, attempting to quantify utilization in relation to specific growth projects becomes difficult due to the varying levels of gas flow

[533] OEB staff Submission, page 38.
[534] CCC Submission, pages 30-31.

at the entry points which are dependent on variable system hydraulics and downstream consumption.[535]

- *Systems with redundancy* -- Further complications arise where multiple flow paths are available from the transmission system into communities where the new growth is occurring, including (i) difficulty of tracking utilization on an annual supply basis to be able to support a comparison of actual vs. modeled project economics,[536] (ii) additional costs if flow measurement were to be added to each new transmission loop to track annual volumes conveyed, and (iii) the fact that an asset providing an alternative flow path or back-up compression during maintenance on a redundant system is still utilized to the customers' benefit[537] but not to serve the initial primary function for which it was intended.

500. The above limitations and complications demonstrate the importance of further exploration among interested parties to reach clear expectations about the feasible methods, scope and outcome of utilization tracking for different growth assets. In this regard, Enbridge Gas also agrees with APPrO's comment regarding the importance of adopting the appropriate utilization metrics, i.e., "If the OEB does view a utilization metric as reasonable, APPrO recommends that an appropriate metric (i.e. total or peak utilization) be determined for the different assets and customer types".[538]

501. Enbridge Gas does not currently have information systems in place to track utilization, so investments will be required to set up and configure systems, roles and processes to support data collection, quality and reporting, including safeguards for customer information such as consumption data, which would be subject to the OEB's

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[535] Moving upstream, measuring asset utilization by new growth projects is even more difficult, e.g., in relation to a transmission pipe expansion that is based on an attachment/demand forecast in a service area, unforeseen customer connections in a different area will cause utilization to vary from forecast.
[536] As the communities' gas demand increase over time, pressures will decrease during peak demand hours. The volumes flowing at each entry point from the transmission to the distribution system are impacted by pressure setpoints that are often changed during the year to allow for maintenance, thus causing bias to the flow measurement across an entry point. While this does not negate the need for the asset to deliver gas for the forecasted demand during peak conditions, it does impact the degree to which an asset is specifically used to serve the intended customers throughout the year.
[537] For example, to enable system isolations without costly tapping and plugging or CNG injection.
[538] APPrO Submission, pages 30-31.

confidentiality rules. As stated during the Oral Hearing, Enbridge Gas continues to consider and is open to opportunities for AMI implementation[539] (subject to finalizing proof of concept and developing a business case), which may enable acquisition of some of the additional data necessary to move towards enhanced understanding of asset utilization as described above.

502. In summary, subject to the limitations/scope of utilization tracking being understood and defined, the necessary tools and processes being implemented, and the associated costs being assessed against benefits, Enbridge Gas may be able to measure utilization for a subset of its new growth-related assets. In terms of timing, requiring such tracking and reporting starting in 2024 would not be realistic. Enbridge Gas is not able to endorse a reasonable target date unless and until the above-noted exploratory work and discussions are completed and resourcing plan identified.

Infrastructure Repair and Life Extension

503. OEB staff asks the OEB to direct 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.[540] SEC submits that repair and/or life extension options should be considered in the assessment of IRPAs.[541]

504. Throughout the Phase 1 proceeding, Enbridge Gas has reiterated that it is not acceptable to run utility assets to failure[542] and also explained the limitations of inspection programs which can help locate damage prior to failure and allow for more localized and cost-effective remediation.[543] Enbridge Gas agrees that the parties to this proceeding and other interested stakeholders could benefit from greater

[539] 14 Tr.132.
[540] OEB staff Submission, page 41.
[541] SEC Submission, page 85.
[542] 11 Tr.99; AIC, page.147.
[543] AIC, page 147.

understanding of the utility's inspection and maintenance programs and gas infrastructure repair options that are actually viable in practice (along with associated limitations). Given the many variables impacting these decisions across thousands of projects, Enbridge Gas does not agree that such additional information would be beneficial or helpful to parties' understanding in every single case. However, Enbridge Gas would support sharing such information as part of future LTC applications.

505. SEC claims that Enbridge Gas's goal is to increase rate base and expand the gas system.[544] Other parties to the proceeding have also suggested that Enbridge Gas has a bias towards asset replacement. Thesesubmissions fail to acknowledge the practical limitations of inspection programs to allow for discovery of damage before failure or the Company's efforts to ensure that only those assets warranting replacement based on data-driven findings are actually replaced.[545]

506. Enbridge Gas has outlined a range of activities that are primarily intended to extend asset life though preventative maintenance, inspection and repair.[546] It bears repeating that despite these efforts, damage and degradation still occur and there are limitations to what these measures can achieve. Specifically, the Company has explained that the majority of the distribution mains and services (138,000 km of buried infrastructure) cannot be inspected to verify localized asset conditions without directly exposing the pipelines, which in most cases would be comparable cost-wise to replacements.[547] Enbridge Gas has therefore leveraged a combination of failure data, predictive analytics and tacit knowledge to develop proactive programs to replace the highest risk pipelines before failure rates for these assets increase to unsafe and

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[544] SEC Submission, page 51.
[545] 13 Tr.191; 13 Tr.99,186,191; 14 Tr.3-4.
[546] AIC, pages 145-147.
[547] Ibid, page 147.

unmanageable levels.[548] To suggest that Enbridge Gas is biased towards replacement over repair/life extension is simply not consistent with the evidence.

507. FRPO submits that Enbridge Gas could improve its asset management by considering "incentives associated with extending service life of an asset".[549] FRPO correctly states there is not enough evidence on the record to inform (and for the OEB to evaluate) any specific recommendations on this topic.[550] The European study cited by FRPO[551] regarding regulatory options relating to energy transition is new evidence that has not been subject to questioning or testing by Enbridge Gas or other parties in this proceeding, and thus should not be given weight by the OEB. Enbridge Gas also notes that the establishment of an expected baseline life expectancy for an asset against which to measure actual life would provide little benefit to the Company to incent life extension activities. As noted above, Enbridge Gas already deploys a host of activities to maximize asset life through preventative maintenance, inspection and repair activities[552] and tracks the completion of these activities against annual workplans as part of normal course work management. Financially incenting Enbridge Gas's staff and management to defer asset renewal solutions may actually have the unintended consequence of increasing operational risk, which would be misaligned with the asset management objective of balancing risk, performance and cost.

Incorporating Integrated Resource Planning

508. Several parties have made submissions regarding the current and future state of IRP as implemented by Enbridge Gas. Enbridge Gas responds to much of the submissions on this topic in the Energy Transition section; whereas certain submissions directly related to the capital plan are addressed below in this section.

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548 Exhibit 2, Tab 6, Schedule 2, pages 95-118.
549 FRPO Submission, page 5.
550 Ibid, page 6. FRPO also acknowledges a Phase 1 undertaking response (Exhibit J1.5) from Guidehouse which confirmed that Guidehouse was not aware of any utilities with specific metrics to incent asset life.
551 Ibid, pages 5-6.
552 AIC, pages 145-147.

509. The suggestion that Enbridge Gas has not reasonably pursued or has missed opportunities to implement feasible IRPAs[553] is unfounded. Since receiving the OEB's IRP Decision, Enbridge Gas has been systematically screening and assessing each project for IRPA feasibility[554] and has not missed any opportunity to implement a technically and economically feasible IRPA that could have avoided, delayed or downsized any capital projects in 2024. Through its technical evaluations, Enbridge Gas has found that the implementation of an IRPA is more likely to impact the scope of growth-driven projects, given that non-growth projects are driven by the need to maintain the integrity and reliability of existing system assets to serve customers on the network. For projects that have been found to have a technically feasible IRPA, an economic evaluation is either underway or planned. Enbridge Gas's economic evaluation will include use of the DCF+ test, which will consider the potential impacts and risks associated with different demand forecasts.

510. Simply assigning a target to arbitrarily increase the number of IRPAs implemented in a year would not be sensical nor provide meaningful information about actual IRP progress. Contrary to the suggestion that the OEB should set such annual targets,[555] the number of IRPAs that Enbridge Gas can implement is dictated by what is technically and economically feasible. Although the number of projects with a technically and economically feasible IRPA may not be as high as some parties would like it to be, it does not mean that Enbridge Gas has not applied the OEB IRP Framework appropriately or that it is assessing projects at a pace that is sub-par. As part of the active review of projects in the 2023 to 2032 AMP for non-pilot IRP plans, the Company has not identified a project with feasible IRPAs that is at risk of not being

[553] ED Submission, page 59.
[554] IRPAs are not applicable to a large portion of the AMP investments. Of the 2,278 gas carrying investments in the AMP (the other 809 are non-gas carrying), 886 investments passed the Binary Screening Criteria approved by the OEB for the IRP screening and evaluation process.
[555] PP Submission, pages 30-31.

able to be implemented. The insinuation that Enbridge Gas is not moving quickly enough and is putting potential IRPAs at risk is unfounded.

511. Pollution Probe in particular makes various submissions and proposals regarding the IRP Framework and associated processes, which Enbridge Gas notes are out of scope for this proceeding. More generally, as explained in the Energy Transition section, it is not necessary for the OEB to make any orders related to IRP in this proceeding as the issues raised by intervenors will be addressed in the normal course as part of the existing IRP processes, including future IRP-related project filings and IRP TWG discussions.

Rate Treatment for PREP and St. Laurent

PREP

512. OEB staff supports the levelized rate recovery mechanism proposed by Enbridge Gas for PREP-related costs and the associated variance account, while commenting positively on the simplicity of the proposal to deal with a circumstance where OEB denies LTC for the project.[556]

513. SEC disagrees with the proposal, arguing that it benefits Enbridge Gas's shareholders to the detriment of ratepayers, is contrary to the Company's proposed rate plan, and is not being applied fairly to all other projects that could offer benefits to customers.[557] Instead, SEC states that PREP should be reflected in 2024 rate base, with a variance account solely to capture outcomes if LTC is denied or if the approved costs change from what has been proposed.[558] SEC's Submission was endorsed by CCC.[559] LPMA opposes the levelized approach for PREP and believes that the project should be

[556] OEB staff Submission, page 63.
[557] SEC Submission, page 85.
[558] Ibid, pages 87-88.
[559] CCC Submission, page 22.

treated as being in-service in 2024, with the associated revenue sufficiency built into 2024 base rates.[560]

514. Before detailing its response, Enbridge Gas wishes to emphasize the crucial importance of receiving OEB approval of a rate recovery mechanism for PREP. Along with the LTC for PREP, this approval is a gating item in terms of whether Enbridge Gas is able to proceed with the project to serve increased demands for firm service in the Panhandle Market (including incremental demands from greenhouse, automotive, and power generation sectors).

515. For the reasons outlined in the Capital Update[561] and AIC[562], Enbridge Gas maintains its position that the proposed levelized rate recovery mechanism and associated variance account are appropriate for PREP, which is sufficiently distinct in both nature and magnitude from other LTC projects. It has become clear that PREP is a highly contentious project facing strong opposition by several intervenors in the LTC proceeding.[563] If the project is included in base rates and subsequently denied LTC, it will cause $14 million in revenue sufficiency for 2024 (growing to about $75 million over the IR term)[564], and this would unfairly benefit ratepayers. In addition, regarding SEC's Submission that the proposal is detrimental to ratepayers and was not made until PREP's in-service date was deferred into 2024, this submission fails to acknowledge that the PREP treatment under a 2023 in-service scenario was appropriate for the project based on the IR term and the price cap mechanism. If PREP had an in-service date in 2023, there would inherently have been an accelerated versus regular CCA benefit recognized as a credit to ratepayers in the

[560] LPMA Submission, page 14.
[561] Exhibit 2, Tab 5, Schedule 4, pages 30-33.
[562] AIC, pages 159-160, 241-242.
[563] EB-2022-0157.
[564] Exhibit 2, Tab 5, Schedule 4, Attachment 2, column (a), line 15.

TVDA. With a 2024 in-service date, customers would still receive the benefits of accelerated CCA tax deductions levelized over 5 years.

516. SEC submits that for any 2024 in-service additions subject to LTC approval, "the OEB should establish a 'Leave to Construct Variance Account' to capture the revenue requirement included in base rates if the project is denied".[565] This appears similar to the PREP Variance Account (PREPVA), though SEC does not provide details as to whether they would expect Enbridge Gas to be able to recover the sufficiency past 2024. In any event, Enbridge Gas does not believe such a variance account is necessary. If the OEB accepts a levelized approach for both PREP and (as discussed below) St. Laurent, the associated project-specific variance account would capture the difference in actual revenue requirement for the relevant project versus revenues collected through the unit rate over the IR term, thus sufficiently protecting ratepayers. There are only two other much smaller reinforcement projects[566] subject to LTC approval with 2024 capital additions which are not at all comparable to PREP or St. Laurent in terms of purpose, magnitude or risk of LTC disallowance.

St. Laurent Phases 3 and 4

517. OEB staff proposes that the levelized approach proposed by Enbridge Gas for PREP should also apply to St. Laurent Phases 3 and 4.[567] LPMA and OGVG both argue that OEB staff's proposal is unnecessary and that St. Laurent should be included in 2024 rate base.[568] SEC supports variance account treatment for the project, but opposes OEB staff's levelized proposal for the same reasons it opposes levelized treatment for PREP.[569]

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[565] SEC Submission, page 88.
[566] Dundalk XHP Reinforcement SRP ($7.2 million) and Caledonia North Reinforcement ($2 million).
[567] OEB staff Submission, page 63.
[568] LPMA Submission, page 22; OGVG Submission, page 11.
[569] SEC Submission, page 88.

518. As noted in AIC, St. Laurent as an integrity driven replacement project is a more "normal course" investment compared to PREP and has much lower 2024 capital additions and revenue requirement than PREP.[570] Nevertheless, having considered the submissions on this topic, Enbridge Gas is prepared to support OEB staff's levelized proposal for St. Laurent, which would involve excluding $75.7 million in direct capital and overhead associated from the project from the 2024 capital budget and removing the associated in-service additions from 2024 rate base, as well as establishing a variance account (similar to the PREPVA) to capture any variance between the project's actual net revenue requirement and the revenues collected through the average unit rate that would be in place during the IR term.[571]

519. The impact of removing 2024 St. Laurent project capital additions, in favour of a levelized recovery approach, would cause the 2024 base revenue requirement and deficiency to increase by $1.7 million. The levelized revenue requirement attributable to St. Laurent through 2024 to 2028 would be $4.9 million annually to be collected through a rate rider, similar to the approach for PREP.

Response to Clarification Questions from OEB Staff

520. This final part of the Capital section deals with two clarification questions posed to Enbridge Gas in OEB staff's Submission, relating to (i) the difference between two amounts ($416.1 million vs. $400.5 million) shown for 2024 growth-related spending;[572] and (ii) difference between $9.5 million for hydrogen blending in the 2024 capital budget versus $7.7 million for LCEP Phase 2 and the Grid Study combined.[573]

521. Regarding question (i), Enbridge Gas notes that the $416.1 million consists of $333.6 million in costs under all asset classes associated with Customer Connections,

[570] AIC, page 159; also see Exhibit J13.1.
[571] OEB staff Submission, page 64.
[572] Ibid, page 11, footnote 17.
[573] Ibid, page 37, footnote 90.

including Community Expansion,[574] $75.6 million in Distribution Growth Reinforcement projects,[575] and $6.9 million for Transmission Growth projects other than PREP.[576] In comparison, as per Table 1 from Exhibit 2, Tab 5, Schedule 1, the $400.5 million amount consists of $304.1 million for Customer Connections, $85.2 million for Distribution Growth, and $11.2 million for Community Expansion. This amount does not include the costs under other asset class associated with Customer Connections (amounting to $18.4 million)[577] or the $6.9 million for Transmission Growth projects. The $400.5 million total does however include $9.6 million for hydrogen projects,[578] which should not have been included. Adding $6.9 million and $18.4 million and then subtracting $9.6 million results in $15.7 million, which is approximately the difference between $416.1 million and $400.5 million when factoring in rounding.

Table 1
Explanation of variance in 2024 growth-related expenditure amounts as requested by OEB staff submission footnote 17

Breakdown of $416.1 million		Breakdown of $400.5 million	
($ millions)		($ millions)	
Gas Infrastructure Growth – Customer Connections (1)	333.6	Customer Connections	304.1
		Community Expansion	11.2
Distribution Growth Reinforcement	75.6	Distribution Growth (2)	85.2
Transmission Growth (other than PREP)	6.9	-	-
Total	416.1	Total	400.5

Notes:

(1) Consists of $304.0 million in Customer Connections, $1.9 million in Distribution Stations – Growth, $16.5M in Utilization – Meters Growth, and $11.2 million in Community Expansion (Exhibit J13.5).
(2) Includes $9.6 million in hydrogen-related costs, which should not have been included.

522. Regarding question (ii), Enbridge Gas notes that it has two other studies underway which are separate from the Grid Study and LCEP Phase 2. The two studies are a

[574] As outlined in Exhibit J13.5.
[575] Exhibit I.2.6-CCC-71, Table 5.1.10-1, sum of lines 6-13.
[576] Ibid, Table 5.3.6-1, sum of line 21-27 minus $194.9 million for PREP.
[577] As outlined in Exhibit J13.5.
[578] Exhibit I.2.6-CC-71, Table 5.1.10-1.

$1.1 million study to investigate the potential use of various hydrogen blends as fuel for process heating systems within Distribution Station and Compression Station assets and a $0.7 million study to investigate the same for fuel burning gas compression assets.[579] Added together, this explains the approximately $1.8 million difference between the two hydrogen-related amounts cited by OEB staff.

D. Operating Expenses (Exhibit 4)

<u>Depreciation Expense</u>

523. Issue 15 – Are the proposed harmonized depreciation rates and the 2024 Test Year depreciation expense appropriate?

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

<u>Summary and Relief Sought</u>

525. Enbridge Gas requests approval of the harmonized depreciation methodologies proposed by Concentric Energy Advisors (Concentric) as set out in their 2021 depreciation study as updated at the Capital Update.[580] In summary, Enbridge Gas requests approval for the harmonization of certain former EGD and Union assets into specific accounts, the use of the Equal Life Group (ELG) depreciation methodology and the continued use of the Constant Dollar Net Salvage (CDNS) methodology for calculating net salvage previously approved by the OEB for use by EGD for all applicable Enbridge Gas assets. Enbridge Gas further requests approval for the survivor curve and net salvage parameter determinations made by Concentric as set out in its 2021 depreciation study as updated.

[579] Exhibit 2, Tab 6, Schedule 2. Appendix B, pages 44-45.
[580] Exhibit 4, Tab 5, Schedule 1, Attachment 1. (Updated by Exhibit 2, Tab 5, Schedule 4, pages 4, 6, 28, 29 and 36, and Attachment 1).

526. The depreciation provision which reflects these updates is set out in Table 2 to this Reply Argument.

Submissions by Other Parties

527. The positions taken by parties who expressed an opinion on depreciation matters can at a high level be grouped together into three camps. The first group consists of those who say that more study and detailed analysis needs to be completed (with or without waiting for direction from the Government of Ontario) before the OEB should consider implementing a depreciation procedure like the ELG methodology which accelerates the depreciation provision modestly versus the Economic Planning Horizon (EPH) and Units of Production (UoP) procedures.[581] While some, like IGUA, argue that the Company has not justified the use of ELG, no party questions that it is a credible methodology given the fact that it is being utilized in various jurisdictions in North America and was recently approved for use by the Public Utilities Commission of Colorado. More is said about this later in this Submission. The common theme with this camp, which includes OEB staff, is that they accept that energy transition issues will occur and recognize that a response from a depreciation perspective will be needed to address expected acceleration of asset retirements, but they do not support prudent steps at this time.

528. Another feature of this camp is that ratepayer groups, generally speaking, favoured in their submissions the depreciation methodology (Average Life Group or ALG), asset lives (lengthened), net salvage parameters (reduced cost estimates) and a CDNS discount rate (higher) which generates the lowest possible depreciation provision. This camp is simply saying do nothing now to avoid current rate impacts (or to see the depreciation provision decline).

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[581] Enbridge Gas understands that the ELG procedure is a straight-line method of depreciation from a depreciation textbook perspective. However, the term “accelerate” has been used throughout this proceeding to describe a directional increase in depreciation relative to the status quo and relative to the decrease in depreciation expense proposed by some parties.

529. The middle camp is occupied by Enbridge Gas and to some extent, OGVG (in respect of its recommendation that the ELG procedure be applied to the Company's distribution assets and the ALG procedure to transmission and storage assets). Several other parties have one foot in this camp by acknowledging that the ELG procedure may be appropriate but only if the OEB is of the view that Enbridge will not continue to operate in a business as usual approach.[582] LPMA submits that accelerated depreciation may be warranted but as Enbridge Gas does not expect large material impacts over the next five years, they do not support the introduction of an accelerated depreciation methodology at this time.[583] CCC expresses support for the recommendation made by Mr. Neme which includes the use of the ELG methodology in the near term while the company undertakes further studies.[584]

530. SEC under one of its scenarios, the incremental approach, also falls into this camp but under what would clearly be draconian circumstances relative to other aspects of the Application.[585]

531. The third camp consists of the environmental groups and under a different scenario, SEC. These parties support the approval of much more severe forms of accelerated depreciation such as the UoP methodology but grudgingly support approval for the ELG procedure on an interim basis subject to the OEB directing the Company to undertake a study of the UoP procedure.[586]

532. No ratepayer group supports the use of an EPH or the UoP depreciation methodology at this time. None as well support the establishment of a segregated fund for future

[582] EP Submission, pages 17 and 18.
[583] LPMA Submission, page 27.
[584] CCC Submission, page 33 refers to Exhibit M9, pages 5 and 44.
[585] SEC Submission, page 97.
[586] ED Submission, page 50; GEC Submission page 43.

site restoration costs. Various parties do support Enbridge Gas being required to undertake a study for the purposes of more accurately calculating future site restoration costs.

533. While several parties have recommended alternative approaches to several of the outstanding matters, for the most part these recommendations were not raised during the Oral Hearing, so there is no evidence of the practicality and, importantly, the impacts of same. To a large measure, neither the Company nor other parties have been afforded an opportunity to provide their views on such recommendations. While the lack of an evidentiary record should cause the OEB to reject these proposals without requiring input from the Company, Enbridge Gas, in the interest of being helpful, offers comments in respect of several later in this Reply Argument.

<u>Enbridge Gas's Response to Other Parties Submissions</u>

Overview and Summary

534. Before providing a detailed response to the positions taken by the parties, Enbridge Gas trusts that it is helpful to first provide an overview and summary. The work which supports the requested changes in respect of depreciation starts with the OEB's MAADs Decision which specifically directed the Company to file a proposal about "harmonization" which it understood to include the harmonization of depreciation methodologies and accounts.[587]

535. Enbridge Gas engaged Concentric, a firm with a recognized depreciation expert, Mr. Kennedy who had previously completed depreciation studies for EGD and numerous other utilities across Canada. Concentric was tasked with considering the options and recommending approaches for harmonized depreciation and net salvage estimation methodologies. The scope of work required Concentric to consider energy transition

[587] EB-2017-0306/0307, OEB Decision and Order, August 30, 2018, pages 43 and 46.

issues.[588] He was also asked to review the harmonized data of the various asset accounts from the legacy Utilities and take whatever steps he considered appropriate for the purposes of making recommendations for the harmonization of accounts.

536. As is noted in the Concentric report and in the oral evidence at the Oral Hearing, Concentric's recommendations were based upon sound depreciation theory and the exercise of professional judgement which considered matters including future energy transition risks. While Concentric's recommendations do result in a depreciation expense of $879 million[589], which represents an increase over the status quo, the recommendations are the result of a comprehensive review and the consideration of all alternatives. While Enbridge Gas acknowledges the directional impact that this will have on rates, it submits that it is the prudent thing to do now as opposed to simply passing on such costs to future ratepayers. This would be inequitable.

537. The Company's Reply Argument below will first respond to submissions made in respect of the ELG versus ALG procedure. It will then respond to the positions taken by parties, primarily OEB staff and IGUA in respect of the treatment of asset lives and curves and net salvage parameters. This Reply Argument will next respond to positions taken in respect of the CDNS methodology and the appropriate discount rate. It will then discuss whether the use of the traditional net salvage method offers a reasonable alternative. Finally, this Reply Argument will turn to the recommendations made that the Company undertake a detailed study of net salvage costs in respect of ten accounts and several of the other suggestions made by parties.

538. Before turning to some of the issues specifically, it is appropriate to reiterate what Enbridge Gas submitted in AIC, namely that the two depreciation experts engaged by

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[588] Exhibit I.1.2-CCC-2, Attachment 2, page 200.
[589] Updated to $866.2 million as presented in Exhibit J17.11, page 3. See paragraph 543 of this Reply Argument for more details.

OEB staff and IGUA, InterGroup and Emrydia, did not see their engagements as requiring them to consider their depreciation recommendations through a lens, at least in part, of energy transition. In its response to interrogatories, InterGroup stated:

> InterGroup did not review documents regarding energy transition for Enbridge Gas or for Ontario broadly in the preparation of the evidence, outside of the noted report, prepared by Concentric.[590]
>
> Opinions regarding the appropriate lives for assets, outside of major questions of energy transition, are set out in the InterGroup report.[591] (emphasis added)

539. In InterGroup's Report, it states that the adoption of ELG is a significant matter of policy that should be addressed directly through decisions of the regulator.[592] InterGroup makes no reference to energy transition risks for the purposes of its recommendations in respect of asset lives and curves and net salvage parameters. They propose only a lengthening of asset lives and a reduction in net salvage parameters.

540. In response to an interrogatory asking where in evidence Emrydia considered energy transition and its impact on consumers, Emrydia responded:

> The evidence does not consider the initiatives being led by the OEB to examine energy transition and its impact on consumers and rate regulated utilities in Ontario...[593]

541. Emrydia also stated in another interrogatory response that:

> The topic of whether and if so how, to adjust depreciation policy in order to address speculative energy transition risk, such as that outlined in this question, is a significant and involved one in its own right, and beyond the scope of my current retainer.[594] (emphasis added)

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590 Exhibit N.M1.EGI-2.
591 Exhibit N.M1.PP-4.
592 Exhibit M1, pages 6 and 26.
593 Exhibit N.M5.EGI-31.
594 Exhibit N.M5.ED-2.

542. The recommendations made by these experts must therefore be considered with the recognition that they have deferred (some might argue the better word is avoided) considering energy transition issues and their potential large impact on asset depreciation. They have therefore not exercised any professional judgment that is in any way reflective of such energy transition considerations.

543. Table 2 identifies the 2024 depreciation provision proposals using the various recommendations of the Company, OEB staff and IGUA. Enbridge Gas notes that the total depreciation expense of $879 million which is included in the tables and attachments to this Reply Argument reflects the impact of the Concentric recommendations made in this proceeding. This figure has not been adjusted to reflect several impacts due to the Settlement Agreement which lower the 2024 depreciation expense to $866.2 million.[595] More specifically, the depreciation expense figures in this Reply Argument have not been updated to remove the impact of the write-off of the GTA & WAMS overspend and the impact resulting from the reduction in overhead capitalization from $310 million to $292 million (approximately $4 million). The depreciation expense of $879 million also continues to include the depreciation impacts of the Dawn to Corunna project which has now been moved to Phase 2 of this proceeding (approximately $9 million). The Company believes that the use of the $879 million figure in this Reply Argument is appropriate for ease of comparison purposes between what has been filed in evidence and the impacts on the Company's proposals due to the recommendations made by InterGroup and Emrydia.

[595] Exhibit J17.11, page 3.

Table 2
Summary of Depreciation Scenarios

	Enbridge Lives and Survivor Curves		**OEB Staff Lives and Survivor Curves (2)**		**IGUA Lives and Survivor Curves (3)**	
($ millions)	**ELG (1)**	**ALG (1)**	**ELG (4)**	**ALG (5)**	**ELG (4)**	**ALG (5)**
CDNS @ 3.75% Concentric proposal	**879.0**	795.6	826.6	768.9	665.0	579.1
CDNS @ 4.48% Intervenor proposal	n/a	n/a	791.9	711.4	631.8	550.6
CDNS @ 6.03% (6) **Intervenor proposal**	n/a	n/a	656.2	668.3	588.7	513.6
Traditional Method	1,034.1	935.7	979.7	878.8	745.6	650.3

2024 Depreciation at EGI Proposal (7)	**879.0**
2024 Depreciation at Current Depreciation Rates	**737.1**

Notes:
(1) Exhibit J17.9, Attachment 1 for details.
(2) Reflects InterGroup's asset life parameter recommendations from Table 10 of OEB staff's Submission. Does not reflect InterGroup's method of the CDNS calculation or net salvage parameters.
(3) Reflects InterGroup's and Emrydia's asset life parameter recommendations from pages 37 and 38 of IGUA's Submission. Does not reflect InterGroup's method of the CDNS calculation or net salvage parameters.
(4) See Attachment 1 for details.
(5) See Attachment 2 for details.
(6) A WACC rate of 6.03% (instead of 5.87%) was maintained for alignment with Exhibit J17.9.
(7) The 2024 depreciation expense is $866.2 million as presented in Exhibit J17.11, page 3 and discussed in paragraph 543.

544. The Company wants to highlight that Table 2 does not incorporate the impact of InterGroup's method of the CDNS calculation or InterGroup's net salvage parameter recommendations. The values calculated for the OEB staff and IGUA columns utilize Concentric's CDNS method and set salvage parameter recommendations. The CDNS calculations of InterGroup were not used because the evidentiary record is not detailed enough for Concentric to replicate the calculation with any degree of accuracy. Furthermore, InterGroup's net salvage parameter recommendations were omitted because, as discussed during the Oral Hearing,[596] after the impact of life lengthening and a higher discount rate, the net salvage provision would already be at

[596] 16 Tr.75.

an unreasonably low amount. In Exhibit J16.6, Concentric estimated the accrual related to net salvage to be only $325,472 using the ALG procedure with a discount rate of 6.03% and life and retirement dispersion estimates as proposed by Emrydia and InterGroup.

ELG Should Be Preferred Over ALG

545. The position taken by intervenors in respect of the ELG vs. ALG debate appears mostly driven by their views on energy transition or rate impacts rather than by depreciation theory. While OEB staff's and IGUA's depreciation experts cast unsubstantiated doubt on the Professional opinions made by Mr. Kennedy of Concentric about the better accuracy of the ELG procedure versus the ALG procedure (indeed Mr. Madsen admits that it is more mathematically accurate than other procedures[597]), the opposition to ELG is motivated primarily by the fact that ELG modestly increases the depreciation expense relative to existing approved methodologies. This proposed increase is certainly modest in comparison to the increase that would be generated by the use of the EPH and UoP procedures.

546. The evidence of Enbridge Gas and Concentric is that the ELG methodology improves inter-generational equity.[598] As noted in the pre-filed evidence, the ELG procedure is viewed as the best option for Enbridge Gas as it offers the following advantages over other methodologies: a) enhances the generational equity for customers; b) provides superior matching of the depreciation expense to the consumption of assets providing service to customers; and c) more accurately reflects the actual useful life of the assets used.[599]

[597] Exhibit M5, page 26.
[598] Please see *inter alia* 16 Tr.90-92 and 110-111.
[599] Exhibit 4 Tab 5 Schedule 1, pages 6-7. See also Exhibit 4 Tab 5 Schedule 1 Attachment 1, pages 16-17.

547. It also represents a modest good first step in terms of the energy transition future.[600] There is no evidence which stands for the proposition that the ALG procedure provides better inter-generational equity and no one is promoting it as a good, or any, step towards addressing energy transition risks.

548. While there are differences in views about the merits of the two depreciation methodologies from the perspective of depreciation theory, there is a consensus in respect of a number of important matters which provide needed context. First, no party claims that energy transition issues are a myth. All parties admit that foundational changes to the natural gas distribution business are inevitable.

549. Second, no party has overtly supported the notion of lowering depreciation rates as an appropriate response to energy transition. While ratepayer groups support the ALG procedure and lengthening asset lives because they lower the depreciation provision, they dare not say that this is the preferred approach from an energy transition perspective. As noted by Dr. Hopkins during the Oral Hearing "waiting makes things worse. The longer the utility waits to change its approach (in a world where building-sector customers and sales are falling towards zero), the larger the rate shock and the larger the potential amount is stranded cost to mitigate".[601] Mr. Neme supported this view by stating "I don't think you can wait for certainty. I don't think you are ever going to get certainty. Policies change; they evolve; and, if you wait for certainty, it's going to be too late to have a significant material effect on things, in part because certainty will never be here."[602]

550. Third, there is also no evidence or submissions to the effect that decreasing the depreciation expense relative to the status quo, will <u>not</u> lead to an even higher

[600] Please see *inter alia* 16 Tr.110-111.
[601] Exhibit M8, page 46.
[602] Please see *inter alia* 6 Tr.99.

depreciation expense in the future. The unchallenged evidence in this proceeding is that if the status quo is continued (or, even worse, the depreciation provision declines relative to the status quo), the impact on future ratepayers will almost certainly be an even higher depreciation expense than would be the case if the ELG procedure was approved at this time. It is notable that none of the parties opposing the ELG procedure identified this resulting inter-generational inequity and none have attempted to justify it.

551. The question that Enbridge Gas submits the OEB needs to answer is whether some form of depreciation methodology which results in an appropriate acceleration of the depreciation recovery is appropriate to implement at this time. The Company states that there is no evidentiary basis supporting a decline in the depreciation expense relative to the status quo given the energy transition issues that have dominated much of this proceeding. Precisely the opposite is the case. Unless some form of reasonable or moderate acceleration in depreciation is undertaken now, things will only get worse. Current ratepayers would benefit from this short-sightedness with a depreciation expense less than what is appropriate. Ratepayers in future, perhaps as early as the next rebasing application, would suffer the inequitable impacts having to make up for the earlier under recoveries. Simply stated, reducing the depreciation expense relative to the status quo, and even the continuation of the status quo, are not viable options.

552. While IGUA's Submission advocates for the adoption of the ALG procedure and the lengthening of numerous asset lives so as to greatly reduce the depreciation provision relative to the status quo, the evidence of its expert witness, Dr. Hopkins, stands for the opposite, namely the early adoption of accelerated depreciation. Enbridge Gas finds it surprising that IGUA did not attempt to explain this inconsistency in its Submission. Enbridge Gas submits that the conclusion which the OEB should draw is that this glaring inconsistency cannot be rationally explained.

553. Dr. Hopkins' report and evidence undermines IGUA's Submission recommending not only no acceleration in depreciation but rather what could be viewed as an artificial reduction of the depreciation provision. Interestingly, Dr. Hopkins acknowledges at page 12 of his report[603] that there is some risk that regulators will prevent utilities from taking appropriate energy transition mitigation actions. This is precisely what IGUA is proposing, namely, that the OEB prohibit the Company from taking an appropriate step to address the energy transition risks it faces including stranded assets by a modest acceleration in depreciation relative to the EPH and UoP procedures.

554. Dr. Hopkins attaches to his report what he describes as his survey of leading states that are taking a proactive look at the potential risks associated with energy transition[604] He refers to the Massachusetts study, which is discussed further below, as being one which went further than almost all other comparable analysis, laying out the challenges for gas utility regulation and the ability of straightforward and regulatory financial tools to mitigate risks. Dr. Hopkins also referenced the work of his firm, Synapse, in the state of Maryland. He specifically stated at page 42 of his report that "we showed that if the state's utilities did not change their approach to managing their capital (<u>e.g. they kept their depreciation rates unchanged</u>) customer departures could result in stranded costs for meters, services and (potentially) mains"[605] (emphasis added).

555. These are the words of IGUA's expert witness. These are the conclusions that Dr. Hopkins reached following his firm's work in Maryland and his survey of "leading States" which was appended to his report as Attachment 3.[606] It is therefore appropriate to look more closely and precisely at Dr. Hopkins' report in light of IGUA's

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[603] Exhibit M8, page 12.
[604] Ibid, page 27.
[605] Ibid, page 42.
[606] Exhibit M8, Attachment 3.

Submissions. The following is a very abbreviated summary of Dr. Hopkins' findings relevant to the issue of depreciation as set out in his survey of leading U.S. States.

556. Massachusetts: Consultants engaged to analyze strategies to achieve net zero emissions elaborated on options and approaches available to address energy transition issues. The Consultants identified and quantified transition costs and evaluated impacts on customers of baseline and alternative approaches to cost recovery (<u>such as accelerated depreciation</u>, exit charges or transferring costs to electricity customers)"[607] (emphasis added). It appears clear to Enbridge Gas that accelerated depreciation is being considered as part of the road map in Massachusetts.

557. New York: The NY Public Service Commission required LDCs to calculate the revenue requirement and bill impacts under (a) full depreciation of all <u>new</u> gas plant by 2050; (b) full depreciation of <u>all</u> plant by 2050; and (c) 50% of gas customers exit the gas system by 2040 and that 10% remain after 2050. National Fuel Gas determined in response that in a high electrification scenario maintaining the current assumed asset lives would result in a rate base that would be almost four times larger compared to the rate base assuming accelerated depreciation.[608] Stated differently, without accelerated depreciation, the risks to remaining customers would increase dramatically with a four-fold increase in rate base without accelerated depreciation.

558. Maryland: This is the State where Dr. Hopkins' firm undertook the study which was sponsored by the Maryland's Office of People's Counsel (OPC). Dr. Hopkins noted that the study he undertook points out that changes in, amongst other things, depreciation can reduce the pace of rate increases and mitigates stranded cost

[607] Exhibit M8, Attachment 3, pages 1-3.
[608] Ibid, pages 3-4.

risks.[609] In response, Baltimore Gas and Electric provided regulatory and policy recommendations including accelerated depreciation.[610]

559. Colorado: The Colorado Public Utilities Commission has required utilities to identify potential changes to depreciation schedules and other actions to align the utilities' cost recovery with statewide GHG goals.[611]

560. Oregon: The Oregon Public Utility Commission conducted a fact-finding process. This Process identified a host of regulatory tools to manage energy transition for gas utilities including, in the near term, depreciation.[612]

561. California: The California Energy Commission (the State's Energy Policy Agency) commissioned a study. The study describes the components of a strategy to maintain gas utility viability. It recommended, *inter alia*, to "accelerate depreciation."[613]

562. What Dr. Hopkins' survey confirms is that no jurisdiction has identified a clear pathway for gas utilities to avoid or eliminate all energy transition risks. This said, his survey confirms that:

- Accelerated depreciation has been commonly determined to be one of the appropriate energy transition mitigation tools.
- The studies by and large are undertaken by either a State regulator or agency, together with affected gas and electric utilities, based upon objectives, articulated by the State.
- No state, including Maryland, where Dr. Hopkins' firm Synapse did the work, has completed a study of the nature he recommends. Indeed, Dr. Hopkins specifically admits that he is not aware of any study that has met the full set of what he calls "best practices" as laid out in his report. This of course means

[609] Exhibit M8, Attachment 3, page 5.
[610] Ibid.
[611] Ibid, page 10.
[612] Exhibit M8, page 11.
[613] Ibid, page 14.

that his recommendations are not best practices as they are in fact not practiced.

563. The bottom line is that while Dr. Hopkins advocates additional modeling and analysis, he already knows that this will lead to the recognition that some form of accelerated depreciation is necessary. While the Company agrees additional study and analysis in future will be needed which will inform future steps, doing nothing now is illogical. Notably, each of the Enbridge Gas witnesses and its experts when asked indicated that they agree further modeling and analysis in future will be required but none supported inaction at this time. Enbridge Gas submits that the one certain thing that additional study will determine is that it would have been prudent to take a modest step in accelerating depreciation in 2024.

564. Dr. Hopkins, while under cross-examination by counsel for APPrO, agreed that to get the full integrated picture you will need the involvement of other parties, including electric utilities[614] and that the path of possible pathways for Ontario is wide at the moment given the absence of the pending government policy directives.[615] Enbridge Gas agrees. That is precisely what it has done by engaging experts and expending a great deal of time considering and investigating potential future pathways.

565. A good portion of this proceeding has been spent addressing energy transition issues. Mr. Elson on behalf of ED, spent the better part of several hours asking Dr. Hopkins questions about the energy transition work undertaken by and on behalf of Enbridge Gas. The fact is that Enbridge Gas has undertaken modeling and analysis and has proposed tools, including modestly accelerating depreciation, to address energy transition issues based upon the best available information at this time.

[614] 5 Tr.82.
[615] 5 Tr.83.

566. Dr. Hopkins, when asked about whether the position taken by IGUA that there should be a decrease in the depreciation provision said that he did not think a year or two while other analysis is completed, one way or the other, is likely to make that great of a difference in terms of long-term risk.[616] Of course, IGUA is not proposing a deferral of one or two years, it is proposing a deceleration of the depreciation expense for the entire IRM term. IGUA's position is also undermined by the following response by Dr. Hopkins during the Oral Hearing:

> MR. O'LEARY: But, directionally, you would expect to see the depreciation expense increase
>
> DR. HOPKINS: To the extent that it is appropriate for the company to plan for futures with shorter asset lives, then yes.

567. Inconsistent with what Dr. Hopkins said at the Oral Hearing, IGUA's depreciation expert, Mr. Madsen, proposed no shortening of the lives of any asset. Mr. Madsen only recommends the lengthening of the asset lives of a number of accounts to the absolute upper end of the applicable range of useful lives. He further supports the lengthening of asset lives as proposed by OEB staff. The Company submits that a balanced review of the depreciation study would not lead a depreciation expert to recommend changes only in one direction.

568. In the end, Enbridge Gas has proposed a depreciation procedure which is appropriate at this time based upon what is currently known and given its acknowledged superiority over the ALG procedure as demonstrated in the Company's AIC. Accelerating depreciation modestly relative to the EPH and UoP procedures at this time is appropriate. This is precisely the determination made by the Public Utilities Commission of the State of Colorado, one of the jurisdictions which Dr. Hopkins in his report considers a leading state. The relevant findings of the PUC are as set out below:

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[616] 5 Tr.166.

> 161. We conclude that the continued use of what can be viewed as a 57-year weighted average depreciation life on future capital plant investments is no longer reasonable given the uncertainty about the future trajectory of the gas utility business as reflected by the record in this Proceeding, including through the diverging views of the parties of that future trajectory. We are also unpersuaded by Public Service's arguments that it is premature to examine depreciation expenses in this Proceeding as a result of the enactment of SB 21-264 and of other recent legislation that will require significant reductions in greenhouse gas emissions from the gas utility sector in Colorado. The record before us, as well as the rapidly evolving regulatory regime for gas utilities, require the Commission to consider some action in the present with respect to depreciation.
>
> 162. We further recognize that if we adopt higher depreciation rates, or otherwise cause the COSS to cause the same effect as higher depreciation rates, customers will face increased rates in the near term as a result of the associated increase in revenue requirements. It is difficult to adopt such an approach when ratepayers are already facing the pancaking of rate increases and higher gas commodity costs. However, we are persuaded by Staff's suggestion that <u>taking a directional step toward higher depreciation expenses is reasonable and gradualism is appropriate in this instance. Taking no action now causes there to be less opportunity to apply gradualism later.</u>
>
> 163. We conclude that it is reasonable to direct Public Service to recalculate the depreciation expense for the HTY using the ELG approach…<u>The increase in the depreciation expense caused by the move to the ELG approach fosters the gradualism we seek to accomplish during the time when the impacts of various potential factors related to the useful lives of facilities become better understood</u> in relation to Public Service's necessary actions to achieve significant reductions in greenhouse gas emissions over the next decades.[617] (emphasis added)

569. Not only did the Colorado PUC reject the recommendation to delay the implementation of some form of accelerated depreciation pending further study, it specifically approved the use of the ELG methodology as it fosters the gradualism the Colorado PUC wished to accomplish. The findings of the Colorado PUC are strikingly relevant to this proceeding.

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[617] Decision No. C22-0642 Before The Public Utilities Commission Of The State Of Colorado, Proceeding No. 22al-0046g, In The Matter Of Advice Letter No. 993-Gas Of Public Service Company Of Colorado To Revise Its Colorado P.U.C. No. 8 – Gas Tariff, September and October 2022, pages 50 and 51.

570. Enbridge Gas further submits that the implementation of the proposed ELG methodology and Concentric's recommended account parameters should not await any further consideration of a different depreciation methodology such as the UoP methodology proposed by the environmental groups. It is noteworthy that a recent decision of the California Public Utilities Commission in an application brought by PG&E rejected approving a UoP methodology for depreciation.[618]

571. In the end, Dr. Hopkins acknowledges that the modeling he suggests will result in some near term rate shock from accelerating depreciation, as soon as that change is made; waiting makes matters worse; and using relatively simple levers around depreciation and retirement, the actual dollars at risk of stranding are quite small.[619] All of these statements support modestly accelerating depreciation now (in comparison to the EPH and UoP procedures), and not waiting for further studies to be completed. IGUA in comparison proposes that the depreciation expense be significantly reduced. Its estimates as stated in its submission are not accurate. The decrease would be significantly more. The correctly calculated impacts are stated in this Reply Argument.

572. Enbridge Gas believes that it is vital to point out that if IGUA's recommendations are accepted, the risk to future ratepayers will increase dramatically particularly should it become necessary in future to introduce an EPH or UoP depreciation procedure. Reducing the depreciation expense now will magnify the increase in future perhaps, as noted by Dr. Hopkins in his survey, by four-fold.

573. It should be noted that while Enbridge Gas sees the ELG methodology as a good first step in addressing energy transition issues, it does not see this as the only and final

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[618] Application 21-06-021, Proposed Decision Of Aljs Deangelis And Larsen Before The Public Utilities Commission Of The State Of California On Test Year 2023 General Rate Case For Pacific Gas And Electric Company, pages 644-650.
[619] Exhibit M8, page 46.

step. As noted by Mr. Kennedy in his oral evidence,[620] once a solid understanding is gained of the energy transition future, informed in part by policy decisions made by the Government of Ontario, other more blunt tools intended to accelerate depreciation more, such as EPHs and UoP methodologies, will be considered by the Company's depreciation expert.

574. The benefits and comparable superiority of the ELG procedure over the ALG method are identified in the Company's AIC and in the interest of brevity will not be repeated here. Notwithstanding, it is appropriate to restate that the ELG procedure has been put forward by the Company in this proceeding for reasons beyond energy transition risks. This was confirmed by Ms. Giridhar in her oral evidence where she stated:

> The ability to address inter-generational equity by ensuring that the consumption of the asset reflects the benefits at the same time period in which the benefits are derived was inherently attractive.[621]

575. Mr. Kennedy also confirmed this during the Oral Hearing stating that in his opinion the ELG procedure better addressed inter-generational equity issues in many circumstances.

> … It is a method that we have used in many provinces across the country and has been used for many decades in other industries throughout North America so it does have some very significant inter-generational benefits.[622]

576. Mr. Kennedy further stated that ELG is an accepted procedure with or without energy transition.[623] He added:

> If, in fact, energy transition occurs at the pace that it may be going, the system may have many assets that would exist on a very long-lived assets where they won't need an EPH. But there definitely is going to be interim retirement activity. There has been for many decades, historically and there will be going forward. And the Equal Life Group deals with those

[620] 16 Tr.95 and 17 Tr.68-69.
[621] 16 Tr.91-92.
[622] 16 Tr.110-111.
[623] 16 Tr.102.

> inter-generational equities related to those interim retirement transactions.[624]

577. Ms. Dreveny on behalf of the Company stated in oral evidence that:

> My first comment to that is that the Equal Life Group is not meant to frontload depreciation. The intent is to match the consumption of the asset with the use and improve the inter-generational equity. I would say the second piece here is that we are not proposing the Equal Life Group as a solution to any energy transition. This will continue to evolve over time. What we are proposing is that, you know, in the face of uncertainty, and we’re not sure how this will unfold, this is perhaps a first step toward managing what may come.[625]

578. Mr. Kennedy also stated:

> In most cases, my experience is that if you use the Equal Life Group and you have a major change in retirement patterns, the Equal Life Group has dealt with that better than the average life group does.[626]

579. Mr. Kennedy further stated in the Oral Hearing:

> If we went back to, say for example, the last major industry that experienced transition, the telecom industry, ELG was used exclusively throughout all of North America to deal with the transition issues that the telecom companies were facing as they became unregulated.[627]

580. Enbridge Gas submits that the adoption of the ELG procedure is appropriate not only because of its methodological improvements over the ALG procedure but because it is a prudent first step towards mitigating energy transition risks and the inter-generational inequity of deferring the expected costs of energy transition to future ratepayers when now is the time for a moderate acceleration of depreciation. It is also an approach which is supported by the tenets of regulated rate making. As noted by Mr. Kennedy during the Oral Hearing:

> So we moved into this period of uncertainty that, you know, we just don’t want to be stretching lives out because that does potentially create some future risk, in addition to the approach in terms of depreciation. We’d like to make sure that we are depreciated as correctly as possible, and, in my view, that was the equal life group.

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[624] 16 Tr.111.
[625] 17 Tr. 106.
[626] 16 Tr.140-141.
[627] 16 Tr.116-117.

> So that kind of – that uncertainty, I wouldn't say it's a probabilistic analysis about the future. It is just that, now, we're into a period of uncertainty.[628]
>
> And, in the case that you are maybe erring on the side of – I don't – I'm not going to use the word "burdening" the current customers but, you know, erring on that side, Dr. Bonbright would have told us in his 1961 textbook that one should err to that sort of earlier recovery of the capital simply to avoid that death spiral in later years.[629]

581. Finally, the Company responds to the submission by SEC that under one of its scenarios the OEB should consider retaining the status quo essentially prohibiting until the next rebasing application the harmonization of the depreciation methodologies used by EGD and Union. This would mean two separate depreciation methodologies, two different net salvage approaches, a doubling of asset accounts and separate tracking for everything. This is not a realistic suggestion and is certainly no solution for any alleged concerns.

582. The directive made by the OEB in its MAADs Decision was that the Company present a harmonization proposal in this proceeding.[630] What SEC proposes should not be accepted because it is inconsistent with this directive and because it is inappropriate for too much time to lapse between depreciation studies as outdated asset and net salvage parameters, and therefore depreciation rates, would no longer reflect the appropriate consumption of assets thereby resulting in an over or under recovery of costs. This would cause intergenerational inequity. EGD's and Union's last full depreciation studies were conducted in 2011. Continuing to apply depreciation rates that are over a decade old over the 2024 to 2028 term would not be appropriate. This is not a credible option.

[628] 17 Tr.156.
[629] 17 Tr.7 and 168.
[630] EB-2017-0306/0307, OEB Decision and Order, August 30, 2018, including pages 43 and 46.

Specific Asset Accounts

583. Unlike the experts engaged by OEB staff and IGUA, Concentric undertook a full and comprehensive depreciation study. This included a detailed analysis of the copious and detailed data provided by Enbridge Gas and meetings with appropriate Company managers. After completion of Concentric's Report, Enbridge Gas discovered that the historical retirement data for Union assets prior to 2010 had not been provided to Concentric. The data was subsequently provided and, as part of the Capital Update, Concentric revised the depreciation rates for the few accounts that were impacted.[631]

584. The most up to date recommendations are summarized in Table 3 of this Reply Argument.

585. In comparison, InterGroup and Emrydia only undertook a critique of Concentric's work and examined some of the data. Their recommendations are based upon only a limited subset of the available information, including their interpretation of the notes taken by Concentric from its various meetings with Enbridge Gas managers. Enbridge Gas submits that this is important to recognize when comparing the various recommendations of the depreciation experts in respect of the specific asset accounts. Indeed Mr. Bowman admitted that InterGroup did not focus necessarily on services because services are probably the types of accounts that will most be impacted in terms of interim retirement by the type of transition components or the transition effects that have been talked about.[632]

586. Ultimately, the survivor curves and net salvage parameters proposed by Concentric were based upon informed professional judgment which incorporated a review of management's plans, policies and outlook, the retirement histories of assets, a

[631] Exhibit 2, Tab 5, Schedule 4, Section 3, and Attachment 1.
[632] 18 Tr. 44.

general knowledge of the natural gas industry and a comparison of the service life and net salvage estimates from peer gas utilities.[633]

587. What is clear from the evidence is that neither InterGroup nor Emrydia paid any attention to energy transition issues for the purposes of their recommendations. They admit to being aware of energy transition issues but did not make a single recommendation for any account parameters in response to energy transition issues.

588. In comparison, Mr. Kennedy stated at the Oral Hearing:

> Concentric has taken a moderated approach to the selection of average service life estimates for long-lived asset groups but we had lengthened the average service life estimates from the longer of the Union or legacy Union or legacy Enbridge systems, in only 7 accounts. This moderated approach was followed to provide for the consideration of energy transition. In contrast, Both Mr. Bowman and Mr. Madsen have lengthened the average service life estimates beyond the Concentric recommendations in 14 accounts.[634]

589. The lengthening of average service lives as recommended by Messrs. Bowman and Madsen has a combined impact amounting to a reduction to Enbridge Gas's proposed depreciation expense of $230.7 million dollars.[635] The Company has updated the impact on all affected accounts and as shown in Table 2, to be $52.4 million for OEB staff's recommendations and $214.0 million for IGUA's recommendations. These reductions, it should be noted, are due solely to the lengthening of the useful lives of asset accounts and survivor curve selections as recommended by Messrs. Bowman and Madsen.

590. Surprisingly, given the magnitude of the impact of these proposed changes, there was very little time spent during the Technical Conference and Oral Hearing in respect of these recommended changes. The vast majority of the time in this proceeding was

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633 Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 24.
634 16 Tr.73-74.
635 Exhibit J17.9, Table 1.

spent debating whether the appropriate group depreciation procedure is the ELG or the ALG methodology (and for the environmental groups, the UoP procedure) and the correct means of calculating the CDNS methodology.

591. It is clear from a review of specific asset accounts below that both InterGroup and Emrydia were true to their words. Energy transition had no impact on their recommendations in respect of the average service lives and survivor curves they recommended.

592. In every instance, InterGroup and Emrydia recommended asset lives and survivor curves which are equal to or greater than the longest measure lives approved for legacy utility assets. It is important to understand that in substantially all instances, the recommendations by InterGroup and Emrydia to extend or to lengthen the average service life would reduce the depreciation recovery significantly below what is currently being recovered using the historical methodologies. In many instances, InterGroup or Emrydia have selected the average service life at the extreme end of the range of service lives applicable for peer Canadian utilities. It is also appropriate to highlight the fact that many of the accounts for which Intergroup and Emrydia have recommended life lengthening's are in respect of distribution plant and the assets which are most vulnerable to energy transition and the stranded cost risk. This makes the recommendations to increase asset lives even more inappropriate.

593. This is a clear example of certain parties making submissions which are inconsistent. With the exception of IGUA, which opportunistically submits that energy transition has not changed the business risk for Enbridge Gas[636], every other party to this proceeding accepts that energy transition issues are likely to have a foundational

[636] IGUA's Submission denies that the Company's business risk has changed sufficiently to warrant a FRS review and that even under a FRS review, an increase in equity thickness is not warranted because the Company faces no near term operational or volatility risks, pages 11-28.

impact on the gas distribution business. Many parties are overtly arguing that much of the Company's plant will no longer be required in a matter of several decades. To then support a lengthening of the average service lives of the assets which these parties submit will no longer be required, perhaps as soon as 2045 or 2050, is frankly remarkable. This only shows that the positions taken by intervenors in respect of the depreciation expense is not driven by the application of appropriate depreciation principles but rather solely to reduce the depreciation expense and hence rates, notwithstanding the promotion of energy transition positions in respect of other issues before the OEB in this proceeding.

594. An example of this is OEB staff who take the position that adjusting asset lives for customer connection capital can wait for another 5 years while also claiming it is important to assume that the revenue horizon should be 20 years or that customers would abandon the gas system when their furnaces need replacement. This could mean that there would be a deferral of the decision on the appropriate asset life and the return of invested capital for customer connections accounts to a period when customers are abandoning the gas system. This is a remarkable position considering that OEB staff also suggests that it might be appropriate to subject the Company to the stranded asset risk.

595. The statement by OEB staff that they are under the impression there was a lack of analytical rigour undertaken by Concentric is extremely unfair[637]. Mr. Kennedy and Ms. Nori are experienced depreciation experts recognized across North America. The fact that professional judgment was exercised being mindful of energy transition issues is not a sign of arbitrariness, it is a sign that the depreciation expert has appropriately considered all relevant factors.

[637] OEB staff Submission, page 88.

596. It is worth noting that in OEB staff's Submission, they acknowledge that "InterGroup commented on the asset life parameters recommended by Emrydia, and in general did not suggest that these recommendations be adopted…"[638] (emphasis added). InterGroup stated in its report:

> The current Application proposes that most accounts retain their currently approved life and dispersion parameters, or involve modest changes that are generally supported by the data and updated retirement history…[639]
>
> for major accounts not listed [in the InterGroup report] no problematic issues were identified that merited a finding for a different life and dispersion combination.[640]

597. Before considering several of the asset accounts in some detail below, the Company believes that it should briefly address several here as they do not seem to be in dispute.

Account 452 Underground Storage Plant – Structures and Improvements

598. As part of the Capital Update, Concentric adjusted its originally proposed 40-R3 curve for this account to a 45-R3 curve to account for the inclusion of additional Union historical retirement data. As noted by OEB staff in its Submission, while this is not the same as Mr. Bowman's recommendation of 45-R2.5, it is substantially similar[641]. There does not appear to be any issue remaining.

Account 464 Transmission Plant – Equipment

599. As part of the Capital Update, Concentric adjusted its recommendation to a 30-L0.5 curve versus the originally recommended 50-S4 curve. Neither InterGroup nor Emrydia expressed any concerns with the original recommendation by Concentric but OEB staff stated in its submission that it could not support this change without further

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638 OEB staff Submission, page 83.
639 Exhibit M1, page 7.
640 Ibid, page 28.
641 OEB staff Submission, page 86.

details.[642] Enbridge Gas notes that the change in the proposed curve was made to account for the inclusion of the additional Union historical retirement data and will result in an increase in the depreciation expense of an immaterial amount estimated at around $100K.

Account 472.35 Distribution Plant – Structures and Improvements – Mainway

600. As part of the Capital Update, the truncation date for Mainway was revised from 2024 to 2027.[643] OEB staff state in their Submission that this revision should partly address Emrydia's concern.[644] IGUA's Submission does not raise this account as a continuing issue so it also appears to have been resolved.

Accounts 490.00 Computer Equipment – post 2023; 491.01 Software Acquired Intangibles – post 2023; 491.02 Software Developed Intangibles – post 2023

601. Mr. Madsen of Emrydia addresses the amortization rate for computer software and equipment – post 2023 in his report. He specifically notes that the peer data for these accounts suggests a range of lives between three and six years for computer equipment and three and ten years for computer software. While he acknowledges a 4-SQ curve is within this range, his view is that 5-SQ curve is preferable although he admits that the estimated impact of his proposal is not material.[645] It was ultimately determined that Mr. Madsen's analysis was wrong because some of the assets in the list were in Enbridge Gas's 10 year CIS software account.[646]

602. By comparison, looking at the Canadian peer utility analysis filed in response to Exhibit JT4.11[647] two utilities use a 3-SQ curve, one utility uses a 4-SQ curve and two use a 5-SQ curve. Enbridge Gas submits that there is simply no reason to apply an

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[642] OEB staff Submission, page 86.
[643] Exhibit 2, Tab 5, Schedule 4, paragraph 33.
[644] OEB staff Submission, page 86.
[645] Exhibit M5, page 77.
[646] Exhibit N.M5.EGI-48.
[647] Exhibit JT4.11 is a revised version of Exhibit I.4.5-IGUA-26, Attachment 1, page 1.

amortization rate different than that proposed by Concentric based upon the peer analysis but agrees with Mr. Madsen that the estimated impact is not material.

603. Finally, before turning to specific asset accounts, it should also be noted that Concentric recommended in its depreciation study average service lives which in all instances were equal to or longer than those previously approved for EGD and Union.[648] While the Capital Update caused Concentric to adjust the lives of two asset accounts down (and two up), unlike InterGroup and Emrydia, it cannot be said that Concentric showed any bias towards adjusting assets lives in only one direction. Please see Table 3 for a summary of the average life parameters recommended by the depreciation experts. These accounts are then discussed individually and the impact of the proposed asset life lengthening's on the depreciation provision as compared to Concentric's recommendation is identified. The impact is noted in the applicable column for Emrydia and InterGroup using the ELG and ALG procedures.

[648] With the Capital Update, Concentric recommended a decrease from 45 to 40 years for account 473.01.

Table 3
Summary of Average Life Parameters

Asset Account Numbers and Description		Current Approved Parameters – EGD	Current Approved Parameters – Union	Concentric Proposed Parameters	InterGroup Proposed Parameters (OEB staff Submission – Table 10)	Emrydia Proposed Parameters (IGUA Submission – pages 37 and 40)
— 456.00	UNDERGROUND STORAGE PLANT – COMPRESSOR EQUIPMENT	40-R2	35-R2.5	40-R4	44-R4	
457.00	UNDERGROUND STORAGE PLANT – REGULATING AND MEASURING EQUIPMENT	30-R1.5	30-R3	35-R3	40-R2.5	
465.00	TRANSMISSION PLANT – MAINS		55-R4	60-R4	70-R4	
466.00	TRANSMISSION PLANT – COMPRESSOR EQUIPMENT		30-S3	30-R4		37-R4
473.01	DISTRIBUTION PLANT – SERVICES – METAL	45-L1.5	50-R1.5	40-S0.5		50-L1
473.02	DISTRIBUTION PLANT – SERVICES – PLASTIC	45-L1.5	55-R3	55-S3		60-S3
474.00	DISTRIBUTION PLANT – REGULATORS		20-SQ	25-SQ		45-S1
475.21	DISTRIBUTION PLANT – MAINS – COATED & WRAPPED	61-R3	55-R4	55-R3	61-R3	65-R3
475.30	DISTRIBUTION PLANT – MAINS – PLASTIC	65-R3	60-L2	60-R4	65-R3	70-R2
478.00	DISTRIBUTION PLANT – METERS	15-S2.5	25-L1.5	15-S2.5		25-L1.5

604. Please note that in the tables which follow, where the Company has calculated the monetary impact of what InterGroup and Emrydia are proposing, the use of brackets around the dollar impact indicates that this is a decrease to the depreciation provision relative to the provision based upon the recommendations of Concentric.

Table 4
Account 456 – Underground Storage Plant – Compressor Equipment

Source	Previously Approved Curve	Concentric Recommended Curve	Emrydia Recommended		InterGroup Recommended	
			Curve	$ Impact	Curve	$ Impact
Enbridge Gas	40-R2 (EGD) 35-R2.5 (Union)	40-R4			44-R4	($3.7M) ELG ($3.0M) ALG

605. Concentric in its depreciation study notes that it analyzed the retirements, additions and other plant transactions for the period 1950 through 2021. The report states that discussions with Enbridge Gas's operational and management staff indicated that the Iowa 40-R4 is a good representation of the historical life and future expectations[649]. One important factual matter identified in the meetings of relevance was highlighted in an interrogatory response to OEB staff.

> As is noted in the interview notes, attached at Exhibit I.4.5-STAFF-171 Attachment 5, there is an upcoming wave of compressor equipment retirements expected in the coming years. It is anticipated that the new compressors will have a life shorter than the historical life indications. As such, Concentric recommends maintaining the currently approved life of 30 years.[650]

606. In the peer analysis evidence produced in response to JT4.11[651], there is only one utility listed with an approved depreciation rate for this asset which is 30-R3. Enbridge Gas submits that this tends to support the Concentric recommendation of a 40-R4 curve which it should be noted, is consistent with the currently approved average useful life for EGD, which is 40-R2.

607. In the InterGroup Report, Mr. Bowman references a draft 2016 study by Gannett Fleming which was never finalized[652]. This study only related to EGD assets so it is therefore inapplicable to draw the conclusion that the recommendation made in this draft report is applicable to the combined assets of Enbridge Gas. As well, Mr. Kennedy was the author of the draft report as he was with Gannett Fleming at that time so he was aware of the earlier data and his preliminary views. InterGroup also interprets Concentric's meeting notes with Enbridge Gas operations staff to mean that the average life of these assets should be lengthened. Mr. Kennedy does not agree with this interpretation.

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649 Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 31.
650 Exhibit I.4.5-STAFF-178 part e).
651 Exhibit JT4.11 which revised Exhibit I.4.5-IGUA-26, Attachment 1, page 1.
652 Exhibit M1; and Exhibit I.4.5-Staff-172 part b).

608. In the end, while the difference between what is proposed by Concentric and InterGroup seems relatively modest in terms of years, for the legacy Union assets, which make up the majority of the account's assets, the increase from the approved 35-R2.5 to 44-R4 is neither modest nor gradual and the impact is material. Under the circumstances, Enbridge Gas continues to recommend the 40-R4 recommended by Concentric.

Table 5
457 Underground Storage Plant-Regulating and Measuring Equipment

Source	**Previously Approved Curve**	**Concentric Recommended Curve**	**Emrydia Recommended**		**InterGroup Recommended**	
			Curve	**$ Impact**	**Curve**	**$ Impact**
Enbridge Gas	30-R1.5 (EGD) 30-R3 (Union)	35-R3			40-R2.5	($1.2M) ELG ($1.2M) ALG

609. There is not a great deal of written evidence about this account in the experts' depreciation reports. Concentric has recommended a 35-R3 curve whereas InterGroup has proposed a 40-R2.5 curve. The response to Exhibit I.4.5-IGUA-26 indicates that there are no Canadian peer utilities for comparison other than the currently approved life and curves for EGD and Union of 30-R1.5 and 30-R3 respectively.[653]

610. InterGroup noted in its report that it requested that Concentric provide additional data for this account excluding various vintages. The report then states that Concentric provided "the requested analysis for account 452" (which is a different underground storage account).[654]

[653] Exhibit JT4.11 revised Exhibit I.4.5-IGUA-26, Attachment 1, page 1.
[654] Exhibit M1, page 36.

611. Concentric's recommendation of an increase to 35 years allows for the recognition of the retirement activities it observed while also being a gradual increase in the life of this account. An increase in life from 30 years to 40 years does not follow the depreciation principle of gradualism and moderation as it represents an increase of 33% from the approved life.

Table 6
Account 465-Transmission Plant-Mains

Source	**Previously Approved Curve**	**Concentric Recommended Curve**	**Emrydia Recommended**		**InterGroup Recommended**	
			Curve	**$ Impact**	**Curve**	**$ Impact**
Enbridge Gas	55-R4 (Union) N/A (EGD)	60-R4			70-R4	($10.8M) ELG ($9.9M) ALG

612. Concentric noted in its depreciation study that its discussions with Enbridge Gas's operational and management[655] staff indicated that the Iowa 60-R4 is a good representation of the historical life and future expectations. It is noteworthy that Concentric has proposed a modest lengthening in the average service life for these assets based upon the evidence relative to the previously approved 55-R4 curve approved for Union.

613. InterGroup then referenced Concentric's response to Exhibit I.4.5-IGUA-26[656] as the basis for its recommendation that this account should have an average useful life of 70 years. Looking specifically at Exhibit JT4.11, which is the Canadian utility peer analysis summary table for these assets, it is noteworthy that of the four peer utilities identified, three utilized the same survivor curve of 65-R4 (FortisBC, Centra Gas and PNG). Only AltaGas uses a longer average useful life and survivor curve of 70-R3 yet InterGroup recommend a life curve of 70-R4.

[655] Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 26.
[656] Exhibit I.4.5-IGUA-26, Attachment 1 which was revised by Exhibit JT4.11.

614. The Company submits that choosing the absolute upper end of the average useful life used by only one utility is inconsistent with the principle advocated by depreciation experts in respect of changes to survivor curve parameters, namely that of moderation. Mr. Madsen specifically states in his report that:

> Where a life estimate is forecast to change materially based on new data, the accepted practice is to seek, wherever possible, to gradually alter the life estimate to achieve a moderate impact to the calculated depreciation expense estimate over time.[657]

615. Going from the previously approved 55-R4 curve to a 70-R4 curve, which is an increase of more than 27%, is hardly moderate. As well, the 70-year average service life proposed by InterGroup also appears inconsistent with the peer utility analysis and demonstrates that Mr. Bowman paid little or no attention to energy transition risks in proposing an average useful life that will continue until the end of the century. The Company submits that now is not the time to be unduly extending the lives of assets. Given all of the energy transition issues that have come up in this proceeding, Mr. Bowman's lengthening is simply not appropriate.

Table 7
Account 466-Transmission Plant-Compressor Equipment

Source	**Previously Approved Curve**	**Concentric Recommended Curve**	**Emrydia Recommended**		**InterGroup Recommended**	
			Curve	**$ Impact**	**Curve**	**$ Impact**
Enbridge Gas	30-S3 (Union) N/A (EGD)	30-R4	37-R4	($11.0M) ELG ($9.8M) ALG	InterGroup disagreed with Emrydia	

616. Concentric noted in its depreciation study that the retirements, additions and other plant transactions for the period 1900 through 2021 were analyzed. It added that the currently approved life parameter for Union is an Iowa 30-S3 however an Iowa 30-R4 provided a better visual fit. Concentric did acknowledge that its review of peer

[657] Exhibit M5, page 29.

Canadian utilities indicated a range of between 35 to 37 years but based upon its review of all relevant information and future expectations for investment in the account[658], it recommended an Iowa 30-R4. The Company submits that this is evidence of Concentric exercising professional judgement taking into account both the available data and energy transition issues.

617. Emrydia by comparison chose the upper end of the average useful life for the two peer Canadian utilities that were considered: FortisBC (37-R4) and PNG (35-R3).[659] Concentric responded to a number of interrogatories in respect of this account from IGUA. First it was asked for an explanation in detail about the underlying characteristics of this account which led to the Concentric recommendation. Concentric responded at Exhibit I.4.5-IGUA-16**:**

> The graph shown on page 6-58 is related to the actuarial analysis located on pages 6-59 through 6-60. When reviewing the actuarial analysis, it is noted that the exposures decrease rapidly from 1 billion dollars at age 0 to $356 million at age 6.5 without any retirement activity. Further, by age 14.5 the exposures drop to 126 million with only 1.4 million dollars in retirements. That indicates that Enbridge Gas has invested a large amount of money in very recent years. As such, it is expected that the historical data indications may not be representative of the future retirement patterns. Therefore, it is appropriate to place less weighting on the actuarial analysis for this account[660]

618. Concentric was also asked to comment on whether this equipment undergoes routine maintenance to extend the useful life of the asset or is it generally replaced within a fixed period of time? Concentric responded by first referencing the location of the detailed supporting information and data and then stating:

> While some smaller components within compressor stations are replaced within a fixed period of time through time-based replacement strategies outlined in Section 5.3.5.4.7 on page 191, replacement of major compression equipment is largely driven by discontinuation of Original Equipment Manufacturer (OEM) support and equipment reliability concerns as described in Section 5.3.5.4.1. While each OEM may support their product lines for different lengths of time, prior discussions with the OEM's

[658] Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 27.
[659] Exhibit JT4.11.
[660] Exhibit I.4.5-IGUA-16 part c).

for several of Enbridge Gas's most critical compressor equipment have suggested availability for equipment support will become limited after 40 years. [661]

619. It is clear that Mr. Madsen has paid little or no attention to Concentric's detailed explanations nor the other factors it identified. It is also obvious that Mr. Madsen failed to consider energy transition issues choosing the longest life curve used by one peer utility.

620. Mr. Bowman addressed this account at the Oral Hearing. Unlike Emrydia, Mr. Bowman acknowledged the information from the Company that transmission compressor lives are limited by the OEM suppliers eventually limiting the availability of parts. In his view, there would likely be a much more significant degree of interim retirements. As a result, he stated that he did not believe that there is an evidentiary basis to support a longer life as proposed by Mr. Madsen.[662]

Table 8
Account 473.01 – Distribution Plant-Services-Metal

Source	**Previously Approved Curve**	**Concentric Recommended Curve**	**Emrydia Recommended**		**InterGroup Recommended**	
			Curve	**$ Impact**	**Curve**	**$ Impact**
Enbridge Gas	45-L1.5 (EGD) 50-R1.5 (Union)	40-S0.5 (updated in Capital Update) 45-S1 (original proposal)	50-L1	($10.4M) ELG ($8.9M) ALG ($5.0M) ELG ($5.8M) ALG	InterGroup agrees with Concentric's original recommendation.	

621. In the depreciation study, Concentric noted that its discussions with Enbridge Gas's operational management staff indicated that the historical fit of the Iowa 45-S1 is a reasonable expectation for this account. IGUA asked Concentric why the underlying data leads to the resulting retirement pattern and why the recommended survivor

[661] Exhibit I.4.5-IGUA-16 part d).
[662] 17 Tr.174-175.

curve is reasonable as compared to a longer life curve.[663] Concentric's detailed response included references to all of the information and data considered including the peer analysis.[664] It specifically noted that 98% of total retirement activity occurred before age 53.5 which would lead to the conclusion that a life shortening might have been appropriate. Concentric utilized historical data from age 53.5 through age 65.5, considered the peer analysis and its discussions with Enbridge Gas operations and management staff and concluded, exercising professional judgment, that a life shortening was not reasonable. As a result, Concentric recommended a slight change to the mode of the Iowa curve from L1.5 to S1 and to maintain the currently approved average service life of 45 years.

622. Importantly, Concentric further noted that the peer group analysis for this account includes both metal and plastic services and that plastic services tend to have somewhat longer useful lives. Accordingly, relying upon the peer analysis figures that aggregate both metal and plastic services must be done so with caution.[665] By comparison, for account 473.02, Services-Plastic, Concentric has recommended an Iowa 55-S3 curve, consistent with the view that plastic services have longer lives than metal services.

623. Mr. Madsen recommended an Iowa 50-L1 curve despite acknowledging that the peer utility analysis applies to both metal and plastic services.[666]

624. Mr. Bowman addressed this account at the Oral Hearing where he said:

> There was a fairly high reliance by Mr. Madsen on peers who were higher, 47 to 57, but the peers tend to put plastic and metal together, which would tend to have a lengthening effect on the averages; plastic tended to last longer.[667]

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[663] Exhibit I.4.5-IGUA-18 part c).
[664] Exhibit I.4.5-IGUA-26, Attachment 1.
[665] 17 Tr.115.
[666] Exhibit M5, page 46.
[667] 17 Tr.176.

625. Mr. Bowman then went on to state that he considered Enbridge Gas's originally proposed life and curve of 45-S1 as reasonable and that he would not recommend Mr. Madsen's 50-L1.[668]

626. As part of the Capital Update, Concentric reviewed the impact of incorporating the additional Union historical retirement data. It determined, based upon a review of the additional evidence, that the account now warranted a life shortening to 40-S0.5 which Concentric had rejected earlier[669]. While OEB staff do not support this life shortening, the apparent basis for this according to Mr. Bowman is that he had not seen the additional data which supports this life shortening.[670]

627. Turning to the recommendation made by Mr. Madsen specifically, we see once again that he has chosen the average useful life at the upper end of the Canadian peer range and has paid little or no attention to energy transition issues. It is as if the risk of customers leaving the gas system in future does not even exist. It is also noteworthy that he remains silent as to the impact that any shortening of the customer attachment revenue horizon would have on this account's parameters. If there is a change in the customer revenue horizon, it may necessitate a change in this account's specific parameters as discussed later in this section of this Reply Argument.

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[668] 17 Tr.176.
[669] Exhibit I.4.5-IGUA-18, part c).
[670] 17 Tr. 176.

Table 9
Account 473.02-Distribution Plant-Services – Plastic

Source	Previously Approved Curve	Concentric Recommended Curve	Emrydia Recommended		InterGroup Recommended	
			Curve	**$ Impact**	**Curve**	**$ Impact**
Enbridge Gas	45-L1.5 (EGD) 55-R3 (Union)	55-S3	60-S3	($19.5M) ELG ($17.5M) ALG	InterGroup disagrees with Emrydia	

628. In its report, Concentric notes that it analyzed the retirements, additions and other plant transactions for the period 1900 through 2021. Concentric determined that the Iowa 55-S3 curve is a better fit to the historical data and is within the range of Canadian peer utilities where the average service life ranges from 47 to 57 years[671]. It is noteworthy from the response to Exhibit JT4.11 that no utility in Canada has an approved 60-year average useful life for metal or plastic services.[672]

629. It appears that Mr. Madsen of Emrydia proposes a 60-S3 curve primarily because Concentric has proposed a 60-R4 curve in respect of account 475.30, Mains-Plastic. He acknowledges in his report, that "the upper bound of the peer data for account 473 is 57 years".[673] He plays down the difference as being "not materially different from his recommended expected life of 60 years."

630. If Plastic Mains are an appropriate proxy why does Mr. Madsen not then propose the same 70 year term for plastic services as he does for plastic Mains?[674] In his report, he states that it is unclear why plastic services are not closely aligned with plastic Mains.[675] Enbridge Gas submits that this is a confirmation of Mr. Madsen's tendency to favour the upper end of the range of useful lives and beyond. It appears that he is neglecting one important fact. Services are far more commonly damaged and

[671] Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 30; and Exhibit I.4.5-26 Attachment 1, page 1.
[672] Ibid.
[673] Exhibit M5, page 53.
[674] Ibid, page 57.
[675] Ibid, page 51-52.

disturbed by activities around customers' homes and businesses than Mains. Their replacement data is therefore fundamentally different from larger diameter Mains.

631. Once again, Mr. Madsen has exercised no professional judgment in terms of giving consideration to energy transition energy issues. As well, he has not addressed the issue of the parameters of this account requiring change should the revenue horizon for customer attachments be reduced.

632. At the Oral Hearing, Mr. Bowman addressed Mr. Madsen's recommendation to adopt a 60-year life. Mr. Bowman stated:

> My concern in plastic services is that we don't have a data – a background data record; we only have a record to about 45 years.
> I don't have a lot of concern that plastic services could last an average of 60, but services, it tends to be the portion of the system that is subject to the type of early retirements Mr. Kennedy talked about, where you are, you know, hit the line when you are drilling for a fence.
>
> So those types of retirements need to be seen in the data as to how much of that type of event is occurring before you would think about lengthening an account like that. And so I didn't come to the same conclusion as Mr. Madsen about extending the plastic services.[676]

Table 10
Account 474 – Distribution Plant-Regulators

Source	**Previously Approved Curve**	**Concentric Recommended Curve**	**Emrydia Recommended**		**InterGroup Recommended**	
			Curve	**$ Impact**	**Curve**	**$ Impact**
Enbridge Gas	20-SQ (Union) N/A (EGD)	25-SQ	45-S1 (per submission) or 50-L1 (alternative life)	($30.2M) ELG ($33.6M) ALG or ($30.3M) ELG ($35.4M) ALG	See below	

633. In the depreciation study, Concentric stated that the assets in this account are expected to have a life of up to 30 to 35 years. As a result, it proposed a moderate

676 17 Tr.177.

increase to the useful life of 5 years relative to the 20-SQ amortization parameter approved for Union.

634. The increase in the depreciation expense for this account is due in part to the recognition that EGD's regulators, that had formerly been included in the services account 473.01, have failed to recover the appropriate depreciation expense. The average life of regulators is much shorter which means that including them in the longer-lived services account 473.01 which, for EGD was 45 years, meant that EGD's regulators were not being depreciated at the appropriate rate and thus the under recovery.

635. Concentric recommended combining the regulators from both legacy Utilities into account 474-Regulators. As noted by Concentric in response to IGUA 19, the under recovery is estimated at $124.9 million. As a result, rather than proposing a depreciation rate of 4% based on the selection of the 25-SQ curve, Concentric recommended the theoretically correct depreciation rate of 8.86% to begin recovering the shortfall.[677]

636. What Emrydia proposes only perpetuates the situation where the depreciation expense has not recovered the appropriate depreciation provision. Mr. Madsen's suggestion at the Oral Hearing that the former EGD regulators continue to be depreciated at the historical rate for services is not a transition provision. It is simply the continuation of the under recovery. Of note, Mr. Madsen proposed in his report that a 50-L1 curve for account 473-01 be applied[678] which would have made the situation even worse. (EGD's services had an approved curve of 45-L1.5). IGUA's Submission clearly recognized this worsening and proposed instead that legacy EGD regulators be depreciated using a 45-year service life.

[677] Exhibit I.4.5-IGUA-19 part a).
[678] Exhibit M5, page 74.

637. Again, this is not a transition provision, it is simply a continuation of a situation which Concentric and the Company submit should end. The appropriate average useful life of regulators should be applied going forward with adjustments for the historical under recovery. There is no evidence that regulators have average lives greater than 30 to 35 years let alone the 50 years originally proposed by Mr. Madsen in his report (or 45 years as proposed by IGUA). Indeed, Mr. Madsen admits that the average service lives for services are much longer than for regulators.[679]

638. Mr. Bowman of InterGroup makes no mention of account 474 Regulators in his report[680]. As stated in the report, this means that InterGroup did not identify any problematic issues that merited finding for a different life and dispersion combination.[681]

639. It is also noteworthy that in OEB staff's Submission, there is similarly no mention of account 474-Regulators. In other words, OEB staff does not express concerns about Concentrics's recommendation, and it does not advocate for some sort of transitional provision for the purposes of recovering the historic under recovery. Enbridge Gas submits that this position is consistent with appropriate depreciation theory.

[679] Exhibit M5, page 72.
[680] Exhibit M1.
[681] Ibid, page 28.

Table 11
Account 475.21- Distribution Plant-Mains Coated and Wrapped (Steel)

Source	**Previously Approved Curve**	**Concentric Recommended Curve**	**Emrydia Recommended**		**InterGroup Recommended**	
			Curve	**$ Impact**	**Curve**	**$ Impact**
Enbridge Gas	61-R3 (EGD) 55-R4 (Union)	55-R3	65-R3 (per submission) or 60-R3 (alternative life)	($37.4M) ELG ($33.1M) ALG or ($21.6M) ELG ($19.3M) ALG	61-R3 (per submission) or 70-R3 (alternative life)	($25.5M) ELG ($21.3M) ALG or ($48.7M) ELG ($43.0M) ALG

640. In the depreciation study, Concentric stated that discussions with Enbridge Gas's staff indicated that the historical fit of Iowa 55-R3 is a reasonable expectation for the assets in this account.[682] Similar to the combining of plastic and metal services, peer Canadian gas distributors also combine plastic and metal mains into this account. The peer group figures must therefore similarly be viewed with caution as the inclusion of plastic artificially increases life of metal mains included in the account. IGUA asked for a detailed explanation for the recommendation made by Concentric for this account and Concentric responded as follows:

> As is noted in the interview notes, provided at Exhibit I.4.5-STAFF-171-Attachment 5, there is an ongoing replacement program targeting steel mains. This program is anticipated to have a wave of retirements in the coming years, with vintage steel mains planned to be replaced predominantly with plastic mains. As such, Concentric recommends maintaining the currently approved life for Union Gas of 55 years[683]

641. Emrydia recommends a 65-R3 curve but acknowledges that a 60-R3 curve can also be justified.[684] However, Emrydia also stated:

> The 55-R3 Iowa curve selected by Concentric provides a reasonable fit to the observed retirement data through age 40.5.[685]

[682] Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 31.
[683] Exhibit I.4.5-STAFF-178 part h).
[684] Exhibit M5, pages 53-54.
[685] Ibid, page 55.

642. Mr. Madsen goes on to describe the 55-R3 curve as "highly conservative".[686] While Emrydia accepts that a replacement effort remains underway for steel mains, he makes no reference to the difference in average useful life between plastic and steel mains and the influence that this has on the Canadian peer utility analysis.

643. Mr. Bowman in the InterGroup Report relies primarily upon the peer analysis and makes no mention of the aggregation of steel and plastic mains by other utilities even though he acknowledged this impact in his oral testimony in respect of services[687]. It appears that Mr. Bowman has relied upon one outlier utility which utilizes an 80-R3 curve to support his recommendation of a 70-R3 curve even though 4 of the 5 other utilities in the peer analysis use an average service life of 65 years with one using a 60-year average service life (which again includes both plastic and steel mains).

644. It is noteworthy that Mr. Madsen is of the view that either the 60-R3 or the 65-R3 curve can be justified. Enbridge Gas submits that the opinion of two depreciation experts favour a shorter life than that recommended by Mr. Bowman to extend the life out to 70 years.

645. By comparison, Mr. Madsen believes that a 70-year useful life is appropriate for plastic mains (account 475.30) which further draws into question Mr. Bowman's recommendation of using the same average useful life for metal mains. Increasing the average useful life from the currently approved lives of 55 and 61 years (for Union and EGD respectively), is inconsistent with the risks of energy transition and the depreciation principle of only making moderate changes to asset lives and curves.

[686] Exhibit M5, page 56.
[687] 17 Tr.177.

Table 12
475.30 Distribution Plant-Mains-Plastic

Source	**Previously Approved Curve**	**Concentric Recommended Curve**	**Emrydia Recommended**		**InterGroup Recommended**	
			Curve	**$ Impact**	**Curve**	**$ Impact**
Enbridge Gas	65-R3 (EGD) 60-L2 (Union)	60-R4	70-R2	($14.8M) ELG ($27.6M) ALG	65-R3 (per submission) or 70-R4 (alternative life)	($11.0M) ELG ($18.3M) ALG or (25.6M) ELG ($23.9M)(ALG

646. Concentric analyzed retirements, additions and other plant transactions from the period of 1958 through 2021 using the retirement rate method[688]. Concentric stated in its report that the Iowa 60-R4 is within a Canadian peer comparison where the average service life ranges from 60 to 80 years.

647. InterGroup stated that in its view there is better support for an Iowa 65-R3. In support InterGroup concluded that Concentric had erred because, according to InterGroup: "…there are no utilities that have a life estimate of 60 years for this account".[689] In fact it is InterGroup that is in error as the currently approved average useful life for Union is 60 years using a 60-L2 curve.

648. Emrydia in its report noted that, like plastic services in account 473.02 the investment in account 475.30 is significant and thus small changes in depreciation parameters can have a significant impact on the depreciation expense.[690] Mr. Madsen ultimately recommended an Iowa 70-R2 curve. It appears that this recommendation is in part motivated by the fact that he recommended a 65-year useful life for steel mains. Given

[688] Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 32.
[689] Exhibit M1, page 44.
[690] Exhibit M5, page 59.

this, he states that it would be inappropriate to recommend a life for plastic mains that is below the life for steel mains.[691]

649. We therefore have a situation where the three depreciation experts have arrived at three different average useful lives (60: Concentric; 65: InterGroup; and 70: Emrydia). These differences, as noted by Mr. Madsen above, can result in significant impacts. Enbridge Gas submits that, with Concentric exercising professional judgment which included considering energy transition issues, it is prudent to approve an average useful life at the lower end of the range of peers. Enbridge Gas notes that the majority of Canadian peer utilities have average useful lives of 65 years. This once again makes Mr. Madsen the outlier at 70 years. By comparison, the Union plastic mains are already approved with useful lives of 60 years. This means that the OEB has earlier determined that the evidence supported a life of 60 years for Unions plastic mains. This supports the recommendation made by Concentric.

Table 13
Account 478-Distribution Plant-Meters

Source	**Previously Approved Curve**	**Concentric Recommended Curve**	**Emrydia Recommended**		**InterGroup Recommended**	
			Curve	**$ Impact**	**Curve**	**$ Impact**
Enbridge Gas	15-S2.5 (EGD) 25-L1.5 (Union)	15-S2.5	25-L1.5	($75.0M) ELG ($71.7M) ALG	See below	

650. Concentric specifically noted in the depreciation study that the Iowa 15-S2.5 is within its Canadian peer comparison where the average service life ranges from 15 to 26 years. The Emrydia Report states that the peer analysis suggests lives for this account of between 18 and 26 years with an average expected life of approximately 21 years. Despite this, Mr. Madsen recommended an average useful life of 25 years

[691] Exhibit M1, page 60.

which is clearly at the upper end of the range. Choosing the upper end of the useful life range confirms that no consideration was given to energy transition considerations.

651. Mr. Bowman stated during the Oral Hearing that he does not support an average life of 25 years for meters as proposed by Mr. Madsen[692]. Mr. Bowman stated that he looked in the operational notes prepared by Concentric in respect of the meetings held with Enbridge Gas Staff and he noted that there are cycles of required certifications for meters. His conclusion was that Enbridge Gas expects these to go through lives that would get to 25 to 27 as a terminal value with interim retirements.[693] While this led Mr. Bowman to state that he felt the 15-year average service life was too short, he specifically stated that he did not agree with Mr. Madsen's recommendation of 25 years.

652. The operations notes, properly interpreted, support the recommendation made by Concentric. Operations staff indicated that it is expected for meters to pass sampling at 9 years and 7 years. It is less likely that meters will pass the additional 5-year testing, resulting in a significant number of meters retired by 21 years. A life of 25 years is therefore incompatible with this and risks significant stranded costs.[694] Mr. Madsen admitted to being unfamiliar with these Measurement Canada standards in an interrogatory response.[695] It therefore follows that he has not placed any weight on the Measurement Canada standards which, it should be noted, if they are not observed, can result in significant fines.

653. The operational notes[696] also highlight the technological changes occurring in the metering accounts as higher cost ultrasonic meters are replacing traditional diaphragm

[692] 17 Tr.178.
[693] Ibid.
[694] Exhibit I.1.4-STAFF-171 Attachment 5 page 1 and 2.
[695] Exhibit N.M5.EGI-46.
[696] Ibid.

meters due to supply chain challenges. Concentric recommends a 15-year life to recognize the technical changes in meters installed today compared to historically and the influence of updated Measurement Canada testing requirements[697].

Depreciation Impacts of Changing Customer Connection Horizons

654. Enbridge Gas has indicated that it would accept a reduction in the customer attachment revenue horizon from 40 years to 30 years in the Customer Attachment Policy section of this Reply Argument. In response to undertaking Exhibit J18.5, Enbridge Gas illustrated the potential impact on the depreciation expense if an EPH were applied to the plastic services account. In the event that the customer service horizon is reduced to 30 years, the Company does not propose that an EPH be utilized at this time, but may request to do so in the future.

655. However, Enbridge Gas believes that a change to a 30-year customer attachment revenue horizon makes it even more clear that the use of the ELG methodology and the asset lives and net salvage parameters proposed by Concentric for the customer connection accounts[698]is appropriate at this time. Concentric's approach is better suited to address the inter-generational equity issues and future rate impacts of a change in revenue horizon than what is being proposed by InterGroup and Emrydia.

656. Enbridge Gas continues to be of the view that if the OEB approves major changes to the customer connection revenue horizon beyond the 30-year mark this is a "sign post" and may precipitate the need for an adjustment to the depreciation parameters of affected assets. In the event that the OEB directs a customer attachment revenue horizon that is shorter than 30 years, either in this case or in a subsequent generic proceeding, then Enbridge Gas will consider the implications on depreciation because there will be a substantial mismatch in customer attachment revenue horizon and

[697] Exhibit I.4.5-IGUA-22.
[698] Exhibit J13.6, Table 1.

depreciation assumptions. Enbridge Gas believes that an EPH may be more appropriate in that context, and submits that it is appropriate that the Company be permitted to address available and proper approaches at that time.

657. Enbridge Gas submits that where the OEB orders a customer attachment revenue horizon of less than 30 years, then the OEB should approve depreciation rates based on the ELG methodology and Concentric's asset lives on an interim basis for the affected accounts, until such time as the matter can be more fully addressed.

658. Misalignment between the depreciation parameters and the new revenue horizon would result in an increase in future stranded risk as the current proposed average useful lives would be significantly out of sync with the revenue horizon. Enbridge Gas further submits that this could lead to inter-generational inequity as customers who connect on this system before the parameters are changed will benefit from a lower depreciation expense relative to what future customers will pay. Enbridge Gas may ultimately propose that implementing an EPH to reflect the expectation of shorter service lives is consistent with the principles outlined in the OEB's uniform system of accounts which indicates:

> Depreciation rates shall be based on the estimated service values and estimated service lives of the Plant.[699]

<u>Net Salvage and CDNS</u>

659. As Enbridge Gas made clear in its AIC, Mr. Bowman was adamant that the net salvage recovery should be sufficient to cover the forecast annual site removal costs and add to the net salvage accrual balance. For example, there is the following exchange:

> MR. O'LEARY: So we're all in agreement, then, that whatever net salvage methodology is adopted, it has to be sufficient to recover the annual removal cost and add appropriately to the site restoration accrual?

[699] Ontario Energy Board Uniform System Of Accounts For Class A Gas Utilities Part I April 1, 1996, Section 7. Plant Accounting Instructions, Part 5 Depreciation, Subpart F.

MR. BOWMAN: I think that's a reasonable conclusion.[700]

660. Enbridge Gas agrees. OEB staff surprisingly submitted that they continue to support InterGroup's net salvage parameter changes, even if it fails to recover the full annual amount of site removal costs. OEB staff state that this difference can be accounted for by reason of the alleged accrual surplus.[701]

661. OEB staff did not ask any witnesses at the Oral Hearing about the appropriateness of eroding the hypothetical surplus. They should have asked Mr. Bowman to speak to this as it is apparent from his testimony that he would not support such a proposition.[702]

662. Enbridge Gas submits that the OEB should not assume that this alleged surplus is in fact surplus to the ultimate costs that will be required to complete future site restorations. The accrual balance currently is approximately $1.6 billion and the net present value of the cost to remove existing plant is estimated at $4.7 billion.[703] There was no consideration given during the Oral Hearing to the impact on the accrual balance of OEB staff's proposal and parties were not afforded an opportunity to provide their views as to whether or not they agree that any surplus should be degraded. The goal should be to ensure the adequacy of the accrual balance, not erode it without supporting evidence and the appropriate consideration of same by the OEB based on a complete record.

663. As noted by OGVG in its submission, it is better overall to have collected too much and be able to refund ratepayers than to have collected too little and have to catch

[700] 18 Tr.33.
[701] OEB staff Submission, page 93.
[702] 18 Tr.33.
[703] Exhibit JT4.15.

up.[704] Enbridge Gas concurs. The prudent course of action is to ensure recovery of funds equal to forecast annual site removal costs and to add to the net salvage accrual balance. Table 14 demonstrates that the net salvage accruals proposed by both OEB Staff and IGUA are insufficient, and only Enbridge Gas's proposed net salvage accrual will recover adequate funds.

Table 14
Summary of Net Salvage Accrual

($ millions)	2024 Net Salvage Accrual within Depreciation Provision	Source
Enbridge Gas's Forecasted Annual Site Restoration Costs	60.0 (1)	Exhibit I.1.8-STAFF-17
3.75% using Concentric's CDNS Calculation and Net Salvage Parameters - EGI Proposal	96.3	Exhibit J17.5
4.48% using InterGroup's CDNS Calculation and Net Salvage Parameters - OEB Staff Proposal	54.0 (2)	OEB staff Submission, pages 92-93
5.87% using InterGroup's CDNS Calculation and Net Salvage Parameters - IGUA Proposal	50.0 (2)	IGUA Submission, page 47

Notes:
(1) Enbridge Gas indicated in Exhibit J17.5 that site restoration costs have been on the rise and could fluctuate significantly depending on the assets being retired.
(2) The net salvage accruals quantified by OEB Staff and IGUA are materially lower if calculated using Concentric's calculation methodology of CDNS.

The CDNS Methodology

664. In terms of the calculation of the CDNS, neither Mr. Bowman nor Mr. Madsen adduced evidence showing that the CDNS calculation which Concentric has undertaken in the past, and which it proposes to continue, is flawed. In the response at Exhibit I.ADR.22, pages 3 to 5, Concentric provided a detailed explanation of how its CDNS calculation is undertaken and why there is no double counting of inflation. Mr. Mondrow attempted unsuccessfully to demonstrate the alleged error in his detailed questions to Mr.

[704] OGVG Submission, page 18.

Kennedy. Mr. Kennedy was clear and adamant in his response that the methodology he follows, which is out of the textbook, does not include inflation twice.[705] It is noteworthy that in its response to an interrogatory, Concentric pointed out that InterGroup does not have access to the course materials used by the Society of Depreciation Professionals (SDP) to undertake the CDNS calculation.[706]

665. Perhaps more importantly, neither InterGroup nor Emrydia provided the details or explained how their method of undertaking the CDNS calculations is correct and would arrive at the appropriate provision which should recover both the annual removal costs and add to the site restoration accrual balance. As is shown by their reports, they arrive at materially different numbers using their methods versus that of Concentric. This is a particularly important point in that they also propose to apply a much higher discount rate than the 3.75% proposed by Concentric the use of which will materially decrease the net salvage provision. It is obviously important to know the impact of the discount rate that is ultimately approved.

666. The fact is that the OEB does not have on the evidentiary record the details of the methodology that Messrs. Bowman and Madsen propose. There were a series of spreadsheets attached to Exhibit M1, the OEB Staff Depreciation report prepared by InterGroup[707] which generated certain figures that InterGroup relies upon but these spreadsheets are not based upon any methodology that has been proven and accepted by the SDP. There is, therefore, no means of verifying the assertions made by Messrs. Bowman and Madsen about what the impact on the net salvage provision will be using a different methodology and the higher discount rates that they propose.

[705] 16 Tr.169, lines 5-20.
[706] Exhibit N.M1.EGI-6.
[707] Exhibit M1, Attachments 1-4.

The CDNS Discount rate

667. Turning to the determination of the appropriate discount rate to be applied in a CDNS calculation, Table 14 demonstrates that using a discount rate higher than 3.75% will reduce the net salvage recovery. Increasing the discount rate as proposed by OEB staff to 4.48%, will reduce the net salvage recovery such that the annual forecast removal costs are not recovered AND there will be no contribution to the future site restoration costs accrual balance. Enbridge Gas submits that this proposal should be rejected. The Company finds it somewhat surprising that OEB staff would take this position as it appears inconsistent with the views of its witness Mr. Bowman who made it plainly clear that such costs should be recovered. This said, it was not clear to the Company that either Mr. Madsen or Mr. Bowman in their net salvage recommendations provided for the recovery of any amount to contribute to the site restoration costs accrual balance.

668. In response to the Company's comparison to the discount rate approved by the CER, IGUA in its Submission tries to play down the fact that the CER approved a discount rate of 3.25% on the basis that the segregated fund approved by the CER is different from the situation where Enbridge Gas has used the net salvage accrual to reduce its capital financing needs which in turn reduces the revenue requirement. Enbridge Gas confirmed in evidence that the total savings that ratepayers enjoyed over the 10-year period 2013 to 2022 due to its use of the accrual is approximately $1,029 million.[708]

669. Enbridge Gas submits that the distinction which IGUA attempts to make in fact only highlights the inappropriateness of using a higher discount rate. Ratepayers in Ontario are already benefiting from the savings generated by Enbridge Gas's use of the accrual balance for its operational needs. Stated differently, the site restoration accrual balance is already "earning" the WACC by delivering savings of this amount

[708] Exhibit I.4.5-ED-136, part f).

by avoiding the costs that ratepayers would otherwise see in rates. To then insist upon a discount rate equal to the WACC, which greatly reduces the net salvage provision penalizes future ratepayers to the benefit of current ratepayers by preventing the net salvage accrual balance from growing at an appropriate rate. Using such a figure would ensure that the amount available in the future would NOT be sufficient for the purposes intended. It should also be noted that by under recovering net salvage, it will erode the accrual balance which will in turn increase rate base relative to what it would have been if an appropriate recovery had occurred.

670. Enbridge Gas submits that the OEB's objective should be to ensure that sufficient funds are available to cover not only annual site restoration costs but to also add to the site restoration accrual balance. The methodology used by Concentric to calculate the CDNS has been successfully used for years. The CDNS methodologies used by Messrs. Madsen and Bowman are unknown and untested. Applying a discount rate higher than 3.75% is therefore risky as the impact of same is not known and could result in inter-generational inequities if they generate under recoveries. As shown in the net salvage accrual Table 14 above, only the Enbridge Gas recommendations and calculations demonstrate that there will be adequate net salvage recoveries.

671. Concentric has made use of its methodology to calculate the CDNS since it was approved by the OEB in 2014.[709] It is familiar with this methodology and the results have been included in the evidence in this proceeding and no party has stated that the amounts recorded are in error. Concentric is not familiar with the methodologies used by InterGroup and Emrydia for the purposes of the CDNS calculations that they have presented in evidence. Concentric will be undertaking the final calculations in respect of depreciation rate impacts following the issuance of the OEB's decision on such matters for the purposes of the draft rate order. Enbridge Gas questions how

[709] EB-2012-0459, OEB Decisions with Reasons, July 17, 2014.

Concentric can be called upon to credibly apply the methodologies used by InterGroup and Emrydia when the methodologies are foreign to it.

Net Salvage Parameters at Issue

672. Utility depreciation is intended to recover the service value of installed assets. The service value consists of the original cost to purchase and install the asset and the cost to remove, decommission and restore affected sites less amounts received for selling off remaining pieces. This is described as salvage. The sum of the cost of removal and salvage is stated as the “net salvage” and this is usually expressed as a negative reflecting the fact that it costs more to decommission and remove plant than what can be recovered by selling off residual pieces. Accordingly, a higher negative figure indicates that the difference between the cost to remove the asset and its residual value is greater than would be the case using a lower negative figure. In terms of the depreciation provision, a lower negative net salvage figure will generate a lower depreciation expense whereas a higher negative figure will generate a larger contribution to the depreciation expense.

673. InterGroup has recommended changes to the net salvage parameters for six accounts. Enbridge Gas notes that three of these accounts relate to transmission equipment for which EGD had no historically approved net salvage parameters. In Table 15 the historic approved net salvage parameters for the legacy Utilities are identified together with Concentric’s harmonized net salvage recommendations. This table also includes the recommended net salvage parameters in respect of the six accounts at issue by InterGroup and the impact of adopting its recommendations in terms of reducing the recovery and applying InterGroup’s CDNS calculation.

674. As the evidence noted and Table 15 identifies, EGD used the CDNS methodology while Union used the traditional method. Importantly, as is further explained below, the net salvage rate under the CDNS method cannot be compared to the net salvage rate

using the traditional method. The former is always materially lower. For example, for the Steel Mains account (475.21), the 51% figure using CDNS cannot be compared to the 60% figure for Union using the traditional method. The 51% figure would need to be adjusted and it is possible that with this adjustment, the net salvage figure could exceed the 60% traditional figure for Union. Enbridge Gas points this out as it believes that there may have been some inadvertent comparison of EGD and Union net salvage accounts by the other depreciation experts.

Table 15
Summary of Net Salvage Parameters

Asset Account Numbers and Description		Current Approved Parameters - EGD (CDNS) (1)	Current Approved Parameters - Union (Traditional)	Concentric Proposed Parameters (Traditional)	Concentric Proposed Parameters (CDNS)	InterGroup Proposed Parameters (Traditional) (OEB staff Submission - Table 15)	Incremental Depreciation Decrease from Using InterGroup Net Salvage Parameters
465.00	TRANSMISSION PLANT - MAINS	N/A	(15%)	(25%)	(12%)	(15%)	($3.8M)
466.00	TRANSMISSION PLANT - COMPRESSOR EQUIPMENT	N/A	(5%)	(10%)	(7%)	(5%)	($2.2M)
467.00	TRANSMISSION PLANT - MEASURING AND REGULATING EQUIPMENT	N/A	(10%)	(25%)	(15%)	(10%)	($2.6M)
473.02	DISTRIBUTION PLANT - SERVICES - PLASTIC	(22%)	(40%)	(50%)	(26%)	(40%)	($7.8M)
475.21	DISTRIBUTION PLANT - MAINS - COATED & WRAPPED	(51%)	(60%)	(80%)	(42%)	(40%)	($30.5M)
475.30	DISTRIBUTION PLANT - MAINS - PLASTIC	(38%)	(40%)	(80%)	(38%)	(25%)	($33.9M)
						Total	**($80.7M) (2)**

Notes:
(1) Net salvage parameters are CDNS parameters. The associated Traditional net salvage parameters are substantially higher.
(2) Reduction to Enbridge Gas's proposed net salvage accrual of $96.3 million.

675. In its report, Concentric confirmed that it exercised professional judgment in respect of its net salvage estimates using the same data, information and knowledge in respect of the net salvage used by peer utilities as it did in respect of the service lives estimates for the various accounts.[710]

[710] Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 24.

676. To arrive at the recommended net salvage parameter for each account using the CDNS methodology, one of the steps involved requires the determination of what the net salvage parameter would be using the traditional methodology. This net salvage figure is then used for the purposes of the CDNS calculation which ultimately generates the figure which Concentric has recommended. In every case, the CDNS methodology will result in a lower net salvage figure than under the traditional method.

677. It is appropriate at this point to highlight once again that if a discount rate higher than 3.75% is used for the purposes of the CDNS calculation, there will be a further material reduction in the net salvage figure which, as noted by the Company and Mr. Bowman, could result in an inadequate recovery to cover annual removal costs and add nothing to the site restoration costs accrual balance.

678. Before turning to the net salvage parameters specifically by account, it is appropriate to note several matters which respond to some of the concerns expressed by Mr. Bowman in his report in respect of Concentric's net salvage recommendations. First, with respect to the Canadian Utility peer analysis figures provided in the response to Exhibit JT4.11[711], it is the practice of depreciation experts such as Concentric to use in their peer utility analysis the survivor curve and net salvage parameters set out in the peer utilities' depreciation studies. This is considered the best evidence of the current needs of the utility.

679. Mr. Bowman noted that the figures included in the peer analysis for AltaGas at Exhibit JT4.11 were slightly higher than what he determined to be the "approved" net salvage parameter. It remains the view of Concentric that the appropriate peer analysis evidence to rely upon is the net salvage parameter which was identified as appropriate in the utility's most recent depreciation study. The approved amounts may reflect a

[711] Exhibit JT4.112, revised Exhibit I.4.5-IGUA-26, Attachment 1.

settlement compromise or other factors which are unrelated to the actual evidence which supports the depreciation study figures.

680. Second, Mr. Bowman seems to suggest that the variation he noted in the net salvage costs incurred by the Company between various years is an irregularity and justifies a downward adjustment. This is not consistent with reality and appropriate depreciation theory. It is quite common for net salvage costs to vary, often dramatically, from year to year, sometimes simply based upon the fact that certain costs are not booked in the year that they have actually occurred. This is why it is appropriate to use a three-to-five-year band. Accordingly, the Company submits that all of Mr. Bowman's comments about perceived irregularities should be disregarded. They do not justify an adjustment to the net salvage parameter as they are to be expected.

681. Third, it should come as no surprise to anyone that the market for used fossil fuel-based equipment has materially declined. To the extent that the energy transition leads to an even greater retirement of transmission and distribution equipment, there will be an even larger difference between supply and demand for used fossil fuel-based equipment thereby eroding the market for such used equipment even more. As the salvage recoveries on such equipment are declining, this is one element of the professional judgment that was exercised by Concentric in making its recommendations. This is a matter of common sense, but it does not appear to have been reflected in the recommendations made by Mr. Bowman.

682. It should be noted that InterGroup's recommendations in every instance result in either a previously approved net salvage parameter being continued or a reduction in the net salvage parameter relative to the previously approved figures. If Mr. Bowman's recommendations are accepted, as noted from Table 15, the aggregate reduction to the net salvage provision in respect of these accounts would lower the net salvage recovery by $80.7 million which would in turn prevent the Company from recovering

even the full amount of its forecast annual costs.[712] These changes alone would mean that for the balance of the IR term, there would be a deficiency relative to annual costs and it would add nothing to the future site restoration costs accrual balance. These facts alone warrant the rejection of Mr. Bowman's recommendations.

683. It should further be noted that all of Mr. Bowman's recommended net salvage figures are expressed using the traditional method. To be comparable to the Concentric recommendations which use CDNS, they would need to be converted. This in each case would reduce the net salvage figure recommended by InterGroup even further.

684. Given the importance of recovering a sufficient net salvage provision to cover forecast annual cost and to add to the site restoration accrual balance, it is important to highlight the significant differences between the Company's calculations of the impact of InterGroup's recommendations and the impacts as calculated by InterGroup. Enbridge Gas request that the OEB exercise caution accepting the estimate of impacts on the depreciation expenses as calculated by InterGroup as the differences can be material.

Account 465 Transmission Plant - Mains

685. Concentric noted in evidence that this account has a historical net salvage indication of -83%. Concentric however recognized that the indications provided by peer utilities are of a much lower amount and as a result, it recommended a gradual increase to -25%.[713]

686. Mr. Bowman's concerns about the volatility of annual removal costs are addressed above as is his reliance upon the AltaGas net salvage approved parameter of -15%. Based on factors which the Company identified above as being inappropriate, Mr.

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[712] Exhibit I.1.8-Staff-17, part f).
[713] Exhibit I.4.5-IGUA-23, page 4.

Bowman recommends that the -15% net salvage figure for transmission mains which had been approved for Union continue. Enbridge Gas notes that this figure is inconsistent with the peer utility analysis, even excluding AltaGas in that the other two utilities use a -20% net salvage[714]

Account 466 Transmission Plant – Compressor Equipment

687. Transmission Compression Equipment and account 467 Transmission Measuring and Regulating Equipment are accounts which are subject to the declining demand for fossil fuel based used equipment. Salvage recoveries not surprisingly are declining.

688. Concentric notes in evidence that this account has a historical net salvage indication of -28%. Concentric adds that while the historical data indicates that a net salvage estimate up to -25% may be appropriate, it recognizes the indications provided by peer utilities of a lower estimate.[715] As a result, Concentric recommends a gradual increase to -10%.

689. Mr. Bowman seems to rely entirely on the peer group analysis and has disregarded the Company's historical evidence other than his notation that there is some volatility in the years in respect of removal costs. This should have no influence on the net salvage parameter. Mr. Bowman proposes a net salvage of -5%.

Account 467 Transmission *Plant - Measuring and Regulating Equipment*

690. This account includes equipment that has seen a decline in salvage recoveries. Concentric notes in evidence that the account has a historical net salvage indication of -47% and that peer utilities show indications that a net salvage estimate between -5% and -75% may be appropriate.[716] Concentric acknowledged that while the historical

[714] Exhibit JT4.11.
[715] Exhibit I.4.5-IGUA-23, page 4.
[716] Ibid.

data indicates a net salvage estimate of up to -45%, this would have a significant impact on the depreciation expense and as such, it recommends a gradual increase to -25%.

691. Mr. Bowman's recommendation at -10% appears based entirely on the volatility of annual removal costs and the difference between the AltaGas requested and approved net salvage parameter for this account. He has obviously made no provision for the decline in salvage recoveries and the Company's specific indications.

Account 473.02 Distribution Plant - Services: Plastic

692. The peer analysis in respect of net salvage parameters for account 473 is similar to the survivor curves. Most peer utilities aggregate metal and plastic services into the one account. The results must therefore be viewed with caution. As well, it should be recognized that plastic services are a more recent phenomena relative to metal services and thus the percentage of plastic services which have been removed is smaller relative to metal services.[717]

693. Therein lies one of the concerns the Company has with Mr. Bowman's recommendations. He notes in his report that only 2% of the gross plant for this account has been removed. This means that the provision for this account must be sufficient to recover the remaining 98% which remains in the ground.

694. Mr. Bowman recommends a -40% net salvage parameter which is significantly lower than the peer group analysis range of between -60% and -125% (albeit these also include metal services). Ultimately, his -40% figure appears arrived at given his view that there is a lack of reliable data. Enbridge Gas disputes this as the evidence states that the account has a historical net salvage indication of -168% and that the historical

[717] Exhibit I.4.5-IGUA-23, page 5.

data indicates a net salvage estimate of up to -165% based on a peer analysis would be appropriate. Concentric therefore recommended a moderate increase in the depreciation expense to -50%.

Account 475.21 Distribution Plant - Mains: Coated & Wrapped (Steel)

695. Mr. Bowman states in his report that his review of Gazifère's 2008 depreciation study[718] shows a requested rate of -70% and not -90% as shown in Concentric's peer analysis. As noted by Ms. Nori during the Oral Hearing, Mr. Bowman did not have the most recent Gazifère depreciation study which does support a -90% figure.[719] The peer analysis range provided by Concentric is therefore accurate.

696. In evidence, Concentric stated that it recommended a -80% net salvage to recognize the long term trend in the historical data it analyzed.[720] The point being made by Concentric is that only a fraction of the installed steel mains have been removed and hence historical removal costs are not a proper representation of the pace of future removal costs given that a substantial majority of steel mains will need to be removed in future. As noted by Mr. Bowman in his report, by his calculations, the reduction in the net salvage to a -40% figure would result in a reduction of approximately $40 million to the 2024 depreciation expense.[721] The actual impact as calculated by the Company would be $30.5 million using the CDNS method. Regardless, this is a very significant decrease and should be viewed against the approved net salvage parameters for EGD and Union which were -51% and -60% respectively. Mr. Bowman's suggestions are clearly going in the wrong direction and raise questions about InterGroup's methodology given the differences in the perceived impacts.

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[718] Exhibit M1, page 61.
[719] Concentric Advisors. 2019 Depreciation Study. March 2020. https://www.regie-energie.qc.ca/fr/participants/dossiers/R-4122-2020/doc/R-4122-2020-B-0005-Demande-Piece-2020_04_30.pdf
[720] Exhibit I.4.5-IGUA-23, pages 5 and 6.
[721] Exhibit M1, page 62.

Account 475.30 Distribution Plant - Mains: Plastic

697. Concentric has recommended the same net salvage parameter for this account as it has for steel mains. The common sense reason is that it costs the same to remove mains whether they are steel or plastic. It is also a matter of common sense that the salvage value of plastic mains is less than the salvage value of steel. The currently approved net salvage parameters for EGD and Union are -38% and -40%. Mr. Bowman recommends a reduction to -25% which would lead to a further reduction in the net salvage provision of $20 million by his calculations.[722] Enbridge Gas calculates the impact of what Mr. Bowman proposes at $33.9 million using the CDNS method.

698. Given the fact that the cost to remove plastic and steel mains is the same and given the lower salvage value for plastic mains, it intuitively makes no sense to lower the net salvage recovery relative to existing approved levels. It is also inconsistent with the fact that the vast majority of plastic mains remain in service. The provision must recover sufficient amounts for their removal in future. Reducing net salvage to -25% would put this in jeopardy.

699. The Company also notes that Mr. Bowman has again not used the most recent Gazifère depreciation study for the purposes of his peer utility observations. He also makes the same mistake of using the AltaGas approved net salvage parameter versus the net salvage parameter that was included AltaGas' depreciation study. For all of these reasons, the Company submits that his recommendations should be rejected.

OEB Staff Proposed Alternative to CDNS: The Traditional Method

700. OEB staff state in their submission that if the OEB has concerns with using the CDNS methodology (which the Company questions why it would given that it has been appropriately used by EGD for the better part of the past decade by without issue at

[722] Exhibit M1, pages 62 and 63.

any time in terms of its mechanics and the amounts recovered), that it might want to consider using the traditional method. OEB staff note that the use of this method would increase the depreciation expense relative to what is proposed under the CDNS as properly applied.[723]

701. Union utilized the traditional method and as noted by the depreciation experts, it is a commonly used methodology. Despite this, all three depreciation experts support the use of the CDNS. This said, the Company is not opposed to the use of the traditional method and it has included in Table 2[724] the net salvage provision that the use of this methodology would generate. The net salvage parameters recommended by Concentric for all relevant accounts using the traditional method is set out in Table 8 to the InterGroup Report.[725]

702. Should the OEB determine that some of the proposed changes to net salvage parameters proposed by InterGroup should be approved, notwithstanding the concerns expressed by the Company and Concentric's evidence in support of its recommendations, using the traditional method might be one means of ensuring that the actual net salvage provision is sufficient to cover forecast annual removal costs and to add to the future site restoration costs accrual balance. While the OEB should be concerned about rate impacts, it should be equally concerned about not recovering appropriate removal and site restoration costs as these will then simply be moved forward and become an inequitable burden on future ratepayers.

703. The Company strongly believes that it is in the interests of ratepayers and the utility for the depreciation expense to increase as proposed largely as a result of energy

[723] OEB staff Submission, page 93.
[724] All else equal, the net salvage provision using the traditional method is $251.4 million. Enbridge Gas's proposed net salvage provision of $96.3 million (Exhibit J17.5) would increase by $155.1 million ($1,034.1 million - $879.0 million from Table 2).
[725] Exhibit M1, page 55.

transition risks and the fact that if nothing is done now, it will only be worse later. It is not prudent to continue depreciation at the current levels and even more inappropriate to see the depreciation expense decline. In the end, the important point is that the status quo is not appropriate and that the aggregate impact on the depreciation provision of the decisions made by the OEB do not make the future matters worse.

Units of Production and Economic Planning Horizon Studies

704. Other than the environmental groups, no other intervenor supports the immediate introduction of the UoP methodology nor applying an EPH. In part this is no doubt a reflection of the fact that the necessary components, details and impacts of using these methodologies are not on the record in this proceeding for consideration by the OEB. Prior to proposing to use such methodologies, it appears that all parties agree that a number of questions need to be considered and answered such as the appropriate denominator for the UoP and the applicable dates and assets which should be subject to an EPH. Enbridge Gas agrees and notes that its depreciation expert Concentric specifically stated that for the purposes of the next depreciation study, it may be appropriate to consider such methodologies.[726]

705. Despite this, some parties have requested that the OEB direct Enbridge Gas to undertake specific depreciation methodology studies for filing prior to the next rebasing. In most instances, they recommend this and the lowering of depreciation rates at this time using the ALG procedure and lengthening asset lives. Enbridge Gas submits that it is not necessary nor appropriate for the OEB to direct it to undertake any additional studies at this time. The Company has already accepted that it may be appropriate to give consideration to other methodologies including the UoP methodology[727] or an EPH procedure in future.[728]

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[726] Exhibit I.4.5-ED-139, part a).
[727] Ibid.
[728] Exhibit 4, Tab 5, Schedule 1, page 16.

706. More specifically the Company questions the value of a UoP study until a meaningful forecast of an appropriate denominator can be developed. Mr. Kennedy noted that selecting an appropriate denominator is extremely challenging where you are trying to estimate how much demand is going to occur on the system into the future. You can make assumptions, but once you start making too many of these assumptions, you lose the benefits of the UoP methodology.[729]

707. As noted by Ms. Giridhar:

> So I think to presume that the right unit of production methodology presupposes annual units of energy is somewhat dissonant with the view we have about how natural gas assets can play in an energy transition, in that it supports an overall energy system providing reliability and resilience when it's needed. So I think there is that added complexity of what unit of production are we talking about, or what unit of energy are we talking about.[730]

708. Such a study will also be informed by the policy direction given by the Government of Ontario which will then need to be considered and analyzed for the purposes of adjusting, where appropriate, the future pathways for the Company. The Company does not believe that it is appropriate to set artificial deadlines for the completion of such studies. It will be commissioning a depreciation study for the purposes of the next rebasing application and this could include seeking approval for an EPH or UoP methodology but such recommendations should be made based on the best available information at that time. To direct the Company to undertake a study into how to implement a UoP or EPH methodology at this time is tantamount to making a determination today about what methodology will be appropriate for the purposes of the next IRM term. Such studies are time consuming and expensive. Enbridge Gas submits no such direction is appropriate or required.

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[729] 16 Tr.198.
[730] 17 Tr.11.

709. There is a complete record in this proceeding in support of the approvals sought in respect of depreciation including a comprehensive study which considered all appropriate methodologies. The record also includes evidence about how and why certain methodologies are not appropriate at this time. None of the depreciation experts recommend use of an EPH or UoP methodology at this time. It is appropriate to approve a methodology now for the 2024 to 2028 rate term.

Net Salvage Ten Account Study

710. Several parties have recommended that the OEB direct the Company to undertake a study of its ten largest accounts for the purposes of attempting to more accurately determine future net salvage costs. While Enbridge Gas reiterates what was stated at the Oral Hearing that it has no objection to undertaking such a study it believes it is appropriate to point out the limitations and difficulties that the Company and the consultants engaged to complete such a study may face even if the study is limited to only ten accounts.

711. It is appropriate to point out that the CER's determinations about the removal costs of various assets is based upon detailed engineering studies. These studies undertake a complex and sophisticated analysis relying upon a substantial detailed review of available data. Studies of this magnitude are time consuming and expensive. Mr. Kennedy noted in Exhibit J16.9 that detailed engineering studies can run into the millions of dollars and take a great deal of time. It was also noted in Exhibit J16.9 that this was the experience of the CER with respect to the studies it undertook as part of its pipeline abandonment update. Considering the geographic diversity of assets in question and the urban, rural and other settings in which the Company's assets exist, the examination of the removal costs for one account will involve the consideration of removal costs in numerous settings across the province.

712. The accuracy of removal cost estimates is of course dependent upon the granularity of the data which is available and the assumptions used. As a practical matter, in a number of instances, Enbridge Gas expects that only high-level estimates should be used. Removal costs in dense urban settings like downtown Toronto and other cities may vary significantly even though such assets are located in relatively close proximity. Site restoration costs will similarly fluctuate depending upon the location. All of this supports the request by the Company that should the OEB support the study proceeding, that it leave the Company adequate flexibility to create a scope of work that is practical and cost effective.

713. Given the costs of completing such studies and the time that they will take, the Company believes that the most efficient means of proceeding would be to complete a study looking at the six largest accounts. These accounts, it should be noted, make up the majority of the in-service plant. By completing studies on these six accounts, it would then be possible to look at the results to determine if there is value in proceeding with a study in respect of the other four accounts that have been identified as candidates.

714. Finally, it is appropriate to point out that there can be no predetermination of the study's results. While Enbridge Gas has used the best available information and relied upon the professional advice of its depreciation experts in terms of determining appropriate net salvage parameters, the study may determine that there has been an under recovery of future site restoration costs. Parties should be cognizant of this potential result and hopefully not be surprised if the study ultimately leads to requests for increases in net salvage recoveries in rates in future.

OGVG Proposal to Mix ELG and ALG

715. OGVG has suggested that the OEB consider requiring Enbridge Gas to apply the ELG methodology to its distribution assets and the ALG methodology to its transmission

and storage assets. When asked about this during the Oral Hearing, Ms. Giridhar noted the complexity of using two methodologies and the efficiency of utilizing only one.[731]

716. Enbridge Gas believes that OGVG made this recommendation under the belief that it would materially reduce the depreciation expense in comparison to applying ELG to all assets. Using the table at Exhibit J17.6 Attachment 1 and isolating the non-distribution asset classes in column D, the impact of OGVG's hybrid approach is a reduction of $16.1 million from the proposed $879 million depreciation provision. Enbridge Gas questions the practicality of an approach which introduces unnecessary complexities and may have unintended accounting complications.

Pollution Probe 15-year EPH For New Assets

717. While no party has recommended that the OEB approves an EPH on all assets, PP submits that a 15-year EPH should be applied to all new assets, regardless of their expected useful life and regardless of whether the assets are more or less likely to be at risk from an energy transition perspective. Enbridge Gas notes that the impact of what PP has proposed is unknown. There is no evidentiary basis for approval of such a blunt instrument. PP's proposal fails to give consideration to how different subgroups of assets, installed in different geographic regions and settings to support differing subsets of customer classes will be impacted. The impacts will vary and would be significant. As noted by Mr. Kennedy during the Oral Hearing, it takes a fair bit of study to determine the right approach to applying an EPH.[732]

718. Finally, what PP proposes makes no intuitive sense. Why should assets installed in 2024 have a depreciable life of only 15 years when the same assets installed in 2023 have depreciable lives of much longer durations.

[731] 17 Tr.62-63.
[732] 17 Tr.72.

PDO/PDCI Payments During Deferred Rebasing Term

719. Issue 18 – In relation to the 2024 Test Year gas cost forecast,

    f) Is the 2024 Test Year Parkway Delivery Commitment Incentive (PDCI) Forecast appropriate?

720. While parties agreed to the proposed updated Parkway Delivery Obligation (PDO) Framework and the 2024 forecast of PDO/PDCI costs as part of the Settlement Proposal[733], there was no agreement as to the treatment of 2019 to 2023 PDO/PDCI costs that have been recovered from customers as part of the OEB-approved Settlement Framework for Reduction of Parkway Delivery Obligation (PDO Settlement Framework).[734]

Summary and Relief Sought

721. Enbridge Gas is requesting that no adjustments be made to the 2019 to 2023 PDO/PDCI costs that have been recovered from customers.

722. The issue of the treatment of 2019 to 2023 PDO/PDCI costs in rates in this proceeding is an outcome from the OEB decision in Enbridge Gas's MAADs Decision where the OEB indicated at the time of rebasing it would:

> Review the costs and amounts recovered through rates to ensure that ratepayers are not paying twice for the required capacity and the legacy Union Gas is not enhancing earnings contrary to the intent of the PDO settlement agreement.[735]

[733] Exhibit O1, Tab 1, Schedule 1, Issues 18(e) and (f), pages 37-38.
[734] The June 3, 2014 Settlement Framework for the Reduction of the Parkway Delivery Obligation is found at pages 23-29 of Exhibit K7.3.
[735] MAADs Decision, page 49.

723. In AIC, Enbridge Gas described the reasons why it should be found that earnings were not enhanced contrary to the intent of the PDO Settlement Framework during 2019 and 2023.[736]

724. As summarized in AIC, denial by the OEB in this Application of the recovery of the Dawn Parkway System demand costs associated with the PDO shift, which were recovered through rates during 2019 to 2023, would be contrary to the intent and guiding principle of the PDO Settlement Framework. The guiding principle was to keep the Company whole rather than to enhance or reduce its earnings during the operation of the IRM. Denied revenue recovery at this time would result in reduced earnings of the Company since it has lost the revenue from Rate M12 turnback used for the PDO shift and would no longer have the ability to market the capacity to recover that lost revenue.[737]

725. This Reply Argument will focus on replying to the submissions of other parties.

Submissions by Other Parties

726. Enbridge Gas's position that no adjustments should be made to the 2019 to 2023 PDO/PDCI costs is supported by OEB staff and LPMA. While not specifically commenting on the 2019 to 2023 PDO/PDCI issue, EP and QMA support the position of OEB staff on all other issues that are not specifically listed in their respective submissions.[738]

727. OEB staff submitted that ratepayers are not paying twice for the same capacity, and therefore the OEB should not make any adjustments to the 2019 to 2023 PDO/PDCI costs that have been recovered from ratepayers.[739] LPMA submitted that the OEB

[736] AIC, pages 203-210.
[737] See AIC, pages 204 -205, and the evidence cited therein.
[738] EP Submission, page 19, QMA Submission, page 7.
[739] OEB staff Submission, page 105.

should not make any adjustments to the 2019 to 2023 PDO/PDCI costs that have been recovered from ratepayers.[740] Both OEB staff and LPMA agree with Enbridge Gas that there is sufficient evidence on this issue for the OEB to make a determination on this issue.

728. OEB staff provides a summary of the background on the 2019 to 2023 PDO/PDCI issue beginning with Union's 2013 Cost of Service proceeding. Enbridge Gas supports the characterization of the issue as summarized by OEB staff.

729. FRPO, SEC and CME have provided submissions that an adjustment should be made to the 2019 to 2023 PDO/PDCI costs recovered from ratepayers during that time period. These parties are requesting the OEB establish a base rate adjustment effective January 1, 2019, the beginning of Enbridge Gas's deferred rebasing term from its MAADs proceeding.

730. FRPO accepts that ratepayers are responsible to pay these costs until the end of 2018 as parties to the Settlement Framework for the Reduction of the Parkway Delivery Obligation.[741] However, FRPO argues that it would have been appropriate and equitable to remove the PDO/PDCI costs from the revenue requirement at the start of the 2019 to 2023 deferred rebasing term, similar to other base rate adjustments made at that time.[742]

731. SEC agrees with FRPO that the OEB should refund customers the amount included in PDO costs that they were already paying through the excess capacity in base rates, beginning January 1, 2019.[743] SEC also comments that while the double recovery was

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[740] LPMA Submission, page 30.
[741] FRPO Submission, page 12.
[742] Ibid.
[743] SEC Submission, page 98.

permissible through the Union IR period according to the terms of the PDO Settlement Framework, it became inappropriate as of December 31, 2018.[744]

732. Similarly, CME acknowledges that the "double recovery" was permissible under the PDO Settlement Framework until December 31, 2018, but submits that the OEB should not allow it to continue beyond that time.[745]

Enbridge Gas Response to Other Parties' Submissions

733. As can be seen, all parties filing submissions on this topic acknowledge that Enbridge Gas appropriately recorded and recovered PDO/PDCI costs during the period 2014 to 2018 in accordance with the regulatory mechanisms approved by the OEB at the time, namely the 2013 Cost of Service and the PDO Settlement Framework. The disagreement (pursued by three parties) is whether this should continue during the deferred rebasing term or be reflected in a base rate adjustment that would reach backwards for five years to January 1, 2019.

734. The fact that the OEB declined to make a final determination on the PDO/PDCI item in the MAADs Decision, and instead instructed Enbridge Gas to track associated costs and revenues for five years for potential re-allocation after the deferred rebasing term, is an exceptional direction. Enbridge Gas submits that this exception should be read narrowly and precisely, taking account of the specific wording of the MAADs Decision. The operative words of the MAADs Decision stated that:

> The OEB at the time of rebasing will review the costs and amounts recovered through rates to ensure that ratepayers are not paying twice for the required capacity <u>and</u> the legacy Union Gas is not enhancing earnings contrary to the intent of the PDO settlement agreement.[746] (emphasis added)

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[744] SEC Submission, page 98.
[745] CME Submission, page 52.
[746] EB-2017-0306/EB-2017-0307, OEB Decision and Order, August 30, 2018, page 49.

735. Based on the wording in the MAADs Decision there are two elements that would have had to been satisfied in this proceeding for the OEB to consider making a base rate adjustment effective January 1, 2019:

- Ratepayers are paying twice for the required capacity, and
- Union enhanced its earnings contrary to the intent of the PDO Settlement Framework.

736. While parties have argued that ratepayers are paying twice for certain capacity, Enbridge Gas submits that the treatment of PDO/PDCI costs was consistent with the intent of the PDO Settlement Framework. All parties have submitted that they also agree with this position. Therefore, Enbridge Gas, and formerly Union, did not enhance earnings contrary to the intent of the PDO Settlement Framework. Earnings on the PDO/PDCI costs by the Company were as contemplated and aligned with the intent of the PDO Settlement Framework.

737. Given that Enbridge Gas did not enhance earnings contrary to the intent of the PDO Settlement Framework, there is no basis for a base rate adjustment for the 2019 to 2023 PDO/PDCI costs in this proceeding. This position is expressly supported by OEB staff and LPMA.

738. The parties seeking a retroactive base rate adjustment all assert that the terms of the PDO Settlement Framework indicate that it would terminate on December 31, 2018. That is not what the document says. Instead, the PDO Settlement Framework states that "[t]he guiding principle is to keep Union whole rather than to enhance or reduce its earnings during the operation of the Incentive Regulation Mechanism (IRM) to December 31, 2018."[747] The clear context is that until rates are re-set (the IR term ends), then Union should be kept whole. As it turned out, the MAADs approval

[747] PDO Settlement Agreement, page 1.

resulted in Union extending the term of the price cap IRM that set its rates. Rates were not re-set as of 2019.

739. As a factual matter, the PDO Settlement Framework did not end on December 31, 2018. The Company's evidence in this case (Exhibit 4, Tab 7, Schedule 1) explains how the PDO Framework established by the PDO Settlement Framework has continued to be in place.[748] No party argued against this. The provisions of the PDO Settlement Framework continued to be observed through the deferred rebasing term. Enbridge Gas complied with the reporting requirements under the PDO Settlement Framework as part of each annual rate adjustment application during the deferred rebasing term.[749]

740. Enbridge Gas proposed changes to the PDO Framework in this case, and all parties agreed to those changes, with some modifications.[750] This is what is set out at the completely settled Issue 18(b) of the OEB-approved Settlement Proposal in Phase 1 of this case, the preamble of which states "[p]arties agree with Enbridge Gas's proposed updated PDO Framework, with the following exceptions …".[751]

741. Enbridge Gas submits that it is appropriate to find that all aspects of the PDO Settlement Framework continued through the deferred rebasing term. The position of the three opposing intervenors would be to rewrite history and find that the PDO Settlement Framework should continue for the deferred rebasing term, except for the "guiding principle" that Union should be kept whole in the context that existed when the Settlement Framework was formed. It is not appropriate to somehow determine

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[748] Exhibit 4, Tab 7, Schedule 1, pages 2-9.
[749] See, for example, 2020 rates proceeding (EB-2019-0194), Exhibit B, Tab 1, Schedule 1, pages 17-20; 2021 rates proceeding (EB-2020-0095), Exhibit B, Tab 1, Schedule 1, pages 14-17; and 2022 rates proceeding (EB-2021-0147), Exhibit B, Tab 1, Schedule 1, pages 15-17.
[750] Exhibit 4, Tab 7, Schedule 1, pages 2-9.
[751] Exhibit O1, Tab 1, Schedule 1, page 37.

that the “guiding principle” of the PDO Settlement Framework has expired, but the operative provisions continue.

742. Enbridge Gas has one additional submission, in response to FRPO’s Submission.

743. In FRPO’s summary of the background on the 2019 to 2023 PDO/PDCI issue, FRPO introduces a new element that it describes as an “important matter” regarding the timing of the argument in chief and reply argument in Union’s 2013 Cost of Service proceeding relative to the timing of an open season capacity request for 2013.[752] This seems to raise an issue that could have been known prior to the PDO Framework, during the MAADs proceeding, and during the evidentiary portion of this case, since it relates to facts from 10 years ago. FRPO has had five years since the OEB’s MAADs Decision to research and develop a position on the PDO/PDCI issue and plenty of opportunity to raise the matter in this proceeding. In order to develop an argument on the PDO/PDCI issue in this proceeding, FRPO is raising concerns with multiple OEB decisions across various past proceedings that have been final for many years. This accusation that Union somehow misled the OEB was not put to the Enbridge Gas witnesses. The Company does not have time, and it would likely not be appropriate, to review and then summarize the records from proceedings a decade ago to defend itself, within final Reply Argument, against FRPO’s accusations. From a process perspective, Enbridge Gas submits that no weight should be given to this FRPO Submission.

744. In any event, it is not clear what FRPO asks the OEB to do with this “important matter”, given that FRPO submits that it accepts the OEB decisions made in the 2013 and 2014 proceedings noted by FRPO.[753]

[752] FRPO Submission, page 14.
[753] Ibid.

E. Cost of Capital (Exhibit 5)

Equity Thickness

745. Issue 20 – Is the proposed 2024 Capital Structure, including return on equity appropriate?

746. Issue 21 – Is the proposed 2024 cost of debt and equity components of the Capital Structure appropriate?

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

Summary and Relief Sought

748. Enbridge Gas requests approval from the OEB of an increase to its equity thickness from 36% to 42% but proposes a phase in of the increase such that in 2024, equity thickness would be 38% for rate making purposes and there would be an increase of 1% in each of 2025, 2026, 2027 and 2028 such that for 2028 the capital structure for Enbridge Gas for rate making purposes will be 42% equity and 58% debt.

749. Enbridge Gas further requests approval for a phase-in approach to the 1% increase in equity thickness in each of the years 2025 through 2028 by an annual base rate adjustment of $13.6 million.[754]

Submissions by Other Parties

750. Enbridge Gas notes that there is support for a change in equity thickness by certain ratepayer groups. Most noteworthy, OEB staff support the OEB increasing Enbridge Gas's equity thickness to 38% for the reasons set out in the report of its expert witnesses at London Economics International (LEI)[755] which Enbridge Gas notes

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[754] Exhibit 5, Tab 3, Schedule 1, pages 5-6 (updated by Exhibit J9.1, Attachment 1).
[755] Exhibit M2.

relied upon a now out of date customer weighted average equity ratio for Canadian peer companies. LEI's customer weighted average equity ratio for Canadian peer companies is now 40.5%. On September 5, 2023, the British Columbia Utilities Commission (BCUC) in its Generic Cost of Capital Proceeding, increased FortisBC Energy Inc.'s (FEI), which is the natural gas distributor, equity ratio from 38.5% to 45%. As a result, LEI's customer weighted equity ratio for the Canadian Peer companies is 40.5%. EP supports the increase to 38%[756]. QMA said that it has no objection to the 38% and the increase being introduced in a gradual stepwise manner. While not opining itself on the precise correct equity ratio figure, QMA submitted that the evidence shows that the range falls between 38% and 42%.[757] APPrO stated that if the OEB believes an increase is warranted it would accept an increase to 38% based upon the (now dated) analysis by LEI phased in at 0.5% per year over four years.[758] LPMA submitted that if the OEB determines that Enbridge Gas's risk has changed, then it should approve an equity thickness of no more than 38%. If the OEB approves an equity thickness of more than 38%, LPMA submits that it should not approve the proposed changes to the volume variance account to reflect weather.[759] VECC submitted that it accepts that some case can be made for some adjustment to capital structure simply due to Enbridge Gas being such a significant outlier as compared to almost all other Canadian utilities. In the end it supports a "conservative change" to 37% and additional modelling along the lines of that proposed by IGUA witness, Dr. Hopkins, together with a "full review of all aspects of EGI cost of capital"[760].

751. IGUA relies on the reports of its expert witnesses, Dr. Cleary and Dr. Hopkins, which purport to find that there has been no significant change to the business risk faced by

[756] EP Submission, page 11.
[757] QMA Submission, page 7.
[758] APPrO Submission, pages 4 and 38.
[759] LPMA Submission, page 36.
[760] VECC Submission, page 28.

Enbridge Gas since the last time its cost of capital parameters were considered by the OEB, notwithstanding the abundance of evidence on energy transition risks as well as the acceleration of those risks facing Enbridge Gas today. Most recently, a key Canadian energy regulator, the BCUC, increased the equity thickness of FEI due to the significant increase in business risk since 2016 primarily due to energy transition. This determination by the BCUC is in direct contrast to the position being advanced by IGUA's experts.

752. The environmental groups generally did not make detailed submissions on business risk nor did they express views about whether the fair return standard has been met. While none support an increase in equity thickness, ED supports the approval of the requested volume variance account as a means to reduce risk. GEC aligned itself with Dr. Hopkins and his belief that there is a need for more analysis before a change in equity thickness should be approved.

<u>Enbridge Gas Response to Other Parties' Submissions</u>

753. Enbridge Gas submits that the determinations made by Concentric are not only correct, they were recently confirmed by the BCUC which approved an increase in the equity thickness of FEI. In its Decision, the BCUC states: "the Panel finds that FEI's overall business risk has increased since 2016. That increase is most significantly attributable to the increase in political risks associated with the Energy Transition...". The findings of the BCUC contradict the opinions of both Dr. Cleary and Dr. Hopkins as is noted in greater detail below. This 45% equity ratio for FEI adjusts LEI's customer weighted average equity ratio for Canadian peer companies upwards from 38% to 40.5%. Given that LEI relied on this weighted average to support its recommended equity thickness of 38%, it follows that LEI's same framework of

analysis would support the adjusted result of a 40.5% equity thickness for Enbridge Gas.[761]

754. Enbridge Gas submits that the credibility of Dr. Cleary and Dr. Hopkins views should also be assessed in light of the following. Dr. Cleary in his report and during the Oral Hearing criticized Concentric for what he views as a failure to undertake persuasive quantitative risk analysis[762]. Dr. Cleary's suggested that his work was much more thorough quantitatively. This was shown to be inaccurate. The true extent of Dr. Cleary's quantitative analysis became apparent when he was asked while under cross examination about the risk of electric LDCs and their deemed equity thickness relative to Enbridge Gas.

> MR. O'LEARY: Do you know what the equity ratio is for electric LDCs in Ontario?
>
> DR. CLEARY: Ah, 37, 38 percent I believe?
>
> MR. O'LEARY: No, it is 40 percent.
>
> DR. CLEARY: 40 percent, sorry. That is for the smaller ones, though. Right?
>
> MR. O'LEARY: That is for all of them.[763]

755. Dr. Cleary was unaware of the equity ratio of utilities operating in the same geographic area and under the same regulator as Enbridge Gas while purporting to undertake a balanced review of the capital structure of the Company and Concentric's Report,

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[761] The Company is aware of the October 9, 2023 Determination of Cost of Capital Parameters decision of the Alberta Utilities Commission being decision number 27084 – DO2-2023 but given that it was only just released, it has not had an opportunity to fully consider the decision and to review the evidentiary record in the proceeding. Enbridge Gas does note that the Commission did not order any changes to the deemed equity thickness of the utilities identified in the LEI customer weighted Canadian utility proxy group. Taking into account the decision from the AUC, the correct average for Canadian Peer group companies remains 40.5%. Upon a quick review, the Company does note the apparent paucity of energy transition discussions in the decision which occupied approximately only one page. Much of the discussion was focused on macroeconomic risks (i.e. inflation and higher interest rates as they relate to the determination of return on equity), which was not the focus of evidence in the BCUC proceeding nor the evidence in this proceeding.

[762] Exhibit M8, page 47, lines 19-24.

[763] 10 Tr.44.

which appropriately considered electric LDCs in Ontario in its analysis. Dr. Cleary's failure is magnified by his further admissions:

> MR. O'LEARY: Would you agree that they [electric LDCs in Ontario] are utilities of like risk?
>
> DR. CLEARY: Similar.
>
> MR. O'LEARY: Thank you. And would you also agree that Ontario electrics do not face the energy transition risk that Enbridge Gas faces in this proceeding, and into the future, as you have noted in your surreply?
>
> DR. CLEARY: Not to the extent, no.
>
> MR. O'LEARY: Thank you. And would you agree that no one, no party, is advocating the ultimate demise of the electric distribution industry in Ontario?
>
> DR. CLEARY: Not to the best of my knowledge, no.[764]

756. What the above confirms is what Concentric has opined. Electric LDCs in Ontario face a less risky future in comparison to Enbridge Gas as agreed to by Dr. Cleary yet he failed to even consider their equity thickness for the purposes of his report. This alone should cause the OEB concerns about the reliability of his report and his evidence. Even a casual review of the OEB's cost of capital determinations would have revealed that this is important information.

757. During the Oral Hearing IGUA referenced the fact that Dr. Hopkins appeared as an expert witness before the Régie de L'énergie (Régie) in the 2022 proceeding involving three gas distributors in Québec. IGUA filed a copy of the evidence filed by Dr. Hopkins in this proceeding in an undertaking response to CCC[765]. If one takes the time to review these submissions, one will be struck by the remarkable similarity of his findings in Québec to those that are made in his evidence in this proceeding despite dealing with entirely different utilities in an entirely different jurisdiction. For example, Dr. Hopkins' evidence stated:

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[764] 10 Tr.44-45.
[765] Exhibit J5.1.

- Énergir and Gazifère face little short-term business risk, as evidenced by their ability to consistently achieve their allowed return on equity and their demonstrated low volatility of returns compared with the U.S. gas utility sample provided by Dr. Villadsen…[766]

- I recommend that the Régie: Set the returns on equity and capital structures at the level that corresponds to the business risk faced by a prudently managed utility in the same situation as each of the utilities in this proceeding. Utility management that fails to mitigate business risks that a prudent utility would mitigate should not be rewarded with a higher allowed return on equity[767]

758. IGUA referenced the decision of the Régie (a translation of which was produced by Enbridge Gas)[768] in its submission. In reviewing this decision, it is not apparent that the Régie placed any reliance upon the evidence of Dr. Hopkins. Indeed, contrary to the recommendations of Dr. Hopkins, the Régie determined:

> [125]…there is the ongoing energy transition and decarbonization efforts by 2030 that could affect the demand for fossil natural gas. In this regard, the Régie notes that pressure from society is prompting the Complainants to accelerate the implementation of initiatives aimed at positioning the natural gas systems as part of the energy transition solution in order to secure their future.
>
> [133] Thus, the Régie deems that the increased level of uncertainty in the business environment justifies an increase of 10 basis points from the top of the current range for Énergir's business risk adjustment, compared to the ROE of a benchmark distributor.
>
> [135] The Régie considers that the higher business risk of Gazifère compared to that of Énergir justifies an adjustment of 15 additional basis points to the range established for Énergir. Consequently, the Régie sets the new range for Gazifère's business risk adjustment at 40 to 60 basis points rather than 25 to 50 basis points, as estimated at the last review.[769]

759. As noted earlier, the positions of both Dr. Cleary and Dr. Hopkins are also at odds with the recent decision of the BCUC.[770] This proceeding was held to determine the

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[766] Ibid, page 3.
[767] Exhibit J5.1, page 4.
[768] Exhibit K8.2.
[769] Ibid, pages 33-34.
[770] British Columbia Utilities Commission Generic Cost of Capital Proceeding (Stage 1) Decision and Order G-236-23, September 5, 2023 (BCUC Decision).

deemed capital structure and allowed return on equity (ROE) of FEI and FortisBC Inc. (FBC). FEI and FBC jointly engaged Mr. Coyne of Concentric.

760. The BCUC decision states that it was guided by fundamental regulatory principles, including the Fair Return Standard (FRS) which requires three elements (which are the same three elements identified by the OEB in its 2009 Cost of Capital Report) to be met for a fair and reasonable return on capital.[771] When determining the cost of capital and the allowable return, the BCUC also stated that there are four key elements that the Panel considers:

1. The actual returns of a proxy group of peer utilities.
2. The business risks facing FEI and FBC, including how those risks may have changed since the last time the BCUC approved a cost of capital for those companies.
3. The credit ratings of FEI and FBC.
4. The results of various financial models that are designed to assess how the market prices risk and considers earnings in the evaluation of cost of capital.[772]

761. Enbridge Gas submits that even the aggregate of the work of Dr. Cleary and Dr. Hopkins combined did not consider all of the necessary elements of the FRS and the above noted key elements.

762. Contrary to the views of Dr. Cleary and IGUA's Submission which rejected the appropriateness of using U.S. comparators, the BCUC noted in its decision that: "Based on Mr. Coyne's explanation, FortisBC submitted that ... there are substantial similarities in the composition of the US proxy groups and the North American proxy groups"[773]. In the end, the BCUC agreed stating:

[771] BCUC Decision, Executive Summary page (i).
[772] Ibid, page (ii).
[773] BCUC Decision. page 12.

> We agree with Mr. Coyne... The Panel finds merit in using a combined North American proxy group and removing certain non-qualifying Canadian utilities.[774]

763. In respect of its reliance upon proxy groups, it is worth highlighting the BCUC's determination to use North American proxy groups, based on a finding that using North American data, consisting of a reasonable mix of both Canadian and U.S. comparators, is superior to using either Canadian proxy groups or U.S. proxy groups alone.[775] It determined that there are insufficient comparators to each of FEI and FBC in Canada to allow the BCUC to use only data pertaining to Canadian counterparts.

764. It is noteworthy that the BCUC's 2016 Decision used U.S. proxy groups results, citing both increasing integration and the scarcity of Canadian publicly traded utilities. Other Canadian regulators (and more recently FERC) have taken a similar approach; and the extent of North American financial and capital markets integration has only increased over time.[776]

765. The following are some of the key findings of the BCUC:

> **Panel Determination** In contrast, some elements of Energy Transition risk pose an existential risk to FEI's shareholders and impact the risk of stranded assets which increases the risk that shareholders will not be able to earn their full return.[777]
>
> The Panel accepts that BC residents' energy choices are increasingly influenced by a desire to use energy efficiently, to adopt lower carbon and renewable energy sources, and to generally reduce the negative impacts of climate change leading to a reduction in the end-use market share for natural gas and resulting in an increase in perceived risk by investors and a real risk for shareholders as compared to 2016. The Panel also agrees this is anticipated to result in a future reduction of new customer capture rates and perhaps even attrition of existing customers. Fewer customers to cover costs may result in an increase in natural gas delivery rates for remaining customers….Accordingly, **the Panel finds that FEI's**

[774] BCUC Decision, Executive Summary, page (ii).
[775] BCUC Decision, page 135.
[776] Ibid, page 15.
[777] Ibid, page 45.

> **demand/market perceived risk for the shareholder and investor to be higher than it was in 2016**. (bolded in the decision)[778]
>
> Given the findings discussed above associated with the changes in FEI's business risks to the shareholder, **the Panel finds that FEI's overall business risk has increased since 2016**. That increase is most significantly attributable to the increase in political risks associated with the Energy Transition and the cumulative effect of the perceived risks in Indigenous Rights and Engagement, energy price, and demand/market risks that could shift the risk to the shareholder if the utility is no longer viewed as an attractive investment by investors (bolded in the decision).[779]
>
> Mr. Coyne's recommended increase of FEI's equity ratio from 38.5 percent to 45.0 percent is due primarily to higher business risks as compared to 2016, which include accounting for "elevated Energy Transition risk in BC". Further, Mr. Coyne submits that his recommended 45.0 percent equity ratio for FEI is the "approximate midpoint between average deemed equity ratio for Canadian investor-owned gas distribution companies and the authorized equity ratio for U.S. gas distribution companies since January 2020.[780]

766. The end result is that the BCUC accepted Mr. Coyne's recommended 45% equity thickness for FEI. The BCUC specifically stated:

> The Panel finds that the 45.0 percent equity thickness meets the comparable investment and capital attraction requirements in the Fair Return Standard because 45.0 percent is premised on FEI's proxy group and supported by our assessment of FEI's business risk. Further, as compared to FEI's current 38.5 percent equity thickness, an increase to 45.0 percent will maintain FEI's financial integrity.[781]

767. The BCUC also approved an allowed ROE for FEI of 9.65% which compares to the current 2023 allowed ROE of Enbridge Gas of 9.36%.[782]

768. Enbridge Gas submits that with this approval from the BCUC, it is appropriate to make adjustments to relevant tables and calculations made by Concentric in its report to reflect the impact of the BCUC increasing the equity thickness of FEI to 45% from

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[778] BCUC Decision, page 48.
[779] Ibid, page 50.
[780] Ibid, page 127.
[781] Ibid, page 134.
[782] Ibid, Executive Summary, page (v).

38.5%. Concentric's original results are found at Figures 34 and 35 of their report.[783] Applying the equity ratio of 45% for FEI, the mean for the Canadian operating company proxy group increases from 41.7% to 42.35% (Figure 34) and the median for the same group increases from 40.5% to 43% (Figure 35). Figure 36 summarized the average adjusted equity ratio for ATCO Gas, FEI, and Énergir. Adjusting based on the BCUC decision, the average for the companies in Figure 36 increases from 39.25% to 41.42%.

The Business Risk of Enbridge Gas has Increased

769. OEB staff submit that 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 EGD's and Union's cost of capital were formally reviewed in 2012.[784] This determination is reinforced by the BCUC decision which increased the equity thickness for the electric LDC FBC by only 1% to 41%. The BCUC stated: "Given the findings associated with each of the business risk categories, the Panel finds that FBC's business risk overall has not changed materially since 2013"[785].

770. IGUA does not question that an energy transition is underway, nor does it question the importance of the associated structural shifts.[786] Similar language can be found in the submissions of virtually every other party. That the world in which natural gas distributors operate has changed and the gravity of the risks that these changes present to the Company relative to 2012 is not in dispute.

771. Given OEB staff's view that business risk has increased for Ontario natural gas distributors relative to LDCs, it seems odd that OEB staff is recommending an equity

[783] Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 101 and 102.
[784] OEB staff Submission, page 111.
[785] BCUC Decision, page 63.
[786] IGUA Submission, page 6.

thickness for Enbridge Gas that is lower than the electric LDCs. For the reasons stated below, it is submitted that OEB staff's reliance on LEI's recommended equity ratio is misguided because LEI failed to actually consider electric LDCs in its comparable investment standard analysis. Even if OEB staff do not want to admit this failure, based upon its own energy transition views, OEB staff could have submitted that the OEB might wish to consider the fact that electric LDCs are comparatively less risky than Enbridge Gas in setting the Company's equity thickness.

The Fiction that LEI and Dr. Cleary undertook a Quantitative Analysis

772. OEB staff submit that Dr. Cleary and LEI have provided more balanced assessments and that Concentric relies too heavily on qualitative support. The Company submits that one need only look at the comparative comprehensiveness of the three reports to conclude that these assertions are not accurate.

773. Risk assessment is inherently both qualitative and quantitative. The FRS mandates the consideration of both. This is certainly the only conclusion that can be reached based upon the OEB's 2009 Report on the Cost of Capital.[787] In that proceeding, the OEB commended Concentric's approach stating:

> Concentric carefully selected comparable companies based on a series of transparent financial metrics, and the Board is of the view that this approach has considerable merit. Commenting on Concentric's analysis, Union Gas noted that no one else in the consultation performed this kind of detailed analysis of U.S. comparators. The use of a principled, analytical, and transparent approach to determine a low risk comparator group from a riskier universe for the purpose of informing the Board's judgment was supported by various participants in the consultation.[788]

774. The OEB further quoted with approval the following submission by the PWU in support of its finding that the U.S. is a relevant source for comparable data:

> Differences and similarities were thoroughly considered before arriving at the conclusions that based on a careful selection of like companies, a proxy group which includes US distribution utilities adheres to the

[787] EB-2009-0084, Report of the Board on the Cost of Capital for Ontario Regulated Utilities.
[788] Ibid, pages 21-22.

> Comparable Investment Standard. Moreover, Concentric was better suited to complete such as an analysis, having recognized expertise in the risks faced by both Ontario and US electricity distributors.[789]

775. In the pre-filed evidence[790], Concentric provided the following quantitative analysis:

- Figure 22 – comparison of market risk indicators for Canadian and US gas utilities including valuation multiples, Beta coefficients, and credit ratings;
- Figure 29 – energy transition risk – comparison of remaining life and percentage of assets depreciated for Enbridge Gas and the proxy group companies;
- Figure 34 and 35 – comparison of mean and median deemed and actual book equity ratios for Enbridge Gas and companies in the four proxy groups;
- Figure 37 – analysis of Enbridge Gas's credit metrics compared to proxy group companies;
- Figure 38 – comparison of weighted ROE for Enbridge Gas and other North American natural gas LDCs; and
- Figure 40 – analysis of change in beta since 2012 for natural gas vs electric sectors; both have increased significantly, indicating higher market risk for utilities.

776. Concentric expanded on its comprehensive pre-filed evidence with extensive and thorough responses to the numerous interrogatories received, much of which was quantitative in nature. In particular, the following interrogatory responses support Concentric's analysis and recommendations using quantitative data:

- Exhibit I.5.3-STAFF-217 – Enbridge Gas's S&P credit metrics annually from 2012 to 2021 actual and 2022 to 2024 Forecast
- Exhibit I.5.3-STAFF-218 – S&P credit metrics annually from 2012 to 2021 actuals for proxy group companies

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[789] EB-2009-0084, Report of the Board on the Cost of Capital for Ontario Regulated Utilities, page 23.
[790] Exhibit 5, Tab 3, Schedule 1, Attachment 1.

- Exhibit I.5.3-STAFF-224 – Expanded Figure 22 to include annual market risk indicators for 2011 to 2022
- Exhibit I.5.3-STAFF-233 – Expanded Figure 40 to include annual Bloomberg and Value Line betas for proxy groups from 2012 to 2022
- Exhibit I.5.3-IGUA-44 – projected credit metrics for Enbridge Gas at 36% equity ratio
- Exhibit I.5.3-IGUA-47 – Update Figure 22 for more recent 2022 data
- Exhibit I.5.3-IGUA-50 – Valuation ratios (P/E ratio and EV/EBITDA ratio) for U.S. gas and electric utility companies
- Exhibit I.5.3-IGUA-55 – Total revenues and total assets for U.S. and Canadian holding companies
- Exhibit I.5.3-IGUA-61 – S&P credit metrics for each proxy group company in U.S. Holdco, Canadian Opco, and US Opco proxy groups annually from 2017 to 2021

777. It is simply not credible upon a careful review of the evidence to argue that Concentric relied too heavily on qualitative evidence.

778. In contrast, for the reasons stated in this Reply Argument, the quantitative analysis undertaken by both LEI and Dr. Cleary are flawed and incomplete. They both lack the depth and breadth of the work completed by Concentric. In respect of LEI, as is noted below, while it identified a North American proxy group through its screening process, it failed to consider the findings in respect of the U.S. comparators for the purposes of its recommendation.

779. As noted above, Dr. Cleary was not even cognizant of the equity thickness of electric LDCs in Ontario. As noted by Concentric at the Oral Hearing:

> Dr. Cleary's approach to measuring risk is overly narrow and backward-looking. He focused on the company's historical ability to earn its allowed return, current credit ratings, and near-term credit metrics. None of these

> measures is indicative of an equity investor's required return, which is forward-looking and considers both near-term and long-term risk.
>
> Nearly all of the third-party evidence Dr. Cleary cites is from debt-focused credit rating agencies, not the equity investor community. And, further, Dr. Cleary states his disagreement with certain findings in third-party investor materials that conflict with his own views, even though those third-party investor views reflects those of the market.
>
> In addition, Dr. Cleary dismisses all other North American utilities, including other Ontario utilities, as being useful in an analysis of Enbridge Gas's equity ratio, therefore rendering a comparable return analysis impossible.[791]

Dr. Cleary's Conclusions lack Credibility

780. There are a number of views expressed by Dr. Cleary which IGUA relied upon that can be shown to be inaccurate or self-serving.

781. Based upon Dr. Cleary's Report, IGUA submitted that Enbridge Gas attracts and retains capital from its parent, Enbridge Inc. which goes to the capital and debt markets based on a number of energy businesses, including Enbridge Gas.[792] Both Dr. Cleary and IGUA have this wrong. Enbridge Inc. only provides equity injections into Enbridge Gas. The Company itself goes to debt markets to raise both short and long-term debt on its own behalf. Enbridge Gas therefore attracts and retains capital from external debt markets.

782. IGUA further submitted that there is no direct observability into Enbridge Gas's equity value, unlike Enbridge Gas debt terms which are easily observable. In that respect, Dr. Cleary notes that Enbridge Gas borrows at slightly below A-rated utility average yield, which he believes shows that Enbridge Gas has no problem attracting capital.[793] The footnote IGUA cites in its submission is to Dr. Cleary's testimony at Tr. Vol.10 9, lines 26 to 27: "They ignore the fact that Enbridge Gas borrows at slightly below the A

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[791] 8 Tr.59-60.
[792] IGUA Submission, page 11.
[793] Ibid, page 25.

rated utility average yield". To support this conclusion, Dr. Cleary relied upon just one single trading date, January 3, 2023, which happens to be the very first trading date of the year and is typically a very light trading day and a day when bond markets may not see accurate price discovery. It is a real stretch to suggest that this is adequate quantitative analysis.

783. To reach a conclusion on the rates at which Enbridge Gas is able to borrow, the graph in Exhibit I.5.2-SEC-198 page 2 is a much more comprehensive data set to rely upon. The graph shows the credit spreads of Enbridge Gas and a number of utility peers. These are peers used by Enbridge Gas's rating agencies and the investment community when assessing relative investment opportunities. This data clearly shows that since 2014, Enbridge Gas's 10-year issuance credit spread has been consistently higher than its peers. This multi-year dataset directly refutes Dr. Cleary's conclusion that Enbridge Gas can attract capital at lower rates than its peers. The exact opposite is true. The data supports that Enbridge Gas has borrowed at higher rates than many of its utility peers.

784. CME submits that rating agencies which analyze Enbridge Gas have not outlined any concerns with respect to its credit metrics or believe that Enbridge Gas's credit rating will be downgraded.[794] As noted by Mr. Reinisch during the Oral Hearing[795], the credit rating agencies, specifically S&P, <u>have</u> expressed concerns with Enbridge Gas's equity thickness. They do so through their assignment of a "significant" financial risk rating. The evidence shows that the Company's financial metrics have weakened over time. In the most current S&P Ratings Report produced as Exhibit K8.2[796], Debt to EBITDA has increased from 5.9 in 2018, just prior to the amalgamation, to 6.4 in

[794] CME Submission, page 44.
[795] 8 Tr.61-62.
[796] Exhibit K8.2, page 92.

2022[797]; FFO to debt has decreased from 13.0% in 2018 to 11.9% in 2022.[798] Neither of these metrics are directionally positive and both of these key metrics are driven by equity thickness and the amount of financial risk within the approved capital structure.

785. It is important to note that S&P provided its forward-looking forecasts under the assumption that Enbridge Gas's equity thickness will increase from the current 36% to approximately 39% for 2024 and 2025[799]. Even with this increase in equity thickness, S&P's projection of FFO to Debt and Debt to EBITDA[800] are only enough to get back to 2018 levels. This same S&P projection shows Enbridge Gas maintaining FFO cash interest coverage around its current 4.1- 4.5 range. Despite the projected increase in equity thickness, S&P is still assessing the Company's financial risk as "significant".

786. IGUA submits, relying on Dr. Cleary and Dr. Hopkins, that Enbridge Gas's ability to earn at or above its allowed ROE is evidence that Enbridge Gas's business risk has not changed. The Company submits that this is a red herring. If the cost of capital is set at an incorrect level, the Company's ability to achieve that return is a secondary consideration. To take this argument to its logical extreme, if Enbridge Gas was awarded an 8% ROE on a 25% equity ratio, and consistently earned that ROE, would IGUA argue this demonstrated low risk and that it satisfied a fair return? The trailing ability of a company to earn its allowed return does not inform the proper equity ratio particularly in an incentive rate-setting environment and when the Company's business risk has increased and is expected to continue to increase as the energy transition progresses. It also important to note that the OEB has previously stated "an

[797] 2018 is the first year which presents combined data for the amalgamated utility.
[798] An increase in the Debt/EBITDA ratio means the percentage of debt has increased relative to earnings and accordingly it means the company has more leverage. A decrease in FFO/Debt means a company has decreased its cash flow to service debt. Accordingly, the company's leverage has also increased.
[799] Exhibit J8.2.
[800] Exhibit K8.2, page 89.

allowed ROE is a cost and is not the same concept as a profit. The concepts are not interchangeable from a regulatory perspective”.[801]

787. CME incorrectly submits: “the metrics also disclose that the cost of that debt, the interest payments Enbridge Gas actually has to make to service that larger debt is more easily covered by Enbridge Gas’s earnings before interest and taxes, as well as funds from operations”.[802] This is not correct. Enbridge Gas’s interest coverage, all else being equal, will decrease as interest rates, and therefore the interest payments required to service the debt, increase. The rates included in the settlement agreement are well below the current rates at which Enbridge Gas is issuing debt. Given that the interest rates included in rates have been fixed by the Settlement Agreement, the more debt the Company is required to service, the higher the interest payments, and the worse the interest coverage metrics will be from 2024 to 2028. This will put further negative pressure on the already significant financial risk under which Enbridge Gas operates.

788. Finally, on the topic of credit ratings, it is important to note the OEB’s explicit findings on this issue in its 2009 Cost of Capital Report:

> Fifth, there was considerable discussion in the consultation about utility bond ratings. The ability of a utility to issue debt capital and maintain a credit rating were generally put forth by stakeholders in the consultation as a sufficient basis upon which to demonstrate that a particular equity cost of capital and deemed utility capital structure meet the capital attraction and financial integrity requirements of the FRS. The Board is of the view that utility bond metrics do not speak to the issue of whether a ROE determination meets the requirements of the FRS. The Board acknowledges that equity investors have, as the residual, net claimants of an enterprise, different requirements, and that bond ratings and bond credit metrics serve the explicit needs of bond investors and not necessarily those of equity investors.

[801] OEB Cost of Capital Report, page 20.
[802] CME Submission, page 42.

And:

> Finally, the Board questions whether the FRS has been met, and in particular, the capital attraction standard, by the mere fact that a utility invests sufficient capital to meet service quality and reliability obligations. Rather, the Board is of the view that the capital attraction standard, indeed the FRS in totality, will be met if the cost of capital determined by the Board is sufficient to attract capital on a long-term sustainable basis given the opportunity costs of capital.[803]

789. The above determinations by the OEB mean that the maintenance of current credit ratings, if achieved, is not sufficient evidence that the current equity ratio is sufficient to meet the fair return standard.

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

Dr. Hopkins' Proposed Detailed Study is not a FRS Prerequisite

791. Dr. Hopkins' Report reads as if Enbridge Gas has been sitting on its hands in respect of energy transition, yet his evidence under cross-examination confirms that this is not the case. First, it is appropriate to acknowledge that Dr. Hopkins admits that no entity has undertaken a study of the magnitude he recommends[804] which of course means that no regulator has required such a study as a prerequisite to undertaking an FRS analysis.

792. As noted earlier, the BCUC confirmed the appropriateness of using the 3 standards of the FRS and it specifically references the four elements that were considered to determine equity thickness:

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[803] EB-2009-0084, Report of the Board on the Cost of Capital for Ontario Regulated Utilities, page 20.
[804] Exhibit M8, page 40.

> When determining the cost of capital and the allowable return, the BCUC also stated that there are four key elements that the Panel considers: 1. The actual returns of a proxy group of peer utilities. 2. The business risks facing FEI and FBC, including how those risks may have changed since the last time the BCUC approved a cost of capital for those companies. 3. The credit ratings of FEI and FBC. 4. The results of various financial models that are designed to assess how the market prices risk and considers earnings in the evaluation of cost of capital. [805]

793. All of these elements were considered by Concentric in its report. The studies and analysis that Dr. Hopkins proposes would not assist, nor are they necessary in determining whether the FRS standards have been met.

794. A substantial portion of the Oral Hearing and a good portion of the cross examination of Dr. Hopkins by counsel related to the energy transition modelling and analysis evidence filed by the Company in this proceeding. As noted in AIC and elsewhere in this Reply Argument, the reports were commissioned by the Company for the purposes of evaluating future pathways and actions which could assist in mitigating some of the risks of energy transition. While under cross-examination, Dr. Hopkins admitted that future government policy could change the way consumers make choices and how utilities act[806] and that given the near term prospect of the government releasing new policy it seemed to Dr. Hopkins that the Company should wait for that and devise scenarios that work from there.[807] Dr. Hopkins also acknowledged that the electrification scenarios which Guidehouse considered are similar to the other scenarios he had seen elsewhere.[808] Enbridge Gas in fact did the very thing that Dr. Hopkins recommended in his oral evidence: “The point is always to use the best information available and incorporate it in as complete and even-handed a fashion as you can”[809]. So, the inference made by Dr. Hopkins that Enbridge Gas

[805] BCUC Decision.
[806] 4 Tr.158-159.
[807] 5 Tr.39.
[808] 5 Tr.7.
[809] 5 Tr.12.

did not act prudently and undertake appropriate studies and analysis based on the information available at the time is simply wrong.

795. What became even more apparent from Dr. Hopkins' oral testimony are the countless scenarios and variables in respect of space and water heating, electrification, fuel supply mix and consumer choice options which exist now, which may or may not exist in the future, and which will undoubtedly change due to government policy and technology. While it is one thing to suggest that credible degrees of probability can be assigned to multiple scenarios, the reliability of the same is only as good as the accuracy of the assumptions used, all of which are uncertain. What is certain, as noted by Concentric expert Mr. Coyne while under cross-examination by counsel to IGUA is that: "…the existence of the energy transition is not speculative. What is uncertain is how that will manifest in respect of Enbridge Gas's business."[810] Energy transition issues are live and will only become more apparent and certain with time and they could be greatly influenced by yet to be announced government policy and direction.

796. In fact, Dr. Hopkin's view is that government policy, ESG concerns, emission reductions targets do not present business and capital risks to Enbridge Gas.[811] His viewpoint is completely inconsistent with a similar set of issues that the BCUC found to have increased the business risk facing FEI:

a. "the Panel finds that FEI's overall business risk has increased since 2016. That increase is most significantly attributable to **the increase in political risks associated with the Energy Transition** and the cumulative effect of the perceived risks in Indigenous Rights and Engagement, energy price, and demand/market risks that could shift the risk to the shareholder if the utility is no longer viewed as an attractive investment by investors".[812]

[810] 8 Tr.81-82.
[811] Exhibit M8, pages 23-24.
[812] BCUC Decision.

797. Enbridge Gas does not deny the need for, and benefit of, additional study in the future. This was confirmed by Enbridge Gas's cost of capital and depreciation witnesses including Concentric witness Mr. Dane who stated:

> Dr. Hopkins recognizes that the energy transition to a decarbonized future is happening and will impact Enbridge Gas's business, but he believes that further scenario modelling of different futures for Enbridge Gas is necessary to better understand how these risks will unfold; this, despite the fact that Dr. Hopkins acknowledges that no other regulatory jurisdiction has done the type of analysis he is suggesting.
>
> We agree that further modelling of these risks will be beneficial, but just the fact that such work is necessary underscores the fundamental shift in the business environment for utilities such as Enbridge Gas, which is a clear distinction from the business environment 10 or even five years ago. An equity investor does not have to wait for the additional modelling suggested by Dr. Hopkins to understand that these risks exist, and there is no credible scenario identified where Enbridge Gas has less risk than it did in 2012 or in 2018[813]

798. What the Company submits is wrong with the position taken by IGUA and those in support is that they all are recommending a deferral of implementing appropriate tools and responses to energy transition to the next rebasing. Paradoxically, when it comes to using accelerated depreciation as a tool, Dr. Hopkins, in his report makes it clear that this is a tool that is being favorably considered in most of the leading jurisdictions that he surveyed. This is discussed further under Issue 15: Depreciation.

799. Importantly, while under cross-examination, Dr. Hopkins admitted that his proposed study is <u>not</u> a prerequisite or new threshold that must be completed before the OEB considers whether the FRS has been satisfied.[814] Aside from being legally correct, it also makes common sense. The Company submits that even if it commissioned a study which ticks off all of the boxes recommended by Dr. Hopkins, there would be no prospect of a consensus. Even at the outset of such a study, there is absolutely no prospect of an agreement with parties on the assumptions that the Company might

[813] 8 Tr.62-63.
[814] 5 Tr.153-154.

propose to use. There is even less prospect of a consensus being reached on the results that such a study generates. One side will always argue that the Company has not taken adequate steps to support electrification while the other side will object to any steps which increase rates. This Oral Hearing is proof of this reality and the certainty that one side or the other will allege that the Company did not act prudently no matter how extensive a modelling exercise it undertakes. Stated differently, does anyone believe that any report that is undertaken and filed by the Company will cause IGUA and others to conclude that an increase in equity thickness is now justified?

800. While Dr. Hopkins describes his hypothetical modelling exercise as simplistic[815], he purports that it can in effect avoid many of the future energy transition risks which the Company faces and which support an adjustment in equity thickness. Dr. Hopkins pointed to no jurisdiction where such an analysis exists and where the results have led to a decrease in equity thickness. He references no jurisdiction where energy transition issues for natural gas distributors have been resolved. Despite this, he makes the unsupported assertion that it is not reasonable to compensate Enbridge Gas's investors where certain costs could "hypothetically, be avoided in the future"[816] by the use of his proposed modelling.

801. This view is expressed even more clearly by IGUA's counsel in IGUA's opening statement. Mr. Mondrow stated:

> Dr. Asa Hopkins…presents conceptually a practical way to model potential gas utility futures in order to quantify risks and identify mitigating actions that, in the end, could avoid billions of dollars of unnecessary costs…It is IGUA's preliminary view that, until that work is done by Enbridge, the extent to which Enbridge's unmitigable business risk has changed cannot be properly evaluated and it would be unjust and unreasonable for customers to be required to pay now to compensate Enbridge Gas on the premise of greater unmitigated risk.[817]

[815] Exhibit M8, Attachment 4, page 7.
[816] Exhibit M8, page 47.
[817] 1 Tr.37-38.

802. This statement by IGUA's counsel is of course inconsistent with the legal requirements of the FRS and, as confirmed by Dr. Hopkins, it is not a prerequisite required before the OEB undertakes an FRS review. Enbridge Gas therefore submits that Dr. Hopkins' hypothetical modeling is a red herring. While future studies might consider undertaking aspects of what Dr. Hopkins proposes, that he opines such extensive modeling and scenario probability evaluation should be undertaken is proof of the fact that energy transition risks are new relative to the last time the capital structure of Enbridge Gas was reviewed. Indeed, following extensive questioning about the differences between then and now, Dr. Hopkins admitted that energy transition issues were absent in the OEB's 2013 decisions in respect of EGD and Union.[818] As well, it is noteworthy that the words "fair return standard" do not appear anywhere in Dr. Hopkins Report. Even more surprising, other than in its citations to Concentric's evidence, Dr. Cleary's Report similarly does not use the words "fair return standard".

Dominion Energy Transaction

803. In its submission, IGUA referenced the acquisition by Enbridge Inc. of three natural gas operating companies (East Ohio Gas Company (East Ohio), Questar Gas Company (Questar) and the Public Service Company of North Carolina (PSNC)) from Dominion Energy Inc. IGUA attached to its submission various press releases that referenced the transaction and the issuance of common shares by Enbridge Inc. which were used in part to finance the transaction.

804. While this transaction occurred after the end of the Oral Hearing, IGUA referred to the transaction as evidence of matters that support its position (i.e. Enbridge Gas's risk has not increased as the bought deal is evidence of Enbridge Gas's ability to raise capital). Enbridge Gas is compelled to respond for two important reasons. First, IGUA

[818] 5 Tr.150.

only provided half of the story. Second, the conclusions it asks the OEB to draw from the transactions are materially wrong.

805. What IGUA did not identify in its submission is that East Ohio, Questar and PSNC have respective authorized equity thicknesses of 51.3%, 51.1% and 51.6%. They have approved ROEs of 10.4%, 9.6% and 9.6% respectively.[819] These figures compare to Enbridge Gas's current 36% equity thickness, which Mr. Coyne has confirmed on the record is the lowest in North America, and an ROE of 9.36%. IGUA conveniently left out these very crucial facts.

806. In terms of the equity offering IGUA referenced, it was for shares in Enbridge Inc., not shares in Enbridge Gas. Although the funds will be used to finance the utility transaction, the share issuance was not contingent on the transactions. Investors in the equity offering own Enbridge Inc. shares, which has investments in natural gas transmission, natural gas distribution, renewable energy and liquids transportation businesses. In other words, the equity financing is evidence of Enbridge Inc.'s ability to attract equity capital and is not indicative of the capital attraction for Enbridge Gas.

807. Enbridge Gas will soon be competing for capital internally within the Enbridge Inc. family with its U.S. natural gas affiliates that have more favorable cost of capital metrics in relation to ROE and equity thickness. It should also be noted that combined,

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[819] U.S. Gas Utilities Acquisition Investor Presentation Sept 2023, Slide 7, https://www.enbridge.com/~/media/Enb/Documents/Investor-Relations/2023/2023_ENB_presentation_US_gas_utilities_acquisition_FINAL.pdf?rev=2f46826f47be4888b9d6feaa1c62b71f&hash=D8F9B1D65E5B8723647880F693C488CD ;
The Public Utilities Commission of Ohio Opinion and Order, Case No. 19-468-GA-ALT, December 30, 2020, https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A20L30B43655F00359 ;
State of North Carolina Utilities Commission Raleigh, Docket No. G-5, SUB 632/634, January 21, 2022, https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=e484199a-b88a-420f-8dfb-45c3d20a851f ; Public Service Commission of Utah, Docket No. 22-057-03, December 23, 2022, https://pscdocs.utah.gov/gas/22docs/2205703/3264942205703o12-23-2022.pdf

the three utilities proposed to be acquired from Dominion Energy Inc. are relatively equivalent in size to Enbridge Gas and therefore they serve as a good comparator.

808. This transaction is further proof that the submission by IGUA and Dr. Cleary that using U.S. comparators in the FRS analysis is inappropriate is simply wrong. Given the proposed acquisitions, Enbridge Gas will undoubtedly be compared to East Ohio, Quest Star, and PNCS and as the BCUC has stated in its recent findings "using North American data, consisting of a reasonable mix of both Canadian and US comparators, is superior to using either Canadian proxy groups or US proxy groups alone".[820]

809. In contrast, Concentric included East Ohio in its credit metrics analysis,[821] in its U.S. operating company proxy group,[822] and in its comparison of Enbridge Gas and proxy groups companies risk assessment.[823] LEI opined that it is appropriate to use a North American peer group of companies with comparable risk profiles because it deepens the sample size and provides a more meaningful reflection of the investors' opportunity space.[824] LEI then went on to include PSNC and Questar in its North American proxy group together with FEI.

810. Accordingly, given that Dr. Cleary's view on this is wrong, his analysis in regards to benchmarking should be given no weight. As the OEB determined as part of its 2009 Cost of Capital Report where it stated that U.S. utilities are appropriate comparators to be used in a FRS review,[825] including U.S. utilities in the exercise remains appropriate and is even more necessary today.

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820 BCUC Decision, page 135.
821 Exhibit 5, Tab 3, Schedule 1, Attachment 1, page 145.
822 Ibid, pages 149 and 161.
823 Ibid, page 152.
824 Exhibit M2, page 44.
825 EB-2009-0084, Report of the Board on the Cost of Capital for Ontario Regulated Utilities, pages 21-23.

LEI did not complete an Appropriate FRS Analysis

811. While OEB staff support LEI's conclusion that there has been a sufficient change to Enbridge Gas's business risk to warrant undertaking a FRS review, OEB staff did not address in its submission the weaknesses of LEI's approach which were made apparent and confirmed by LEI while under cross-examination. Before turning to these specific failings, it should be noted that LEI admits that there were no energy transition discussions in the 2012 proceedings involving EGD and Union[826] and that there has certainly been an increase in the energy transition risk between 2012 and 2022.[827] Indeed, LEI specifically admitted that the energy transition risks that warrant the FRS review and the increase in equity thickness have taken place in the last 5 to 10 years[828]. This evidence is completely contrary to the views of Dr. Cleary and Dr. Hopkins. But LEI's views in this regard should not be surprising given the positions taken by the parties in this proceeding. Energy transition poses a real risk to the natural gas distribution business.

812. While LEI admitted that it was appropriate to undertake a review of Canadian and U.S. comparable utilities, as became clear from its responses to cross-examination questions, there is absolutely no evidence, either in LEI's Report or in its oral evidence, that indicates the list of U.S. comparators that it identified and their metrics had any influence whatsoever on the recommendation by LEI for a 38% equity thickness for the Company. Upon being asked under cross examination to review the OEB's decision in 2012[829], LEI acknowledged that the OEB did not undertake a full FRS review in the 2012 proceedings. This means that the OEB did not undertake a comparable investment standard review at that time, and it did not look at or consider any U.S. comparators.[830] Unfortunately, this fact was lost on LEI for the purposes of

[826] EB-2011-0210 and EB-2011-0354.
[827] 9 Tr.140.
[828] 9 Tr.154.
[829] EB-2011-0210 and EB-2011-0354.
[830] 9 Tr.148.

its report. This is confirmed by the following statement in its report referencing the U.S. companies it identified in its North American proxy group:

> Relative to U.S. companies, while Canadian companies have lower average equity ratios and lower average ROEs, it is notable that the US companies had similar equity ratios averaging more than 50% in 2011 and higher ROE averaging 9.9% in 2011.[831]

813. To be clear, the references to 2011 relate to the Union and EGD proceedings in 2012.[832] What the above clearly indicates is that because LEI found the differences in equity thickness and ROEs to be about the same now as they were in 2011, it viewed the difference as being of no significance. LEI therefore did not feel it was necessary to then actually compare the allowed equity ratios of the U.S. comparators to Enbridge Gas. There is absolutely no indication in the report or in LEI's oral evidence that it utilized the U.S. comparator groups for the purposes of its recommendation to increase the equity thickness to 38%. This is plainly wrong for a number of reasons.

814. First, as LEI admitted, the OEB did not undertake a comparable investment standard review in the 2012 proceedings. It is therefore a mistake to assume that the difference between equity thickness and ROEs between Canadian and U.S. companies was considered at all by the OEB. It was not undertaken because the OEB determined that the threshold test had not been satisfied by either EGD or Union.

815. Second, a comparable investment standard requires more than a comparison of the changes in the "spreads" between Canadian and U.S. utilities between then and now. LEI should have asked why the differences in equity thickness existed then and are they appropriate now. LEI should have undertaken a more thorough analysis along the lines of what Concentric did. LEI did not undertake such an analysis because the differences as it viewed matters, between then and now appeared about the same. The fact is that even this high-level observation is not accurate. The customer

[831] Exhibit M2, page 45.
[832] EB-2011-0210 and EB-2011-0354.

weighted average of the equity thickness for U.S. utilities increased by approximately 0.5%.[833] LEI should have recognized in its report the fact that there was no directional change in the weighted average for Canadian companies (until the recent BCUC decision). The Company submits this should have been a further consideration LEI examined for the purposes of its recommendation, namely that the Canadian utilities were falling further behind U.S. utilities in terms of authorized equity thicknesses. In the end, LEI did not delve into the reasons why U.S. utilities have much higher equity thicknesses. The spread now seemed the same as it was when the OEB last looked at cost of capital issues and this was apparently good enough for LEI. Enbridge Gas submits that this is not evidence of a proper FRS analysis as is required by law.

816. LEI was given every opportunity to explain at the Oral Hearing how it utilized the U.S. comparators for the purposes of its equity thickness recommendation for Enbridge Gas. None of the LEI witnesses offered any explanation or stated how the U.S. comparator group was at all impactful (whether helpful or hurtful) in terms of its recommendation. LEI's Report should have stated why the metrics from U.S. utilities were or were not relevant. There is simply nothing. The only conclusion is that U.S. comparable utilities were simply disregarded. Had LEI given any consideration to the U.S comparators, the Company submits that it would have caused LEI to indicate that directionally, the increase in equity thickness should be materially higher than 38%.

817. The same is also true in respect of electricity distributors in Ontario. While LEI admitted that the magnitude of risk is higher for natural gas distributors than for electric LDCs[834], it similarly took the position that because the difference in the equity ratios existed back in 2011 when the OEB in the 2012 proceedings last looked at cost of capital issues, that it did not need to consider whether the difference now warranted any impact on its recommendation in respect of Enbridge Gas. LEI witnesses were

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[833] 9 Tr.152; Exhibit M2, page 46.
[834] 9 Tr.158.

asked, while under cross examination, to take the OEB to that place in its evidence where it discussed the relevance of the difference between the less risky electric LDCs and Enbridge Gas and the only statement that could be identified is the last bullet on one of the last pages of the report where LEI states that:[835]

> The equity ratio for Ontario electricity distribution companies has consistently been higher than Enbridge Gas (and its predecessor companies, EGD and Union Gas) and was so in both 2012 and 2017.[836]

818. Once again, LEI did not give any reasons as to why or why not the equity thickness of electric LDCs at 40% is or is not relevant. LEI's analysis is therefore also incomplete in this respect and does not satisfy the FRS.

819. As discussed above, LEI included a customer weighted average table in which it identified appropriate Canadian comparable operating companies.[837] The table in its report originally included Centra Gas Manitoba. This generated a weighted average equity thickness result of 37.2%.[838]

820. LEI was reminded in an interrogatory that Centra Gas Manitoba is owned by Manitoba Hydro and in turn the Government of Manitoba and that it was therefore not an appropriate comparator. LEI rightly agreed and revised the customer weighted average to exclude Centra Gas Manitoba. This raised the weighted average to 38%.[839] This is the equity ratio figure that LEI recommends for Enbridge Gas.

821. Importantly, as noted earlier in this Reply Argument, with the recent BCUC decision in respect of FEI and the increase in its equity thickness from 38.5% to 45%, it is appropriate to once again revise LEI's weighted average table as FEI is a large

[835] 9 Tr.157-158.
[836] Exhibit M2, page 49.
[837] Ibid, Figure 30, page 46.
[838] Ibid.
[839] 9 Tr.152.

Canadian natural gas distributor and is acknowledged by all cost of capital experts, Concentric, LEI and Dr. Cleary, as being an appropriate comparator. Using the same weighted averaging, the revised customer weighted average for the Canadian utilities is now 40.5%. Accordingly, the Company submits that by using LEI's own analysis (even with its failings), Enbridge Gas's equity thickness should be no less than 40.5%.

822. Finally, one minor point. During cross-examination, LEI stuck to its view that Enbridge Gas had the opportunity to seek a change to its equity thickness as part of its MAADs Application.[840] OEB staff in its submission concurred with Enbridge Gas (disagreeing with LEI) stating that it would not have been appropriate to undertake a review of the Company's business risk at that time for three valid reasons. Accordingly, OEB staff do not submit that the appropriate time period to assess business risk is between the MAADs Application and today. In any event, it is irrelevant given LEI's agreement that the changes in business risk warranting an FRS review have occurred in the last five or more years.

I. Deferral & Variance Accounts (Exhibit 9)

<u>Deferral and Variance Accounts</u>

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

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

<u>Summary and Relief Sought</u>

825. In AIC, Enbridge Gas included the following requests for establishment or continuation of deferral and variance accounts:

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[840] EB-2017-0306/0307.

a) Establishment of the VOLUVAR and PREPVA, effective January 1, 2024.

b) Continuation of the Short-term Storage and Other Balancing Services Account on an interim basis until such time that the outcomes of the OEB's decision in Phase 2 and/or Phase 3 related to storage issues are known.

826. Other participants in this proceeding argue that it is either inappropriate or premature to include protection against weather variances in the VOLUVAR. Enbridge Gas does not agree. Weather variances are out of the Company’s control. They cause impacts that can affect both customers and the Company. History shows that those impacts are relatively symmetrical, but with significant consequences in single years. It is appropriate, therefore, that the VOLUVAR include both average use and weather variance protection for both Enbridge Gas and customers. In the event that the OEB does not agree, Enbridge Gas notes that virtually every party supports having Enbridge Gas establish a VOLUVAR that would operate in a manner that is comparable to the existing Average Use True Up Variance Account (AUTUVA) and Normalized Average Consumption (NAC) Account. It should be noted, though, that the Company’s proposal to increase equity thickness takes account of the protection of a VOLUVAR with weather variances – if that is not approved, then the Company’s risk is actually higher and that should be taken into account in the determination of the appropriate equity thickness.

827. As set out throughout this Reply Argument, Enbridge Gas is requesting the establishment of two additional new deferral and variance accounts:

a) *OEB Directive Deferral Account (OEBDDA)* – This account will record the incremental costs incurred by Enbridge Gas to respond to OEB directives or requirements from this proceeding. This would include directives for new or further proceedings, studies and/or reports to address energy transition related issues, as well as required work to develop and implement updated internal processes (including incremental TIS costs and costs from incremental internal or contracted resources) required to address the OEB’s directions in this proceeding and in follow-on proceedings taking place during the IR term. None of these costs are in base rates, as the Company’s O&M budget was settled, with a $50 million reduction, based on the filed budget which did not contemplate further directives and requirements during the IR term.

b) *St. Laurent Project Variance Account (SLPVA)* – As explained earlier, Enbridge Gas agrees with OEB staff that it would be fair to use the same levelized rate treatment and cost tracking for both the PREP and the St. Laurent project. The SLPVA would be established using the same parameters and approach as the PREPVA.

828. Additionally, OEB staff propose that Enbridge Gas should establish a “Potential Change to IFRS Deferral Account”.[841] This account would record the revenue requirement impact of changing to IFRS should the Company’s current exemption from IFRS (which allows US GAAP to be used) not be renewed. Enbridge Gas supports this request, but notes that the account should also record incremental administrative and implementation costs from any transition to IFRS. This is consistent with the OEB’s direction in the Transition to International Financial Reporting Standard Report, where the OEB indicated that it would “establish a deferral account for distributors for incremental one-time administrative costs related to the transition to IFRS”.[842]

829. Enbridge Gas is not proposing the following additional new deferral and variance accounts addressed in submissions from OEB staff and intervenors.

a) *Property Dispositions Deferral Account*– Enbridge Gas submits that proceeds of property dispositions in years from 2025 to 2028 are appropriately addressed through ESM, like other utility gains and losses. For 2024, no ESM is appropriate, and the potential gains/losses from the one forecast 2024 property disposition is small such that no account is needed.[843]

[841] OEB staff Submission, page 127.
[842] EB-2008-0408 Report of the Board – Transition to International Financial Reporting Standards, July 28, 2009, page 27.
[843] Starting at paragraph 909.

b) *LTC Variance Account* – Enbridge Gas submits that no supplementary variance account treatment is required for LTC project revenue requirement, other than as addressed in the PREPVA and the SLPVA.[844]

c) *2023 Capex asymmetrical variance account* – Enbridge Gas submits that it is more efficient, and more appropriate, to address any 2024 opening rate base and revenue requirement impacts from variances from forecast by way of a symmetrical true-up in the Phase 2 Rate Order. No variance account is needed.[845]

d) *EDIMP Variance Account for capital saving* – Enbridge Gas submits that no change to the current EDIMP Variance Account is required.[846]

e) *2024 ESMDA* – Enbridge Gas submits that no ESM is appropriate or required for 2024. Therefore, no corresponding deferral account is needed.[847]

830. As these items are addressed in other parts of this Reply Argument, no further discussion is included in this section of Reply Argument.

831. There are two deferral and variance accounts for which Enbridge Gas is requesting clearance in this Oral Hearing.

832. The credit balance in the TVDA relates to the CCA benefits associated with the integration capital projects. As already stated, Enbridge Gas submits that the remaining undepreciated capital costs of the integration capital projects should be included in 2024 opening rate base. Taking into account the OEB's "benefits follow costs" principle, customers (given that they will be paying for these assets starting in 2024) should receive the CCA benefit recorded in the TVDA.[848]

[844] See paragraph 516.
[845] See paragraph 221.
[846] See paragraph 431.
[847] See paragraph 935.
[848] AIC, page 254, and associated references.

833. Enbridge Gas submits that in the event that the OEB does not agree with Enbridge Gas and disallows some (or all) the undepreciated costs of the integration capital projects from 2024 rate base, then Enbridge Gas should receive the portion of the credit balance in the TVDA related to the disallowed costs.[849]

834. All parties who made submissions on TVDA clearance agree with the Enbridge Gas position that the balance be directed in proportion to the treatment of the underlying integration capital costs. Enbridge Gas has no further submissions on this item.

835. Enbridge Gas requests that the OEB approve the clearance of the balance in the APCDA as filed.

836. The contentious item in the APCDA is the Union pension receivable amount (reflecting unamortized actuarial gains and losses and past service costs). Enbridge Gas submits that these are amounts that are properly included in the APCDA, and properly recoverable from customers. The amounts sought for recovery were part of the Union balance sheet up until the time that EGD and Union amalgamated. At that time, US GAAP accounting rules allowed that the Union pension receivable could be placed in a regulatory account for future recovery. Enbridge Gas included the pension receivable amount in the APCDA and drew it down between 2019 and 2023. The remaining balance is appropriately collectible from customers, just as would have been the case had there been no amalgamation between EGD and Union.

837. As described in detail below, the purchase price paid to Spectra in the merger transaction did not factor in the Union pension receivable amount in a manner that would suggest that the amount is settled. Instead, the Union pension receivable amount was on both the Enbridge Inc. and Union balance sheets at historical

[849] AIC, page 254.

unamortized cost immediately before the amalgamation of Union and EGD and was then transferred to the APCDA at the same cost.

838. It cannot fairly be said that Enbridge Gas has already recovered some or all of the remaining Union pension receivable through rates. The Company has continued to recognize the same accrual-based pension expense (as provided by Mercer annually) to determine the remaining pension receivable amount as it is drawn down over time. Recognizing a different level of pension expense/amortization would have been inconsistent with Enbridge Gas's historical pension accounting methodology which underpinned rates. As such, recognizing a different level of expense would also have been inconsistent with incentive regulation (IR) principles that require costs to be recognized in a manner consistent with those used to determine rates, and would have required the same amount to be captured/recognized in the APCDA. Moreover, linking specific revenues to specific costs is not consistent with the IR principle that revenues and costs are decoupled during an IR term.

Submissions by Other Parties

839. The submissions about Enbridge Gas's proposals for the establishment of new accounts were primarily focused on the VOLUVAR request. As already noted, OEB staff and some intervenors also made their own proposals about new accounts – those proposals are summarized in paragraph 829 above.

840. ED supports the Company's proposal for including weather variance impacts in the VOLUVAR.[850] ED's view is that it is better to help Enbridge Gas mitigate the risks that it faces, but cannot control, rather than increasing ROE or equity thickness.

[850] ED Submission, page 53.

841. Generally speaking, OEB staff and parties support the continuation of a volume variance account as has existed for many years (through the AUTUVA and NAC), but do not support including variance impacts related to weather in the account.[851]

842. PP suggests that if the VOLUVAR is approved, the OEB should require that Enbridge Gas provide information about annual balances due to factors such as DSM, declining customer use, fuel switching and building code and other regulatory changes. PP further submits that Enbridge Gas should include the results of the relevant DSM audit in the clearance request.[852]

843. The only party to oppose the establishment of a VOLUVAR excluding weather variance impacts is FRPO.[853] FRPO suggests that there is insufficient evidence to describe how a harmonized average use true up account would operate and submits that this should be considered in a later phase of the proceeding.

844. The submissions about the clearance of deferral and variance accounts focused on the Union pension receivable amount in the APCDA.

845. OEB staff[854], along with LPMA[855], support the clearance of the Union pension receivable amount, with adjustments to the balance. EP[856] and QMA[857] indicate that they support the OEB staff Submissions.

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[851] See, for example, OEB staff Submission, pages 121-122; CCC Submission, pages 36-37; CME Submission, page 50; LPMA Submission, page 38; SEC Submission, pages 103-104; and VECC Submission, page 30.
[852] PP Submission, page 55.
[853] FRPO Submission, page 21.
[854] OEB staff Submission, pages 123-127.
[855] LPMA Submission, page 41.
[856] EP Submission, page 19.
[857] QMA Submission, page 7.

846. OEB staff include a helpful summary of the relevant facts, events and accounting entries relevant to the issue of the Union pension receivable. This presentation makes clear that the relevant balance was always included on the Union (and then Enbridge Gas) balance sheet as a receivable amount.[858]

847. On the question of whether the merger of Enbridge Inc. and Spectra (the Merger), and the subsequent amalgamation of EGD and Union (the Amalgamation), impacted the recoverability of past amounts, OEB staff agree with Enbridge Gas that this is not determinative, stating the following:

> 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. …. 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.[859]

848. OEB staff indicate, however, that the $156 million requested for disposition should be reduced by $80.2 million to $75.8 million, to recognize the amounts actually received by Enbridge Gas for Union pension costs during the deferred rebasing term. The argument made is that Enbridge Gas received $135.5 million in revenues associated with Union pension costs, but only recognized the actual amount of amortization of actuarial gains/losses, which was $80.2 million less.[860] As explained below, this position is untenable, as it ignores the basis on which Enbridge Gas's pension accounting is done, as well as the fundamental premise of incentive regulation where revenues and costs are decoupled beyond the cost of service year.

[858] OEB staff Submission, pages 124-125, including Table 21.
[859] Ibid, page 125.
[860] Ibid, pages 126-127.

849. Clearance of the Union pension receivable amount is opposed by CME[861], FRPO[862], OGVG[863], SEC[864] and VECC[865]. Some of these parties say it would be a "windfall" if Enbridge Gas recovers this amount.[866] As described later, Enbridge Gas says that the opposite is true.

850. There are two main bases for the position of the opposing parties.

851. These parties assert that as part of the Enbridge/Spectra Merger, a decision was made to attribute the Union pension receivable amount to goodwill and this means that it became unrecoverable and the (subsequent) purchase price allocation implies that Enbridge Inc. recovered the amount from proceeds of the transaction.[867]

852. These parties further assert that Enbridge Gas has already fully recovered the amount of the Union pension receivable through rates over the 2013 to 2024 period. The assertion is similar to OEB staff's position, except that it includes the 2013 to 2018 period, and applies annual price cap adjustments to increase the revenue amount received each year.[868]

853. OGVG and SEC also respond to the OEB staff Submission, arguing that over the 2019 to 2023 deferred rebasing term Enbridge Gas should be considered to have received revenues of $168 million related to Union pension costs. The different

[861] CME Submission, pages 48-50.
[862] FRPO Submission, page 22.
[863] OGVG Submission, pages 15-17.
[864] SEC Submission, pages 104-110.
[865] VECC Submission, page 31.
[866] CME Submission, page 48; and SEC Submission, pages 104 and 106.
[867] CME Submission, page 49. See also OGVG Submission, page 15; SEC Submission, pages 104-107; and VECC Submission, page 31.
[868] OGVG Submission, page 16 (and Exhibit K15.3); and SEC Submission, pages 107-109.

number (compared to the OEB staff $135 million) is comprised of a slightly higher annual amount, plus the addition of annual price cap adjustments.[869]

854. SEC advances several additional arguments. SEC argues that it would be impermissible retroactive ratemaking to permit recovery, asserting that the amounts at issue had been "written off" before they were recorded in the APCDA.[870] SEC further asserts that any deferred tax benefit associated with the Union pension receivable should be credited to ratepayers, and requests that the Company address this item in this Reply Argument.[871] Finally, SEC submits that if the OEB permits recovery of the Union pension receivable amount, this should be done over time, as has been the approach used for the Transition Impact of Accounting Changes Deferral Account (TIACDA).[872]

855. The only other area of comment about the APCDA is the OEB staff Submission[873], supported by LPMA[874], about the overhead capitalization sub-account. OEB staff submits that if the OEB accepts OEB staff's recommendation to calculate Operation Costs capitalization rates using a three-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.

[869] OGVG Submission, pages 16-17.
[870] SEC Submission, page 107.
[871] Ibid, pages 109-110.
[872] Ibid, page 110.
[873] OEB staff Submission, pages 123-124.
[874] LPMA Submission, page 41.

Enbridge Gas Response to Other Parties' Submissions

856. As noted, there are two areas of focus for the outstanding deferral and variance account issues: a) Establishment of New Deferral and Variance Accounts; and b) Clearance of the APCDA.[875] Each is addressed below.

Establishment of New Deferral and Variance Accounts

857. There is no opposition to the Company's proposal to continue the Short-term Storage and Other Balancing Services Account on an interim basis until such time that the outcomes of the OEB's decision in Phase 2 and/or Phase 3 related to storage issues are known.

858. In relation to the VOLUVAR, Enbridge Gas believes that it is appropriate that both the Company and customers have protection against the impacts of weather. This is not a factor that the utility can control. The evidence shows that over time the impacts are relatively symmetrical – customers would benefit from variance account protection some years, and the Company would benefit other years, and the total benefits would be fairly even.[876] That being said, the impacts in any one year can be significant, so the as-proposed VOLUVAR would provide appropriate protection.

859. Enbridge Gas acknowledges that at this time there is broad opposition to including weather variance impacts in the VOLUVAR. Parties have linked this question to the Company's Straight Fixed Variable with Demand (SFVD) rates proposal, which will be considered in Phase 3. The linkage is around the fact that the SFVD proposal would minimize the impact of weather and volume impacts on distribution rates. Enbridge Gas does not believe that a decision on including weather variances in a VOLUVAR is

[875] The Company's position in relation to the clearance of the TVDA is described in the Overview above. As there is no opposition to this position, no further discussion is included.
[876] 15 Tr.13-14 and Exhibit JT3.27.

dependent on the determination on the SFVD proposal. The OEB can approve the VOLUVAR as proposed now and consider the SFVD proposal in Phase 3.

860. In the event that the OEB does not approve the VOLUVAR as proposed by Enbridge Gas (with weather variance treatment), then Enbridge Gas agrees with the position of virtually all interested participants that the OEB should establish a VOLUVAR that is substantially similar to the existing AUTUVA and NAC Accounts.

861. Enbridge Gas disputes the submission from FRPO that there is insufficient evidence to approve this modified VOLUVAR. Given that the account would be consistent with accounts that have existed for many years, it can be established on a combined basis for Enbridge Gas. If there are details to determine in terms of the description and mechanics of the account, these can be addressed through the Draft Rate Order process. Enbridge Gas agrees with OEB staff[877] that the Company will file a draft Accounting Order for this account that will accompany the Draft Rate Order.

862. Enbridge Gas does not agree with PP that further reporting requirements are necessary for the VOLUVAR. The Company already provides details with the AUTUVA and NAC about the factors influencing variances. It is not possible to include the relevant DSM audit reports as proposed by PP, because those audits are typically not completed at the time that Enbridge Gas files its deferral accounts clearance application (the DSM audits take more time than the deferrals proceeding).

863. As noted, Enbridge Gas agrees with the proposal from OEB staff that the OEB should establish a Potential Change to IFRS Deferral Account.[878] The Company acknowledges that its IFRS exemption expires during the 2025 to 2028 IR term. While there remains uncertainty surrounding the timing of International Accounting

[877] OEB staff Submission, page 122.
[878] Ibid, page 127.

Standards Board (IASB) implementation of a final IFRS standard for regulated entities, it is possible that Enbridge Gas could be required to transition to IFRS during the IR term. With this in mind, Enbridge Gas agrees that it is appropriate to establish the proposed account that will record the revenue requirement impact of changing to IFRS. Enbridge Gas submits that the account should also record incremental administrative and implementation costs from any transition to IFRS.[879] If approved, Enbridge Gas would provide a Draft Accounting Order as part of the Draft Rate Order process for Phase 1.

864. As summarized above in paragraph 827, in other parts of this Reply Argument Enbridge Gas has proposed or agreed about the appropriateness of new deferral and variance accounts that were not requested in the Application. In the subparagraphs below, Enbridge Gas provides some details about each of these accounts. Further details would be provided within the Draft Accounting Order that will be part of the Draft Rate Order package reflecting the Phase 1 Decision.

a) *OEB Directive Deferral Account (OEBDDA)* – This account will record the incremental costs incurred by Enbridge Gas to respond to OEB directives or requirements from this proceeding. This would include directives for new or further proceedings, studies and/or reports to address energy transition related issues, as well as required work to develop and implement updated internal processes (including incremental TIS costs and costs from incremental internal or contracted resources) required to address the OEB's directions in this proceeding and in follow-on proceedings taking place during the IR term. The Company submits that this new account would meet the OEB's eligibility requirements for establishment of a new deferral/variance account (causation, materiality and prudence).[880] If approved, Enbridge Gas would provide a Draft Accounting Order as part of the Draft Rate Order process for Phase 1. The scope of the account would include new proceedings and studies and reports beyond what was known and contemplated when the Settlement Agreement was completed. This would include the generic hearing about customer

[879] As noted above, this is consistent with the OEB's direction in its 2009 Report on the Transition to IFRS.
[880] The OEB's Filing Requirements and eligibility requirements for new accounts for Enbridge Gas are described at Exhibit 9, Tab 1, Schedule 3, pages 1-2.

attachment policies, as well as other items directed by the OEB to be completed during the IR term, beyond what the Company is proposing.

b) *St. Laurent Project Variance Account (SLPVA)* – As explained earlier, Enbridge Gas agrees with OEB staff that it would be fair to use the same levelized rate treatment and cost tracking for both the PREP and the St. Laurent project. The SLPVA would be established using the same parameters and approach as the PREPVA, and would be in place for 2024 and the next IR term. Disposition of any cumulative balance will be requested following the conclusion of the 2025 to 2028 IR term.

Clearance of the APCDA

865. Enbridge Gas submits that the OEB should approve the clearance of the full balance in the APCDA, without adjustments. This would include recovery of the $156 million Union pension receivable amount. Enbridge Gas is open to recovering this pension receivable amount over time, as was done in the past with the EGD TIACDA. Enbridge Gas proposes that it would be appropriate for the balance to be collected over 5 years.

866. As recognized in AIC, the facts underlying this topic are complex. Enbridge Gas summarized the key facts in AIC[881], and will try not to repeat itself. For context, though, the Company relies on both AIC and this Reply Argument together to provide a complete answer to the positions advanced by those who object to recovery of the Union pension receivable amount.

867. While Enbridge Gas appreciates that OEB staff and several parties support the recoverability of half of the Union pension receivable amount, the Company maintains that the amount sought for clearance is the proper amount. This is discussed below.

[881] See AIC, pages 245-251 and supporting evidentiary references.

i) The Union pension receivable amount was not settled by the Merger

868. As summarized above, a main reason why some parties object to the recovery of the Union pension receivable amount is their position that the amount was already “paid off” through the Enbridge/Spectra Merger. That is simply not true.

869. The Merger transaction price and related valuation of shares as part of the transaction did not involve a detailed review of the individual assets, liabilities and equity balances of each of the Spectra entities including Union. The transaction did not involve the purchase of Spectra assets outright but was based on a valuation methodology (i.e. Discounted Cash Flow or DCF). This means that the purchase price that was determined was independent of any of the individual assets of Spectra entities, it was determined on a DCF basis factoring in other considerations for market comparatives and EBITDA multiples (among other factors) that would have been available for the Spectra organization at the time. Enbridge Gas acknowledges that this is not something that was explored at the Oral Hearing, or in discovery, but the Company submits that there is no conclusive evidence that the Union pension receivable was accounted for in the purchase price.

870. It should be recalled that the purchase price associated with the Merger was $37 billion. The enterprise value of the combined entities was $165 billion.[882] With this in mind, it should be clear that it would be a stretch to suggest that a single balance of approximately $250 million was specifically factored into the price per share paid in the transaction.

871. SEC’s suggestion that “[t]he Union Pre-2017 Actuarial Losses were effectively recovered as a reduction in the price of the transaction” [883] is simply not accurate. The purchase price was set as described above. The allocation of identifiable assets

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[882] Enbridge press release, September 16, 2016, found at page 19 of Exhibit K15.2.
[883] SEC Submission, page 106.

against the purchase price occurred after the close of the transaction[884], which can only impact the characterization of how the price relates to assets, including the residual amount allocated to goodwill. It does not impact the purchase price itself.

872. Enbridge Gas therefore specifically disagrees that there has been an admission that Enbridge Inc. already accounted for the unamortized losses (Union pension receivable) in the purchase price paid to acquire Union Gas Limited (or Spectra).[885] Mr. Vinagre's testimony was that when the purchase price adjustment process took place (after the Merger transaction), the Union pension receivable amount was initially allocated to goodwill on the Enbridge Inc. balance sheet, but subsequently this was re-assessed.[886]

873. Enbridge Gas reiterates its evidence from examination in chief that the initial Enbridge Inc. purchase price allocation that failed to recognize the Union pension receivable balance as recoverable, and therefore as a known asset, was an error. This error was identified and corrected, as allowed under US GAAP (Business Combinations).[887] The correction and restatement was effective before the Amalgamation.

874. With the correction made, the Union pension receivable amount was recognized on both the Enbridge Inc. and Union balance sheets as a receivable. As explained in testimony, the Union pension receivable amount had always been recognized on the Union balance sheet.[888] The Merger had no impact – before and after the Merger, the amount was included on the Union balance sheet. And Union continued to draw down the amount in a manner and quantum identical to the pre-amalgamation pension accounting basis (i.e. the methodology for determining the accrual based expense

[884] 15 Tr.78-78.
[885] In response to OGVG Submission, page 15.
[886] 15 Tr.78-78.
[887] 15 Tr.10-11. See also Exhibit K15.1.
[888] 15 Tr.10. See also Exhibit K15.1.

was employed consistently). All of this is set out in an annotated timeline and an annotated balance sheet format in Exhibit K15.1 – Enbridge Gas believes that this is a very important summary for the OEB to review in determining this issue.

875. These facts support OEB staff's Submission that the financial reporting aspect of the questions asked/issues raised by other parties on this issue of recoverability of the Union pension receivable may not be relevant[889].

876. Enbridge Gas disputes that Enbridge Inc. (or Enbridge Gas) benefited from the consideration of the Union pension receivable amount in the purchase price paid to Spectra and that recovery of the remaining Union pension receivable from customers would be a "windfall" or a double payment. To the contrary, if customers are able to avoid paying for this cost based on a mistaken theory that the Merger price extinguished the obligation, then it is customers who receive a windfall. In the ordinary course, there is no debate that customers pay towards a utility's pension costs (calculated on an accrual basis). The outcome argued by some parties would avoid that obligation.

877. Simply stated, neither the Merger nor the Amalgamation absolved customers from their obligation to pay the Union pension receivable. This is neither unfair, nor a windfall, as can be seen in the fact that Enbridge Gas would similarly not have absolved itself of its corresponding obligation had the balance been a net gain or payable back to customers before the Merger. In fact, Enbridge Gas has brought forward an EGD rate zone pension transition payable balance of $255 million in this proceeding for refund to customers, and that benefit is being credited to customers.[890] The credit to customers is premised on the expected consistent recovery of pension costs by way of accrual based pension costs in rates, as opposed to cash based

[889] OEB staff Submission, page 125.
[890] See AIC, page 252.

amounts, which also supports the recovery of the Union pension receivable balance. Parties have agreed that it is appropriate for customers to receive the benefit of this payable amount.[891]

878. Enbridge Gas reiterates, and OEB staff acknowledged, that the nature and substance of the incurred cost (pension losses incurred) did not and has not changed either as a result of the Merger or the Amalgamation.[892] The Merger transaction and the associated initial purchase price allocation determined by Enbridge Inc. in no way changed the fact that Enbridge Gas is required to fund the pension plans on a cash basis, and that over time the accrual-based pension expense recovered in rates should equal the cash basis. The balances are, and continue to be, recoverable in the same manner as pension expense/costs have been recovered since 2013, through the initial IR term, and then through the deferred rebasing term and then going forward, in accordance with accrual-based pension accounting.

879. As described in testimony and AIC, as a result of the Amalgamation, Enbridge Gas was required under US GAAP to adopt and reflect the accounting policy change that had previously been recognized by its parent, Enbridge Inc. The treatment on the Enbridge Inc. balance sheet of the Union pension receivable was required to be "pushed down" to Enbridge Gas.[893]

880. Enbridge Gas recognized the residual pre-Merger unamortized net losses of Union within the APCDA as a result of this accounting policy change. Inclusion of this $211.3 million balance in the APCDA and subsequent annual amortization, or drawdown, nullified the revenue requirement impact that would have existed given the absence of

[891] See AIC, page 251, and associated references.
[892] See AIC, pages 250-251.
[893] Ibid, page 249.

its amortization within the new pension expense basis. Absent the Amalgamation, Union would have continued to collect this receivable over time.[894]

ii) There is no retroactive ratemaking

881. These circumstances demonstrate, contrary to the submissions from SEC[895], that there is no “retroactive ratemaking”. The Union pension receivable (as drawn down over time), existed on the Union balance sheet until Amalgamation. At the time of Amalgamation, the corresponding amount included on the Enbridge Inc. balance sheet was pushed down to Enbridge Gas, recognized as a regulatory asset and was ultimately recorded in the APCDA. This allowed for continued draw-down during the deferred rebasing term, and again as noted nullified the revenue requirement impacts to customers.

iii) Additional amounts recovered in rates should not be applied as reductions

882. Enbridge Gas disputes the position advanced by OEB staff and some intervenors that the Union pension receivable should be adjusted by amounts recovered through rates each year. There are two problems with this position. First, it is at odds with the way Union’s and subsequently Enbridge Gas's accrual-based costs have consistently been determined (since and even before 2013). Second, it fails to recognize the decoupling between base year costs and utility rates and revenues that occurs over an IR term and over a deferred rebasing term.

883. Enbridge Gas has consistently followed the methodology for determining accrual-based pension costs, underpinning Union's 2013 OEB-approved rates, in order to draw down the pension receivable balance each year. Just because there was a specific amount included in Union’s 2013 base rates related to pension costs does not

[894] See AIC, page 249.
[895] SEC Submission, page 107.

mean that the corresponding amount is or should notionally be applied to accrual-based pension costs each year.[896]

884. As explained by Enbridge Gas's expert, Ben Ukonga from Mercer, the basis upon which Enbridge Gas has been amortizing amounts to drawdown the APCDA asset since 2017 are calculated by Mercer with the amortization amount updated annually by Mercer based on changes to Enbridge Gas's actuarial valuation. In accordance with the accounting standard, cumulative unrecognized gains and losses are charged to the income statement each year through the net periodic benefit cost.[897]

885. The argument that Enbridge Gas should have allocated all of the revenues associated with this particular component of Union pension costs (as determined in 2013 base rates) to reduce the Union pension receivable is not only at odds with the way that pension accounting is performed, it is also at odds with the principles of incentive regulation.

886. As explained in the OEB's Renewed Regulatory Framework Report[898]:

a) Performance based (or incentive) regulation (PBR) provides the utilities with incentive for behaviour which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies.

b) Customers and shareholders alike can gain from efficiency enhancing and cost-minimizing strategies that will ultimately yield lower rates with appropriate safeguards for service quality.

c) Under PBR the regulated utility will be responsible for making its investments based on business conditions and the objectives of its shareholder within the constraints of the price cap, and subject to service quality standards set by the OEB.

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[896] See AIC, page 252.
[897] See Exhibit I.9.2-OGVG-11, part b), as well as the testimony from Mr. Ukonga at 15 Tr.108-111.
[898] Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, pages 10-11.

d) PBR decouples the price (the distribution rate) that a distributor charges for its service from its cost. This is deliberate and is designed to incent competitive, cost-minimizing and profit-maximizing behaviours. This approach provides the opportunity for distributors to earn, and potentially exceed, the allowed rate of return on equity.

887. As seen, a key feature of IR/PBR is that it is not cost of service and is designed to incent a utility to find efficiencies. The utility's costs and revenues are "decoupled". No specific revenues are associated with any specific costs. Mr. Small explained this in the context of the Union pension receivable amount:

> The utility is intended to manage its business and incur all the typical costs it needs to, to operate that business under that revenue stream. There isn't, in our minds, an explicit approval of a specific cost in that revenue stream; you are just expected to manage the business under that revenue stream, but expected to still expense the same cost that you would normally expense, as required.
>
> And I think our position here -- or not I think -- our position was, is that we continued to expense pension costs as a whole under the consistent parameters, all the way through.
>
> So my concern was saying that rates in 2020 were specifically tied to a level of pension expense, whether that is a particular line item in pensions or pensions overall. It was just rates were set for 2020, and we needed to accommodate our pension costs under those rates.[899]

888. By reducing the Union pension receivable balance (and recognizing a corresponding expense) beyond the annual amortization amounts calculated by Mercer, using amounts that are notionally related to 2013 Union pension costs, Enbridge Gas would effectively be refunding amounts that it previously collected to fund all its operations. This is not the proper approach under IR or a deferred rebasing term. In fact, if this was to be required, this methodology for recognizing pension expense would have represented an additional accounting policy change being implemented during the deferred rebasing term. That would have required Enbridge Gas to record an additional receivable amount in the APCDA to offset the higher expense (and higher corresponding draw-down of the Union pension receivable) recognized under this

[899] 15 Tr.102.

revised methodology. As a result, the ending balance in the APCDA related to the Union pension amounts under this scenario would have been the same (i.e. $156 million receivable).

889. The circumstances of the Union pension receivable are different from EGD, because the parties specifically agreed to variance account true-ups of pension costs for EGD through the Post-Retirement True-Up Variance Account.[900] There was no similar approach for Union. Those seeking reductions to the Union pension receivable balance are effectively asking the OEB to "read in" an additional mechanism for the Union rate zone which the parties themselves never bargained for or obtained.

890. If there is to be a reduction to the amount of the Union pension receivable (which Enbridge Gas says is not appropriate, as just explained), then this is effectively retroactive ratemaking. The financial results for the years 2013 to 2022 are complete, and rates have been set and recovered for those years. To say that the allocation of revenues for those years should be re-stated is not appropriate.

891. Enbridge Gas submits that the retroactive ratemaking concerns are true for all impacted years. This is particularly clear in response to the arguments from OGVG and SEC, which seek to recapture revenues and earnings from two separate IR terms. Surely it amounts to retroactive ratemaking to reach back into a prior IR term (with effect reaching back 10 years), to adjust pension accrual amounts that have been determined in accordance with accounting policy. Effectively, this is recapturing amounts that Union earned in the 2013 to 2018 term, before amalgamation. Not only those years, but also that entire IR term, is complete. Union was subject to ESM throughout and these amounts would have been included. Reaching back to recapture earnings from prior years (from 2013 to 2022) is not fair or appropriate.

[900] See OEB staff Submission, page 127.

892. In response to the argument from OGVG and SEC that adjustments to the Union pension receivable amount should be based on a $28.1 million annual revenue, with price cap adjustments, Enbridge Gas repeats its position that this entire approach is not appropriate. In the event that the OEB decides against Enbridge Gas on this item, the Company acknowledges that the base annual amount to consider is $28.1 million, which includes the amortization of OPEB actuarial losses. Enbridge Gas does not agree that any price cap adjustment is appropriate – the annual adjustment applies in an undivided fashion to all revenues, to cover a wide variety of inflationary and other cost pressures. It is not intended to represent a line-by-line increase in each base year cost.

893. Finally on this topic of the Union pension receivable amount, Enbridge Gas strongly disagrees with SEC's suggestion that the amount should be expressed as the net balance (including the remaining deferred tax benefit), rather than as the gross amount.[901] As noted by SEC, this is not a topic that was explored in evidence.

894. Amounts recovered through deferral accounts are typically settled (recovered / refunded) on a gross basis. Gross costs (i.e. before reflecting the impact of their tax deductibility) need to be recovered because the collection or recovery of the amount will be treated as revenue from a tax perspective, resulting in incremental income tax which offsets the tax reduction caused by the tax deductibility of the cost. The result is a net income tax position of nil. Similarly, credits or revenues refunded to customers are also on a gross basis, not net of income tax, because the act of refunding amounts will reduce taxable income and corresponding income tax, thus eliminating or offsetting the tax incurred on the original revenue amount being refunded.

[901] SEC Submission, pages 109-110.

895. With regards to the pension receivable balance, the deferred tax amount reflects the future tax deductibility of the unamortized actuarial losses and past service costs (which will be recognized through deductions for cash-based pension funding, and as stated in evidence during the Oral Hearing,[902] over the course of the pension plan should equal the accrual-based expense). However, when the amounts are recovered, the recovery will be subject to income tax, thereby offsetting the tax benefit provided by the deductible expense (i.e. net tax will be nil). As such, the gross value of the pension receivable balance needs to be recovered.

iv) No adjustments to the APCDA related to overhead capitalization are appropriate

896. Moving to a different entry in the APCDA, Enbridge Gas does not agree with the OEB staff and LPMA argument that if changes to the Company's overhead capitalization proposal are directed, then adjustments should be made to the balance in the APCDA.

897. First and foremost, as explained under Issue 8 above, Enbridge Gas disputes that any changes are required to its overhead capitalization proposal. The use of a three-year rolling average to determine overhead capitalization amounts is not appropriate (and is not even feasible for past years due to lack of comparable data and historical differences in organizational structure).

898. In any event, Enbridge Gas does not agree that it would be appropriate (even if it was possible) to apply the change to the overhead capitalization methodology on a retroactive basis, back to 2020, as OEB staff and LPMA advocate. The effect would be to say that Enbridge Gas should have adopted this updated approach at the time of harmonization of overhead capitalization policies, even though the updated approach has nothing to do with harmonization.

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[902] Exhibit 9, Tab 2, Schedule 1, page 19; Exhibit 9, Tab 2, Schedule 1, Attachment 9, page 1 and 15 Tr.10.

899. This is not consistent with the terms and wording of the APCDA. The description of the APCDA indicates that “The purpose of the Accounting Policy Changes deferral account, as established in the Board’s EB-2017- 0306/EB-2017-0307 Decision and Order, is to record the impact of any accounting changes that affect revenue requirement, which are required as a result of the amalgamation of Enbridge Gas Distribution and Union Gas Limited into Enbridge Gas Inc.”[903] As described in pre-filed evidence, Enbridge Gas made changes to its overhead capitalization policy to harmonize approaches of EGD and Union. Enbridge Gas received guidance from Ernst & Young in this exercise. The APCDA records the revenue requirement impacts of the change, during the time when the change has been in place.[904]

900. The changes now proposed by OEB staff are incremental changes to the harmonization approach. These are not changes that should be considered to have been (or expected to have been) in place since 2020. No retroactive adjustments to the balances in the APCDA are necessary or appropriate (or even feasibly determined).

J. Other

<u>Treatment of Property Dispositions</u>

901. Issue 10 – Is the 2024 other revenue forecast appropriate?

<u>Summary and Relief Sought</u>

902. Enbridge Gas is requesting OEB approval of its proposed forecast of other revenue to exclude any forecast of property disposition gains or losses.[905] As explained in AIC, Enbridge Gas has forecast property disposition proceeds as equal to the net book value of these capital assets for 2024.[906]

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[903] EB-2018-0305, Exhibit F1, Tab 3 Enbridge Gas Inc. Rate Order, Appendix I, page 7.
[904] Exhibit 9, Tab 2, Schedule 1, pages 13-14.
[905] Exhibit 3, Tab 5, Schedule 1, page 3.
[906] AIC, page 256.

903. Enbridge Gas asserts that no deferral account is needed to track and share proceeds from the sale of property. For 2024, there is only one property forecast to be sold, likely with modest gains/losses. For the future years of the IR term (2025 to 2028), Enbridge Gas proposes that any property disposition gains/losses related to land would be subject to sharing with customers under the ESM.[907]

Submissions by Other Parties

904. OEB staff and all parties who made submissions on this issue agree that it is not appropriate to include forecast gains/losses from property dispositions in 2024 within other revenue, given that such gains/losses are unknown and do not represent transactions that repeat each year.[908]

905. All parties also argue that it is appropriate for the Company to create and use a deferral account to record gains/losses from property dispositions in 2024, for later disposal.

906. Parties do not agree with the Company's proposal to treat property disposition gains/losses as being subject to ESM in future years of the IR term. Instead, all parties other than Enbridge Gas argue that the 2024 deferral account should continue for all years of the IR term.

907. OEB staff notes that any determination of sharing of gains/losses from a property disposition should be conducted in the future, when there are details about the nature

[907] AIC, pages 256-257.
[908] Parties making submissions on this issue are OEB staff, CCC, LPMA and SEC. EP supports OEB staff, and FRPO and PP support SEC.

of the properties and the reasons for the sales.[909] CCC and LPMA agree with this position.[910]

908. SEC goes further than other parties and argues that within the property disposition gains/losses deferral account, customers should be credited with 100% of the proceeds from the disposition of buildings and 50% of the net gains/losses from the disposition of land (except where the land is replaced with newly purchased land).[911]

Enbridge Gas Response to Other Parties' Submissions

909. Enbridge Gas asserts that no deferral account is needed to track and share proceeds from the sale of property.

910. For 2024, there is only one modest property to be sold – total proceeds (not gain) are expected to be around $6 million.[912] It will require significant administration to establish, review and clear an account that would only be needed for one year.

911. For future years, Enbridge Gas submits that the simplest and most transparent approach is to treat gains/losses from property disposition the same way as all other utility activities during the IR term (past the test year) and include the results in ESM calculations. This avoids the need for detailed review, and debate, about the nature of each specific transaction. There is no compelling reason why this one particular item within the Company's financial results needs to be addressed separately – for many years, property disposition results for EGD, Union and Enbridge Gas have been treated within ESM like all other utility activities. It is through the ESM process that customers review and (where the threshold is reached) share in the Company's

[909] OEB staff Submission, pages 72-73. Both EP and QMA indicate that they agree with OEB staff submissions on items not specifically addressed in the EP / QMA Submissions.
[910] CCC Submission, page 32 and LPMA Submission, page 25.
[911] SEC Submission, page 113.
[912] See AIC, pages 262-263, and associated references.

results, including impacts from cost pressures (including one-time costs), efficiencies and one-time revenues. Including gains/losses from sales of property within ESM provides customers with assurances that the Company will not retain all the benefits from property dispositions where Enbridge Gas is otherwise earning more than a reasonable margin above allowed ROE.

912. In the event that the OEB does not accept the Company's position and decides to establish a property disposition deferral account for 2024, or for the full IR term, Enbridge Gas submits that the terms of the account should stipulate that proceeds of property dispositions should be shared 50/50 between Enbridge Gas and customers. To be clear, this sharing relates to the gains/losses related to land and does not include gains/losses attributable to buildings.

913. An equal sharing of the gains/losses from the sale of land is consistent with many past OEB decisions. Other OEB decisions have found that all gains should go to the shareholder, or all gains should go to customers.[913] Establishing a set 50/50 allocation now creates certainty and avoids lengthy debates in the future about the nature of a particular transaction.

914. SEC argues that ratepayers should be credited with 100% of the proceeds from the disposition of buildings.[914] That is already the case. Enbridge Gas explained in AIC that customers already receive 100% of the benefit from the disposition of buildings.[915] As required by the OEB's Uniform System of Accounts for Class A Gas Utilities[916], upon disposition of a building Enbridge Gas credits gross plant for the cost of the building (bringing the gross plant value to $0 and stopping subsequent depreciation),

[913] See AIC, page 258, including the reference to the Brantford Power and Energy + decision.
[914] SEC Submission, page 113.
[915] See AIC, page 259, and associated references.
[916] Uniform System of Accounts for Class A Gas Utilities (April 1, 1996) (oeb.ca), Section 3A in Appendix A (page 127 of 131).

with a corresponding credit to accumulated depreciation, which effectively consolidates the net book value in accumulated depreciation. The Company then debits accumulated depreciation for any costs of disposition, and credits accumulated depreciation for the proceeds received. As a result, any gains (or losses) on building dispositions stay in accumulated depreciation and are credited to (or recovered from) customers through lower (or higher) depreciation expense based on subsequent depreciation studies.

Regulated Treatment of NGV

915. Issue 34 – Is the proposed regulatory treatment of the Natural Gas Vehicle Program appropriate?

Summary and Relief Sought

916. Enbridge Gas proposes the following regulatory treatment for the NGV Program:[917]

1. Continue the NGV Program as an ancillary activity for the utility;
2. Expand the NGV Program to all Enbridge Gas franchise areas; and
3. Modify the current regulatory treatment to remove the requirement to impute revenue when the achieved annual rate of return (RoR) does not meet or exceed the required RoR, recognizing that the NGV Program is funded solely by the monthly service fees charged to participating customers.

917. Continuing the NGV Program in the manner proposed by Enbridge Gas is a clear win/win for customers, the transportation sector and GHG abatement and energy transition objectives. Further, Enbridge Gas and its predecessors have been operating the NGV Program in various forms for many decades with OEB endorsement and support. There is an even greater need for the NGV Program today across the amalgamated service territory of Enbridge Gas in light of the clear alignment with federal policies, energy transition objectives and growing support from the

[917] Exhibit 1, Tab 14, Schedule 2, page 1.

transportation sector. There is no evidence of a competitive market for these services in Ontario, and Enbridge Gas continues to play a unique and trusted role as a market enabler and facilitator. As such, the OEB should approve the NGV Program as an ancillary utility activity as proposed by Enbridge Gas and supported by OEB staff.

918. Enbridge Gas also notes a point it made in AIC that there are no 2024 revenue requirement implications if Enbridge Gas receives approval to continue the NGV Program as proposed. However, if the NGV Program is moved out of regulation, there will be a corresponding modest change to rate base, O&M and other revenue[918], because the NGV Program is currently forecast to produce a revenue sufficiency.

Submissions by Other Parties

919. OEB staff and eight intervenors provided submissions on this issue, with the majority of parties (12) taking no position. OEB staff and three intervenors are supportive, with some minor caveats. OEB staff provides a succinct summary of the reasons why the OEB should approve Enbridge Gas's proposed changes to the NGV Program:

> 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.
>
> 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.
>
> 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.[919]

[918] AIC, page 253, Table 10.
[919] OEB staff Submission, pages 130-131.

920. Without making specific comment on the NGV Program, QMA is generally supportive of the energy transition safe bet proposals of Enbridge Gas, recognizing that natural gas will remain a necessary, reliable, cost-effective energy source and the pathways to a net zero future remain in flux at this time.[920] FRPO supports the OEB staff recommendation to accept Enbridge Gas's proposed regulatory treatment of the NGV Program subject to a 2026 mid-term report that would set out evidence for a considered review in light of other energy transition evolutions.[921]

921. LPMA is generally supportive of Enbridge Gas continuing the NGV Program, subject to two caveats, namely the OEB will direct Enbridge Gas (1) to file an annual report setting out revenue, costs and RoR; and (2) to investigate the potential for a competitive market for NGV services in Ontario and report back as part of the next rebasing application.[922]

922. Five intervenors are not supportive of Enbridge Gas's proposed changes to its NGV Program, generally because they take the position that it should be operated as a wholly unregulated activity, if at all. Enbridge Gas will address these submissions below.

<u>Enbridge Gas Response to Other Parties' Submissions</u>

NGV Program Reporting and Oversight

923. Enbridge Gas appreciates the support of OEB staff and supporting intervenors for the NGV Program. OEB staff recommends the OEB accept the Enbridge Gas offer to file a report in or about 2026 (depending upon the duration of the IR term) setting out the

[920] QMA Submission, pages 5-6.
[921] FRPO Submission, page 22.
[922] LPMA Submission, pages 42-43.

actual revenues, costs and RoR on the NGV Program. Enbridge Gas reiterates its acceptance of a requirement to provide a mid-IR term report on the NGV Program.

924. Any more frequent reporting, as suggested by LPMA, would be overly burdensome and unnecessary for such a limited activity and for which there are already adequate ratepayer protections in how services are fully borne by NGV Program customers. Further, it would add to the regulatory burden of the annual rate filings during the IR term for no apparent benefit that could not be achieved through the filing of the mid-term report. In any event, parties involved in annual rate filings would not be prevented from asking interrogatories about the NGV Program as part of annual rate filings and ESM proceedings.

925. VECC states that if the OEB is inclined to approve continuation of the NGV Program within the regulated business, the OEB should undertake an independent audit of the program, "… for ratepayers not to suspect that they are being taken out to lunch with this program."[923] Such an insinuation is unsubstantiated and uncalled for, implying that Enbridge Gas is not providing an honest representation of accounts for the NGV Program.

926. The OEB has very broad powers of audit and Enbridge Gas would of course cooperate and comply with any inspection, investigation or audit that the OEB may conduct in respect of the NGV Program or any of its regulated activities. The OEB may exercise these powers at any time. However, there is absolutely no evidence or reason presented in this proceeding to suggest there is any need for the OEB to undertake an audit of the NGV Program and no reason for the OEB to act on the unsubstantiated comment of VECC.

[923] VECC Submission, page 30.

Competitive Market Concerns

927. As noted, LPMA requests the OEB direct Enbridge Gas to investigate the potential for a competitive market for NGV services in Ontario and report back in its next rebasing application on this and efforts made by Enbridge Gas to facilitate a competitive market. LPMA cites unsubstantiated concerns that continuation of the NGV Program may be contributing to the lack of a competitive market in Ontario.[924] EP cites section 29 of the OEB Act that, to paraphrase, requires the OEB to forbear from regulating services that are or will be subject to competition sufficient to protect the public interest, on the premise that keeping the NGV Program within the utility is not required to protect the public interest.[925]

928. First, it is somewhat late for EP to be raising section 29 of the OEB Act as applicable to the NGV Program in its final submissions. Further, it makes this submission without presenting or referencing any evidence to substantiate a claim of a competitive market existing for NGV services in Ontario. In fact, the record demonstrates quite the opposite, that Enbridge Gas does not believe there is a competitive market for the type of turnkey NGV and CNG related services that Enbridge Gas provides through the NGV Program and there are no parties to this proceeding that are or are intending to offer services competitive with the NGV Program.[926]

929. This reasoning also serves to reinforce why the OEB should also reject LPMA's assertion that Enbridge Gas should make and document its efforts to facilitate a competitive market. The development of a competitive market would be dependent upon the actions of parties other than Enbridge Gas and on market forces external to Enbridge Gas. It is not the role of Enbridge Gas to stimulate or induce competition or to investigate reasons why competition may not exist. Neither is it within the expertise

[924] LPMA Submission, page 43.
[925] EP Submission, pages 10-11.
[926] Exhibit I.1.14-STAFF-43, page 3.

of Enbridge Gas to measure the level of competitiveness of any NGV market component.

930. In the case of the NGV Program, Enbridge Gas has simply observed, as a provider of CNG and NGV refueling stations, appliances and tube trailers, that it helps to bring customers, suppliers and other market participants together, fostering collaboration and growth in the market.[927] Further, Enbridge Gas sees promising signs that there is significant growth potential for the market, as NGVs present an opportunity to reduce GHG emissions from transportation and through the recent developments related to environmental benefits, clean energy regulations, price competitiveness and technological improvements.[928]

Environmental Benefits of NGV Program are not Clear

931. Somewhat surprisingly, the environmentally oriented intervenors, ED and PP, are not supportive of Enbridge Gas continuing the NGV Program. ED calls for the OEB to deny approval unless Enbridge Gas commits to restrict the NGV Program to the delivery of RNG to the heavy transportation sector.[929] PP asserts that the NGV Program is incompatible with energy transition and is not a credible decarbonization option considered by consumers and businesses today and it recommends that the program be wound down as a regulated activity over the rebasing term.[930] CCC also questions why Enbridge Gas should be ramping up its NGV activities while there is a push to promote electric vehicles.[931]

932. It is on the one hand surprising that ED and PP have taken these positions given the very clear environmental benefits associated with the NGV Program. On the other

[927] Exhibit 1, Tab 14, Schedule 2, page 9.
[928] Ibid, pages 3-4.
[929] ED Submission, pages 53-54.
[930] PP Submission, page 58.
[931] CCC Submission, page 39.

hand, it is consistent with their purist position of electrification or bust, despite how imprudent or impractical that position might be. Fleets require technologies that are suitable for their specific set of conditions and needs, considering technology readiness, range, weight, refueling time and related infrastructure. It will take multiple technologies to decarbonize medium and heavy-duty transportation, in particular.[932]

933. The environmental benefits of the NGV Program are abundantly clear and are well-presented in the evidence, including how the program is closely aligned with the federal Clean Fuel Regulation and NRCan's Green Freight Program[933] and how RNG is considered to be the lowest carbon intensity fuel.[934] Also, restricting the NGV Program to only RNG in the heavy transportation sector would significantly limit the ability of the program to contribute to GHG reduction initiatives across the entire transportation sector and support the growth of the NGV market. The use of conventional natural gas in the transportation sector still provides significant environmental benefits compared to traditional gasoline and diesel fuels.[935] Separating out various components of the program would be impractical due to the interconnected nature of the services provided.[936]

<u>ESM for 2024</u>

934. Issue 37 – Is it appropriate to have an earnings sharing mechanism for 2024?

[932] Exhibit I.1.14-STAFF-42.
[933] Exhibit 1, Tab 14, Schedule 2, pages 5-6.
[934] Exhibit I.1.10-GEC-51, page 3.
[935] Exhibit I.1.14-STAFF-42 part b).
[936] Exhibit 1, Tab 14, Schedule 2, page 1.

Summary and Relief Sought

935. As summarized at pages 272 and 273 of AIC, Enbridge Gas proposes that there be no ESM for 2024 and that the ESM deferral account (ESMDA) will not apply to the year rates are set based on the cost of service, consistent with current practice.[937]

936. Enbridge Gas is proposing an asymmetric ESM to share excess utility earnings between Enbridge Gas and customers during the IR term from 2025 to 2028. Enbridge Gas has proposed to share utility earnings in excess of 150 basis points above the OEB-approved ROE on a 50/50 basis with customers.[938] This proposal will be addressed in Phase 2.

937. While some parties agree that no ESM in 2024 is necessary, others submit that it is necessary to provide protection for customers even in a cost of service review year.

938. Neither EGD nor Union ever had an ESM in a cost of service year. This is not part of the OEB's typical approach in the first year of a price cap IRM. The very detailed cost of service process for 2024 provides appropriate protection for customers.

Submissions by Other Parties

939. OEB staff agrees with Enbridge Gas, that the cost of service process provides appropriate protection for Enbridge Gas customers in 2024, noting the rigorous and detailed cost of service proceeding, with lengthy discovery and a long Oral Hearing.[939] EP supports OEB staff's position.[940]

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[937] Exhibit 9, Tab 1, Schedule 2, pages 27-28.
[938] Exhibit 10, Tab 1, Schedule 1, page 12.
[939] OEB staff Submission, page 132.
[940] EP Submission, page 19.

940. Several other parties argue for an ESM, even in the 2024 cost of service review year.[941]

941. The general argument is that Enbridge Gas typically over earns, therefore ESM protection is needed.

942. LPMA asserts that an ESM is appropriate for 2024 in the event that Enbridge Gas is permitted to have levelized rate treatment for PREP. The premise here is that levelized rate treatment is a departure from usual practice that justifies including a test year ESM, which is also a departure from current practice.[942]

943. Parties do not appear to agree about whether it is typical practice to include an ESM for a utility in a cost of service year. Some parties agree with Enbridge Gas on this point.[943] On the other hand, VECC submits (without any references) that this is "the norm"[944] and SEC submits that for large utilities not including an ESM in the first year is the exception, not the rule[945].

944. There is no consensus among parties as to the parameters of an ESM that would apply for 2024. VECC and PP indicate that Enbridge Gas's proposed ESM parameters should be used[946] while CCC proposes more aggressive earnings sharing[947]. Other parties are silent on this item, suggesting that they are content with Enbridge Gas's

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941 See CCC Submission, page 39; FRPO Submission, page 23; LPMA Submission, page 43; PP Submission, page 59; SEC Submission, page 115; and VECC Submission, page 32.
942 LPMA Submission, page 44.
943 CCC Submission, page 39; and LPMA Submission, page 44.
944 VECC Submission, page 32.
945 SEC Submission, page 115.
946 VECC Submission, page 32 and PP Submission, page 59.
947 CCC proposes asymmetrical earnings sharing starting at 100bp above allowed ROE – CCC Submission, page 39.

proposal.[948] SEC proposes that the parameters of the 2024 ESM be determined in Phase 2.[949]

Enbridge Gas Response to Other Parties' Submissions

945. Enbridge Gas submits that the OEB does not need to order an ESM to provide the "belt and suspenders" protection that some intervenors think is necessary to protect against overearning in a cost of service year.

946. The Company typically finds ways to operate efficiently and earn above its allowed rate of return. This should be encouraged. The benefits are passed to customers in cost of service proceedings, and incremental benefits in future years of an IR term are eligible to be shared through the ESM.

947. Enbridge Gas disputes that it is typical to include an ESM in a cost of service rebasing year. While that may be true for a "Custom IR" filing, this case is a standard cost of service year preceding a price cap IRM. The rates in a cost of service case that form the base for a price cap IRM are set specifically through the testing of the forecast of test year costs. That is different from Custom IR. As the OEB stated in the EB-2012-0459 Decision approving the Custom IR Plan for EGD, "[a] Custom IR is not set based on a single cost of service year the way Enbridge's prior traditional IR plan was. A Custom IR is based on five-year forecasts of costs."[950]

948. In any event, the need for the "protection" of an ESM in this cost of service rebasing year is overstated. The amalgamated Enbridge Gas has had an ESM in place for each year of the deferred rebasing term. Under the terms of that mechanism (which is the same as proposed for 2025 to 2029), Enbridge Gas shares earnings that are more

[948] Those without any proposal for 2024 ESM parameters are FRPO, LPMA and PP.
[949] SEC Submission, page 115.
[950] EB-2012-0459 Decision with Reasons, July 17, 2014, page 13.

than 150 basis points above allowed ROE. Over the course of the first four years of the deferred rebasing term (2019, 2020, 2021 and 2022), Enbridge Gas has never exceeded the ROE threshold by more than 150 basis points, and therefore there has been no earnings sharing.[951]

949. Enbridge Gas submits that if the OEB is to require an ESM for 2024 (which Enbridge Gas opposes), then the parameters should be set in Phase 1. The parameters should be the same as what is currently in place, which Enbridge Gas proposes to continue for the 2025 to 2028 IR term. There is no evidence to support an ESM that is different from the existing ESM parameters, and only one party even proposes anything that is different.

Dawn Parkway Turnback Risk

950. Issue 38 – How should Dawn Parkway capacity turnback risk be dealt with?

Summary and Relief Sought

951. Enbridge Gas is not requesting any relief in relation to this issue.

952. In AIC, Enbridge Gas explained that Dawn Parkway turnback is unlikely over the next IR term, and that in any event it is Enbridge Gas and not customers who are at risk for the cost consequences of any such turnback.[952]

953. Enbridge Gas also responded to the evidence and proposals from John Rosenkranz, FRPO's expert. The Company noted Mr. Rosenkranz's agreement that his recommendations for cost allocation are not in scope for Phase 1. Enbridge Gas also

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[951] This can be seen in the Deferral and Variance Account clearance applications for each of these years.
[952] See AIC, pages 276-278 and associated evidentiary references.

explained why Mr. Rosenkranz's proposal for a buyout option to existing shippers to avoid future Dawn Parkway capacity expansions is problematic and incomplete.[953]

954. Enbridge Gas concluded its submissions by confirming that it will consider and reflect all appropriate IRP investigations (which could include things like "term-up" for existing shippers) before seeking LTC approval for a future Dawn Parkway capacity expansion.[954]

955. Having reviewed the submissions of other parties, Enbridge Gas maintains the position set out in AIC.

Submissions by Other Parties

956. OEB staff[955] (supported by EP[956]) and LPMA[957] agree with the Company's position and submissions on this issue.

957. All parties who filed submissions on this issue (including Enbridge Gas) agree that the Company should investigate and pursue IRP options to seek to avoid (or presumably to delay or downsize) a future Dawn Parkway capacity expansion.[958]

958. No party specifically endorses Mr. Rosenkranz's proposal for mandated buyout payments to existing Dawn Parkway shippers to avoid a capacity expansion. While CME and SEC see this as an interesting concept that should be examined further,

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[953] See AIC, pages 278-280 and associated evidentiary references.
[954] See AIC, pages 280-281.
[955] OEB staff Submission, pages 134-135.
[956] EP Submission, page 19.
[957] LPMA Submission, page 46.
[958] In addition to OEB staff and LPMA, the parties filing submissions on this issue are CME, FRPO, PP and SEC.

neither party argues that this should be a mandated requirement to be ordered at this time.[959]

959. There are only two specific proposals made by intervenors on this issue.

960. FRPO argues that a buyout payment is a demand side IRPA that Enbridge Gas should consider before submitting a LTC Application for a future Dawn Parkway capacity expansion, but then continues by saying that this is just one factor to consider, and that Enbridge Gas should also be directed to assess stranded asset risk on a probabilistic basis.[960]

961. SEC states that the proposal for buyout payments to existing shippers is a concept that deserves serious consideration. SEC acknowledges that the concept is not ready for implementation but argues that Enbridge Gas should be required to consider the concept and bring it forward to the IRP TWG.[961]

Enbridge Gas Response to Other Parties' Submissions

962. Enbridge Gas does not believe that any OEB direction is required on this issue.

963. Enbridge Gas submits that the appropriate place to consider IRP measures to avoid, delay or downsize a future Dawn Parkway capacity expansion is in the context of an actual project. Defining and mandating a specific demand side IRPA that might be applied at some later time is not necessary now. In any case, Enbridge Gas submits that there are serious conceptual flaws with the proposed buyout mechanism, which suggest that this should not be a priority for investigation by Enbridge Gas or the IRP TWG at this time.

[959] See CME Submission, pages 53-54 and SEC Submission, pages 116-117.
[960] FRPO Submission, pages 27-28.
[961] SEC Submission, page 117.

964. FRPO's argument that Enbridge Gas should be directed to undertake probabilistic assessment of stranded asset risk for a future Dawn Parkway capacity expansion is not something that was considered or discussed in the report or testimony from FRPO's expert, Mr. Rosenkranz. This concept was not raised with the Enbridge Gas witnesses speaking to Dawn Parkway issues at any time, including in interrogatories, Technical Conference or Oral Hearing. This proposed requirement is being advanced in final submission for the first time, with one paragraph of description about what is being requested.[962] Enbridge Gas submits that in these circumstances, it would not be fair or appropriate for the OEB to make the requested direction. There is nothing to stop FRPO or other parties from making this request in the context of a future Dawn Parkway capacity expansion LTC Application.

SQRs

965. 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?

Summary and Relief Sought

966. Enbridge Gas reiterates below the components of its request for a partial exemption, effective January 1, 2023[963], under Section 1.5.1 of the OEB's GDAR related to three service quality requirement (SQR) performance measures:

   a) GDAR Section 7.3.3 Meter Reading Performance Measurement (MRPM)

      i. *Current:* 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 target for the metric is 0.5%.

[962] FRPO Submission, page 28.
[963] As noted in AIC, page 282, Enbridge Gas assumes the OEB will consider the 2023 Request as part of this Issue 40 and notes that this was the assumption implied in the OEB staff and intervenor submissions.

ii. *Relief Sought:* approval for MRPM to be a target of no more than 2% of meters with consecutive estimates for four months or more.

b) GDAR Section 7.3.1.1 Call Answer Service Level (CASL)

i. *Current:* the percentage of calls reaching the general inquiry number, including IVR calls that are answered within 30 seconds. The yearly performance shall be 75% with a minimum monthly standard of 40%.

ii. *Relief Sought:* approval for CASL to achieve 65% of calls reaching the general inquiry number answered within 30 seconds. This aligns with the Distribution System Code (DSC).

c) GDAR Section 7.3.4.2 Time to Reschedule a Missed Appointment (TRMA)

i. *Current:* At minimum, the distributor must contact the customer to reschedule the work within 2 hours of the end of the original appointment time. The TRMA metric is set at 100%.

ii. *Relief Sought:* approval for TRMA to be an attempt to contact customers requiring a rescheduled appointment within one business day of the original appointment window 98% of the time. An attempt within one business day aligns with the DSC.

967. Enbridge Gas requires these partial exemptions because despite its many ongoing efforts to meet these SQRs, accepted by OEB compliance staff to date as satisfactory, they are unachievable in today's operating environment, and they are therefore no longer appropriate as a measure of satisfactory gas utility performance. Ultimately, Enbridge Gas urges the OEB to conduct a generic review of these performance measures in the GDAR and consider amendments that align with current day industry experience and consumer behaviours.

968. As suggested by OEB staff, Enbridge Gas will pursue its GDAR amendment request with the OEB's Chief Executive Officer (CEO), however Enbridge Gas would welcome any supportive findings from the OEB panel in this regard. If the CEO does agree to review the GDAR, Enbridge Gas expects that process may extend beyond the end of 2024, in which case the temporary exemption for 2023 and 2024 recommended by

OEB staff would not be sufficient for Enbridge Gas to ensure it can remain compliant with the SQRs until the more comprehensive review is completed. Enbridge Gas therefore requests that in the event the OEB sees fit to grant a time-limited partial exemption, that it be extended at least to the end of 2025.

Submissions by Other Parties

969. For 2023 and 2024 and as long as Enbridge Gas continues to take all reasonable steps in accordance with its mitigation plans (as it has been doing to date), OEB staff supports the Enbridge Gas requests for partial exemptions.[964] EP and QMA make no comment on this issue, but accept the submissions of OEB staff.[965] CCC supports only the partial exemption request for TRMA, noting that it is consistent with the DSC and it is not unreasonable to expect it may take one full business day to contact and reschedule a missed appointment with a customer.

970. Six other parties provided comments and were not supportive of the partial exemption requests, primarily because they view the requests as providing Enbridge Gas relief from poor performance related to cost savings and/or amalgamation.[966] These submissions represent an incomplete consideration of the evidence and an unfair characterization of the ongoing customer care focus of Enbridge Gas.

Enbridge Gas Response to Other Parties' Submissions

971. The prevailing perception of the non-supporting intervenors that Enbridge Gas has not been able to meet certain SQRs due to lack of performance or integration activities is simply false, as clearly outlined in the evidence. In fact, the main factors contributing to not meeting the SQRs are unrelated to the amalgamation and are outside of the control of Enbridge Gas. Intervenors have seemingly ignored these important facts.

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[964] OEB staff Submission, page 140.
[965] EP Submission, page 19.
[966] BOMA, PP, SEC, LPMA, FRPO and VECC.

972. Without repeating all of the details in evidence and AIC, the primary factors justifying the need for the requested exemptions are:

a) There are ongoing challenges with meeting these SQRs, despite the best efforts of Enbridge Gas and implementation of its comprehensive mitigation plans[967] (including increased customer communication, improved digital channel functions, improved staffing and retention, systems integration and process alignment to ensure a consistent customer experience). Enbridge Gas continues to report monthly to OEB compliance staff about the implementation of and progress with its mitigation plans and OEB compliance staff have been satisfied with Enbridge Gas efforts to date. Intervenors have offered no additional mitigation measures that Enbridge Gas could be taking beyond what it is already doing.

b) The residual impacts of the COVID-19 pandemic are continuing with respect to the labour market, specifically with respect to meter-reading service providers and call centre staff, and in customer behaviours (like working from home) causing increased access problems for meter readers. Naively, FRPO comments that Enbridge Gas should be able to overcome access issues through customer service measures.[968] This is of course what Enbridge Gas has been attempting to do, as outlined in its mitigation plans, but despite its best efforts, these access issues continue to account for approximately 1-3% of the total MRPM. The way in which the metric is calculated makes it difficult to "catch up" on missed meter reads due to labour shortages or access issues. While the more pronounced impacts of the pandemic are hopefully behind us, Enbridge Gas is continuing to experience the residual impacts and expects that to continue for several more months.[969]

c) The SQRs are outdated and misaligned with the DSC, indicating that the SQRs are due for a comprehensive review and consideration to ensure they are reflective of the current operating environment, customer expectations and consistent with an overall positive customer experience (such as allowing for longer call times to address more complex customer issues, given that self-serve digital tools are used for an increasing number of simpler matters).[970]

d) Neither Enbridge Gas nor its predecessors have been able meet the TRMA historically, so it is clear that this 100% SQR standard of perfection is and has always been unrealistic and the inability to meet it has nothing to do with the

[967] Exhibit 1, Tab 7, Schedule 1, Attachments 1 to 3.
[968] FRPO Submission, page 29.
[969] AIC, page 286.
[970] AIC, page 287.

amalgamation. Enbridge Gas appreciates the support and recognition from CCC that modifying the TRMA to 98% within one business day and aligning it with the DSC is a very reasonable and fair request.[971] No other intervenor provided any recognition of this discrepancy.

973. FRPO states that Enbridge Gas has made no mention of the integration of its billing system as a factor in the missed SQR metrics.[972] This is also false as Enbridge Gas clearly mentioned system integration a few times in its evidence and AIC as a contributing factor.[973]

974. Despite the fact that Enbridge Gas does not have a proposal related to AMI in this proceeding, BOMA requests that the OEB require Enbridge Gas to present an AMI strategy for commercial buildings by March 31, 2024, complete installation of the reporting infrastructure and metering for 20% of commercial buildings by the end of 2025 and for all commercial buildings by the end of 2026. BOMA ties this request to the SQR issue by requesting the OEB also to disallow the partial exemption for the MRPM for commercial buildings and "beefing" it up until the AMI installation is complete.[974]

975. Enbridge Gas reiterates that while it is conducting pilots for AMI, it will not be in a position to bring forward an AMI proposal for any customer group within the next several months, especially with the ongoing resource demands of this proceeding until Phase 3 is completed.[975] Regarding the MRPM, Enbridge Gas notes that it is not a separate metric for different groups of customers and Enbridge Gas therefore does not track the MRPM in that manner. All general service customers are subject to the same operational and customer care processes with respect to meter reading and

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[971] CCC Submission, page 41.
[972] Ibid, page 30.
[973] Exhibit 1 Tab 7 Schedule 1, pages 4, 14, 15, 18; and AIC, page 287.
[974] BOMA Submission, page 10.
[975] Exhibit 1.2.7-SEC-151.

Enbridge Gas does not see the need for the OEB to entertain a separate MRPM for commercial buildings at this time. BOMA constituents and other customers are free to participate in any future generic proceeding that the OEB may convene to review the GDAR and SQRs and address these issues in a more comprehensive manner.

976. The evidence of Enbridge Gas's ongoing challenges and extraordinary efforts to meet the SQRs clearly demonstrates that it would not be fair for the OEB to deny the partial exemption requests on the basis of the intervenors' unsubstantiated concerns. LPMA suggests that the OEB should not grant an exemption without a full review of the GDAR.[976] Enbridge Gas agrees that a full review of the GDAR is required, and that review should take place in a timely manner. However, Enbridge Gas is concerned that if the partial exemption requests are not granted in this proceeding, it will be put in an inevitable position of non-compliance in the interim period without further recourse, as it has exhausted available mitigation measures and OEB consultation efforts. The more direct relief of granting the partial exemptions now and soon thereafter undertaking a comprehensive review and modernization of the SQR metrics is the more appropriate regulatory response in these circumstances.

K. Rate Implementation

Rate Implementation Proposal

977. 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?

Summary and Relief Sought

978. Enbridge Gas is requesting OEB approval for interim 2024 rates based on the OEB's Phase 1 Decision, to be effective January 1, 2024. The 2024 rates are to be interim, because as set out in Procedural Order No. 2 and in the Settlement Proposal,

[976] LPMA Submission, page 47.

determinations on Phase 2 issues may require rate adjustments effective January 1, 2024.

979. Enbridge Gas acknowledges that it will not be possible to implement the new interim 2024 rates on January 1, 2024. However, Enbridge Gas will implement the rates at the earliest date possible. Enbridge Gas seeks recovery of the full approved interim revenue requirement for 2024. Consistent with current practice, as part of the Draft Rate Order (DRO), Enbridge Gas would include a revenue adjustment rider for the period between the effective date of January 1, 2024, and the implementation date.

980. In AIC, Enbridge Gas summarized why it is appropriate for the Company to recover the full-year impact of the new interim 2024 rates, including the fact that this has been a very complicated proceeding and that Enbridge Gas has acted in a timely and responsible manner throughout.[977]

Submissions by Other Parties

981. All parties who provided submissions on this issue either support[978], or do not oppose[979], Enbridge Gas's proposal. OEB staff summarized its position as follows:

> 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 and the calculation of this recovery can be included as part of the draft rate order process in Phase 1 of the proceeding.[980]

[977] AIC, page 293.
[978] OEB staff Submission, page 141; CCC Submission, page 141; EP Submission, page 19; LPMA Submission, page 48; and VECC Submission, page 34.
[979] FRPO Submission, page 30; PP Submission, page 60; QMA Submission, page 7; and SEC Submission, page 119.
[980] OEB staff Submission, pages 141-142.

982. LPMA supports the Enbridge Gas proposal, but asked the Company to address a couple of matters in this Reply Argument[981]:

a) How the revenue adjustment rider would be calculated in the DRO and over what period(s); and

b) Will the rate rider be a one-time charge based on the volumes between the effective date and the implementation date, or a charge that would continue on for a number of months or until the end of 2024.

983. LPMA further indicated that the OEB should direct Enbridge Gas to do two things in connection with rate implementation[982]:

a) Direct Enbridge Gas to file sufficiently detailed information as part of the DRO that would allow the OEB and intervenors the ability to verify not only the amounts but also the allocation of the amounts to the various rate classes; and

b) DirectEnbridge Gas to implement the rates as quickly as possible rather than wait for the April 1, 2024, QRAM, to take into account that winter months are high volume consumption months for most customers and delaying the change in rates to April 1 would have the potential to levy significant additional costs onto customers based on their historical consumption.

Enbridge Gas Response to Other Parties' Submissions

984. Enbridge Gas appreciates the recognition from all parties that it is appropriate or acceptable to recover the full-year impact of the new interim 2024 rates.

985. In response to LPMA's questions, Enbridge Gas can advise that the rate adjustment rider would be calculated to recover the variance between the current approved revenue and the approved 2024 revenue requirement from the effective date of January 1, 2024, to the implementation date. The rate adjustment rider is proposed to be applied prospectively over a period of time from the implementation date until the end of 2024 for both in-franchise general service and contract rate classes, consistent with the current practice for the EGD rate zone. Enbridge Gas is proposing that the

[981] LPMA Submission, page 48.
[982] Ibid.

rate adjustment rider will include volumetric and/or demand charge riders, consistent with the rate design of each class. Enbridge Gas is also proposing a one-time adjustment for ex-franchise contract rate classes, consistent with current practice.

986. Enbridge Gas confirms that it will file sufficiently detailed information as part of the DRO to allow the OEB and all parties to verify amounts and allocation of the amounts to all rate classes.

987. Enbridge Gas proposes, subject to the OEB's direction, that it will implement the approved interim rates arising from Phase 1 and the approved interim Rate Order as soon as possible after approval, even where the implementation date is different from an established QRAM rate adjustment effective date, such as April 1.

Summary of Approvals Requested

988. Enbridge Gas has described the approvals requested in the discussions above for each topic covered in this Reply Argument. As explained, they are consistent with, and in most cases the same as what was set out in AIC.

989. The Approvals Requested that are different from what is included in AIC are the following:

   a) Inclusion of a 30-year customer attachment revenue horizon within the harmonized customer attachment policies, effective January 1, 2025.

   b) Suggestion that a generic proceeding to review gas distributor customer attachment policies may be appropriate.

   c) Inclusion of a true-up for 2023 closing rate base, to be done with the Phase 2 Rate Order, to reflect actual 2023 results.

   d) Amendments to 2024 capital expenditures forecast to reflect the current net capital estimate for the Selwyn Community Expansion project, and reclassify the St. Laurent project using a levelized rate treatment.

e) Creation of three new deferral accounts:

   i. OEB Directive Deferral Account (OEBDDA)

   ii. St. Laurent Project Variance Account (SLPVA)

   iii. Potential Change to IFRS Deferral Account

990. As done in AIC, Enbridge Gas has collected all of the Approvals Requested into the table set out below. The relevant sections of the Reply Argument have been added. In the first column of the table, the Approvals Requested are summarized and grouped according to the Exhibit in the evidence to which they relate. In the second column of the table, a cross-reference to the Issues List is indicated, and links are provided to the relevant parts of AIC. In the third column, links are provided to the relevant parts of this Reply Argument.

Approvals Requested	Relevant Issue and Link to Argument in Chief	Link to Reply Argument
Exhibit 1 - Administration		
• Partial exemption request for certain performance metrics	SQR – Issue 40	SQRs
• Harmonized customer attachment policies	Customer Attachment Policy – Issues 3, 6 and 7	Customer Attachment Policy
• Regulatory treatment of the Natural Gas Vehicle (NGV) Program	NGV Program – Issue 34	Natural Gas Vehicle (NGV) Program
Exhibit 2 – Rate Base		
• Harmonized indirect overhead capitalization methodology	Indirect Overhead Capitalization – Issue 8	Indirect Overhead Capitalization
• 2024 Test Year capitalized overhead amounts	Indirect Overhead Capitalization – Issue 8	Indirect Overhead Capitalization
• 2024 Test Year capital expenditures and resulting in-service capital additions	2024 Capital – Issue 7	2024 Capital
• Levelized rate treatment for PREP	2024 Capital – Issue 7	2024 Capital
• Levelized rate treatment for St. Laurent	N/A	2024 Capital
• 2024 Rate Base (inclusive of 2023 additions and Integration Capital additions)	Rate Base – Issue 6	Rate Base

Approvals Requested	Relevant Issue and Link to Argument in Chief	Link to Reply Argument
Exhibit 3: Operating Revenue • 2024 Test Year other revenue forecast	Treatment of Property Dispositions – Issue 10	Property Dispositions
Exhibit 4: Operating Expenses • 2024 depreciation rates and expense	Depreciation Expense – Issues 15 and 16	Depreciation
Exhibit 5: Cost of Capital and Capital Structure • Increase from 36% to 42% equity thickness • Phase-in the proposed change to equity thickness	Equity Thickness – Issues 20 and 22	Equity Thickness
Exhibit 8: Rate Design • Approval of ELC	Customer Attachment Policy – Issue 29	Customer Attachment Policy
Exhibit 9: Deferral and Variance Accounts • Establishment of VOLUVAR and PREPVA and continuation of Short-term Storage and Other Balancing Services Account	Deferral and Variance Accounts - Issues 32 and 33 For PREPVA see also 2024 Capital – Issue 7	Deferral and Variance Accounts For PREPVA see also 2024 Capital
• Establishment of OEBDDA, SLPVA and Potential Change to IFRS Deferral Account	N/A	Deferral and Variance Accounts
• Clearance of APCDA	Deferral and Variance Accounts - Issues 32 and 33	Deferral and Variance Accounts
• Clearance of TVDA	Deferral and Variance Accounts - Issues 32 and 33	Deferral and Variance Accounts

Approvals Requested	Relevant Issue and Link to Argument in Chief	Link to Reply Argument
Rate Implementation (Application) • Interim rates to be implemented as of January 1, 2024, on a full-year basis	Rate Implementation Proposal – Issue 41	Rate Implementation

All of which is respectfully submitted this October 11, 2023.

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ENBRIDGE GAS INC. DEPRECIATION PROVISION COMPARISON - EQUAL LIFE GROUP

		EGI PROPOSAL	INTERVENOR PROPOSALS/SCENARIOS				
Asset Account	Concentric Recommended Life and Curve (1)	EQUAL LIFE GROUP CDNS 3.75% (2)	Board Staff Recommended Life and Curve	ELG + Intervenor Life and Curve CDNS 3.75%	ELG + Intervenor Life and Curve CDNS 4.48%	ELG + Intervenor Life and Curve CDNS 6.03%	ELG + Intervenor Life and Curve Traditional Method
442.00	40-S5	121,037	N/A	121,037	121,037	121,037	121,037
443.01	45-R4	70,295	N/A	70,295	70,295	70,295	70,295
443.02	55-R4	245,157	N/A	245,157	245,157	245,157	245,157
451.00	55-R4	1,103,268	N/A	1,103,268	1,103,268	1,103,268	1,103,268
452.00	45-R3	3,164,111	45-R2.5	3,018,866	2,887,832	2,756,807	3,346,438
453.00	45-R2.5	5,806,931	N/A	5,806,931	5,361,360	4,767,274	7,292,157
454.00	40-R2	215,265	N/A	215,265	215,265	215,265	215,265
455.00	55-R3	9,857,986	N/A	9,857,986	9,591,111	9,324,250	10,792,028
456.00	40-R4	21,390,221	44-R4	17,691,447	17,637,459	16,992,273	19,312,829
457.00	35-R3	5,389,636	40-R2.5	4,192,475	3,966,273	3,627,242	4,988,756
461.00	60-R4	1,558,436	N/A	1,558,436	1,558,436	1,558,436	1,558,436
462.00	50-S4	3,442,222	N/A	3,442,222	3,384,367	3,268,664	3,731,475
463.00	55-S4	160,119	N/A	160,119	155,308	150,500	179,427
464.00	30-L0.5	180,907	N/A	180,907	183,042	178,773	191,567
465.00	60-R4	52,439,913	70-R4	41,655,295	39,833,626	38,023,130	44,716,522
466.00	30-R4	38,709,127	N/A	38,709,127	37,932,158	37,223,238	41,040,030
467.00	40-R4	15,204,608	N/A	15,204,608	14,767,844	13,899,142	17,388,414
471.00	60-R4	1,221,703	N/A	1,221,703	1,218,658	1,221,703	1,221,703
472.00	40-S0.5	5,945,106	N/A	5,945,106	5,945,106	5,945,106	5,945,106
472.31	40-S0.5	1,516,289	N/A	1,516,289	1,516,289	1,516,289	1,516,289
472.32	40-S0.5	1,125,018	N/A	1,125,018	1,125,018	1,125,018	1,125,018
472.33	40-S0.5	2,684,144	N/A	2,684,144	2,684,144	2,684,144	2,684,144
472.34	40-S0.5	798,633	N/A	798,633	798,633	798,633	798,633
472.35	40-S0.5	2,569,080	N/A	2,569,080	2,569,080	2,569,080	2,569,080
473.01	40-S0.5	29,969,149	N/A	29,969,149	28,551,015	10,859,232	38,478,005
473.02	55-S3	136,735,162	N/A	136,735,162	127,415,141	42,655,580	174,298,545
474.00	25-SQ	46,298,774	N/A	46,298,774	46,298,774	46,298,774	46,304,967
475.00	25-SQ	10,469,399	N/A	10,469,399	10,469,399	10,469,399	10,469,399
475.21	55-R3	129,657,949	61-R3	104,181,989	93,826,508	78,485,054	152,891,105
475.30	60-R4	107,007,350	65-R3	95,966,796	86,921,560	75,516,696	139,226,624
476.00	17-S2.5	482,255	N/A	482,255	482,255	482,255	482,255
477.00	40-R2	30,924,387	N/A	30,924,387	30,553,110	29,480,325	32,886,768
477.01	35-R3	5,584,218	N/A	5,584,218	5,584,218	5,584,218	5,584,218
478.00	15-S2.5	119,877,761	N/A	119,877,761	119,877,761	119,877,761	119,877,761
482.00	40-R1.5	302,463	N/A	302,463	302,463	302,463	302,463
482.01	40-R1.5	5,780,346	N/A	5,780,346	5,780,346	5,780,346	5,780,346
482.04	40-R1.5	0	N/A	-	-	-	-
482.05	40-R1.5	1,562,381	N/A	1,562,381	1,562,381	1,562,381	1,562,381
482.51	40-R1.5	4,945,676	N/A	4,945,676	4,945,676	4,945,676	4,945,676
482.52	40-R1.5	3,164,180	N/A	3,164,180	3,164,180	3,164,180	3,164,180
483.00	15-SQ	1,732,767	N/A	1,732,767	1,732,767	1,732,767	1,732,767
484.00	12-L2.5	6,708,608	N/A	6,708,608	6,708,608	6,708,608	6,708,608
485.00	17-L1.5	4,305,666	N/A	4,305,666	4,305,666	4,305,666	4,305,666
486.00	15-SQ	10,258,875	N/A	10,258,875	10,258,875	10,258,875	10,258,875
487.70	15-SQ	250,902	N/A	250,902	250,902	250,902	250,902
487.80	20-SQ	352,999	N/A	352,999	352,999	352,999	352,999
488.00	10-SQ	2,088,746	N/A	2,088,746	2,088,746	2,088,746	2,088,746
490.00	4-SQ	3,990,450	N/A	3,990,450	3,990,450	3,990,450	3,990,450
490.00 (Post 2023)	4-SQ	1,958,107	N/A	1,958,107	1,958,107	1,958,107	1,958,107
490.30	10-SQ	0	N/A	-	-	-	-
491.01	4-SQ	10,638,821	N/A	10,638,821	10,638,821	10,638,821	10,638,821
491.01 (Post 2023)	4-SQ	2,158,742	N/A	2,158,742	2,158,742	2,158,742	2,158,742
491.02	4-SQ	3,730,251	N/A	3,730,251	3,730,251	3,730,251	3,730,251
491.02 (Post 2023)	4-SQ	2,520,837	N/A	2,520,837	2,520,837	2,520,837	2,520,837
491.03	10-SQ	9,922,379	N/A	9,922,379	9,922,379	9,922,379	9,922,379
Software Intangibles - 10YR	10-SQ		N/A				
491.04	10-SQ	9,153,052	N/A	9,153,052	9,153,052	9,153,052	9,153,052
Sub-total		877,451,863		825,109,551	790,376,754	654,620,266	978,178,970
RNG and Sales-type lease assets		1,532,536		1,532,536	1,532,536	1,532,536	1,532,536
2024 DEPRECIATION @ EGI OR INTERVENOR PROPOSED DEPRECIATION RATES		**878,984,399**		**826,642,087**	**791,909,290**	**656,152,802**	**979,711,506**

2024 DEPRECIATION @ CURRENT DEPRECIATION RATES (3)	**737,115,889**

NOTES

(1) Consistent with Capital Update at Exhibit 2, Tab 5, Schedule 4, Attachment 1
(2) See Exhibit J17.1 for details
(3) See Exhibit J16.5 for details

ENBRIDGE GAS INC. DEPRECIATION PROVISION COMPARISON - EQUAL LIFE GROUP

		EGI PROPOSAL	INTERVENOR PROPOSALS/SCENARIOS				
Asset Account	Concentric Recommended Life and Curve (1)	EQUAL LIFE GROUP CDNS 3.75% (2)	IGUA Recommended Life and Curve	ELG + Intervenor Life and Curve CDNS 3.75%	ELG + Intervenor Life and Curve CDNS 4.48%	ELG + Intervenor Life and Curve CDNS 6.03%	ELG + Intervenor Life and Curve Traditional Method
442.00	40-S5	121,037	N/A	121,037	121,037	121,037	121,037
443.01	45-R4	70,295	N/A	70,295	70,295	70,295	70,295
443.02	55-R4	245,157	N/A	245,157	245,157	245,157	245,157
451.00	55-R4	1,103,268	N/A	1,103,268	1,103,268	1,103,268	1,103,268
452.00	45-R3	3,164,111	45-R2.5	3,018,866	2,887,832	2,756,807	3,346,438
453.00	45-R2.5	5,806,931	N/A	5,806,931	5,361,360	4,767,274	7,292,157
454.00	40-R2	215,265	N/A	215,265	215,265	215,265	215,265
455.00	55-R3	9,857,986	N/A	9,857,986	9,591,111	9,324,250	10,792,028
456.00	40-R4	21,390,221	44-R4	17,691,447	17,637,459	16,992,273	19,312,829
457.00	35-R3	5,389,636	40-R2.5	4,192,475	3,966,273	3,627,242	4,988,756
461.00	60-R4	1,558,436	N/A	1,558,436	1,558,436	1,558,436	1,558,436
462.00	50-S4	3,442,222	N/A	3,442,222	3,384,367	3,268,664	3,731,475
463.00	55-S4	160,119	N/A	160,119	155,308	150,500	179,427
464.00	30-L0.5	180,907	N/A	180,907	183,042	178,773	191,567
465.00	60-R4	52,439,913	70-R4	41,655,295	39,833,626	38,023,130	44,716,522
466.00	30-R4	38,709,127	37-R4	27,719,025	27,275,082	26,832,623	27,275,082
467.00	40-R4	15,204,608	N/A	15,204,608	14,767,844	13,899,142	17,388,414
471.00	60-R4	1,221,703	N/A	1,221,703	1,218,658	1,221,703	1,221,703
472.00	40-S0.5	5,945,106	N/A	5,945,106	5,945,106	5,945,106	5,945,106
472.31	40-S0.5	1,516,289	N/A	1,516,289	1,516,289	1,516,289	1,516,289
472.32	40-S0.5	1,125,018	N/A	1,125,018	1,125,018	1,125,018	1,125,018
472.33	40-S0.5	2,684,144	N/A	2,684,144	2,684,144	2,684,144	2,684,144
472.34	40-S0.5	798,633	N/A	798,633	798,633	798,633	798,633
472.35	40-S0.5	2,569,080	N/A	2,569,080	2,569,080	2,569,080	2,569,080
473.01	40-S0.5	29,969,149	50-L1	19,610,115	18,159,693	15,741,744	26,008,147
473.02	55-S3	136,735,162	60-S3	117,188,759	109,087,637	98,120,890	138,980,603
474.00	25-SQ	46,298,774	45-S1	16,143,355	16,143,355	16,143,355	16,143,355
475.00	25-SQ	10,469,399	N/A	10,469,399	10,469,399	10,469,399	10,469,399
475.21	55-R3	129,657,949	65-R3	92,292,363	81,936,881	69,663,718	137,933,188
475.30	60-R4	107,007,350	70-R2	92,223,647	83,216,184	72,072,932	86,813,990
476.00	17-S2.5	482,255	N/A	482,255	482,255	482,255	482,255
477.00	40-R2	30,924,387	N/A	30,924,387	30,553,110	29,480,325	32,886,768
477.01	35-R3	5,584,218	N/A	5,584,218	5,584,218	5,584,218	5,584,218
478.00	15-S2.5	119,877,761	25-L1.5	44,871,902	44,857,170	44,871,902	44,871,902
482.00	40-R1.5	302,463	N/A	302,463	302,463	302,463	302,463
482.01	40-R1.5	5,780,346	N/A	5,780,346	5,780,346	5,780,346	5,780,346
482.04	40-R1.5	0	N/A	-	-	-	-
482.05	40-R1.5	1,562,381	N/A	1,562,381	1,562,381	1,562,381	1,562,381
482.51	40-R1.5	4,945,676	N/A	4,945,676	4,945,676	4,945,676	4,945,676
482.52	40-R1.5	3,164,180	N/A	3,164,180	3,164,180	3,164,180	3,164,180
483.00	15-SQ	1,732,767	N/A	1,732,767	1,732,767	1,732,767	1,732,767
484.00	12-L2.5	6,708,608	N/A	6,708,608	6,708,608	6,708,608	6,708,608
485.00	17-L1.5	4,305,666	N/A	4,305,666	4,305,666	4,305,666	4,305,666
486.00	15-SQ	10,258,875	N/A	10,258,875	10,258,875	10,258,875	10,258,875
487.70	15-SQ	250,902	N/A	250,902	250,902	250,902	250,902
487.80	20-SQ	352,999	N/A	352,999	352,999	352,999	352,999
488.00	10-SQ	2,088,746	N/A	2,088,746	2,088,746	2,088,746	2,088,746
490.00	4-SQ	3,990,450	N/A	3,990,450	3,990,450	3,990,450	3,990,450
490.00 (Post 2023)	4-SQ	1,958,107	N/A	1,958,107	1,958,107	1,958,107	1,958,107
490.30	10-SQ	0	N/A	-	-	-	-
491.01	4-SQ	10,638,821	N/A	10,638,821	10,638,821	10,638,821	10,638,821
491.01 (Post 2023)	4-SQ	2,158,742	N/A	2,158,742	2,158,742	2,158,742	2,158,742
491.02	4-SQ	3,730,251	N/A	3,730,251	3,730,251	3,730,251	3,730,251
491.02 (Post 2023)	4-SQ	2,520,837	N/A	2,520,837	2,520,837	2,520,837	2,520,837
491.03	10-SQ	9,922,379	N/A	9,922,379	9,922,379	9,922,379	9,922,379
Software Intangibles - 10YR	10-SQ		N/A				
491.04	10-SQ	9,153,052	N/A	9,153,052	9,153,052	9,153,052	9,153,052
Sub-total		877,451,863		663,419,957	630,229,839	587,151,095	744,088,200
RNG and Sales-type lease assets		1,532,536		1,532,536	1,532,536	1,532,536	1,532,536
2024 DEPRECIATION @ EGI OR INTERVENOR PROPOSED DEPRECIATION RATES		**878,984,399**		**664,952,493**	**631,762,375**	**588,683,631**	**745,620,736**

2024 DEPRECIATION @ CURRENT DEPRECIATION RATES (3)	**737,115,889**

NOTES

(1) Consistent with Capital Update at Exhibit 2, Tab 5, Schedule 4, Attachment 1
(2) See Exhibit J17.1 for details
(3) See Exhibit J16.5 for details

ENBRIDGE GAS INC. DEPRECIATION PROVISION COMPARISON - AVERAGE LIFE GROUP

				INTERVENOR PROPOSALS/SCENARIOS			
Asset Account	Concentric Recommended Life and Curve (1)	ALG + Concentric Life and Curve CDNS 3.75% (2)	Board Staff Recommended Life and Curve	ALG + Intervenor Life and Curve CDNS 3.75%	ALG + Intervenor Life and Curve CDNS 4.48%	ALG + Intervenor Life and Curve CDNS 6.03%	ALG + Intervenor Life and Curve Traditional Method
442.00	40-S5	118,854	N/A	118,854	118,854	118,854	118,854
443.01	45-R4	65,369	N/A	65,369	65,369	65,369	65,369
443.02	55-R4	228,866	N/A	228,866	228,866	228,866	228,866
451.00	55-R4	1,070,580	N/A	1,070,580	1,070,580	1,070,580	1,070,580
452.00	45-R3	2,570,461	45-R2.5	2,442,812	2,335,684	2,244,001	2,735,364
453.00	45-R2.5	4,778,828	N/A	4,778,828	4,390,523	3,873,096	6,073,164
454.00	40-R2	164,917	N/A	164,917	164,917	164,917	164,917
455.00	55-R3	8,643,932	N/A	8,643,932	8,406,954	8,169,975	9,473,352
456.00	40-R4	19,658,806	44-R4	16,636,390	16,335,988	15,740,817	17,848,713
457.00	35-R3	4,714,423	40-R2.5	3,501,792	3,304,757	3,011,746	4,191,786
461.00	60-R4	1,457,089	N/A	1,457,089	1,457,089	1,457,089	1,457,089
462.00	50-S4	3,338,770	N/A	3,338,770	3,290,181	3,193,003	3,581,717
463.00	55-S4	150,739	N/A	150,739	146,248	141,769	168,748
464.00	30-L0.5	116,069	N/A	116,069	117,501	114,636	123,224
465.00	60-R4	48,757,344	70-R4	38,830,845	37,139,387	35,461,256	41,667,588
466.00	30-R4	35,588,987	N/A	35,588,987	34,935,776	34,311,923	37,451,332
467.00	40-R4	14,119,524	N/A	14,119,524	13,717,267	12,913,471	16,148,824
471.00	60-R4	1,138,109	N/A	1,138,109	1,135,064	1,138,109	1,138,109
472.00	40-S0.5	5,358,729	N/A	5,358,729	5,358,729	5,358,729	5,358,729
472.31	40-S0.5	1,350,235	N/A	1,350,235	1,350,235	1,350,235	1,350,235
472.32	40-S0.5	1,004,164	N/A	1,004,164	1,004,164	1,004,164	1,004,164
472.33	40-S0.5	2,670,266	N/A	2,670,266	2,670,266	2,670,266	2,670,266
472.34	40-S0.5	712,552	N/A	712,552	712,552	712,552	712,552
472.35	40-S0.5	2,550,168	N/A	2,550,168	2,550,168	2,550,168	2,550,168
473.01	40-S0.5	22,576,607	N/A	22,576,607	21,399,920	18,420,184	29,900,799
473.02	55-S3	124,004,969	N/A	124,004,969	115,420,448	104,387,006	157,952,828
474.00	25-SQ	46,298,774	N/A	46,298,774	46,298,774	46,298,774	46,304,967
475.00	25-SQ	10,469,399	N/A	10,469,399	10,469,399	10,469,399	10,469,399
475.21	55-R3	113,122,032	61-R3	104,181,989	81,169,809	67,746,037	135,350,079
475.30	60-R4	99,402,770	65-R3	95,966,796	75,516,696	65,684,917	120,290,516
476.00	17-S2.5	429,221	N/A	429,221	429,221	429,221	429,221
477.00	40-R2	24,955,061	N/A	24,955,061	24,652,043	23,785,031	26,723,076
477.01	35-R3	4,857,045	N/A	4,857,045	4,857,045	4,857,045	4,857,045
478.00	15-S2.5	104,685,609	N/A	104,685,609	104,685,609	104,685,609	104,685,609
482.00	40-R1.5	211,833	N/A	211,833	211,833	211,833	211,833
482.01	40-R1.5	5,592,980	N/A	5,592,980	5,592,980	5,592,980	5,592,980
482.04	40-R1.5	0	N/A	-	-	-	-
482.05	40-R1.5	1,404,042	N/A	1,404,042	1,404,042	1,404,042	1,404,042
482.51	40-R1.5	4,258,936	N/A	4,258,936	4,258,936	4,258,936	4,258,936
482.52	40-R1.5	3,129,402	N/A	3,129,402	3,129,402	3,129,402	3,129,402
483.00	15-SQ	1,889,229	N/A	1,889,229	1,889,229	1,889,229	1,889,229
484.00	12-L2.5	5,440,686	N/A	5,440,686	5,440,686	5,440,686	5,440,686
485.00	17-L1.5	3,288,351	N/A	3,288,351	3,288,351	3,288,351	3,288,351
486.00	15-SQ	10,258,875	N/A	10,258,875	10,258,875	10,258,875	10,258,875
487.70	15-SQ	250,902	N/A	250,902	250,902	250,902	250,902
487.80	20-SQ	357,020	N/A	357,020	357,020	357,020	357,020
488.00	10-SQ	2,088,746	N/A	2,088,746	2,088,746	2,088,746	2,088,746
490.00	4-SQ	4,217,378	N/A	4,217,378	4,217,378	4,217,378	4,217,378
490.00 (Post 2023)	4-SQ	1,958,107	N/A	1,958,107	1,958,107	1,958,107	1,958,107
490.30	10-SQ	0	N/A	-	-	-	-
491.01	4-SQ	10,810,743	N/A	10,810,743	10,810,743	10,810,743	10,810,743
491.01 (Post 2023)	4-SQ	2,158,742	N/A	2,158,742	2,158,742	2,158,742	2,158,742
491.02	4-SQ	3,824,244	N/A	3,824,244	3,824,244	3,824,244	3,824,244
491.02 (Post 2023)	4-SQ	2,520,837	N/A	2,520,837	2,520,837	2,520,837	2,520,837
491.03	10-SQ	10,111,622	N/A	10,111,622	10,111,622	10,111,622	10,111,622
Software Intangibles - 10YR	10-SQ		N/A				
491.04	10-SQ	9,153,052	N/A	9,153,052	9,153,052	9,153,052	9,153,052
Sub-total		794,054,995		767,389,783	709,831,809	666,754,539	877,242,977
RNG and Sales-type lease assets		1,532,536		1,532,536	1,532,536	1,532,536	1,532,536
2024 DEPRECIATION @ EGI OR INTERVENOR PROPOSED DEPRECIATION RATES		**795,587,531**		**768,922,319**	**711,364,345**	**668,287,075**	**878,775,513**

2024 DEPRECIATION @ CURRENT DEPRECIATION RATES (3)	**737,115,889**

NOTES

(1) Consistent with Capital Update at Exhibit 2, Tab 5, Schedule 4, Attachment 1
(2) See Exhibit J17.1 for details
(3) See Exhibit J16.5 for details

ENBRIDGE GAS INC. DEPRECIATION PROVISION COMPARISON - AVERAGE LIFE GROUP

		INTERVENOR PROPOSALS/SCENARIOS					
Asset Account	Concentric Recommended Life and Curve (1)	ALG + Concentric Life and Curve CDNS 3.75% (2)	IGUA Recommended Life and Curve	ALG + Intervenor Life and Curve CDNS 3.75%	ALG + Intervenor Life and Curve CDNS 4.48%	ALG + Intervenor Life and Curve CDNS 6.03%	ALG + Intervenor Life and Curve Traditional Method
442.00	40-S5	118,854	N/A	118,854	118,854	118,854	118,854
443.01	45-R4	65,369	N/A	65,369	65,369	65,369	65,369
443.02	55-R4	228,866	N/A	228,866	228,866	228,866	228,866
451.00	55-R4	1,070,580	N/A	1,070,580	1,070,580	1,070,580	1,070,580
452.00	45-R3	2,570,461	45-R2.5	2,442,812	2,335,684	2,244,001	2,735,364
453.00	45-R2.5	4,778,828	N/A	4,778,828	4,390,523	3,873,096	6,073,164
454.00	40-R2	164,917	N/A	164,917	164,917	164,917	164,917
455.00	55-R3	8,643,932	N/A	8,643,932	8,406,954	8,169,975	9,473,352
456.00	40-R4	19,658,806	44-R4	16,636,390	16,335,988	15,740,817	17,848,713
457.00	35-R3	4,714,423	40-R2.5	3,501,792	3,304,757	3,011,746	4,191,786
461.00	60-R4	1,457,089	N/A	1,457,089	1,457,089	1,457,089	1,457,089
462.00	50-S4	3,338,770	N/A	3,338,770	3,290,181	3,193,003	3,581,717
463.00	55-S4	150,739	N/A	150,739	146,248	141,769	168,748
464.00	30-L0.5	116,069	N/A	116,069	117,501	114,636	123,224
465.00	60-R4	48,757,344	70-R4	38,830,845	37,139,387	35,461,256	41,667,588
466.00	30-R4	35,588,987	37-R4	25,745,076	25,333,496	24,921,920	25,333,496
467.00	40-R4	14,119,524	N/A	14,119,524	13,717,267	12,913,471	16,148,824
471.00	60-R4	1,138,109	N/A	1,138,109	1,135,064	1,138,109	1,138,109
472.00	40-S0.5	5,358,729	N/A	5,358,729	5,358,729	5,358,729	5,358,729
472.31	40-S0.5	1,350,235	N/A	1,350,235	1,350,235	1,350,235	1,350,235
472.32	40-S0.5	1,004,164	N/A	1,004,164	1,004,164	1,004,164	1,004,164
472.33	40-S0.5	2,670,266	N/A	2,670,266	2,670,266	2,670,266	2,670,266
472.34	40-S0.5	712,552	N/A	712,552	712,552	712,552	712,552
472.35	40-S0.5	2,550,168	N/A	2,550,168	2,550,168	2,550,168	2,550,168
473.01	40-S0.5	22,576,607	50-L1	13,648,887	12,622,558	10,775,189	18,370,688
473.02	55-S3	124,004,969	60-S3	106,499,693	99,172,634	89,249,090	126,227,403
474.00	25-SQ	46,298,774	45-S1	12,747,503	12,747,503	12,747,503	12,747,503
475.00	25-SQ	10,469,399	N/A	10,469,399	10,469,399	10,469,399	10,469,399
475.21	55-R3	113,122,032	65-R3	80,019,200	71,197,864	60,075,310	120,290,516
475.30	60-R4	99,402,770	70-R2	71,821,396	64,698,850	56,132,796	67,542,687
476.00	17-S2.5	429,221	N/A	429,221	429,221	429,221	429,221
477.00	40-R2	24,955,061	N/A	24,955,061	24,652,043	23,785,031	26,723,076
477.01	35-R3	4,857,045	N/A	4,857,045	4,857,045	4,857,045	4,857,045
478.00	15-S2.5	104,685,609	25-L1.5	32,953,669	32,938,937	32,953,669	32,953,669
482.00	40-R1.5	211,833	N/A	211,833	211,833	211,833	211,833
482.01	40-R1.5	5,592,980	N/A	5,592,980	5,592,980	5,592,980	5,592,980
482.04	40-R1.5	0	N/A	-	-	-	-
482.05	40-R1.5	1,404,042	N/A	1,404,042	1,404,042	1,404,042	1,404,042
482.51	40-R1.5	4,258,936	N/A	4,258,936	4,258,936	4,258,936	4,258,936
482.52	40-R1.5	3,129,402	N/A	3,129,402	3,129,402	3,129,402	3,129,402
483.00	15-SQ	1,889,229	N/A	1,889,229	1,889,229	1,889,229	1,889,229
484.00	12-L2.5	5,440,686	N/A	5,440,686	5,440,686	5,440,686	5,440,686
485.00	17-L1.5	3,288,351	N/A	3,288,351	3,288,351	3,288,351	3,288,351
486.00	15-SQ	10,258,875	N/A	10,258,875	10,258,875	10,258,875	10,258,875
487.70	15-SQ	250,902	N/A	250,902	250,902	250,902	250,902
487.80	20-SQ	357,020	N/A	357,020	357,020	357,020	357,020
488.00	10-SQ	2,088,746	N/A	2,088,746	2,088,746	2,088,746	2,088,746
490.00	4-SQ	4,217,378	N/A	4,217,378	4,217,378	4,217,378	4,217,378
490.00 (Post 2023)	4-SQ	1,958,107	N/A	1,958,107	1,958,107	1,958,107	1,958,107
490.30	10-SQ	0	N/A	-	-	-	-
491.01	4-SQ	10,810,743	N/A	10,810,743	10,810,743	10,810,743	10,810,743
491.01 (Post 2023)	4-SQ	2,158,742	N/A	2,158,742	2,158,742	2,158,742	2,158,742
491.02	4-SQ	3,824,244	N/A	3,824,244	3,824,244	3,824,244	3,824,244
491.02 (Post 2023)	4-SQ	2,520,837	N/A	2,520,837	2,520,837	2,520,837	2,520,837
491.03	10-SQ	10,111,622	N/A	10,111,622	10,111,622	10,111,622	10,111,622
Software Intangibles - 10YR	10-SQ		N/A				
491.04	10-SQ	9,153,052	N/A	9,153,052	9,153,052	9,153,052	9,153,052
Sub-total		794,054,995		577,521,476	549,116,619	512,075,566	648,772,810
RNG and Sales-type lease assets		1,532,536		1,532,536	1,532,536	1,532,536	1,532,536
2024 DEPRECIATION @ EGI OR INTERVENOR PROPOSED DEPRECIATION RATES		**795,587,531**		**579,054,012**	**550,649,155**	**513,608,102**	**650,305,346**

2024 DEPRECIATION @ CURRENT DEPRECIATION RATES (3)	**737,115,889**

NOTES

(1) Consistent with Capital Update at Exhibit 2, Tab 5, Schedule 4, Attachment 1
(2) See Exhibit J17.1 for details
(3) See Exhibit J16.5 for details