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September 19, 2023

Ms. Nancy Marconi
Registrar
Ontario Energy Board
P.O. Box 2319
26th Floor
2300 Yonge Street
Toronto, ON
M4P 1E4

DELIVERED BY EMAIL

Dear Ms. Marconi,

RE: EB-2023-0200 - Enbridge Gas Inc. - 2024 Rate Application Phase 1

Please find enclosed the submissions of the Ontario Greenhouse Vegetable Growers in the above noted proceeding.

Yours very truly,

Michael R. Buonaguro
Encl.

ONTARIO ENERGY BOARD

Ontario Greenhouse Vegetable Growers Submission

Enbridge Gas Inc.

2024 Rates Application – Phase 1 EB-2022-0200

September 19, 2023

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Introduction

1. These are the submissions of the Ontario Greenhouse Vegetable Growers (OGVG) with respect to the unsettled issues in Enbridge Gas Inc.'s (EGI) 2024 Cost of Service Application.

2. OGVG has reviewed the submission filed by OEB Staff and believes that those submissions serve as a suitable starting point from which OGVG will provide its position on a select number of specific issues.

3. OGVG's submissions are organized in the same order that witness panels were organized in the hearing of the application. Where OGVG is silent on an issue it is because the resolution of the issue will not impact its members in a direct or material way or, alternatively, OGVG believes that the submission of other intervenors that have shared their draft submissions or the submissions of OEB Staff have adequately responded, where necessary, to the EGI position.

Energy Transition

4. OGVG generally agrees with OEB Staff's assessment of the issues facing EGI and its various stakeholders with respect to Energy Transition. Regardless of the "path" that Energy Transition takes, it will almost certainly involve material declines in gas usage and declining (and likely negative) growth in customer attachments as certain customer segments turn to electrification. Indeed, OGVG recognizes that by 2050, the notional "net zero" target date, the EGI customer base and system may look very different than the customer base and system that exists today.

5. At the same time, however, OGVG recognizes that, today:

    a) the precise scope and pace with which customers will disconnect from natural gas service is unknown;

    b) there are customer groups, such as greenhouse operators, that have a significant and specific interest in natural gas service over the long term;

    c) there are currently over 3.9 million customers that rely on natural gas service from EGI with more being added, some with the aid of provincial funding;

    d) there is approximately $16B in net assets being utilized to provide service to those customers, assets that continue to require maintenance and, in some instances, replacement in the near term to maintain the safety and integrity of EGI's system regardless of how long the replacement assets will be fully utilized; and

    e) integrated resource planning (IRP) is in its infancy in Ontario, with EGI having yet to complete its initial analysis of its "status quo" asset management plan (AMP) to convert it to an Energy Transition responsive plan, and a lack of meaningful participation from counterparties like local electricity distribution companies in EGI's IRP process to provide options that EGI cannot currently undertake.

6. To that end OGVG agrees with the OEB Staff submission, which in turn relies on the OEB submission to the provincial Electrification and Energy Transition Panel (EETP) asserting that:

> *The work of the energy sector to facilitate the energy transition – including that of the OEB – will be iterative. Given uncertainties related to the pace of change, the OEB will ensure that our approach to regulation remains adaptable, flexible, and responsive to changing expectations and needs. The energy transition represents massive change; but not all problems need to be solved immediately. Instead, an incremental and prioritized approach that tackles issues one at a time will allow us to move forward, assess and change course as necessary.*[1]

7. To the extent that OGVG believes there are impacts that need to be accounted for because of Energy Transition issues OGVG's position on the relevant issues reflects what OGVG believes to be the appropriate incremental response.

Equity Thickness

8. OGVG did not sponsor an expert on the issue of equity thickness, relying instead on the experts retained by IGUA and OEB Staff to provide evidence and analysis in response to the evidence and proposal brought forward by EGI. Accordingly, OGVG does not propose to make comprehensive submissions on the appropriate equity thickness.

9. OGVG would like to, however, provide the following specific submission with respect to EGI's claim with respect to stranded asset risk as it relates to equity thickness.

10. In its application EGI cites Energy Transition and the related increased risk of stranded assets as one of the most significant factors impacting its business risk:

> *. . . energy transition has become the most significant factor contributing to increased business risk for Enbridge Gas, as evidenced by findings in the Equity Ratio Study:*
>
> *. . .*
>
> *There is increased risk of stranded assets. This risk could be mitigated by accelerating depreciation rates (e.g., through an EPH), however this will increase rate pressure for customers and may result in natural gas becoming less competitive than alternative energy sources;*[2]

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[1] Report of the Ontario Energy Board to Ontario's Electrification and Energy Transition Panel, p. 12.

[2] Exhibit 1 Tab 10 Schedule 4 pp. 18 and 19.

11. In response to these assertions OGVG sought to clarify how stranded assets are currently handled from both a regulatory and accounting perspective to understand the asserted risk to EGI; in its initial response EGI did not appear to be able to provide a clear answer:

From a regulatory perspective, to Enbridge Gas's knowledge, there is no prescribed treatment for stranded assets or the costs related to stranded assets. While Enbridge Gas believes that prudently incurred cost of assets which become stranded should be recoverable, the manner in which they could be recovered could be dependent upon the circumstances leading up to the time they become stranded/abandoned. For instance, where the stranding of assets is seen well in advance, the costs could be charged to ratepayers through higher depreciation rates (e.g. through an economic planning horizon) included within rates, for a period of time leading up to, and/or after, the stranding (where other assets/customers continue to exist). Another possible option could be that at the time the assets become stranded, the retirement is treated as an extraordinary retirement, and a loss would be included within rates. It is also possible that should such a situation arise, the OEB could order or approve some other mechanism for recovery.

From an accounting perspective, Enbridge Gas is not able to answer this question with certainty because it would depend upon the circumstances leading up to the assets becoming stranded and the costs related to stranded assets. Enbridge Gas follows the provisions of US GAAP for the accounting treatment of property, plant and equipment and, in the event of a stranded asset, would generally rely on the guidance found in ASC 360 (Property, Plant and Equipment) and ASC 980 (Regulatory Operations) for determining the accounting treatment of stranded asset costs.[3]

12. OGVG followed up on this answer in the technical conference, at which time EGI was able to provide further clarification by way of undertaking as to when, if ever, EGI expected to experience stranded costs:

In Scenario 1, where a single customer disconnects from the system, the assets would not be considered stranded as they are considered as part of typical retirements already contemplated within the depreciation study. In such instances, the Company may not even know why the customer is disconnecting (e.g. an existing structure is being demolished with intent is to build a new structure in the future).

In Scenario 2, where an entire neighbourhood disconnects from the system resulting from a change in government policy, the assets would meet Enbridge

[3] Exhibit I.1.10-OGVG-1 p. 2.

Gas's definition of stranded assets if they cannot be repurposed to remain used or useful.

However, Enbridge Gas does not believe there would be stranded asset costs in either scenario, to the extent the scenarios were reasonably contemplated in prior depreciation studies. From an accounting and regulatory perspective, Enbridge Gas applies group depreciation procedures to plant assets, including gas meters and distribution service lines. If the assets disconnected are retired before their expected average service life is reached (as reflected for the group), the implied loss is captured in accumulated depreciation. The loss would be reflected in subsequent depreciation studies and recovered through depreciation expense over the remaining life of the assets left within the group.

Enbridge Gas expects that large scale retirements (e.g. municipalities transitioning to full electrification) as a result of changes in market conditions or government policies would be implemented over an extended period of time and would be communicated in advance. As a result, subsequent depreciation studies reflecting the need for accelerated depreciation and economic planning horizons, or some other regulatory mechanism, could be implemented to address stranded asset costs.[4]

13. Based on this answer it appears to OGVG that, while there may be an increased risk of stranded assets as a result of Energy Transition, there appears to be no or minimal risk of stranded costs, at least not to EGI, as their depreciation policies would nevertheless recover the related costs over time. Rather, the risk of stranded costs is something that EGI believes is borne by ratepayers.

14. Furthermore, it appears to OGVG, the risk of material stranded assets in the period covered by EGI's proposed 5-year IRM term is, based on their own assessment, purely hypothetical.

15. For these reasons OGVG respectfully submits that in considering EGI's request for an increase in equity thickness in response to an apparent increase in stranded asset risk that the OEB recognize that any such risk does not exist in any material sense in the short term covered by this rate application and EGI's proposed 5 year IRM term, and even to the extent such a risk does materialize in the future EGI's position is that the status quo regulatory and accounting regimes serve to protect EGI against the costs of stranded assets.

16. To be clear, OGVG does not necessarily believe that EGI should be protected against stranded cost risk in the way EGI describes going forward for all time; it is simply that in the near term, OGVG respectfully submits, it is not a material issue that needs to be addressed. To that end OGVG agrees with OEB Staff's assessment of the potential next steps as they relate to the allocation of stranded asset risk:

[4] Exhibit JT2.14

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

OEB staff notes that there are many details that would need to be addressed prior to establishing any mechanistic risk sharing approach. Should the OEB wish to further explore these ideas, these matters may be better addressed through a policy consultation or generic hearing on this topic. OEB staff notes that a review of natural gas stranded assets and risk allocation was listed as a potential future initiative of the OEB in the OEB's most recent business plan. Alternatively, this can be considered as part of Enbridge Gas's next rebasing application.[5]

Customer Attachment Policies (Revenue Horizon)

17. OGVG's members and potential members are generally larger contract class size customers that, under the existing E.B.O. 188 policy guidelines, are subject to a 20-year revenue horizon when their costs of connection are being evaluated. In addition, the OEB's recent decision in EB-2020-0094 provides for the use of EGI's Hourly Allocation Factor framework to directly allocate cost responsibility for distribution projects under E.B.O. 188 to large customers, with those customers being required to produce a Profitability Index of 1.0 or better for their allocation of a distribution project's costs either through a confirmed term of service and related revenue or through a Contribution in Aid of Construction (CIAC).

18. Accordingly, the issue raised in the hearing with respect to proposed reduction in the revenue horizon for residential and other small customers for use in the discounted cash flow analysis underpinning the E.B.O. 188 evaluation of their connection costs from 40 years to a shorter term does not have a direct impact on OGVG's members or potential members in terms of their costs to connect to EGI's system. Furthermore, in the event the revenue horizon is shortened, existing and future greenhouse customers of EGI would benefit from a reduced total rate base, which in turn would reduce greenhouse operator's future risk should EGI seek to recover future stranded costs from all customers rather than matching stranded asset costs with the classes for whom those assets were purchased in the first instance.[6]

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[5] OEB Staff Submission p. 50.

[6] OGVG expects that it remains an open question as to how, in the future, stranded costs related to assets stranded by departing residential customers, for example, will or will not be recovered from the contract rate classes.

19. OGVG does maintain an interest, however, in ensuring that changes such as the one that is being proposed treat both existing and future new customers fairly.

20. OGVG understands the concern that assuming that newly connected residential and other small customers will remain connected for 40 years may no longer be appropriate in the context of a period of energy transition where there is evidence that many if not most small customers that currently seek to connect to natural gas service primarily for space heating will, within a period shorter than 40 years, fully disconnect from the natural gas system in favour of electrification.

21. At the same time OGVG recognizes that, at least in theory, applying a revenue horizon materially below 40 years for new customers going forward when the rates charged to those customers remain based on an assumed 40-year revenue horizon for EGI's existing 3.9 or so million customers may result in a subsidy paid by new customers to existing customers.

22. That such a subsidy may exist is most obvious in the extreme example where new customers are required to pay 100% of the costs associated with the meters, regulators and services that connect them to the distribution system. Under this scenario it is, OGVG would argue, relatively clear that charging those new customers existing rates, which include an allocation of the meter, regulator, and service costs associated with existing customers, constitutes a material subsidy from new customers to existing customers that would warrant consideration of a separate, new rate class for "new" customers that does not include an allocation of capital costs that they have already fully funded.

23. That such a subsidy may exist is also illustrated in an example where new customers are charged a CIAC calculated on the basis of current rates that assume a "normal" life curve for the purposes of the depreciation cost associated with connection assets, and then the depreciation cost for those assets are subsequently increased using an economic planning horizon (EPH) in order to accelerate the recovery of costs from the pre-existing customers that had originally benefitted from a 40 year revenue horizon. In such a scenario had the economic evaluation been conducted using the newer, higher depreciation costs caused by the EPH there is the possibility that any resulting CIAC would have been much lower if not eliminated. In OGVG's view this scenario demonstrates the possible complications of, essentially, treating new customers as though the costs of their connection assets need to be recovered over a (for example) 20-year horizon even though those assets are included in rates over a horizon that may be 40 years or longer (i.e. for services); if and when those assets are included in rates on the basis of a shorter amortization period those new customers will have, OGVG expects, overpaid their connection costs relative to other customers.

24. OGVG notes, by way of further example, the impact on depreciation expense on just one category of connection asset, plastic pipes, of imposing EPHs in conjunction with various revenue horizons as requested by Commissioner Moran though Exhibit J18.5 b). Materially increasing rates to recover the added depreciation expense for plastic services through an

EPH in the amounts set out in J18.5 would, in turn, materially impact the economic analysis for any new connecting customer. Using the most drastic example, an EPH of 10 years increases depreciation expense, for that one asset category, by $611.2M; divided by the current customer base provides, roughly calculated, an increase in annual rate recovery per customer by more than $156 per year.[7] Depending on whether the economic analysis underpinning any required CIAC was performed before or after an EPH was imposed, and depending on how many categories of asset become subject to an EPH, it is probable, OGVG submits, that the new customers being attached to the system under a materially reduced revenue horizon (and consequentially paying a higher CIAC where, under a 40 year horizon, a lower or no CIAC would have been required) will materially subsidize existing customers.

25. For these reasons OGVG respectfully submits that it may be prudent to evaluate the impact of shortening the revenue horizon more fully for new residential and other small customers from 40 years to a lesser number to ensure that, in trying to avoid a cross subsidy between existing customers and new customers, the result is not the creation of a subsidy between new customers and existing customers.

Capital Expenditures and Asset Management Plan (AMP) Including IRP

The Impact of 2024 Spending on the 2024 Revenue Requirement

26. OGVG's position on an appropriate capital budget for the purpose of setting the 2024 Revenue Requirement is informed largely by three factors:

    a) the proposed updated capital budget of $1.47B for 2024 is consistent with historical spending by EGI over the 2013 to 2023 period, accounting for inflation and the fact that all materially large expansion and reinforcement projects have been subject to review by the OEB through leave to construct applications;

    b) the revenue requirement impact of EGI's proposed 2024 in service additions on the 2024 revenue requirement is relatively modest at $10M,[8] such that even drastic cuts to the proposed forecast capital budget on an envelope basis would fail to produce material reductions to EGI's proposed 2024 rates, and in many cases would increase the revenue requirement for 2024 (because for many assets the revenue requirement in the year the asset is placed in service is negative as a result of the impact of CCA deductions from income tax); and

    c) while Energy Transition concerns dictate that EGI, under any reasonable view of the future, must materially change its approach to capital spending, that change will be manifested through a combination of the OEB's approved IRP framework, the statutory

[7] OGVG simply divided the incremental depreciation expense of $611.2M by the total 2024 forecast number of customers per Exhibit I.3.2-OGVG-4 Attachment 1.
[8] Exhibit I.2.2-OGVG-3 d).

requirement for leave to construct under s. 90 of the OEB Act, and already implemented changes to the rigour with which EGI determines its ability to defer capital spending, i.e. the introduction of the EDIMP program.

The Status Quo 2024 Capital Budget is Adequate for the Purpose of Setting 2024 Rates

27. Given that EGI has yet to complete its IRP analysis of its AMP OGVG believes it is fair to characterize the current 2024 (and beyond) budget as a "status quo" budget reflecting EGI's pre-Energy Transition approach to capital planning, subject to ongoing change and modification because of the impact of Energy Transition issues both internally because of IRP analysis and externally because of ongoing changes in Energy Transition policies.[9]

28. Seen through the lens of a "status quo" budget, OGVG respectfully submits that the proposed budget of $1.47B is in line with historical spending for EGI over the 2014 to 2023 period. OGVG came to this conclusion as a result of its review of the annual line by line spending for EGI over the 2014 to 2023 period, with capitalized overheads separately accounted for so as to provide a true year over year view of direct spending in each category, and spending subject to leave to construct approval separately accounted for so as to provide a clean view of the annual spending that EGI has undertaken over the past decade without direct OEB oversight.[10]

29. In OGVG's review it appears that, outside of LTC and capitalized overhead spending, the material differences between the 2024 proposed capital spend and the preceding 10-year history are largely explained by:

    a) a material ($124M) budget for "other" spending, which is entirely made up of RNG injection station and CNG station spending that is new relative to historical years and which is directly recovered from the customers for whom those stations are being built;

    b) a material and sustained increase in the "utilization" budget as a result of increased meter costs;

    c) a sustained increase in customer connection costs, driven by customer demand and therefore subject to increase and decrease outside of the direct influence of EGI; and

    d) inflationary pressures on costs over time.

30. It appears to OGVG that OEB Staff reached a similar conclusion. Although OEB staff does recommend a cut to the 2024 budget of $271.5M, OGVG notes that:

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[9] OEB Staff came to a similar conclusion at page 35 of their submission, asserting "that the capital budget is based on a traditional facilities solution for all system needs".

[10] Exhibit J14.5 Attachment 1.

a) $75.7M of that proposed reduction relates to the proposed St. Lauren Phases 3 & 4 project but only pending LTC approval; and

b) $131.2M of the proposed reduction relates to OEB Staff's position on the appropriate revenue horizon to be used for the economic evaluation small customer connections, and not the prudence of the proposed spend based on the status quo application of E.B.O. 188 parameters.

31. More importantly, in the context of an application to set rates, 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.

32. By way of example and as noted above, OEB Staff has suggested that the St. Laurent Phases 3 & 4 spending be lifted out of the 2024 capital budget and provided similar treatment as what EGI has proposed for the Panhandle Regional Expansion Project, since the project remains subject to a leave to construct application.

33. In OGVG's view this measure is unnecessary for two reasons:

a) the revenue requirement impact of the St. Laurent spending is a sufficiency of $2M.[11] In other words, removing that spending from the 2024 capital budget will increase rates; and

b) EGI, understanding the risk that the St. Laurent spending remains subject to leave to construct, nevertheless has maintained that spending, including the related $2M revenue sufficiency, in its application, as would be expected in the normal course.

34. In the event the St. Laurent project does not receive leave to construct then EGI will not go ahead with that spending and it will never impact EGI's approved rate base.

35. Accordingly, in OGVG's view, the OEB is in the position of being able to accept the proposed 2024 capital budget and related in service addition forecast for the purpose of setting 2024 rates without a concern that 2024 rates will be materially higher or lower than what is just and reasonable as a result of variations between the forecast used for rate setting purposes and the actual spending incurred by EGI in 2024.

Future Approval of 2024 and Beyond Capital Spending

36. Having suggested that the applied for budget for 2024 is acceptable for 2024 rate making purposes, OGVG recognizes that spending in 2024 will impact rates in subsequent years on rebasing when EGI brings forward its actual 2024 spending for inclusion in rate base, in the

[11] Exhibit J13.1

same way EGI has brought forward its 2013 to 2022 actual spending for approval and inclusion in rate base in this proceeding. Accordingly, it is important that upon bringing forward actual 2024 and beyond spending for inclusion in rate base in future proceedings EGI is held to its obligations under the IRP framework to demonstrate that its spending was prudent within the confines of that new regulatory paradigm.

37. Put another way, in OGVG's view approval of the proposed 2024 capital budget for the purpose of setting 2024 rates should not be considered as approval of the proposed 2024 capital budget for inclusion in rate base in a future proceeding. In any such future proceeding EGI will have to demonstrate that its original, "status quo" based 2024 capital budget has been appropriately constrained through the IRP process.

38. OGVG recognizes that OEB Staff has provided extensive proposals with respect to the IRP Process going forward. OGVG also recognizes that several intervenors involved in the IRP Technical Working Group have raised concerns about the effectiveness of EGI's IRP process to date and will make submissions about how the process can be improved going forward. To that end relies on the submissions of OEB Staff and intervenors involved in the IRP process to provide constructive proposals for how the IRP process can be improved going forward.

IRP-Expectations for 2024 and Beyond

39. While OGVG supports the notion that the IRP framework is and should be the primary mechanism through which EGI transforms its capital planning from the current status quo approach to an approach that meets the expectations of the Energy Transition, OGVG recognizes that there are limitations on the impact that the current IRP framework can have on EGI's capital obligations.

40. First, IRP solutions that EGI can reasonably implement require lead time; accordingly, OGVG is sceptical that IRP will have a significant impact on EGI's proposed 2024 capital budget. OGVG notes, for example, that the pilot projects EGI is undertaking pursuant to the IRP Decision are only just now coming forward for approval under EB-2022-0335. OGVG does expect, however, that as EGI is able to process capital spending further out into its AMP that the impacts of IRP on the status quo proposals will become more substantial.

41. Second, and in OGVG's opinion most importantly, it appears that EGI is currently, amongst regulated entities, alone in its IRP endeavor. It seems obvious to OGVG that IRP will be most effective when, for example, regulated electricity distributors in Ontario have a fully articulated mandate to engage in the IRP process alongside EGI to offer alternatives that EGI simply cannot provide.

42. EGI is limited in its ability to offer IRP alternatives to its status quo infrastructure solutions in no small part because it can only recover its IRP costs from its own natural gas customers. OGVG's position in the IRP Framework proceeding (a position it continues to hold) is that

while electrification as an IRP alternative should obviously be considered and pursued where cost effective, it is inappropriate to have natural gas customers fund the cost of either disconnecting or avoiding the connection of customers to EGI's system; those are costs that are appropriately recovered from electricity customers.[12] This position, OGVG respectfully submits, is reflected in the IRP Framework, within which EGI is currently prevented from engaging in activities that involve electrification.

43. During the hearing EGI acknowledged that while the goal is, certainly, to have local electricity distributors engaged in IRP related discussions, that engagement does not currently occur on an IRP project analysis level:

MR. BUONAGURO: Well, I'm trying to understand if there is a point at which you are sitting down with, and I guess I'll use the example, the local electricity distributor and saying, there is an energy need here. Right now, we're serving that, and I'm going to give an example off the top of my head. We are serving this energy need now because we have a pipeline in there providing gas. That is seven[ty] years old and it is deteriorating, and we think we have to go in there and replace it. And we are looking at alternatives through the IRP process, which [we] are obligated to do, and one of the options might be repairing the pipe, for example, or the bests option from your perspective would be to replace the pipe.

Is there ever an opportunity, or does it happen, that, on the other side of that, the local distributor says, Well, maybe we run a fuel switching program and get all the customers connected to that pipe off the system and we convert them to electricity completely? Is that the kind of conversation you are having, or is that not happening yet?

MS. WADE: Yes, so that's a great question. And it links, I think, very closely into the safe bet of integrated planning that we've included within our energy transition plan.

So, the discussions that we're having -- I'll use Parry Sound again as an example -- have been around: Is our demand accurate? Do you have any programs planned, for example, just as you've said, to fuel switch customers?

We have not yet gotten down into that next level of detail. So we've started these discussions. We are proactively trying to reach out to some LDCs. We are having conversations with the IESO to understand what planning looks like for them and how this could unfold and do just what you're saying. I think, even one step further, it would be doing that ahead of the need even coming forward, so looking at our system, understanding, you know, from a broader, longer-term forecast what could this look like. So those very detailed, system-specific

[12] EB-2020-0091, OGVG Submissions dated March 31, 2021, p. 8.

conversations have not yet occurred, but we, as part of our safe-bet proposal, that's absolutely what we're thinking about.

MR. BUONAGURO: Okay, so it's not happening yet, but that's the plan?

MS. WADE: Yes, and so I would maybe just touch on something that Ms. Giridhar and I noted, as well, that, as part of the electrification and energy-transition panel -- this is obviously a key focus for them -- one of their engagement sessions that they held with stakeholders was focused on just this and understanding how do we make this happen in an effective and efficient way in a province that has roughly 65 LDCs and one big electric planner for transmission, obviously the IESO. So we're hoping out of that there will be some guidance around how exactly this could be structured in the province so that there is a charter, there is consensus on the approach to this, the outcomes that we are looking to achieve, and hopefully, you know, a facilitator to help guide those discussions so that the outcomes can achieve what we're hoping.[13]

44. In other words, any time EGI reviews a particular capital project for IRP alternatives, there is no entity directly involved in the process with the resources, access to ratepayer funding and mandate to advance cost-effective electrification-based IRP alternatives for consideration. In OGVG's respectful submission unless and until entities like local electricity distributors with their own complementary IRP mandates are directly engaged by EGI at the project level the expectations of EGI's stand-alone IRP process should remain tempered.

Integration Capital

45. OGVG had not originally intended to make submissions with respect to the recoverability of the remaining $116M in integration capital related rate base. However, on reading OEB Staff's submission on the recoverability of integration related capital, OGVG feels compelled to make the following comments.

46. In OGVG"s respectful submission the OEB should be cautious not to oversimplify the circumstances of the Enbridge Gas Distribution Inc. and Union Gas Limited amalgamation by assuming that the OEB's MAADs Policy with respect to the amalgamation of electricity LDCs generally applies. In OGVG's view the OEB provided a framework for the deferred rebasing period for EGI that was tailored to the specific circumstances of its amalgamation; the OEB did not, it appears to OGVG, mechanically apply its MAADs policy, with the truncation of the deferral period to 5 years representing only an isolated exception to that framework.

47. To that end OGVG has been provided a preview of the submissions of SEC with respect to the recoverability of the costs of integration capital and supports those submissions as a reasonable analysis of the circumstances surrounding the amalgamation of Enbridge Gas

[13] Transcript Volume 14, pp. 47-49.

Distribution Inc. and Union Gas Limited and supports SEC's conclusion that under those circumstances recovery of the remaining undepreciated integration related capital costs should not be allowed.

Variance Accounts (APCDA)

OGVG Position

48. In OGVG's respectful submission the OEB should not permit EGI to recover the $155.2M that EGI is claiming within the APCDA with respect to Union Gas Limited related unamortized losses.

49. EGI admits that it already accounted for the unamortized losses in the purchase price paid to acquire Union Gas Limited.[14] Accordingly, OGVG respectfully submits, EGI has no claim in equity or fairness with respect to the unamortized losses; EGI's shareholder has already been compensated for the value of those losses in the purchase price it paid for Union Gas Limited. OGVG notes that SEC has provided a detailed analysis of this issue and relies on that submission in support of its position that EGI should not recover any amount for unamortized losses.

50. As acknowledged by EGI, recovery of the unamortized losses in rates is only possible through an OEB order permitting EGI to create a regulatory asset to be tracked in an appropriate deferral or variance account and brought forward for disposition.[15] in the absence of any such regulatory relief a $211.3M expense would have been fully realized in 2019, during EGI's IRM period.

51. During the hearing EGI repeatedly relied on the notion of the decoupling of costs from rates during IRM to suggest that the OEB should not consider the unamortized losses funding included in rates during the 2013 to 2023 period when considering the recoverability of the unamortized losses costs.[16]

52. In OGVG's respectful submission the moment EGI seeks to isolate a cost, like the unamortized losses amount, during an IRM period for regulatory asset treatment it is necessary to consider that request in the proper, full context, including consideration of the funding already included in rates for that cost in order to establish whether there is a need for the requested relief.

53. As demonstrated in exhibit K15.3 the unamortized losses funding included in rates from 2013 to 2023 is approximately $345.7M, an amount that not only offsets the unamortized losses expense claimed by EGI, it exceeds that amount by approximately $8.4M.

[14] Transcript Volume 15, pp. 78-79.
[15] Transcript Volume 15, pp. 85-86.
[16] Transcript Volume 15, p. 73.

54. Accordingly, EGI is not seeking recovery of $155.2M through the APCDA to keep itself whole with respect to unamortized losses expenses; EGI is seeking to maintain a windfall with respect to the disparity between the unamortized losses funding included in rates from 2013 to 2023 and the unamortized losses expense it says it would have realized over that same period if it had not been required to realize all the outstanding amortization losses upon amalgamation.[17] In OGVG's respectful submission that result would be wholly inappropriate; there is simply no burden related to unamortized losses during the 2013 to 2023 period that EGI needs to be protected against, and deferral and variance accounts are not intended as mechanisms to protect windfalls.

OEB Staff's Alternative Proposal

55. OGVG notes that OEB Staff has proposed an alternative recovery framework for the unamortized losses:

> *If the OEB approves the recovery of the pre-2017 Union unamortized gains/losses and views a reduction to the proposed amount as appropriate, OEB staff submits that the reduction should be equal to Union Gas's actual unamortized actuarial gains/losses for 2019 to 2023 net of the amortization that was embedded in base rates and already recovered for the same period.*[18]

56. In essence, OEB Staff's proposal allows EGI to retain the net benefit resulting from the disparity between the embedded unamortized losses expense in Union Gas Limited's 2013 rates and Union Gas Limited's realized unamortized losses expense between 2013 and 2018, and then nets the immediately realized $211.3M unamortized loss in 2019 against the actual amounts embedded in rates from 2019 to 2023, providing a partial "windfall" for EGI limited to the period between 2013 and 2018 and APDCA treatment from 2019 to 2023.

57. In calculating the amount embedded in rates from 2019 to 2023 OEB Staff assumes a fixed amount of $27.1M per year based on Union Gas Limited's 2013 distribution rates.

58. To be clear, OGVG continues to believe that EGI should not be allowed to recover any of the claimed $155.2M for the reasons already cited. However, in the context of OEB Staff's submission, OGVG notes that using a fixed amount of $27.1M per year from 2019 to 2023 materially understates the amount of amortization expense that was actually recovered in rates from over that period. As detailed in Exhibit K15.3, the amount recovered in rates over the 2019 to 2023 period is materially higher than $27.1M per year, with a base amount of

[17] OGVG notes that the annual amounts notionally expensed by EGI from 2019 to 2023 are fictional; they represent what "would" have been expensed absent the merger. In reality, as noted, the full outstanding amount of $211.3M was expensed in 2019;

[18] OEB Staff Submission p. 126.

$28.1M as opposed to OEB Staff's (incorrect) $27.1M, plus accumulated PCI and customer growth increases:

	Opening Balance	**2019**	**2020**	**2021**	**2022**	**2023**	**Remaining Balance**
Amount recovered per OEB Staff's incorrect Submission	211.3M	27.1M	27.1M	27.1M	27.1M	27.1M	75.8M
Amount recovered accounting for corrected base amount plus PCI Customer Growth (K15.3, line 11)	211.3M	31.8M	32.6M	33.5M	34.3M	35.8M	43.2M

59. Accordingly, using the OEB Staff approach after accounting for the proper base amount, PCI escalation and growth escalation, the amount to be disposed of in the account for unamortized losses would be reduced from $155.2M to $43.2M.

Depreciation Expense / Site Restoration Costs

Depreciation Methodology and Life Curves

60. OGVG's position with respect to depreciation expense is informed by the following facts:

   a) The differences between depreciation methodologies are ultimately a zero-sum game, in that while the pattern of depreciation expense can vary over time between methodologies, the total amount of depreciation expense recovered through rates is the same under all methodologies;

   b) there is a high likelihood that EGI's depreciation methodology as a component of its revenue requirement will be revisited, in detail, on a regular basis as EGI deals with the evolving nature of the Energy Transition; and

   c) under all reasonably plausible scenarios there will be a material decrease in load and customers connected to EGI's system, with the result that, at a minimum, distribution level assets that serve individual customers, like meters, services, and regulators, are going to become stranded assets more and more frequently.

61. With that context in mind OGVG does not have any fundamental objection to EGI's proposed depreciation expense based on the Equal Life Group methodology, recognizing that increased depreciation expense in early years results in lower rate base related expense in terms of the weighted average cost of capital and reduced risk of stranded asset costs in future years.

62. Having said that, OGVG recognizes that much of the increase in EGI's revenue requirement for 2024 is related to its proposed new depreciation methodology, and that, depending on the OEB's decision on other issues impacting the revenue requirement, it may be appropriate to use an alternative approach to EGI's depreciation expense to mitigate the rate impact of EGI's proposed revenue requirement.

63. To that end OGVG notes that all three of the depreciation experts that provided evidence in this proceeding confirmed that there was nothing preventing the OEB from utilizing different depreciation methodologies for different aspects of EGI's asset base.[19]

64. OGVG generally prefer ELG and aggressive life curves for distribution assets because distribution assets are most likely to become stranded each time an existing customer disconnects from the system. Distribution assets comprise approximately 73% of EGI total net plant; within distribution assets, services, meters, regulators and mains, the assets most directly connecting each customer to the distribution system, make up approximately 86% of the total asset pool.[20]

65. In OGVG's submission the OEB could mitigate the impact of the EGI application by utilizing the more conservative ALG methodology and Intergroup/Emrydia life curves for EGI's Storage, Transmission and General Plant assets in recognition of the fact that those assets are used more generally by its customers and are not as susceptible to becoming stranded or materially underutilized in because of the gradual transition of customers to full electrification.

66. Consistent with the updated information at Exhibit J17.6, the depreciation expense claimed by EGI based on the ELG methodology and the Concentric life curves is $879M using the CDNS methodology for net salvage at a rate of 3.75%.

67. Adjusting the depreciation expense claimed by EGI using the ALG methodology and the alternative life curves proposed by Intergroup and Emrydia for the Storage, Transmission, and General Plant asset groups reduces the claimed depreciation expense by $43.8M.[21]

Net Salvage

68. Both Intergroup and Emrydia challenged the accuracy of Concentric's calculation of net salvage to be included in rates based on the CDNS methodology, with Intergroup going so far as to suggest that the OEB might consider using the Traditional Method going forward. As detailed in OEB Staff's submissions, different combinations of ELG/ALG, asset life curves and discount rates produce a multiplicity of results. Ultimately OEB Staff proposed the use

[19] Transcript Volume 17, pages 61-62, 188-189, Transcript Volume 18, pp. 77-78.
[20] Exhibit 7 Tab 2 Schedule 1 Attachment 3 p. 2.
[21] Calculated using the updated information at Exhibit J17.6 starting from the ELG/Concentric life curve figures and then substituting the ALG/"Intervenor" Life Curves for all Transmission, Storage, and General Plan asset groups.

of CDNS methodology at an updated CARF rate of 4.48%, which appears, methodologically speaking, identical to EGI's proposal, although in making that recommendation OEB Staff notes that while a rate based on WACC may be more appropriate "in principle" it produces a materially lower amount of net salvage funding than what EGI expects to incur on an annual basis from 2023 to 2026.[22]

69. OGVG respectfully agrees with OEB Staff that, in this proceeding, the CDNS methodology at the updated CARF of 4.48% is a reasonable proposal, although not necessarily for the same reason cited by OEB Staff. OGVG notes that, as confirmed by Emrydia, the net salvage amount is not intended to match on annual basis the amount expended in the year.[23]

70. In OGVG's submission, pending further review of the actual net future salvage costs EGI expects to experience (an examination proposed by OEB Staff in its submission based at least in part on the inquiries put forward by the commissioners in Exhibits J18.1 and 18.2) the relatively more modest reduction in Net Salvage costs embedded in rates a as result of the proposed 4.48% rate makes sense in what OGVG believes is appropriately considered a transition year.

71. OGVG fully expects that as provincial policy is released and EGI comes back with updated responses to those policies, along with further and better information about the fate of the various components of its system in the long term, depreciation rates and net salvage requirements will likely change materially at least once if not multiple times going forward, and that it is better in terms of rate stability to embed only modest reductions to status quo rates now in order to avoid rate shock in the future. In OGVG's view if ratepayers continue to be credited for any excess depreciation and net salvage expense collected because of what turns out to be, in hindsight, overly aggressive depreciation and net salvage recoveries, it is better overall to have collected too much and be able to refund ratepayers than have collected too little and have to catch up.

Segregated Funds

72. OGVG generally agrees with both EGI and OEB Staff that establishing a segregated fund for future Site Restoration Costs is not currently necessary. Like OEB Staff, OGVG believes that the issue can and should be revisited in EGI next and subsequent rebasing applications as more information about the future of EGI's system and the related Site Restoration requirements become available.

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 19th DAY OF SEPTEMBER 2023

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[22] OEB Staff submission, pp. 89-92.
[23] Transcript Volume 18, p. 77.