EB-2022-0200

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.

SUBMISSIONS OF
CANADIAN MANUFACTURERS & EXPORTERS ("CME")

September 19, 2023

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Contents

1. Introduction & BAckground 4

2. The Energy Transition 5

2.2 Government Policy Has Not Provided a Net Zero Direction 6

2.3 The Potential for Hydrogen and Other Clean Fuel is Unknown 7

2.4 The Electricity Grid's Capacity to Accept Increased Demand is Unknown 8

2.5 EGI Should Study Which Assets are At Risk 9

3. Capital Spending 9

3.2 EGI's Mandatory Investments Do Not Necessarily Have Fixed Timing 11

3.3 EGI's Value Framework Scores Vary Without Sufficient Explanation 13

3.4 Amalgamation Costs are Not Recoverable from Ratepayers 16

4. Depreciation 18

4.2 ELG Is Not More Accurate Than ALG 20

4.3 Moving to ELG is Not the Appropriate Response to the Energy Transition 21

4.4 ELG Does Not Address Intergenerational Equity – It Only Raises Rates 23

4.5 The Board Should Prefer Intergroup's Net Salvage Calculation 24

4.6 Asset Lives 28

4.7 EGI Should Increase its Salvage Reporting 28

5. EGI Equity Thickness Should Remain at Thirty-Six Percent 29

5.2 The Appropriate Baseline for the Test is the Level of Risk at Amalgamation ... 31

5.3 The Relevant Risk Horizon is the Next Five Years 33

5.4 There is No Evidence that EGI's Energy Transition Risks Will Increase During the Next Five Years 35

5.5 EGI's Other Risks Have Remained Constant and Do Not Warrant an Increase in Equity Thickness.......... 41

5.6 Concentric's Comparators for the Equity Thickness are Inappropriate 45

6. Variance and Deferral Accounts 48

6.1 EGI Is Not Entitled to a Windfall from Union's Actuarial Losses.......... 48

6.2 EGI has Not Justified a Weather Normalized Average Use Account 50

7. Turnback, PDO and PDCI 50

7.1 The Board Should Make a Base Rate Adjustment.......... 50

7.2 The Board Should Consider Reverse Open Season Buy-Outs.......... 53

8. costs 54

1. INTRODUCTION & BACKGROUND

1. Enbridge Gas Inc. ("EGI") applied to rebase and to set rates for the sale, distribution, transmission, and storage of natural gas the years 2024-2028 on October 31, 2022. This is EGI's first rebasing application since the amalgamation of EGI's two legacy utilities, Enbridge Gas Distribution ("EGD") and Union Gas ("Union"). The legacy utilities were last rebased as part of file numbers EB-2011-0210 and EB-2011-0354. Accordingly, it has been approximately a decade since EGI's rates were matched to costs.

2. The cost consequences of EGI's application are significant, including an applied for increase in EGI's revenue requirement of $269 million.[1] This will have significant impacts for natural gas rates across the province.

3. EGI requested and the Ontario Energy Board ("OEB" or the "Board") approved a phased process whereby portions of the application would be heard sequentially rather than at once. The Board held an issues conference on January 9, 2023.[2] This was followed by submissions on the issues list. Ultimately, the Board determined that Phase 1 of the proceeding would contain the majority of the issues and be dedicated primarily to resolving the issues that had a bearing on 2024 rates.[3] Phase 2 issues included incentive rate making framework issues, storage, rate harmonization and other issues.[4]

4. The parties were given the opportunity to ask interrogatories of EGI, as well as experts sponsored by Board Staff and intervenors. The parties also attended a technical conference in late March 2023.

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[1] EB-2022-0200, Oral Hearing Transcript. Volume 1, p. 5. Mr. Kitchen's opening statement included reference to a $269 million deficiency including the capital update and the settlement agreement, but excluding Dawn to Corunna project and the Pandhandle Regional Expansion Project.

[2] EB-2022-0200, Procedural Order #1, December 16, 2022, p. 5.

[3] EB-2022-0200, Decision on Issues List & Expert Evidence and Procedural Order No. 2, January 27, 2023, Schedule A.

[4] EB-2022-0200, Decision on Issues List & Expert Evidence and Procedural Order No. 2, January 27, 2023, Schedule A.

5. The parties engaged in a settlement conference in May 2023.[5] The parties settled a substantial number of the issues. However, some issues remained to be determined through an oral hearing. These issues included EGI's request for an increase to its equity thickness, a change and harmonization to its depreciation rate, its capital spending/asset management plan, overhead capitalization policy, the treatment of integration capital, and how to best manage the energy transition which could have a significant impact on energy in Ontario over the long term.

6. CME has benefitted from reviewing the advance of submissions of a variety of parties, including SEC, IGUA, FRPO, and Board Staff, which has allowed CME's submissions to focus on those topics that are critical to its constituents. CME's submissions therefore do not encompass all of the outstanding issues. Where these submissions do not discuss a topic, CME takes no position with respect to that issue.

2. THE ENERGY TRANSITION

7. The fact that there is a transition occurring in the way energy is produced and consumed in Ontario is clear. CME's constituent members are very well aware of it. They operate energy intensive businesses and regularly invest in their operations and their infrastructure in order to better meet net zero goals, including those created internally.

8. What is less clear is how the energy transition will unfold, the pace of change, and how those changes will impact EGI. Some experts have opined that energy transition will likely cause a wholesale shift from the use of natural gas to electricity, an there is a likely risk of major declines in natural gas.[6] EGI's witnesses and other experts have maintained that a diversified scenario is a likely outcome, wherein some uses are transitioned to electrical power as the default energy source, but natural gas, renewable natural gas and/or hydrogen take on a large role for other uses, or as backup models if the electricity system were to falter.[7]

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5 EB-2022-0200, Decision on Issues List & Expert Evidence and Procedural Order No. 2, January 27, 2023, p. 9.
6 For instance, see Chris Neme's report: EB-2022-0200, Exhibit M9-GEC-ED Energy Transition, p. 8.
7 For instance, see Ms. Giridhar's evidence, EB-2022-0200, Oral Hearing Transcript, Volume 2, pp 18-20.

9. The various potential outcomes of the energy transition were illustrated by the Pathways to Net Zero study authored by Guidehouse (the "Pathways Study"). The Pathways Study looked at two potential ways that Ontario could reach its net zero carbon goals. Guidehouse and EGI explained that the pathways examined in the studies were not predictions, or likely outcomes. They were only potential pathways by which Ontario could achieve a net zero energy outcome.[8]

10. Currently, however, there is no way of knowing how the energy transition will proceed. There is no clarity regarding government policy on how the energy transition and pathways to net zero will unfold, the technological potential of various green energy options, how the electricity grid will meet the increased demands of a transition away from natural gas, and other variables.

11. Accordingly, CME agrees with IGUA's submission on this topic. The Board should adopt Dr. Asa Hopkins' recommendation and order EGI to conduct a thorough study to analyze how EGI's business is likely to change as a result of the energy transition, what customers are likely to leave the system and at what rate, and what actions EGI can and should take in order to mitigate the risks of the energy transition.

2.2 Government Policy Has Not Provided a Net Zero Direction

12. The Government of Ontario has not outlined a comprehensive policy to achieve net zero by 2050. However, the most recent government report, entitled "Powering Ontario's Growth", indicated that Ontario was moving ahead with "no regret" recommendations from the IESO's own pathways to net zero report.[9] These included the development of low carbon fuels if they can "replace at scale some of the flexibility that natural gas currently provides to the system".[10]

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8 EB-2022-0200, Oral Hearing Transcript, Volume 1, p. 80.

9 EB-2022-0200, Exhibit K1.5, Powering Ontario's Growth, Ontario's Plan for a Clean Energy Future, July 10, 2023, p. 6.

10 EB-2022-0200, Exhibit K1.5, Powering Ontario's Growth, Ontario's Plan for a Clean Energy Future, July 10, 2023, p. 60.

13. The Government of Ontario also makes it clear that the province will continue to rely on natural gas over the near term:

> ***"Natural gas will continue to play a critical role in providing Ontarians with a reliable and cost-effective fuel supply for space heating, industrial growth, and economic prosperity. With developments in energy efficiency, and low-carbon fuels such as RNG and low-carbon hydrogen, the natural gas distribution system will help contribute to the province's transition from higher carbon fuels in a cost-effective way."***[11]

14. However, the report does not address policies that will guide how the energy transition will unfold, or the pace at which that change will come. Without a more definitive direction from the Government of Ontario, it is difficult for the Board, or for stakeholders, to understand how they should act in order to achieve that policy goal.

2.3 The Potential for Hydrogen and Other Clean Fuel is Unknown

15. Hydrogen is one of the most promising alternatives to fossil fuel burning for Ontario, and manufacturers in particular. Hydrogen has the capability to be burned in a similar fashion to natural gas. Since hydrogen does not contain any carbon, the burning of hydrogen does not release carbon into the atmosphere. However, at the present time, there are uncertainties about EGI's ability to fully leverage hydrogen. For instance:

(a) It is currently unknown what level of hydrogen blending is safe within EGI's current infrastructure. In their oral testimony, EGI's witnesses indicated that EGI had not yet completed an engineering assessment to "determine what levels [of hydrogen] are safe within EGI's system.[12] EGI indicated that it would complete that assessment over the course of the next rebasing term. CME notes that there are promising results for hydrogen's potential to be included into EGI's system without significant modifications to the physical

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11 EB-2022-0200, Exhibit K1.5, Powering Ontario's Growth, Ontario's Plan for a Clean Energy Future, July 10, 2023, p. 30.

12 EB-2022-0200, Oral Hearing Transcript, Volume 2, p. 114.

infrastructure.[13] However, it understands that at this time, EGI will need to complete more work before

(b) As a result of hydrogen's lower energy value per volume, it requires a higher volume of gas to transmit the same amount of energy. As outlined in the oral hearing, 3.1 cubic metres of hydrogen has the same energy capacity as 1 cubic metre of methane.[14] EGI's witnesses testified that it may not be simply that the system requires three times more hydrogen.[15] However, it is not clear to what degree EGI's system could accept the increased volumes necessary to accommodate Ontario's energy needs with its current infrastructure, and what additional infrastructure may be required in order to achieve 100% hydrogen delivery.[16]

2.4 The Electricity Grid's Capacity to Accept Increased Demand is Unknown

16. The energy transition is a tandem of complementary changes. A move away from carbon emitting fuels, matched with a reciprocal move towards cleaner energy sources. In addition to fuels such as hydrogen and renewable natural gas, the other alternative is a switch into electrical power. The energy transition therefore will likely have an upward pressure on the amount of electrical power Ontario needs.

17. According to the IESO's Annual Planning Outlook, Ontario has the potential to be in an energy shortfall position beginning as early as 2028, where there is not enough electricity generation to meet Ontario's needs.[17] This shortfall would be exacerbated by a significant shift away from natural gas and towards electricity. While CME believes a transition away from carbon emitting fuels is both necessary and beneficial for the province, there is a great deal of uncertainty about Ontario's electricity infrastructure will respond to meet the increased demand. The first step therefore would be for the province

13 EB-2022-0200, Oral Hearing Transcript, Volume 2, pp. 120-121.
14 EB-2022-0200, Oral Hearing Transcript, Volume #, p. 193.
15 EB-2022-0200, Oral Hearing Transcript, Volume #, p. 193.
16 EB-2022-0200, Oral Hearing Transcript, Volume 2, p. 194.
17 EB-2022-0200, Exhibit K3.3, p. 16.

and the IESO to determine a path forward for increased electricity generation. Only after that is completed would the Board be able to help guide a departure from the natural gas system.

2.5 EGI Should Study Which Assets are At Risk

18. The Board is right to be keenly interested in the energy transition, and the specific matters at issue in this proceeding can help to focus the Board's attention on the parts of energy transition that need to be addressed now, and what elements of the energy transition can wait until more of the uncertainties have been resolved.

19. The Board already recognized this in its decision on the issues list, where Issue 3, regarding energy transition, is contemplated in relation to matters at issue in EGI's application, such as EGI's capital structure, depreciation, capital expenditures, and other issues. CME's submissions will therefore be focused on those aspects of EGI's application and will discuss elements of the energy transition as it is relevant to those other topics.

3. CAPITAL SPENDING

20. EGI capital forecast capital spending over the rate term represents a significant increase over its historical spending. The following facts were confirmed by EGI's witnesses during the oral hearing:

(a) The OEB approved rate base for EGI's legacy utilities was $7.9 billion in 2013, and has increased to an 'as filed' request of $16.2 billion for EGI in the 2024 test year;[18]

(b) The legacy utilities capital expenditures were $798 million in 2013, and has increased to and 'as filed' request of $1.47 billion for the 2024 test year. This is approximately an 84% increase;[19]

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[18] EB-2022-0200, Oral Hearing Transcript, Volume 11, pp. 105-106. This number does not include the PREP Project.

[19] EB-2022-0200, Oral Hearing Transcript, Volume 11, pp. 106-107.

(c) The capital spending requested increased from the ‘as filed’ amounts as part of EGI’s capital update;[20]

(d) EGI’s historical capital spending for the period 2018-2022 was less than the requested 2024 amounts at $1.158 billion per year, including integration capital, which will not recur in the same quantities during the upcoming rate period. EGI proposed 2024 spending is 44% higher than the historical averages, which included integration costs;[21]

(e) EGI’s in-service additions for 2024 are $1.565 billion, as compared to a historical average of $1.186 billion from 2019-2022, and increase of 32%;[22]

21. Accordingly, EGI’s proposed capital spending significantly out of step with its prior spending. CME notes that in the customer engagement conducted by EGI, they did not provide the above comparisons to demonstrate to the survey participants an apples-to-apples comparison of their proposed increase to their capital spending. Instead, they provided statistics on a ‘total bill basis’ while assuming that the commodity costs of gas were frozen.[23] This reduced the impact of EGI’s proposed changes compared to its historical capital spending. Additionally, EGI acknowledged that it did not conduct any customer engagement at all with respect to the capital update.[24]

22. As will appear, despite claiming that this level of capital spending is necessary, EGI’s evidence and the capital update make it clear that many of the projects that were once deemed necessary to complete by EGI in the original filing have been moved out of the plan. Moreover, the value scores assigned to ‘value driven’ investments have changed significantly without sufficient explanation. CME submits that the value framework is not transparent or robust enough to justify EGI’s capital spending decision making.

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20 EB-2022-0200, Oral Hearing Transcript, Volume 11, pp. 111-112.
21 EB-2022-0200, Oral Hearing Transcript, Volume 11, pp. 112-113.
22 EB-2022-0200, Oral Hearing Transcript, Volume 11, pp. 119-120.
23 EB-2022-0200, JT1.6.
24 EB-2022-0200, Oral Hearing Transcript, Volume 13, p. 132.

23. CME submits that EGI's drastic increase to capital spending is inappropriate, and not supported by the evidence. The Board should reduce EGI's capital spending by $400 million. A capital expenditure of $1.265 billion for 2024 (EGI's requested $1.665 billion capital envelope minus CME's proposed reduction) would still provide EGI with a higher capital budget than it spent in its last three years of actuals (2020-2022), when it was also making incremental integration investments which will not recur in the plan period.[25] CME submits that its requested reduction to EGI's capital envelope will bring EGI's capital spending more in line with historical spending, and would still be consistent with the asset needs.

3.2 EGI's Mandatory Investments Do Not Necessarily Have Fixed Timing

24. EGI categorizes its capital investments into several groups. "Compliance" investments are those investments that EGI is required to make in order to "adhere to applicable law and regulations", and other codes, standards and internal policies. Compliance investments must be made within their required time frame. "Mandatory" investments are those investments that meet any one of the following criteria:

(a) Exceed an upper risk threshold;

(b) Are necessary for a third-party relocation;

(c) Are part of program work with sufficient history and risk to warrant continuation; or

(d) Feasible projects as defined by EBO 188 and 134.[26]

25. EGI stated that "mandatory" projects must also be completed within a required time frame. However, this is not necessarily the case. As EGI's witness outlined in the

[25] The three year average is $1.251 billion as derived from Exhibit K 11.2, p. 6.
[26] EB-2022-0200, Exhibit 2, Tab 6, Schedule 2, p. 46.

technical conference, EGI can change the timing of "mandatory" projects in a number of different circumstances.[27]

26. In order to justify its capital spending forecast, EGI stated that it could not spend any lower than $1.2 billion per year on capital projects:

> ***"Optimization constraints lower than $1.2B (i.e., $1.1B) caused the optimization to fail as they do not accommodate all investments with fixed timing."[28]***

27. In the oral hearing, EGI's witness contextualized the statement provided above and stated that it was not the case that EGI could not spend less on capital because of fixed cost investment, but rather that it would prevent EGI from investing in projects to deliver safe and reliable service.[29]

28. However, an examination of EGI's proposed spending on projects before and after the capital update makes it clear that many of the projects that EGI stated it had to complete in the initial filing (in other words, were alleged to be necessary to deliver safe and reliable service) were no longer required to be completed in the capital update.

29. JT5.13, which was updated as part of the capital update, demonstrates that 227 projects, which previously had been within the investment plan, were now "no longer in plan".[30] In many cases, the projects that were no longer in the plan were the highest scored projects in the "value framework".[31]

30. EGI has justified the removal of these projects by explaining that these projects were moved, out of the plan in response to inflationary cost pressures. EGI's witness stated that the capital update:

> ***"[L]ooked at the 2024 forecast, made sure all of those were up to date, and then we had to make decisions to determine how we were***

27 EB-2022-0200, Technical Conference Transcript, Volume 5, pp. 54-55.
28 EB-2022-0200, Exhibit 2, Tab 6, Schedule 2, p. 253.
29 EB-2022-0200, Oral Hearing Transcript, Volume 11, pp. 143-144.
30 CME derived this figure by sorting the Excel Spreadsheet provided in JT5.13 to only show the projects listed as "no longer in plan".
31 EB-2022-0200, JT5.13.

> ***able to execute within the capital budget that we had set for ourselves…"***[32]

31. EGI has not indicated that the removal of these projects will negatively impact the company's ability to provide safe and reliable service now that they have removed them from the plan. EGI was able to remove these projects in order to accommodate for inflationary cost pressures and to keep within EGI's self-determined budget. Accordingly, at least 227 projects in EGI's pre-filed evidence were not actually required in the budget optimization.

32. CME sees no reason why the updated capital plan is any different. While EGI believes it should be granted its entire capital budget in order to invest in needed projects, CME submits that the total capital request includes projects that EGI could defer in order to achieve a more reasonable level of capital spending. This is supported by the fact that EGI's proposed capital budget is 44% above its historical spending. EGI has provided no compelling reason justifying such a significant increase with reference to the asset needs and what is required for safe and reliable service.

3.3 EGI's Value Framework Scores Vary Without Sufficient Explanation

33. For capital projects that are not "mandatory" or "compliance" projects, they are generally considered by EGI to be "value driven" projects. EGI defines "value driven" projects as projects whose timing is based on the value it brings to ratepayers and EGI.[33]

34. EGI uses the Copperleaf tool to provide a common economic scale to evaluate disparate proposed investments against one another.[34] As explained By Mr. Kennedy, EGI's witness, the Copperleaf value score is the "baseline" upon which all of the other considerations for a value project are layered.[35]

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32 EB-2022-0200, Oral Hearing Transcript, Volume 11, pp. 123.
33 EB-2022-0200, Exhibit 2, Tab 6, Schedule 2, p. 46.
34 EB-2022-0200, Exhibit 2, Tab 6, Schedule 2, p. 46.
35 EB-2022-0200, Oral Hearing Transcript, Volume 13, p. 135-136.

35. The centrality of the value framework to EGI's investment decisions was described by Mr. Kennedy during his testimony:

> ***"[W]here we have a multitude of investments that need to be executed in order to achieve our asset class strategy, the value scores help us distinguish across hundreds of assets where the best return on investment lies, because of a -- you know, unique characteristic associated with that group of assets that is reflected through the value score."***[36]

36. However, an examination of the value scores demonstrates that they are extremely fluid and subject to significant change over a short period of time. As outlined by CME in its cross-examination, EGI's capital update evidence shows that in a single category of project, real estate investments, the value framework scores for a significant number of the investments have changed drastically. They are set out below:[37]

Investment Name	Value As of March, 2023	Value as of July, 2023
New London Site	-$26,457,000	+$14,863,000
VPC Core and Shell	-$12,944,000	+$13,435,000
Kelfield Operations Centre New Land	-$19,163,000	+$2,500,000
Kelfield Operations Centre – Building	-$15,088,000	+$2,000,000
Sudbury Regional Operations Centre	-$4,950,000	+$3,692,000
Micro Operations Site	+$12,627,000	+$24,665,000
Total	**-$65,975,000**	**+61,155,000**

37. CME asked EGI to provide a reason why these projects' value score had varied so significantly over such a short period of time. In their response, EGI provided a spreadsheet that included a few words regarding the causes. For the New London Site project, which gained $41 million in value in four months, EGI simply stated "updated forecast and value assessment".[38] EGI provided similar answers for the VPC Core and

36 EB-2022-0200, Oral Hearing Transcript, Volume 13, p.
37 EB-2022-0200, Exhibit I.2.6-CME-23, Attachment 1, p. 20; J13.22.
38 EB-2022-0200, J13.22, Attachment 1.

Shell and Sudbury Regional Operations Centre.[39] "Updated Forecast" is one of the most common responses in EGI's table at response to undertaking J13.22.

38. CME finds this response puzzling. When counsel asked Mr. Kennedy if EGI was also reforecasting the value scores as part of the capital update, Mr. Kennedy responded that EGI had only started that process and that it was "quite time consuming".[40] Accordingly its not clear how so many of the value scores were reforecast between March and July 2023.

39. In any event, the significant changes to the value scores underscore a deeper concern. The value framework score is leveraged by EGI to compare various types of investments to determine which ones should proceed and which ones should be held back. To the extent that the value score is wrong or does not accurately reflect the benefits and costs of the project, EGI will not make the correct choices about its investment optimizations. EGI's witness acknowledged as much in cross-examination:

> **MR. POLLOCK:** ***"if the value score is wrong, then you get the wrong idea about where the best value is. Right?***
>
> **MR. WELLINGTON*: Yes, that's right.*[41]**

40. This issue is exacerbated by the fact that EGI did not go through the full asset management prioritization process when deriving its capital update. According to EGI's witnesses, instead of going through the normal prioritization process, EGI worked off a single excel spreadsheet, with various stakeholders determining what changes should occur. Given the size of the changes to the plan as a result of the capital update,[42] and the very significant changes to the value scores which occurred between March and July, 2023, CME doubts whether or not EGI is appropriate planning and pacing its capital investments through the plan term.

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39 EB-2022-0200, J13.22, Attachment 1.
40 EB-2022-0200, Oral Hearing Transcript, Volume 13, pp. 136-137.
41 EB-2022-0200, Oral Hearing Transcript, Volume 13, pp. 146-147.
42 EB-2022-0200, Oral Hearing Transcript, Volume 11, pp. 158-159.

41. Moreover, it was unclear to CME what other considerations are being layered onto the value framework score that underpin EGI's investment decisions. For instance, CME asked EGI's witnesses about the Dawn Administrative Centre Project. The Dawn project was described by EGI in an interrogatory response as having primarily financial benefits.[43] It also had a negative investment score, which meant that it cost more to invest in the project than it would generate in benefits. When asked why EGI would invest in a negative value project where the benefits of completing it were monetary, EGI's witness either speculated that its answer to CME's interrogatory was incomplete, or a cost was improperly entered into the calculation.[44]

42. This fluidity of EGI's value scores as well as the potential for improper or mistaken entries mean that EGI's choices with respect to various projects could be wrong oreven imprudent when compared to projects that would have priority if EGI's forecasts were accurate and up to date.

43. Accordingly, CME submits that the Board should not approve EGI's capital budget as proposed. CME recommends a reduction of $400 million for 2024, which would reduce EGI's requested budget from approximately $1.665 billion to $1.265 billion. This lower capital budget would still be higher than EGI's previous three years of actuals, which included integration capital spending which should be reduced as a result of the completion of the deferred rebasing period.

3.4 Amalgamation Costs are Not Recoverable from Ratepayers

44. In its application, EGI has requested that $119 million be added to rate base as a result of the capital spending it incurred to integrate EGD and Union as an amalgamated entity.[45] This request runs contrary to the Board's Handbook for consolidations. The Board should deny this request.

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43 EB-2022-0200, Oral Hearing Transcript, Volume 13, pp. 149-150.
44 EB-2022-0200, Oral Hearing Transcript, Volume 13, pp. 149-150.
45 EB-2022-0200, Oral Hearing Transcript, Volume 14, p. 155.

45. The Board's Handbook for consolidation makes it clear that incremental costs of an amalgamation are not generally recoverable through rates.[46] In the Handbook, the Board acknowledges that these costs can be considerable. In order to compensate the utility for undertaking a consolidation, the Board allows the utility to reap the savings caused by the integration during the deferred rebasing period.

46. In its submissions, Board Staff has taken the position that the ability for a utility to realize the efficiency gains was premised on a 10-year rebasing period. Since EGI was only granted a 5-year deferred rebasing period, Board Staff argues that EGI should be allowed to add 50% of the proposed amounts to ratebase.

47. CME submits that the Board should reject both EGI and Board Staff's reasoning. While the Handbook states that utilities are generally granted 10-year rebasing periods, ultimately, the purpose of the Board's *quid pro quo* is that the utility is allowed to realize efficiencies that match or exceed the costs of integration. This is clear from the Board's comments when discussing the 10-year deferred rebasing period:

> ***"In this report, the OEB has provided the opportunity for distributors to defer rebasing for a period up to ten years following the closing of a consolidation transaction. <u>This deferred rebasing period is intended to enable distributors to fully realize anticipated efficiency gains from the transaction and retain achieved savings for a period of time to help offset the costs of the transaction</u>."[47] (emphasis added)***

48. Accordingly, it is not the length of time of the rebasing period that is relevant when determining whether EGI should be able to rate-base its integration costs, but whether it has had a fair opportunity to realize anticipated efficiency gains and offset the cost of the transaction. CME submits that EGI has had that opportunity.

49. In EB-2017-0307, the Board explicitly found that a five-year rebasing period would offer EGI a "reasonable opportunity" for it to recover its transition costs.[48] This has been

[46] Ontario Energy Board, *Handbook to Electricity Distributor and Transmitter Consolidations*, January 19, 2016, p. 8.

[47] Ontario Energy Board, *Handbook to Electricity Distributor and Transmitter Consolidations*, January 19, 2016, p. 8.

[48] EB-2017-0307, Decision and Order, August 30, 2018, Amended September 17, 2018, p. 22.

born out during the deferred rebasing period. EGI has over-earned its allowed ROE in each of the last four years as follows:[49]

Year	**Amount Over-Earned**
2019	$96.2 million
2020	$13.1 million
2021	$57.7 million
2022	$64.4 million
Total	$231.4 million

50. EGI has already received the benefit of rebasing. It has over-earned its allowed return on equity by $231.4 million over four years, and will undoubtedly over-earn again in 2023. The evidence demonstrates that EGI did not require a 10 year deferred rebasing period in order to reasonable realize the benefits the integration and offset the costs of the transaction. Accordingly, CME sees no reason to depart from the Board's rule that the incremental costs of integration are not recoverable in rates, and submits that the Board should deny the proposed integration additions to rate base

4. DEPRECIATION

51. EGI proposed a harmonization of its legacy utilities' depreciation methodologies under the "equal life group" depreciation methodology ("ELG"). Previously, EGD used the "average life group" methodology ("ALG"), whereas Union used a methodology called "generation arrangement".[50] Accordingly, EGI's proposal is a novel calculation method which was not used by either legacy utility previously.

52. Fundamentally, a depreciation methodology attempts to match the cost of the assets to their service lives. The various methodologies, however, do so in very different ways. The ALG methodology, previously used by EGD, takes various assets, and separates them out into groups that have similar lifespans. For instance, there are currently accounts for gas mains that are constructed from plastic, gas mains that are

49 EB-2022-0200, J14.10. We note that the fifth year's data is not available. Accordingly, EGI's total over-earning would be higher.
50 EB-2022-0200, Exhibit M – IGUA Depreciation, p. 28.

coated and wrapped, for meters, and each other type of asset in the utilities' system. The ALG methodology assigns an average lifespan to the group of assets. By assigning an average, the ALG methodology recognizes that some individual assets in the group will retire earlier, and some later than the average.[51] The group amount is depreciated over the average lifespan determined for that category of assets.

53. ELG is a much more complicated methodology. In the ELG methodology, the depreciation expert subdivides the asset categories into subsets that are expected to live the length of time. For instance, plastic mains that will survive for 1 year, or 2 years, and so on.[52] As a result of having to subdivide the categories, the ELG procedure is much more sensitive to the assumptions made by the practitioner, including the correct Iowa survivor curve, as well as the dispersion of assets around the average – in other words, whether the failures are diffuse or concentrated, and if so, at what points in their lives.

54. The generation arrangement subdivides components based on the vintages when the assets were installed and analyzes each vintage separately.[53] Despite subdividing the asset classes, it is conceptually different from ELG, with generation arrangement analyzing historical vintages separately, while ELG subdivides asset classes into expected future performance. None of the experts recommended using the 'generation arrangement'.

55. EGI harmonization of depreciation methodologies and its proposal to move from the 'generation arrangement' and ALG methodologies to the ELG methodology would increase EGI's depreciation from $736 million using the current methodologies to $878 million using its harmonized methodology.[54] The increase to the depreciation expense is the single largest driver of EGI's "deficiency" that they are seeking to recoup through increased rates.

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[51] EB-2022-0200, Exhibit M – OEB Staff Depreciation, p. 13.
[52] EB-2022-0200, Exhibit M – OEB Staff Depreciation, p. 13.
[53] EB-2022-0200, Exhibit M – OEB Staff Depreciation, p. 15.
[54] EB-2022-0200, Oral Hearing Transcript, Volume 17, p. 28. CME notes that in the answer provided to SEC in J17.2, the depreciation expense in current rates for 2023 are only $603 million. Accordingly, EGI's change to its proposed depreciation expense is even more significant.

56. EGI justifies its proposed increase to depreciation expense on three bases. First, that it enhances intergenerational equity. Second, that it is the most accurate method of calculating depreciation expense. Third, that it is the best match for Union's 'generation arrangement' methodology. Finally, that it is a better match for the risks of the energy transition.

57. As will be outlined further below and by the evidence from Board Staff and IGUA's respective experts, the bases cited by EGI are in many cases not accurate, and do not justify a nine-figure increase in the revenue requirement to be applied to existing customers.

4.2 ELG Is Not More Accurate Than ALG

58. EGI's expert, Concentric, stated that one of the benefits of switching to the ELG procedure is that it is more accurate than the ALG procedure, which is recommended by Board Staff and IGUA's respective experts.[55] However, this point is contested by the experts. Emrydia and Intergroup gave evidence that the ELG's supposed accuracy is a mirage.

59. The accuracy of the ELG procedure, to the extent it ever exists, is premised on the existence of significant accurate data. As outlined above, the ELG methodology subdivides the asset categories into subcategories based on their expected future performance. For instance, mains that are expected to last 1 year, then mains that are expected to last 2 years and so on. In order to make accurate assumptions about the percentage of assets that will last in each subcategory, the ELG methodology requires a significant amount of high-quality data about assets retirements in each year of the group's life.[56] For some accounts with long-lived assets, the time needed to gather retirement information could be as long as 100 years.[57]

55 EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, p. 16.
56 EB-2022-0200, Exhibit M – OEB Staff Depreciation, pp. 13-14.
57 EB-2022-0200, Exhibit M – OEB Staff Depreciation, p. 14.

60. EGI does not have the requisite level of data for a particularly accurate ELG methodology to be constructed. This issue is exacerbated by the fact that EGI has two separate legacy utilities' records that may not be aligned or kept in the same way, thereby complicating data collection.

61. In contrast, ALG is requires much less data in order to provide an accurate estimate. As the assets are not subdivided by expected future performance, the ALG procedure requires fewer data points in order to be accurate, and implicitly accepts that some assets will retire earlier than the average, and some later, without relying on specific understanding of when those retirements would take place. Accordingly, given the data limitations in the utility context with long-lived assets, ELG would be no more accurate than ALG in calculating an appropriate depreciation expense.

4.3 Moving to ELG is Not the Appropriate Response to the Energy Transition

62. Another factor that EGI points to as a basis for its decision to change to the ELG procedure is that it is an appropriate response to the energy transition. In essence, EGI's position is that the risks of energy transition are such that it would be prudent for it to reduce depreciation horizons for its assets. Besides the fact that this would cause greater intergeneration inequity than it solves, a change to the depreciation methodology is not an appropriate response to the energy transition as it indiscriminately raises rates without a solid understanding of how the energy transition will unfold.

63. As outlined earlier in these submissions, there is currently significant uncertainty surrounding the energy transition. How quickly it will occur, what energy sources will take the place of carbon emitting sources and how the Government of Ontario will react to the energy transition are all currently unknown.

64. The move to ELG is a blunt instrument. It essentially front-loads depreciation expense for all asset classes in equal measure, without giving any consideration to which assets will be more likely to be impacted by the energy transition. This burdens current customers with additional costs for assets that may live out their entire useful service

lives despite the energy transition. This would cause a significant inequity to current customers.

65. CME submits that while the energy transition might cause additional costs, or a review of the appropriate depreciation rates for certain classes of assets, it is highly unlikely that it will affect all assets equally, or over the same time frame.

66. Dr. Asa Hopkins recommended that EGI conduct a scenario analysis, which would go further than simply the Pathways Study provided in this application. The scenario analysis would develop a number of plausible scenarios, assign them weights regarding their relative likelihood, and model the conduct of a prudent utility in response to those scenarios, to get a sense of the cost of responding to and mitigating the risks identified in those scenarios.[58] CME has recommended that the OEB order EGI to conduct this study, in order to get a better understanding of how the energy transition is likely to affect EGI's business in particular.

67. As part of the analysis, Dr. Hopkins recommends a capital risk analysis, where scenario modeling could identify which pipes or other assets are used and useful for what amount of time in each scenario. The analysis would also be able to identify which assets will continue to be used and useful throughout their remaining lives.[59] This analysis would inform a more accurate assessment of what assets, if any, are likely to need a quicker depreciation rate because they are likely to be underutilized or abandoned at some point in the future, and those where the depreciation rate is reasonable and appropriate.

68. From there, EGI could propose to change depreciation rates for specific assets with an evidentiary foundation, instead of simply increasing the up-front depreciation amounts for all assets without further investigation. This would increase equity between

[58] EB-2022-0200, Exhibit M8, p. 36.
[59] EB-2022-0200, Exhibit M8, p. 36.

different customer groups as well as inter-generational equity by more closely matching the use of an asset with its depreciation.

4.4 ELG Does Not Address Intergenerational Equity – It Only Raises Rates

69. Concentric's evidence indicates that one of the reasons that the ELG is the preferable methodology is that it increases inter-generational equity.[60] In essence, EGI's expert, Concentric, argues that under the ALG methodology, current customers are gaining a benefit of a lower depreciation expense that future customers need to make up. However, this is a misunderstanding of the ALG methodology. By taking an average, the ALG methodology implicit assumes that all generations of ratepayers will experience in total, the average service life of the assets. Ratepayers now enjoy the average service life for assets, as will ratepayers in the future. While it is true that some individual assets may last longer or shorter amounts of time, in the main both sets of ratepayers are treated equally.

70. The ELG methodology does not account for the service value of the group of assets. Intergroup gives the example of the ELG procedure being applied to a fleet of four trucks, with an average service life of 2.5 years. Despite gaining the service value of the same assets (4 trucks for 2.5 years) the ELG depreciation expense is frontloaded, with early customers paying more for the depreciation expense than later customers. In contrast the ALG provides a uniform recovery of depreciation expense, which matches the service value being received by the ratepayer.[61]

71. Moreover, the ELG procedure not only raises rates for current customers, it also likely raises rates for future customers as well. As outlined by Mr. Bowman and Mr. Mahmudov, the central purpose of a depreciation methodology is to allocate the cost of an asset across the asset's life. One would assume that an increase to the depreciation expense in the early years of an asset's life would have a reciprocal lowering of an

60 EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, p. 15.
61 EB-2022-0200, Exhibit M – OEB Staff Depreciation, pp. 17-18.

asset's depreciation expense in the later years of its life. However, this is the not the case in group-based ELG applications.

72. The actual ELG studies for utility property have shown a higher depreciation expense for ELG than ALG using the same life and dispersion estimates, regardless of where they are on the asset life curves or maturity.[62] This would lead to customers paying more for the depreciation expense at all points in the assets' lives. This is as a result of the impacts of inflation, with newer assets more expensive in nominal dollars than older assets, as well as the expansion of utility investment.[63] This is not a proper outcome. A procedure that requires ratepayers to pay more across the board does not engage inter-generational equity, it is simply an additional cost to the benefit of the shareholder. In the absence of a compelling reason justifying such an increase, CME submits that the Board should reject the use of the ELG methodology and require EGI to use the ALG procedure instead.

4.5 The Board Should Prefer Intergroup's Net Salvage Calculation

73. Net salvage is a calculation intended to determine the cost of to remove and asset, net of the proceeds of sale from the selling the salvageable portion of the asset. Once calculated, the utility can collect the net salvage amount in multiple different ways. Since the funds collected are not required to be used immediately for the net salvage of future assets, the utility could use those funds for other purposes, and there are impacts to other regulated elements of a utility's business based on what's done.

74. In EGI's case, it is proposing to apply a constant dollar net salvage approach ("CDNS") to recovery of the net salvage amounts. In short, CDNS is a process whereby the expert estimates the life span of the assets in question. They then apply a discount rate to account for inflation and create "constant dollars" which is to say dollars that are

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62 EB-2022-0200, Exhibit M – OEB Staff Depreciation, p. 22.
63 EB-2022-0200, Exhibit M – OEB Staff Depreciation, p. 22.

equivalent in real terms that are then collected over the lifetime of the asset to ensure that the collection in each year is an amount of money of equivalent value.[64]

75. The utility can also apply a higher discount rate than the current inflation rate. This would recognize the time value of money. Since a utility is collecting money now that it will not need to expend until the lifespan of the asset is over, the utility can, theoretically, use the extra funds collected for other purposes prior to applying them to the actual net salvage expense. In EGI's case, it uses early collected net salvage amounts as an offset to rate base, which lowers future revenue requirements.[65] This is inherently a benefit to the utility, who doesn't need to finance those amounts from debt or equity offerings, as well as future ratepayers, who enjoy the benefits of the lower rate base because of the amounts collected by today's customers. When the utility chooses a higher discount rate than simply inflation, it balances the benefits enjoyed by current ratepayers as well as future ratepayers such that there is a general parity in the real cost that each one pays towards the salvage of the asset for which they both gain a benefit.

76. EGI proposes to continue the use of a CDNS approach.[66] This proposal has largely been accepted by Intergroup[67] as well as Emrydia.[68] However, the other experts indicated that are two issues with EGI's proposal:

(a) The CDNS has not been calculated correctly, and has doubled the application of inflation to artificially increase net salvage cost; and

(b) The discount rate used by EGI in its CDNS calculation is inappropriate. EGI should instead use the weighted average cost of capital ("WACC") rate as a discount rate in order to credit ratepayers with the use of the net salvage amounts collected prior to the obligation becoming due.

64 EB-2022-0200, Exhibit M – OEB Staff Depreciation, p. 48.
65 EB-2022-0200, Oral Hearing Transcript, Volume 16, p. 183.
66 EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, p. 5.
67 EB-2022-0200, Exhibit M – OEB Staff Depreciation, p. 9.
68 EB-2022-0200, Exhibit M – IGUA Depreciation, p. 9.

77. As outlined by Intergroup and Emrydia and confirmed by Concentric's answer to a Board Staff interrogatory,[69] the traditional net salvage calculation is a function of the actual net cost of removals minus salvage proceeds in the dollar value at the time the asset is removed, divided by the original cost dollars at the time the asset was put in place.[70] Since the calculation involves components from both the time of installation and the time of removal, there is implicit in the net salvage percentage an inflationary factor built in.

78. Despite this fact, Concentric then applies an inflation factor a second time. Concentric takes the net salvage percentage (which already implicitly contains inflation in its calculation), applies it to the cost of the investment to calculate the estimated cost of removal, and then inflates that cost again to account for inflation a second time. As a result, the cost of removal is inappropriately and artificially increased. Accordingly, Concentric's calculation is incorrect and should not be accepted by the Board. Instead, CME agrees with IGUA's submission that the Board should adopt Intergroup's CDNS calculation methodology over Concentric's.

79. Concentric also chose an inappropriate discount rate. As previously outlined, a discount rate higher than inflation can be chosen to balance the benefit that future ratepayers will enjoy with the benefits enjoyed by current ratepayers. By paying for net salvage amounts ahead of time, current customers provide an upfront infusion of cash for EGI now that it can spend in the course of its day-to-day business. In their testimony, EGI's witnesses stated that these funds were comingled with EGI's other money, and used, amongst other things, for funding additions to rate base.[71]

80. Concentric calculated the discount rate by using EGI's current credit adjusted risk free rate ("CARF"). Concentric provided four justifications for the use of CARF: it was consistent with the requirements of US GAAP, those mandated for asset retirement obligations ("ARO") for financial statement disclosure, and securitization calculations, it

[69] EB-2022-0200, Exhibit I.4.5-Staff-176(a).
[70] EB-2022-0200, Exhibit M – OEB Staff Depreciation, p. 51.
[71] EB-2022-0200, Oral Hearing Transcript, Volume 16, p. 183.

was consistent with intervenor positions in EGI's last rebasing application, and applications made by Group 1 pipelines to the Canadian Energy Regulator.[72]

81. Concentric's reasoning is not persuasive. In this regard:

(a) US GAAP standards are not specifically applicable to rate regulated utilities. In cross examination, Concentric's witness, Mr. Kennedy, acknowledged that US GAAP have a provision for regulated utilities, but that the provision does not have to do with the applicable discount rate.[73] Instead, it allows companies using US GAAP to recognize *the decisions of their regulators for accounting policies*.[74] In essence, the only provision of US GAAP relevant to regulated utilities makes it clear that the decisions regarding regulatory accounting are the regulators to make. CME submits that this factor does not militate towards using the CARF but simply leaves it to the regulator to decide the appropriate discount rate.

(b) Many intervenors, including CME, argued for the use of a higher discount rate than the one proposed by Mr. Kennedy in EB-2012-0459. The fact that his proposal may be consistent with some intervenors in EB-2012-0459 is not a persuasive reason for his recommendation to be accepted by the Board in this proceeding. This is especially true considering the Board in EB-2012-0459 found that a higher discount rate was warranted.[75]

82. CME submits that the discount rate applied should reflect the purpose to which the utility puts the additional funds collected. EGI has acknowledged that the money collected is used to fund rate base additions that EGI would have to finance through its WACC. We note that Intergroup acknowledged that the use of the WACC would better match the benefits of the funds provided by current ratepayers.[76] Accordingly, CME

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72 EB-2022-0200, Exhibit 4, Tab 5, Schedule 1, Attachment 1, p. 24 of 451.
73 EB-2022-0200, Oral Hearing Transcript, Volume 16, p. 176.
74 EB-2022-0200, Oral Hearing Transcript, Volume 16, p. 176.
75 EB-2012-0459, Decision with Reasons, July 17, 2014, p. 62.
76 EB-2022-0200, Exhibit M – OEB Staff Depreciation, p. 54.

submits that the Board should prefer Emrydia's proposal of using the WACC as the discount rate.

4.6 Asset Lives

83. Concentric, Emrydia, and Intergroup also opine on the appropriate asset lives for the various classes of assets. In general, CME agrees with the submissions from IGUA on the appropriate asset lives calculations.

4.7 EGI Should Increase its Salvage Reporting

84. Emrydia proposed several measures that EGI could do to increase transparency relating to net salvage, including:

(a) EGI should begin to separately track and report the annual changes in the current net salvage liability, including the existing balance in the account inclusive of any approved funding and actual costs incurred;[77]

(b) Reporting on the expected future net salvage cost liability based on assumptions regarding the applied for net salvage rates and the five year actual experienced net salvage costs for each account;[78]

(c) Conduct a study on its 10 largest property accounts and report on its current approach to salvaging the assets, alternative approaches to salvage assets, such as abandonment, and EGI's best estimate of future costs to salvage the assets;[79]

85. CME supports these recommendations. Emrydia provides a high-level estimate of $12.5 billion as EGI's future salvage cost obligations. This is a significant level of future cost. CME submits that parties and the Board would benefit from transparent reporting with respect to this amount, as well as a thoughtful review of other potential ways of

[77] EB-2022-0200, Exhibit M – IGUA Depreciation, p. 90.
[78] EB-2022-0200, Exhibit M – IGUA Depreciation, p. 90.
[79] EB-2022-0200, Exhibit M – IGUA Depreciation, pp. 92-93.

salvaging its assets so that EGI can reasonably and prudently manage the future salvage cost obligations and mitigate the cost to ratepayers.

5. EGI EQUITY THICKNESS SHOULD REMAIN AT THIRTY-SIX PERCENT

86. EGI applied for an increase to its equity thickness from the current 36% to 42% by the end of the plan term. EGI proposed that this increase should be phased in such that its equity thickness would increase from 36% to 38% for 2024, and then increase by 1% per year for the remaining years of the term (2025-2028) until it reaches 42%.[80]

87. EGI's proposal, if accepted, would cause an increase in EGI's revenue requirement of $26.1 million in 2024, and approximately $80.6 million per year once it increased to 42% by 2028.[81] Since these increases are related to equity thickness, the increased revenues would flow directly to the shareholder, and do not represent any additional investments in assets to improve reliability or customer service to ratepayers.

88. EGI has taken the position that the proposed increased to its equity thickness is justified because its business and financial risks have increased since the former constituent utilities Enbridge Gas Distribution ("EGD") and Union Gas Ltd. ("Union") rebased on or around 2012. EGI relies on the report provided by Concentric Energy Advisors ("Concentric") for their proposal that 42% equity is the appropriate equity thickness.[82]

89. In addition to EGI's expert evidence on equity thickness, Board Staff and the Industrial Gas User's Association ("IGUA") also commissioned expert evidence. Board Staff contracted London Economics International ("LEI"), and IGUA sponsored Dr. Sean Cleary to provide expert reports outlining their own views about EGI's appropriate equity thickness. LEI opined that EGI's equity thickness should increase to 38% for the

80 EB-2022-0200, Oral Hearing Transcript, Volume 8, p. 57.
81 EB-2022-0200, Exhibit 5, Tab 3, Schedule 1, p. 3 of 7.
82 EB-2022-0200, Exhibit 5, Tab 3, Schedule 1, Attachment 1.

upcoming rate term.[83] Dr. Cleary opined that EGI's equity thickness should remain unchanged at 36%.[84]

90. Concentric provides a list of the following factors that it believes justifies an increase in EGI's equity thickness to 42%:

(a) Energy transition risks, composed of volumetric risks, operational risks, and financial risks related to the potential change from GHG emitted fuels to greener energy;

(b) Volumetric risks;

(c) Financial risks; and

(d) Operational risks.[85]

91. Concentric made it clear in their oral evidence that the greatest increase in risk driving their recommendation to increase equity thickness to 42% is the energy transition risk,[86] and that absent that risk, the other risks identified are not fundamental changes to EGI's risk profile:

> ***MR. MONDROW: "Mr. Coyne, if I could just confirm with you my understanding, that the real driver of your recommendations in respect of Enbridge Gas's equity thickness in this case is represented on the first row of that table, the energy transition, where we see your conclusion of a significant increase. And the other four rows all have modest to neutral impacts, so really aren't driving your recommendation. Is that a fair conclusion?***
>
> ***MR. COYNE: I would say we -- yes, it is fair in that the most significant risk that is really driving it over the level of significance is energy transition. I think the others would fall short of that degree of fundamental change in the company's risk profile that we have identified."***

83 EB-2022-0200, Exhibit M – Staff Cost of Capital, p. 1.
84 EB-2022-0200, Exhibit M6 (IGUA Cost of Capital) Corrected 2023-05-15, p. 3.
85 EB-2022-0200, Exhibit 5, Tab 3, Schedule 1, Attachment 1, p. 6. While regulatory risks are analyzed by Concentric, its conclusion is that EGI's regulatory circumstances represent lower risk than the baseline if EGI's proposal for a straight-fixed-variable rate design is accepted.
86 EB-2022-0200, Oral Hearing Transcript, Volume 8, pp. 54-55.

92. LEI also indicated that its recommendation to increase EGI's equity thickness to 38% are mainly based on the perceived risks of the energy transition.[87]

93. CME submits that EGI's energy transition risks during the five-year rebasing term are minimal. While energy transition represents a long-term change for EGI and Ontario's energy landscape, this change will likely take several decades to unfold.[88] During the next rebasing term, there is no evidence that EGI's risks will increase. Accordingly, the Board should keep EGI's equity thickness at 36%.

5.2 The Appropriate Baseline for the Test is the Level of Risk at Amalgamation

94. Pursuant to the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, dated December 2009 (the "Cost of Capital Report"), the cost of capital is regulated by the "fair return standard".

95. The fair return standard requires that a regulator should ensure that the utility has a return on capital that:[89]

(a) Is comparable to the return available from enterprises of like risks;

(b) Enables its financial integrity; and

(c) Permits incremental capital attraction on reasonable terms and conditions.

96. After setting an equity ratio that meets the fair return standard, the Board has articulated that for future proceedings, the Board's equity thickness analysis will be conducted in two stages. First, a threshold stage whereby the Board determines whether or not the utility's business or financial risk has significantly changed.[90] If the Board find that the risks have changed, it then engages in a review of what the fair return should be for the utility.

87 EB-2022-0200, Exhibit M – Staff Cost of Capital, p. 1 of 60.
88 EB-2022-0200, Oral Hearing Transcript, Volume 8, p. 144.
89 EB-2009-0084, *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, December 11, 2009, p. 18.
90 EB-2011-0354, Decision on Equity Ratio and Order, February 7, 2013, pp. 4-5.

97. In EB-2011-0354, the Board outlined what the relevant period of review was changes in a utility's risk since the date of the Board's last equity thickness decision:

> ***"In EB-2006-0034, the Board performed an assessment of the change in Enbridge's risk and determined the appropriate equity ratio for Enbridge at that time. In this proceeding, the Board's task in assessing the change in risk is to examine <u>how risk has changed from the time the issue was previously decided in EB-2006-0034.</u> <u>To extend the analysis to a date before the Board's last consideration of the issue would inappropriately revisit the basis for the Board's risk assessment</u> in EB-2006-0034, which was embodied in the approved equity ratio at that time."[91] (emphasis added)***

98. In this proceeding, EGI has taken the position that the baseline for a review into changes to EGI's business and financial risk should be the legacy utilities' last rebasing application in EB-2011-0354 and EB-2011-0210 rather than EGI's merger proceeding in EB-2017-0306/0307 (the "MAADs Application").[92] However, the Board set EGI's equity thickness in the MAADs Application.

99. When CME questioned EGI in the oral hearing about its position, EGI's witness stated that the company's view was that the MAADs handbook did not provide for a change to EGI's cost of capital.[93] Accordingly, it was EGI's view that the Board did not perform a cost of capital review as part of the MAADs Application and the baseline should be the risks faced by the legacy utilities at the time of their rebasing applications in 2012/2013.

100. CME submits that the MAADs Handbook and the Board's decision with respect to the MAADs Application indicate that the Board did address EGI's capital structure in 2017. Accordingly, CME submits that the proper baseline against which to measure EGI's current risk is the utility's risk as of 2017.

101. The MAADs Handbook provides which rate-related items will be dealt with by the Board as part of a MAADs proceeding:

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91 EB-2011-0354, Decision on Equity Ratio and Order, February 7, 2013, p. 7.
92 EB-2022-0200, Oral Hearing Transcript, Volume 8, pp. 52-53.
93 EB-2022-0200, Oral Hearing Transcript, Volume 8, pp. 52-53.

> ***"Rate-setting following a consolidation will not be addressed in an application for approval of a consolidation transaction <u>unless there is a rate proposal that is an integral aspect of the consolidation</u>..."[94] (emphasis added)***

102. However, CME submits that the cost of capital is an integral aspect of the consolidation. EGI's amalgamation application supports this contention. In the application, EGI stated "The Board <u>requires</u> the use of approved cost of capital parameters when calculating the revenue requirement." (emphasis added)[95] In recognition of that fact, EGI included a proposal that the Board set the cost of capital using the "latest forecast cost of debt, incremental long-term debt requirement for the capital project and allowed ROE at the time of the application and be based on the Applicants' current capital structure at 64% debt and 36% equity."[96]

103. Consequently, without the cost of capital parameters, there would be no revenue requirement calculated. This is in and of itself integral to the consolidation. Moreover, without a revenue requirement, certain mechanisms ordered by the Board and in some cases required by the MAADs Handbook, would be redundant and ineffectual. Consequently, the rate proposal with respect to the capital structure of the amalgamated utility was an integral aspect of the consolidation.

104. This conclusion is borne out by the fact that the Board addressed EGI's capital structure in the MAADs Application. The Board set EGI's capital structure to 36% equity and 64% debt. EGI used that capital structure make various regulatory calculations, including its earnings throughout the deferred rebasing period. Accordingly, the proper baseline from which to measure EGI's change in risk is therefore 2017, not 2012 as argued by EGI.

5.3 The Relevant Risk Horizon is the Next Five Years

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94 Ontario Energy Board, *Handbook to Electricity Distributor and Transmitter Consolidations*, January 19, 2016, p. 11.

95 EB-2017-0307, Exhibit B, Tab 1, p. 15.

96 EB-2017-0307, Exhibit B, Tab 1, pp. 15-16.

105. The Board has determined that the relevant future looking risks are the risks that the utility will face over the term of the rebasing period:

> ***"Regarding the risk of future events, the Board agrees with CCC that the <u>relevant future risks are those that are likely to affect Enbridge in the near term</u>. Any risks that may materialize over the longer term can be taken into account in subsequent proceedings. In considering the risk of future events, the Board will take into account the fact that, generally, the more distant the potential event, the more speculative is any conclusion on the likelihood that the risk will materialize."***[97] **(emphasis added)**

106. When asked about Concentric's understanding of what the 'near term' meant in the Board's decision in EB-2011-0354, Concentric agreed that it considered "near term risks as those likely to impact Enbridge Gas over the five-year rate period from 2024 to 2028".[98]

107. The Board's decision in EB-2011-0354 rightly outlines two reasons why the relevant risks are the near-term risks that will occur during the rate term. First, longer-term risks are more speculative. As a result, the risks identified may change, be mitigated, or may disappear entirely such that the utility never actually has to face them. Second, longer term risks that remain and begin to crystallize can be dealt with by a future panel in the next rebasing case, where it will have additional information upon which to base its equity thickness determination.

108. In some respects, energy transition is a novel situation. However, the risks EGI faces as a result of the energy transition are no different than any other long-term risks. The energy transition will take decades to complete,[99] and over time, stakeholders and the Board will gain additional information that they can use to make better decisions on how to manage it. Just like any long-term risks, energy transition risks are currently highly speculative. This is evident in how uncertain the pathways to net zero are. As its authors repeatedly emphasized, the pathways articulated by Guidehouse in its study are simply two ways that Ontario could decarbonized. Guidehouse did not even attempt to predict

97 EB-2011-0354, Decision on Equity Ratio and Order, February 7, 2013, p. 7.
98 EB-2022-0200, Exhibit I.5.3-CME-42, p. 2 of 2.
99 Concentric agreed with this timeline. See EB-2022-0200, Oral Hearing Transcript, Volume 8, p. 144.

how the energy transition would unfold.[100] Concentric agreed that the impact of energy transition on EGI's business was uncertain:

> ***MR. MONDROW: "[Y]ou are saying 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.***
>
> ***MR. COYNE: Yes"***

109. Concentric also agreed that in another five years, when a future panel is asked to review EGI's next rebasing application, that it would have five additional years' worth of information, knowledge, and experience to work with when determining if and how energy transition risks will affect EGI.[101]

110. The same reasoning applies in this case as applied in EB-2011-0354. The appropriate risks to review are the risks that will impact EGI's business over the course of the rebasing term, not the full speculative risks which may or may not materialize throughout the decades of the energy transition.

5.4 There is No Evidence that EGI's Energy Transition Risks Will Increase During the Next Five Years

111. Concentric argued that an increase to EGI's equity thickness is justified primarily because of increased risks to EGI's business from the energy transition. However, the evidence does not support Concentric's conclusion. EGI's risks have not changed significantly since 2012 or 2017.

112. The first way that Concentric argued the energy transition impacted EGI's forward looking risk is through volumetric risk. According to Concentric's report, "the opposition to natural gas threatens the Company's sales volumes…".[102]

113. However, this assertion is not supported. EGI's witnesses stated in their oral testimony that the energy transition was not forecast to have material risks to EGI's

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100 EB-2022-0200, Oral Hearing Transcript, Volume 3, pp. 114-115.

101 EB-2022-0200, Oral Hearing Transcript, Volume 8, p. 144. However, Concentric noted that even after 5 more years, there would still be open ended questions that have not yet been answered about the energy transition.

102 EB-2022-0200, Exhibit 5, Tab 3, Schedule 1, Attachment 1, p. 38 of 164.

volumes over the course of the rate term. Ms. Wade stated that EGI only forecast 400 customer disconnections over the five years of the rate term resulting from energy transition. Ms. Wade stated:

> ***"I think roughly in the next -- I think, from a customer additions forecast, you are correct; over the next five years, it is not a substantial number. And that is because, over the next five years, we don't see this coming to fruition, or the changes that are going to happen in the energy transition happening in a major way over the next five years."***[103]

114. Ms. Giridhar stated that EGI was actually ahead of its forecast connections as of the time of the oral hearing:

> ***"I would just frame that in the context of two observations. The first is that we continue to attach customers steadily. In fact, my understanding is that as of today, this year, we have exceeded our sort of pro rata customer connections that we would have at this point in time. Obviously, in terms of the short term, we are also seeing the potential for a dampening of housing starts with the changes in interest rate and so on, but, you know, those are cyclical issues. And we also note that the government's desire to build 1.5 million homes, building homes faster, is a priority for this government, so I think those are two additional factors that we have to keep in mind."***[104]

115. In addition to its witnesses' oral testimony, EGI's historical results and forecasts for the plan term show continued strength in demand. EGI's 2013 OEB-Approved total volumes on a combined basis for EGD and Union were 25,887,855 10^3 m^3.[105] EGI's forecast volume throughput for the 2024 test year is 27,922,873, an increase of more than 2 million 10^3 m^3.[106] Similarly, EGI's total revenues have continued to increase regularly. EGI's OEB revenue for 2013 was $3,766,100,000.00.[107] EGI forecasts that its revenue for the 2024 test year will be $5,851,600,000.00, an increase of over $2 billion from its 2013 approved revenue.[108] Customer additions forecast by EGI are also

103 EB-2022-0200, Oral Hearing Transcript, Volume 3, pp. 94-95.
104 EB-2022-0200, Oral Hearing Transcript, Volume 4, p. 122.
105 EB-2022-0200, Exhibit 3, Tab 3, Schedule 1, Attachment 7, p. 2 of 5.
106 EB-2022-0200, Exhibit 3, Tab 3, Schedule 1, Attachment 7, p. 4 of 5.
107 EB-2022-0200, Exhibit 3, Tab 3, Schedule 1, Attachment 9, p. 2 of 8.
108 EB-2022-0200, Exhibit 3, Tab 3, Schedule 1, Attachment 9, p. 6 of 8.

generally flat over the period, with 2028 customer additions not being materially different from those EGI currently enjoys.[109]

116. EGI's evidence demonstrates that there will not be a volumetric impact from the energy transition over the rate plan period. Accordingly, CME submits that there is no reason for the Board to increase EGI's equity thickness due to volumetric risks from the energy transition.

117. Concentric calls the second category of energy transitions risk "operational risk". Concentric describes this risk as being the risk that increasing opposition to natural gas will make it more "difficult, costly and time intensive for natural gas distribution utilities" to construct and permit new facilities.[110]

118. In response to questioning from CME at the technical conference, Concentric clarified that operational risk from the energy transition is primarily concerned with:

(a) An increase to the risk that the Board will deny EGI's facilities applications;

(b) An increase to the regulatory cost of applications; and

(c) An increase to the time it takes for the Board to process EGI's applications.[111]

119. Concentric argued that the increase in the number of intervenors and the number of interrogatories in EGI's facilities applications demonstrated that opposition to its facilities applications increased and it therefore faced increased operational risks. CME disagrees. EGI has not demonstrated that any of the risks are more likely to materialize during the upcoming rate term.

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109 EB-2022-0200, Oral Hearing Transcript, Volume 4, p. 94.
110 EB-2022-0200, Exhibit 5, Tab 3, Schedule 1, Attachment 1, p. 39.
111 EB-2022-0200, Exhibit K8.5, pp. 54-55.

120. In response to an interrogatory, EGI provided a list of all of EGD/Union as well as EGI's facility applications since 2012.[112] EGI provided a list of approximately 85 applications.[113] CME asked EGI to confirm which applications out of the 85 listed where instances where the Board denied EGI's leave to construct. EGI confirmed that there was only one instance where the Board denied leave, EB-2020-0293.[114]

121. However, the decision in EB-2020-0293 states that EGI was not able to demonstrate that its proposed constructions solution was prudent in light of the risk it was trying to address:

> ***"The OEB finds that Enbridge Gas has not demonstrated that the risk associated with the subject pipelines warrants complete replacement at this time. The issue of associated risk is addressed in this section. The issue of Project alternatives is addressed in the next section.***
>
> ***The risk of a catastrophic failure of the subject pipelines is a function of the probability of failure and the consequences of such failure. While Enbridge Gas may have demonstrated that a catastrophic failure of the pipelines could have severe consequences for its customers by virtue of their location in a densely populated urban area, the OEB finds that Enbridge Gas has not demonstrated that the likelihood of such failure warrants a replacement of these pipelines at this time."***[115]

122. When questioned directly by CME about whether it agreed that the OEB had never denied EGI's requested relief because of environmental or energy transition concerns, EGI's witness, Ms. Ferguson, stated "I would have to agree with that".[116]

123. Accordingly, the evidence demonstrates that EGI has never been denied leave to construct by the OEB as a result of environmental or energy transition concerns. Given that the OEB's statutory objectives in relation to natural gas continue to include the "rational expansion of transmission and distribution systems",[117] CME submits that the

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112 See EB-2022-0200, Exhibit I.5.3-CME-43.
113 EB-2022-0200, Exhibit I.5.3-CME-43.
114 EB-2022-0200, Exhibit JT8.2, p. 1 of 1.
115 EB-2020-0293, Decision and Order, May 3, 2022, p. 14, excerpted in the Compendium of Canadian Manufacturers & Exporters, Panel 7- EGI Equity Thickness, Exhibit K8.5 at p. 25.
116 EB-2022-0200, Oral Hearing Transcript, Volume 8, p. 158.
117 *Ontario Energy Board Act, 1998,* S.O. 1998, c. 15 Sched. B, section 2.

risk of EGI being denied leave to construct during the rate plan period on energy transition grounds is *de minimis*.

124. The second component of ‘operational risk’ as outlined by Concentric is that EGI will face higher regulatory costs in its facilities applications going forward. However Concentric did not complete an analysis of EGI’s regulatory costs between 2012 and the present as part of its report.

125. During the technical conference, CME asked EGI’s witnesses whether there was any information on the record that outlined EGI’s regulatory costs since 2012. EGI’s witnesses indicated that there was not.[118] CME asked EGI to undertake to provide evidence about its regulatory costs between 2012 and the present. EGI refused that undertaking.[119] CME raised the issue with EGI’s witnesses at the oral hearing. CME asked the witnesses to confirm that there was still no evidence on the record that would demonstrate what EGI’s regulatory costs were or whether they had increased since 2012. EGI’s witnessed agreed.[120]

126. Accordingly, CME submits that EGI has not met the burden of proof to demonstrate that EGI’s costs have increased as a result of an increase in the number of intervenors or the number of interrogatories.

127. The final aspect of ‘operational risk’ outlined by Concentric is an increase to the regulatory time taken to approve facility applications. In its report, Concentric states that approval periods have grown from 386 days in 2009 to 587 days in 2018 for gas pipelines.[121] When asked about regulatory timeframes in the technical conference, Concentric stated that applications which used to take two or three years now are taking “six or seven years for approval”.[122] However, Concentric did not analyze EGI’s actual

118 EB-2022-0200, Technical Conference Transcript, March 31, 2023, p. 14.
119 EB-2022-0200, Technical Conference Transcript, March 31, 2023, pp. 14-15.
120 EB-2022-0200, Oral Hearing Transcript, Volume 8, p. 159.
121 EB-2022-0200, Exhibit 5, Tab 3, Schedule 1, Attachment 1, p. 40.
122 EB-2022-0200, Exhibit K8.5, pp. 54-55.

regulatory wait times between 2012 and the present. The evidence demonstrates that EGI's regulatory approvals are not increasing significantly.

128. On March 29, 2021, the Board published updates to its performance standards and other process improvements. The Board outlined that for leave to construct applications, the Board's service standard required a decision to be made within 135 days of receiving a completed application for short-form LTC applications, and within 210 days for complex LTC applications.[123]

129. The Board published statistics on its efforts to meet the service standards. In the 2022-2023 year, the Board issued more than 260 decisions, 98% of which were within the service standard.[124] The average time for a short form LTC application was 119 days, and the average time for a complex LTC was 177 days.[125] When brought to the Board's dashboard in the oral hearing and asked whether he agreed that it demonstrated that EGI was not facing a significant regulatory lag, Concentric's witness, Mr. Coyne stated "I think that's right".[126]

130. Similarly, the Board's statistics for 2021-2022 demonstrate that the Board completed 273 decisions and 99% of them were completed within the service standard.[127] The average completion time for LTC applications were 112 days for short form LTCs and 174 days for complex LTC applications.[128]

131. The Board's statistics do not support the conclusion that EGI's regulatory waiting period is increasing. It demonstrates that the Board has made a conscious effort towards making the OEB a responsive and efficient regulator that makes determinations

[123] EB-2022-0200, Compendium of Canadian Manufacturers & Exporters, Panel 7- EGI Equity Thickness, Exhibit K8.5 at pp. 40-42.
[124] EB-2022-0200, Compendium of Canadian Manufacturers & Exporters, Panel 7- EGI Equity Thickness, Exhibit K8.5 at pp. 40-43.
[125] EB-2022-0200, Compendium of Canadian Manufacturers & Exporters, Panel 7- EGI Equity Thickness, Exhibit K8.5 at pp. 40-43.
[126] EB-2022-0200, Oral Hearing Transcript, Volume 8, pp. 161-162.
[127] EB-2022-0200, Compendium of Canadian Manufacturers & Exporters, Panel 7- EGI Equity Thickness, Exhibit K8.5 at pp. 40-57.
[128] EB-2022-0200, Compendium of Canadian Manufacturers & Exporters, Panel 7- EGI Equity Thickness, Exhibit K8.5 at pp. 40-57.

regarding LTC applications quickly. Moreover, it also demonstrates that EGI enjoys a significantly shorter lag in getting facilities approved than gas pipeline companies did, even in 2009 prior to the advent of energy transition opposition.

132. Accordingly, CME submits that EGI and Concentric have not demonstrated that EGI is facing any increase to its operational risks as a result of the energy transition.

133. The final two risks outlined by Concentric as part of EGI's alleged energy transition risks are the risk of stranded assets and the risk of a death spiral. CME submits that either scenario is not a realistic risk that EGI will face during the next rebasing term. This is tacitly acknowledged by EGI. In addition to the comments its witnesses made regarding forecast customer additions and disconnections due to the energy transition over the next five years, they stated that EGI had not provided any information on the risk of stranded or underutilized assets because they "don't have any indication of [stranded or underutilized assets] coming to fruition…".[129]

134. EGI has not forecast a significant decline in customer additions and forecasts a *de minimis* number of disconnections as a result of the energy transition. Given that it also doesn't see any indication that there will be stranded or underutilized assets over the rate term, CME submits that EGI has not proven a real risk of a death spiral and there is therefore no basis upon which to find that the energy transition has caused any increase to OPG's risk for the next five years.

5.5 EGI's Other Risks Have Remained Constant and Do Not Warrant an Increase in Equity Thickness

135. Concentric also argues that EGI's financial risk has increased in comparison to 2012. However, the evidence from EGI's financial metrics and rating agency reports does not support this conclusion.

136. Concentric provides three separate tables outlining EGD/EGI's financial metrics in 2012, 2021, Union's financial metrics during those periods and the forecast 2024

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[129] EB-2022-0200, Oral Hearing Transcript, Volume 12, pp. 110-111.

financial metrics for the combined utility. When reviewed together, the utilities' credit metrics demonstrate that some metrics are improved as compared to 2012, while other have declined. A table provided a comparison of Union and EGD's 2012 metrics compared to the forecast 2024 metrics if the Board keeps equity thickness at 36% is provided below. The trend column has been added by CME:[130]

	2012 EGD	2012 Union	2024 Forecast	Trend
Debt/EBITDA	4.42	4.70	5.24	Declining
FFO/Debt	15.69%	14.24%	13.76%	Declining
FFO/Interest Coverage	3.83	3.35	4.25	Improving
EBIT/Interest Coverage	2.03	2.13	2.40	Improving
Debt/Capitalization	64.0%	64.0%	64.0%	Stable

137. EGI's financial metrics are therefore mixed. While they indicate that EGI's debt has increased between 2012 and the 2024 forecast relative to its earnings before interest, taxes, depreciation, and amortization as well as funds from operations, the metrics also disclose that the cost of that debt, the interest payments EGI actually has to make to service that larger debt is more easily covered by EGI's earnings before interest and taxes, as well as funds from operations.

138. These results are no surprise. EGI and its constituent legacy utilities have been operating in a very low interest rate environment. EGI therefore took the opportunity to increase its debt levels (thereby causing the first two measures to decline) specifically because the cost of borrowing was so low. Critically, however, EGI's funds to meet its obligations to service that debt have increased such that EGI today is more able to meet its debt obligations as they become due than the constituent utilities were in 2012.

139. In its filed evidence, EGI included rating agency reports outlining what Standard & Poors ("S&P") as well as DBRS Morningstar ("DBRS") think of EGI's business and

130 Values are taken from Exhibit 5, Tab 3, Schedule 1, Attachment 1, Figures 17, 18, 20.

financial risks. S&P made the following findings in its most recent report dated July 14, 2023:[131]

(a) EGI is a "low risk, rate-regulated natural gas distribution and transmission company";

(b) EGI warranted an A- credit rating with a stable outlook; and

(c) Environmental and social governance factors have no material influence on its credit rating analysis of EGI.

140. In its report, Concentric admits that the utility's credit rating has been stable since 2012 for EGD, and an improvement on Union's credit rating from 2012, which was BBB+ until February 2017, when it was improved to A- as a result of the Enbridge Inc. and Spectra Energy merger.[132]

141. In its most recent report on EGI, dated September 27, 2022, DBRS makes similar findings with respect to EGI. In this regard, DBRS found:[133]

(a) EGI maintained a stable business risk profile;

(b) EGI's financial performance remained solid, with improved credit metrics for the 12 months ended June 30, 2022, and an expectation that EGI's metrics will improve further over the medium term as a result of rate base growth and synergy realization;

(c) EGI's liquidity remained solid;

(d) EGI warranted an "A" credit rating with a stable outlook; and

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131 EB-2022-0200, Exhibit K8.2, Ratings Direct Enbridge Gas Inc., July 14, 2023, pp. 1, 8.
132 EB-2022-0200, Exhibit 5, Tab 3, Schedule 1, Attachment 1, p. 67.
133 EB-2022-0200, Exhibit I.1.8-STAFF-14.

(e) There were no environmental, social, or governance factors affecting EGI's rating.

142. Neither rating agency which analyzes EGI have outlined any concerns with respect to its credit metrics or believe that EGI's credit rating will be downgraded. Moreover, both rating agencies agree that there are no environmental factors which have a bearing on their analysis of EGI.

143. Accordingly, CME submits that the evidence does not support the idea that EGI's financial risks have increased since 2012 or 2017.

144. Finally, as part of Concentric's review of non-energy transition related risks, it highlights an increasing concern with respect to cyber-security. However, Concentric did not review EGI's operations to date or its plan going forward to determine whether EGI's cyber security risk is increasing rather than simply the industry's as a whole.

145. EGI's evidence demonstrates that EGI spends significantly more than its peers on IT related costs, even on a normalized basis.[134] When responding to CME's interrogatories regarding why EGI's normalized costs were so much higher than the comparator group, Guidehouse responded that it understood that EGI made:

> ***"[S]ignificant investments this period in improvements to system reliability, enhancing business systems and to ensure system security as cyber security threats continue to grow."[135]***

146. Similarly, EGI responded to a SEC interrogatory and indicated that EGI's move towards 'software as a service' ("SAAS") would also decrease its cybersecurity risk:

> ***"The benefits of leveraging the "As a Service" (AAS) model are improved business productivity through reduction of incidents, higher velocity of TIS projects, <u>increased cybersecurity</u>, the lowering of system failure risks caused by natural disaster, lower energy consumption and accommodates business as well as data growth seamlessly."[136] (emphasis added)***

134 EB-2022-0200, Exhibit I.4.4-CME-39.
135 EB-2022-0200, Exhibit I.4.4-CME-39, p. 2 of 2.
136 EB-2022-0200, Exhibit I.4.4-SEC-176, p. 2 of 3.

> ***"The risks noted above [including cyber security risks] are now passed onto the service provider, who is better equipped with the expertise, resources, and foresight to manage those risks. Upgrades and enhancements are seamless and patches that protect the Company's operations and data as a result of cyber warfare are readily implemented for the benefit of Enbridge and all other clients of the service provider."***[137]

147. While CME agrees that in general, cyber security may play a more important role as technology progresses, EGI and Concentric have not demonstrated that EGI's cyber security risk is increasing. The evidence demonstrates that EGI is spending above its comparators for IT costs, even on a normalized basis. The evidence also discloses that the reasons EGI has given for its higher-than-average costs include significant investments in cyber security, as well as a move to SAAS, which decreases cyber security risk through increased responsiveness from a service provider.

148. Given that Concentric has not completed an evaluation measuring the reciprocal increases and decreases to cyber security risk and EGI's mitigation of that risk through its investments, there is not way to determine if EGI's risk has increased on a net basis. Accordingly, CME submits that EGI has failed to demonstrate an increase in either its business risk or its financial and its request for an increase to its equity thickness should be denied.

5.6 Concentric's Comparators for the Equity Thickness are Inappropriate

149. If the Board determines that EGI's business or financial risks have increased such that it should review what the appropriate equity thickness for EGI should be, then the Board should apply the fair return standard to determine what EGI's equity thickness should be. In CME's view, the fair return standard indicates that 36% is still the appropriate equity level for EGI's risks.

150. The fair return standard has three components:

(a) The comparable return standard (as compared to entities of 'like risk');

[137] EB-2022-0200, Exhibit I.4.4-SEC-176, p. 2 of 3.

(b) The financial integrity standard;

(c) The capital attraction standard.

151. The comparable return standard demonstrates that EGI's equity thickness is appropriate at 36%. Concentric argued that EGI's equity thickness is significantly lower than its peers of like risk. However, Concentric's analysis is flawed. Dr. Cleary's analysis showed the following flaws in Concentric's approach:

(a) Concentric's approach comparing the awarded equity ratios of utilities in other jurisdictions to EGI's is flawed by design. Concentric does not provide any insight into the record before the regulatory of those comparator utilities and therefore it is impossible to untangle how much of the comparators' awarded equity is properly transferrable to an analysis of EGI, and how much of it is based on idiosyncratic issues faced by those comparators or of the markets at the time the regulator set their equity thicknesses.[138]

(b) Three out of four of Concentric's comparator groups do not have a 'like risk' to EGI. In this regard:

(i) Concentric's US HoldCo comparator group only has half of the entities with at least as good a debt rating as EGI.[139]

(ii) The US HoldCo comparators likely struggle to earn their ROE. In comparison, EGI (and its legacy utilities) overearned its ROE by an average of 1.1% over the last 30 years.[140]

(iii) Concentric's Canadian HoldCo comparator group only include two entities with a debt rating as high as EGI.[141] This could be the result

[138] EB-2022-0200, Exhibit M6 (IGUA Cost of Capital), Corrected 2023-05-15, p. 3.
[139] EB-2022-0200, Exhibit M6 (IGUA Cost of Capital), Corrected 2023-05-15, p. 16.
[140] EB-2022-0200, Exhibit M6 (IGUA Cost of Capital), Corrected 2023-05-15, p. 17.
[141] EB-2022-0200, Exhibit M6 (IGUA Cost of Capital), Corrected 2023-05-15, p. 20.

of having operating companies that are held by the holding company being based in the United States rather than Canada; and

(iv) The Canadian HoldCo comparator group also has much more variability around earning their ROE, in comparison to EGI, who has earned or over earned regularly for the last few decades.[142]

(c) In the one comparator group that does have a 'similar risk' to EGI, only 3 of the 10 companies listed are comparable. Seven of the comparators have a revenue size that is 5.5% or less than that of EGI.[143] Some of the comparators only generate 1% of EGI's revenue.[144] The smaller comparators have higher risk than EGI, a fact noted by Concentric in its evidence in another proceeding.[145] The three remaining comparators are still much smaller than EGI, and so when reviewing EGI's equity thickness in comparison to those entities, some adjustment is required. The three remaining comparators have an average equity thickness of 38%, which, when adjusted for their smaller size and increased risk, indicates that 36% remains appropriate.

152. The evidence demonstrates that EGI would be able to meet the financial integrity standard at 36% equity. As outlined earlier, the credit ratings agencies that analyze EGI, DBRS and S&P both give EGI a stable outlook at its current credit rating (A and A-respectively). They indicated no concerns with EGI's current 36% equity thickness.[146]

153. Moreover, EGI is also able to continue to attract capital. The average yield on a 'A' rated utility bonds was 4.88%.[147] EGI's bond yields were 4.825%-4.881%.[148]

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142 EB-2022-0200, Exhibit M6 (IGUA Cost of Capital), Corrected 2023-05-15, p. 21.
143 EB-2022-0200, Exhibit M6 (IGUA Cost of Capital), Corrected 2023-05-15, p. 25.
144. EB-2022-0200, Exhibit M6 (IGUA Cost of Capital), Corrected 2023-05-15, p. 25.
145 EB-2022-0200, Exhibit M6 (IGUA Cost of Capital), Corrected 2023-05-15, p. 25.
146 EB-2022-0200, Exhibit M6 (IGUA Cost of Capital), Corrected 2023-05-15, p. 33.
147 EB-2022-0200, Exhibit M6 (IGUA Cost of Capital), Corrected 2023-05-15, p. 13.
148 EB-2022-0200, Exhibit M6 (IGUA Cost of Capital), Corrected 2023-05-15, p. 13.

Accordingly, EGI was able to attract debt capital at a similar rate to the average for 'like risk' companies and meets the capital attraction standard.

154. Accordingly, CME submits that EGI's capital structure should remain at 36% equity and 64% debt.

6. VARIANCE AND DEFERRAL ACCOUNTS

6.1 EGI Is Not Entitled to a Windfall from Union's Actuarial Losses

155. EGI is proposing to clear $142.2 million plus interest from the Accounting Policy Change Deferral Account ("APCDA").[149] Within that account is $155 million debit from ratepayers recorded in relation to unamortized pension and other post employment benefits ("OPEBs") from Union.[150]

156. These amounts reflect losses from Union gas that arose from changes to the actuarial assumptions used to estimate the value of Union's pension obligations that occurred prior to February 27, 2017, the date of the merger between Spectra Energy (Union's parent company) and Enbridge Inc. (Enbridge Gas's parent company).[151]

157. At the time of the merger of the parent companies, Enbridge Inc.'s view of Union's unamortized pension and OPEB liabilities were that they were required to be written off pursuant to US GAAP and the Accounting Standards Codification ("ASC") rules.[152] The memo at the time outlines its treatment of the amounts:

> ***"Upon the Enbridge Inc. (EI) acquisition of UGL through the Spectra merger, EI eliminated the previously incurred losses of UGL ($250M gross / $185M net of deferred taxes) that resided in other comprehensive income. As part of the purchase price adjustment the amount written off was ultimately included in the goodwill balance recognized. This is because EI did not recognize an identifiable asset to allocate purchase price to since UGL did not recognize as a regulatory asset."[153]***

149 EB-2022-0200, Exhibit 9, Tab 2, Schedule 1, pp. 4-5.
150 EB-2022-0200, J15.1, p. 1.
151 EB-2022-0200, Oral Hearing Transcript, Volume 15, p. 30.
152 EB-2022-0200, Oral Hearing Transcript, Volume 15, p. 35.
153 EB-2022-0200, JT3.31, Attachment 1, p. 4 of 21.

158. Goodwill is not recoverable in rates.[154] Accordingly, Enbridge Inc.'s decision was effectively to write off those amounts and knowingly classify them as an amount that could not be recovered in rates.

159. EGI subsequently changed its mind on this point. According to EGI's witnesses, after receiving the order from the Board to amalgamate the utilities, EGD and Union employees reassessed the unamortized pension and OPEB amounts and determined that they were recoverable from ratepayers.[155] EGI therefore now takes the position that it can undo the write-off to goodwill that occurred in the Enbridge Inc. Spectra transaction and recognize the $155 million as a deferred asset.[156]

160. Both Enbridge Inc. and Spectra were very sophisticated commercial entities negotiating a major acquisition/merger. As outlined in Enbridge's own memo, when Spectra and Enbridge Inc. merged, the amounts now sought for recovery were written off "as part of the purchase price adjustment" and were included in the goodwill balance.[157] In other words, the purchase price paid by Enbridge Inc. when purchasing Spectra's shares were proportionally lower than it would have otherwise been as it was adjusted downward to recognize that this amount was unrecoverable. As a result, Enbridge Inc. already enjoyed the benefit of this amount as it lowered the purchase price it had to pay to purchase Spectra. To allow EGI to now recover these balances from ratepayers, which would flow to Enbridge Inc. through EGI's earnings would allow Enbridge to gain the benefit of this balance twice. To properly undo this transaction, the amounts collected from ratepayers would need to flow to Spectra's shareholders as of the time of the Spectra/Enbridge Inc. merger. EGI's witnesses have confirmed that they are not proposing to flow those benefits to Spectra's shareholders.[158]

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154 EB-2022-0200, Oral Hearing Transcript, Volume 15, p. 37.
155 EB-2022-0200, Oral Hearing Transcript, Volume 15, p. 46.
156 EB-2022-0200, Oral Hearing Transcript, Volume 15, p. 46.
157 EB-2022-0200, JT3.31, Attachment 1, p. 4 of 21.
158 EB-2022-0200, Oral Hearing Transcript, Volume 15, p. 56.

161. Accordingly, EGI's proposal amounts to a double recovery and should be denied by the Board.

6.2 EGI has Not Justified a Weather Normalized Average Use Account

162. EGI is proposing a harmonized average use account which would record revenue of the volume forecast variance resulting from both average use as well as weather during the rate term.[159]

163. Currently, EGI and Union both have average use accounts. In the Enbridge rate zone, the account is the average use true up variance account, and the Union rate zones account is the normalized average use account.[160] These would true up normalized average use for general service customers. In the existing accounts, Enbridge still bears the risk for weather differences between the forecast and actual. In contrast, EGI's new harmonized account would not only protect EGI from the difference between actual and forecast average use, but also differences in revenue as a result of weather variance.

164. EGI justifies this additional protection on the basis that the actual weather versus forecast has been roughly symmetrical since 2013. In CME's submission, this is no reason to approve a weather normalized account. What this demonstrates is that EGI, when it bears the risk of variances in weather to forecast, has a good track record of fairly estimating the weather, leading to similar variances between parties. It does not necessarily suggest that EGI will continue to forecast accurately if it does not bear any risk in this regard.

165. Accordingly, while CME supports the creation of a harmonized account, it should not include protection for weather variations.

7. TURNBACK, PDO AND PDCI

7.1 The Board Should Make a Base Rate Adjustment

[159] EB-2022-0200, Exhibit 9, Tab 1, Schedule 2, p. 26.
[160] EB-2022-0200, Exhibit 9, Tab 1, Schedule 2, p. 26.

166. Prior to 2013, large volume customers on Union's system had to make some of their deliveries at Parkway, rather than at Dawn. These Parkways Delivery Obligations ("PDO") were considered to be of a benefit to the system, as the delivered gas at Parkway was geographically closer to where the gas would be needed than if it had been delivered at Dawn. Union did not have to build infrastructure to carry that gas to Parkway, and it was therefore a reduction in cost on the system.

167. In Union's 2014 rates application, the parties agreed to reduce the PDO by allocating ex-franchise 'Dawn to Kirkwall' turnback to allow an increased amount of gas to be delivered at Dawn instead of Parkway (the "PDO Settlement Agreement"). The entities that were still required to deliver gas at Parkway were paid the Parkway Delivery Commitment Incentive ("PDCI") to compensate them for the additional cost of delivering gas to Parkway.

168. Union took the position that the shift from deliveries at Parkway to deliveries at Dawn was not net-neutral, but was a cost to the utility, as it had to allocate capacity to accommodate the shift and then return the gas to Parkway in order for it to be used upstream. This capacity could have otherwise been offered at market values to other entities and increased Union's earnings.[161] Since the forecasts approved by the Board factored in the use of that capacity for earnings, Union would be earnings less than forecast as a result of the accommodation of the PDO shift.

169. However, there is a surplus of capacity that is built into rates that is not being utilized. Included in 2013 rates was the full capacity of the Dawn to Parkway system of 6,803 TJs per day.[162] However, EGI is not using the full capacity of the Dawn to Parkway system. According to EGI's answer to an interrogatory, it is only using 6,593 TJs per day, leaving a surplus of 210TJs per day, which was built into base rates.[163] Therefore, rate payers were already paying for that 210TJs per day. Since they are surplus however, EGI was free to sell that capacity in the market and earn separate revenues from its sale,

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161 EB-2022-0200, Oral Hearing Transcript, Volume 7, p. 101.
162 EB-2022-0200, Oral Hearing Transcript, Volume 7, p. 103; EB-2022-0200, Exhibit I.4.7-FRPO-169.
163 EB-2022-0200, Oral Hearing Transcript, Volume 7, pp. 103-104.

or to use them for the PDO shift. They could then collect an additional amount from the sale, or from ratepayers through the PDO framework.

170. CME submits that this represents a double recovery on the sale of that capacity. Once where it is recouped in rates from ratepayers, and again if EGI sells the capacity on the open market or is remunerated through the PDO Settlement Agreement for using it to facilitate the PDO shift.

171. While CME acknowledges that the double recovery was permissible under the PDO Settlement Agreement until December 31, 2018, the Board should not allow it to continue beyond that time. The PDO Settlement Agreement expressly stipulated that one of its guiding principles was to keep Union whole “during the operation of the Incentive Regulation Mechanism (“IRM”) to December 31, 2018”.[164]

172. In the absence of the rebasing application, the Board would have been free to review Union’s costs, and to make a decision whether it was appropriate for Union to continue to keep collecting revenue in base rates for the 210 TJs of excess capacity in addition to the potential second recovery for that capacity.

173. Instead, Union and EGD merged in 2017. In essence, EGI now argues that it was entitled to continue recouping both the base rates amounts for the 210 TJs capacity as well as the revenue from the capacity’s sale from the time of the merger until now because it did not rebase. EGI therefore kept “the framework” it was operating under for an additional five years, and by operation of the settlement agreement, it was entitled to be “kept whole” for those additional years.[165]

174. CME submits that the Board should not allow EGI to continue recovering amounts for this capacity twice. EGI’s witness acknowledged that the proposed remedy for this double counting as proposed by FRPO was a base rate adjustment beginning in 2019.[166]

164 EB-2013-0365, Appendix B, p. 1 of 7; Eb-2022-0200, Oral Hearing Transcript, Volume 7, pp. 106-107.
165 EB-2022-0200, Oral Hearing Transcript, Volume 7, pp. 112-114.
166 EB-2022-0200, Oral Hearing Transcript, Volume 7, pp. 113.

EGI's witness also confirmed that EGI requested other base rate adjustments as part of the MAADs proceeding.[167]

175. EGI should not pick and choose base rate adjustments that it favours, while denying adverse base rate adjustments. The MAADs proceeding was broader than simply approving the amalgamation. It was a wide-ranging rate application that set rates for the proceeding five years and included several base rate adjustments. Moreover, the Settlement Agreement expressly set out that it contemplated an end to the framework as of December 31, 2018.

176. Accordingly, CME submits that the Board should make the necessary base rate adjustment to prevent double recovery starting January 1, 2019.

7.2 The Board Should Consider Reverse Open Season Buy-Outs

177. In his evidence, FRPO's expert, Mr. Rosenkranz suggested that EGI should allow buy-out payments in reverse open seasons.[168] As a result of the Storage and Transportation Access Rule ("STAR"), EGI is required to provide for a 'reverse open season' prior to undertaking any expansion. The reverse open season process allows entities that are on the system to indicate if they would like to relinquish their capacity. Capacity that is turned back could then reduce or eliminate the need for the facility investment.

178. Currently, EGI's practice is to canvass entities that wish to leave the system without providing any incentive. Mr. Rosenkranz proposes to allow buy-out payments to incent that turnback. As CME understands it, a buy-out could be beneficial to customers in that those entities that are bought out are presumably better off otherwise they would not accept the buy-out, and the larger population of customers are better off as the buy-out would be less than the cost of the facility investment.

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[167] EB-2022-0200, Oral Hearing Transcript, Volume 7, pp. 115.
[168] EB-2022-0200, Exhibit M – Rosenkranz Evidence, p. 14.

179. While it likely requires additional consideration before implementation, CME submits that this suggestion has merit and should be considered by the Board as long as it is expected to be of general benefit to ratepayers.

8. COSTS

180. We request that CME be awarded 100% of its reasonably incurred costs in connection with this matter.

ALL OF WHICH IS RESPECTFULLY SUBMITTED this 19th day of September 2023.

Scott Pollock
Counsel for CME

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