ONTARIO ENERGY BOARD

Enbridge Gas Inc.

**Application to change its natural gas rates
and other charges beginning January 1, 2024**

ARGUMENT

Industrial Gas Users Association (IGUA)

> *To the extent that EGI acts imprudently by failing to appropriately plan for the energy transition, it may experience lower returns and/or fail to recover its capital. However, this unlikely case is not the regulator's responsibility when considering the business risk facing a prudently run utility (such as for the purpose of setting the equity thickness).* [Evidence of Dr. Asa S. Hopkins, Exhibit M8, page 21, lines 8-12]
>
> *We do not expect a death spiral scenario to be likely for Enbridge Gas because it is reasonable to anticipate both the Company and its regulators would work proactively to avoid such a scenario.* [Evidence of Concentric Energy Advisors, Exhibit 5, Tab 3, Schedule 1, Attachment 1, page 59]

INTRODUCTION

1. Against the backdrop of "the energy transition", Phase 1 of this proceeding is about setting rates for EGI for 2024, which rates will then form the basis for determining rates for an ensuing rate plan period which EGI proposes to run from 2025 through 2028 and which will be determined in Phase 2 of this proceeding.

2. Taking account of the now accepted Settlement Agreement, the gross delivery revenue deficiency for the 2024 test year under existing (2023) delivery rates is $208.8 million, inclusive of the forecast 2024 revenue requirement impact of the Dawn to Corunna project consideration of which is deferred to Phase 2 of this proceeding.

3. EGI's proposed new depreciation policy would increase depreciation expense by $141.9 million relative to the existing approved depreciation policies[1], contributing a 2024 revenue deficiency of $187.5 million[2]. Over the proposed 5 year rate plan period implementation of EGI's proposed depreciation policy would increase rates by almost a billion dollars (~$938 million), prior to annual escalation.

4. EGI's proposal to increase its equity thickness by 2% in 2024 contributes an additional 2024 revenue deficiency of $26.1 million.[3] EGI's full equity thickness proposal, which is to increase its equity thickness from 36% to 42% in steps between now and 2028, has an annual revenue requirement impact, once fully implemented, of $80.6 million[4]. Over the proposed 5 year rate plan period from 2024 through 2028 implementation of EGI's proposed phased in equity thickness proposal would increase customer rates by more than $260 million, prior to annual escalations.

5. EGI's proposed depreciation policy and equity thickness increase together contribute over 100% of EGI's proposed 2024 revenue deficiency.[5]

6. In respect of both of these proposals – a new depreciation policy and a proposed increase in equity thickness – EGI has identified the energy transition as a driver; directly in respect of the latter and as subsequent justification for the former.

7. IGUA's intervention in Phase 1 of this case, and this final argument, focus on 3 topics:

   (a) EGI's response to the energy transition (Issue 3).

   (b) EGI's request to increase its equity thickness (Issue 21).

   (c) EGI's proposed new depreciation policy (Issues 15 and, in respect of Site Restoration Costs, 16).

8. There are many other topics in this proceeding of concern to IGUA and its members, and on those we will defer to other parties who have focussed on them. Silence on those other topics in this argument does not indicate acceptance of EGI's positions thereon.

---

[1] EGI AIC p. 175.
[2] Exhibit J17.11, Attachment 1, page 5, line 5.
[3] Exhibit J17.1, page 5.
[4] Exhibit J9.1.
[5] Exhibit J17.11, page 5, lines 5 and 6.

9. In respect of the topics on which IGUA has focussed, it is IGUA's position that:

(a) ***In respect of responding to the energy transition***, while EGI has done a considerable amount of work on external challenges to its business arising from the energy transition, it has done very little (at least to public knowledge) to asses how its gas delivery business could/will actually need to change in response to those external challenges. EGI's response in the current application is to ask for a lot more money from customers to cover its unexplored, unsubstantiated and unmitigated business risks and recover the cost of all of its assets sooner rather than later. This is insufficient response to the energy transition.

Until EGI demonstrates that it has identified, quantified and prudently considered how it might mitigate energy transition risks (and take advantage of opportunities) it is premature to conclude that EGI's business business risk has significantly increased so as to require an increase in equity thickness, or justify a broad acceleration of return of invested capital across EGI's entire asset base as EGI's depreciation proposal contemplates.

(b) ***In respect of equity thickness***, without an understanding of EGI's specific risks and EGI's plans to mitigate them, there is insufficient evidence to conclude that EGI's business risk has changed significantly, and it would be inappropriate to reward the company's shareholders with a greater equity share and thereby charge ratepayers $260 million to compensate the utility for risks that may not occur, and that prudent utility management could mitigate. Paying more now, absent prudent actions by EGI to reduce the need to pay more later, is neither just nor reasonable.

Further, there is no apparent current or near term impairment of the financial market's continuing confidence in EGI or EGI's continuing ability to attract capital on reasonable terms.

(c) ***In respect of depreciation***, there are two candidate procedures which have been advanced in this proceeding; Average Life Group (ALG, currently in use for legacy EGD assets and most other North American gas utilities[6]) and Equal Life Group (ELG, proposed by EGI).[7] Of the two, both are justified as a matter of general depreciation practice, though one (ELG) has a materially higher near term cost for customers. EGI has not justified the adoption of the ELG procedure either as a practically superior depreciation method nor as an appropriately nuanced and transparent approach to addressing energy transition asset recovery risk where it might ultimately be demonstrated to exist (i.e. in respect of which assets) and in appropriate measure.

10. EGI's request to increase its equity thickness and its proposal to adopt the ALG depreciation methodology should both be rejected at this time, pending proper study by EGI of how the energy transition could change its energy delivery business going forward

[6] Exhibit I.4.5.Staff-173(d).
[7] Two additional depreciation tools; an Economic Planning Horizon and a Units of Production approach, have also been discussed but how they would be implemented has not been fully evidenced.

and what actions it can/should take to mitigate risks, and take advantage of opportunities, attendant on such change. The evidence of Dr. Asa Hopkins of Synapse Energy Economics Inc. (Synapse), filed as Exhibit M8, addresses the type of modelling that EGI can and should be doing to study its options, and presents an illustrative approach to the type of modelling and associated quantification of risks to EGI and its customers that would support identification of tools and strategies available to EGI and the OEB to avoid or substantially mitigate those risks.

11. EGI should be directed to complete a proper analysis, such as that commended by Dr. Hopkins' work, of how its operations can/should change in response to the energy transition. Such analysis should properly consider;

(a) which customers are more likely to leave the system sooner rather than later, when, where and in what numbers;

(b) which of EGI's assets are more likely to be underutilized sooner rather than later and at what potential cost;

(c) where should capital and operating costs be deployed in order to most effectively meet the demand for gas delivery services and take advantage of energy transition opportunities into the future; and

(d) what regulatory mitigation tools may be most useful to address shareholder ***and*** customer risks.

12. Once that analysis is done and reviewed, this Commission will be in a position to consider, on a properly informed basis, the extent to which EGI's business risk has changed so as to require an increase in equity thickness, what approach to depreciation is best suited to targeting demonstrated asset risks, and which additional regulatory tools could and should be deployed in order to protect both customers and shareholders as the energy transition continues to unfold.

13. Pending that work, EGI's equity thickness request and depreciation proposal (to the extent justified by the energy transition) are premature and should be rejected.

14. Subject to completion of an appropriate record for Phase 2 of this proceeding, IGUA also believes that 5 years is too long to wait for this work to be completed and considered, and

that a shorter rate plan term than the 5 years requested by EGI in its application should be considered. As the preliminary modelling completed by Dr. Hopkins illustrates[8]:

> *Waiting makes things worse. The longer the utility waits to change its approach (in a world where building-sector customers and sales are falling toward zero), the larger the rate shock and the larger the potential amount of stranded costs to mitigate.*
>
> *Having a clear long-term plan sooner rather than later is key for successfully managing a scenario like the one we modeled, and likely for other scenarios as well. Thankfully, Ontario is developing a provincial plan. It will be important for EGI to adapt its business to that plan quickly after it is adopted.*

15. This position will be further explored and advanced in Phase 2 of this proceeding, though the possibility of a shorter rate plan term and/or interim reporting on energy transition work could be considered by the Hearing Panel in assessing EGI's proposals being determined in this Phase 1 of the proceeding.

[8] Exhibit M8, page 46, lines 10 to 18.

EGI's RESPONSE TO THE ENERGY TRANSITION

16. To be clear, IGUA does not question that an energy transition is underway, nor does it question the importance of the associated structural shifts.

17. IGUA's members well understand that there is an energy transition underway, and what its impacts might and should be on the way we do business in our society. They face it every day. They make both operating and capital decisions in the face of it. Most, if not all, of Ontario's large industrial gas consumers have ambitious net zero targets of their own, which have been noted and are being watched by their customers, policy makers and capital markets. To meet those commitments they are investing many billions of dollars in changes to their businesses, and they believe that it is very important for them to do so.

18. For some of these industries, increasing their use of gas is the most effective decarbonization tool in their arsenal for the time being, and probably for some time to come. For them, medium and long-term reliance on a safe, reliable and affordable gas delivery system will be necessary, perhaps long after smaller customers with more near and medium-term options have left the system.

19. IGUA members are supportive of contributing their fair share to the cost of maintaining and evolving gas delivery services that they do, and will continue to, rely on in the face of the energy transition. However, if they are to be called upon to do so, it must be with rigorous consideration of the most effective response by EGI to the external changes faced, so that adaptation costs are incurred purposefully, in a timely manner, and with sufficient consideration for the risk mitigating impact of such cost incurrence. Customers should not be required to, for example, pay significantly increased depreciation costs for large diameter pipes which, proper analysis could indicate, are not likely to face significantly premature economic obsolescence. Not only could such a measure be ultimately unnecessary, it could increase the costs of an energy source that properly managed could further industrial decarbonization and enhance industrial competitiveness in Ontario.

20. EGI's response to the energy transition in this proceeding has been at best incomplete, and at worst opportunistic. On the one hand EGI advocates a continuing role for its system through decarbonization and beyond, insisting that the value and optionality afforded by its existing and planned infrastructure is well suited to an affordable energy transition. On

the other hand, EGI seeks to significantly increase delivery customer rates in order to accelerate capital recovery and increase shareholder earnings all in the face of the significant risk to its business that it asserts the energy transition poses.

21. Which is it?

22. EGI has done quite a bit of work exploring what is happening outside the company towards energy transition, where that could go and what the overall cost scenario could be.

23. In response to what may happen outside the company, EGI is proposing to:

(a) Increase its equity thickness and resulting shareholder earnings by just over 16%, recovering from customers an additional $80 million a year, phased in over time.

(b) Adjust its approach to depreciation, adding $187.5 million[9] (relative to the current approach) to rates in 2024, justified at least in part by reference to potential energy transition changes.

(c) Restructure its rates to recover more through fixed costs, mitigating the risk to its revenues of declining per customer volumes.

(d) Take further tentative steps towards diversifying its business through expansion of its RNG and hydrogen blending initiatives, bringing all of its NGV business into regulation, and establishing a ratepayer funded innovation fund.

24. All of EGI's "safe bet" actions serve to decrease EGI's risk or increase its earnings, rather than actually addressing how the energy transition will impact/change EGI's business, and how to respond to that in the best interests not only of EGI but also of its customers.

25. Against this backdrop EGI is proposing to spend approximately $14 billion in capital for the 2023 to 2032 period. As noted by OEB Staff in its Submissions[10]:

> *Considering that natural gas consumption is expected to decline significantly by 2050, it is not clear how $14 billion of capital expenditures that is on average recoverable over 40 years aligns with the potential for significant future declines in natural gas throughput. The proposed $14 billion of capital expenditures is close to the entire 2024 proposed rate base of $16 billion. Enbridge Gas expects to continue to add new customers and expand its rate base in what appears to be "business as usual"*.

[9] Exhibit J17.11, Attachment 1, page 5, line 5.
[1010] OEB Staff Submissions, page 59, 2nd full paragraph.

26. EGI's planning takes little account of the energy transition changes that, in the context of equity thickness and depreciation, EGI laments have significantly increased its risk. EGI's capital update is based on a customer forecast without energy transition changes[11], and as explored in discussion at the oral hearing with Commissioner Moran EGI's asset management plan was developed without any assessment of energy transition or stranded asset risk beyond the modest adjustment which EGI has made to its volume and customer growth forecasts.[12]

27. In the several jurisdictions that are attempting a real look at how the energy transition will impact the natural gas delivery business, study is being done on quantifying potential "business as usual" risks and exploring potential regulatory changes to help the utility manage the energy transition while mitigating customer impacts and investor concerns. Dr. Hopkins canvasses this work in his evidence.[13]

28. Dr. Hopkins in his evidence also presents his own illustrative modelling, the results of which indicate that using relatively simple levers around depreciation and asset retirement, the actual dollars at risk of ultimate asset stranding could be quite small; i.e. 1% of today's plant in service. Instructively, this illustrative modelling shows that, properly managed, future dollars at risk for EGI could be *"less than the net increase in ratepayer costs resulting from EGI's proposed change in equity ratio just between 2024 and 2028"*.[14]

29. Dr. Hopkins acknowledges that the model presented in his evidence is illustrative rather than dispositive. It includes numerous simplifying assumptions required *"because of the limits in the information available to an independent consultant regarding a particular utility's gas system"*.[15] The model is offered in order to illustrate *"that modeling of this sort is reasonable and appropriate for EGI to conduct in order to understand its actual stranded cost risk."* Dr. Hopkins explains the model and its potential value as follows (emphasis added):[16]

[11] Exhibit J14.3, second paragraph.
[12] Transcript 14, pages 105 *et seq.*
[13] Exhibit M8, pages 40-42 and Attachment 3.
[14] Exhibit M8, pages 42 through 47. See also Attachment 4 for details of the modelling done.
[15] Exhibit M8, page 42, lines 19-26.
[16] Exhibit M8, page 43, lines 3-16.

> *Attachment 4 describes a simplified illustrative model of a gas distribution utility undergoing a strategic downsizing over the course of the time between now and 2050. The purpose of this modeling is to show what the rate implications of such a transformation would be for customers of the retiring or retained gas systems and the financial implications for the utility. The model is designed to avoid stranded assets and identify the extent to which avoiding stranded assets creates unsustainable rate implications. If rates in the model become unsustainable, that implies that some stranded costs may be forced by competitive factors, unless these costs are mitigated through regulatory means.* ***A model of this sort (especially if tailored to the specific knowledge that a utility has about its own systems and finances) can be used to examine different scenarios and identify whether and when any assets become stranded. The model can also evaluate what the value of those assets at risk might be, and thereby assess whether each scenario includes any capital risk for the utility, along with the size of that risk.***

30. Dr. Hopkins explains that such modeling supports further insights regarding proactive planning for asset reinvestment and retirement, the potential magnitude of stranded capital, and insight into how such potential stranded capital could be provided for in a manner that is equitable for all customers and avoids rate shock and resulting undue competitive pressures for natural gas services.[17]

31. ***IGUA submits that rather being allowed to simply increase rates across the board for customers to mitigate its own risk, and "addressing" the energy transition by seeking more money from customers to diversify into new lines of business without examining how to mitigate customer risks related to its current mode of operation, EGI should be directed to conduct a proper analysis of its options along potential pathways to decarbonisation, and come back to the OEB with a quantitative assessment of capital recovery risk and a real plan for addressing that risk.***

32. Dr. Hopkins has suggested the scope for such a plan:[18]

> *That plan should identify and quantify risks and opportunities, including when they would manifest in impacts on the company as well as what their impacts would be. This plan should include a comprehensive assessment of electricity and gas utility roles in decarbonisation, gas load forecasts, infrastructure needs, gas price forecasts, analysis of customer counts and consumption patterns by customer type, and the availability and costs of alternative fuels.*

[17] Exhibit M8, page 45, lines 15 *et seq.*
[18] Exhibit M8, page 53, lines 6 through 12.

33. IGUA agrees with Dr. Hopkins that:[19]

> *Developing such a plan would reduce uncertainty regarding the company's future business, and thereby lower investor risk. Such a plan should also inform analysis of, and selection of, additional mitigating actions.*

34. OEB Staff has offered a similar recommendation, in the context of discussing its concerns regarding EGI's proposed capital spending:[20]

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

35. EGI has proposed to increase rates for customers to address *EGI's* energy transition risk without proper analysis of how that risk will manifest for customers and how to mitigate it.

36. IGUA submits that it would be inappropriate to reward the company's shareholders with a greater equity share, mitigate the shareholder's capital risk through an across the board increase in depreciation, and approve incremental funding in support of business diversification, without first requiring the utility to develop a plan to demonstrate what risks are likely to occur and what prudent actions can be taken now to mitigate them. As Dr. Hopkins puts it[21]:

> *Paying more now, without prudent actions to reduce the need to pay more later, is neither just nor reasonable.*

[19] Exhibit M8, page 53, lines 12-14.
[20] OEB Staff Submissions, page 59, 3rd full paragraph.
[21] Exhibit M8, page 52, lines12-17.

EQUITY THICKNESS

37. IGUA acknowledges that the energy transition will require that EGI's business in the future will be different than it has been in the past and remains currently. As it was put in the discussion between IGUA counsel and Mr. Coyne of Concentric Energy Advisors (Concentric);

> *… the existence of the energy transition is not speculative. What is uncertain is how that will manifest in respect of Enbridge Gas's business.*[22]

38. The OEB's Cost of Capital framework examines applications for an adjustment to equity thickness in two steps. The first step is to examine whether an applicant's business risk has changed significantly so as to warrant re-examination of its capital structure. If it is determined that a significant change is apparent, the next step is to examine whether the existing capital structure meets the fair return standard and if not how it should be adjusted in order to do so.

Business Risk

39. EGI and Concentric both assert that the energy transition presents a significant change in EGI's business risk, such that without a 16% increase in equity thickness from 36% to 42% EGI will have trouble attracting and retaining capital. Of course, in reality EGI attracts and retains capital from its parent, Enbridge Inc. (EI), and EI goes to the capital and debt markets based on a number of energy businesses, including EGI.

40. EI went to the capital market on September 5th with a $4.0 billion offering of common shares to raise funds for a ~$14 billion acquisition of 3 U.S. natural gas distribution companies. EI publicized its intention to become the largest North American gas distributor.

41. Three days later, on September 8th, EI confirmed closing that offering, on an oversubscribed basis, raising $4.6 billion of capital. (the Attachment to this argument contains EI press releases and press articles related to the acquisition.)

[22] Transcript 8, page 82, lines 8-11.

42. It seems that EI is not having any trouble attracting financing for continued expansion of its gas distribution business. To the extent that any concerns are apparent from the public material accessed, they relate to EI's growth plans driven leveraged balance sheet (i.e. its business growth aspirations driven level of borrowing), and not the energy transition.

43. Concentric agrees that *"over the near term, Enbridge is not projecting mass abandonment from its system, and a gradual continuation of declining use per customer, <u>which has been going on for the past decade"</u>* (our emphasis).

44. That energy transition considerations for EGI are not new is also noted by Dr. Hopkins in his written evidence. Dr. Hopkins observes that Ontario's climate plans have called for *"dramatic reduction in emissions (including a reduction in emissions from natural gas) since at least 2016, and Enbridge Gas has been aware of this context and planning for it."*[23] Dr. Hopkins considers Enbridge Gas strategic planning materials from June 2016[24] which address the need to reduce emissions significantly by 2050, including from natural gas, the competitive position of gas vs. electricity, the degree to which electrification will impact peak gas demand, and the need to "rebrand" existing gas infrastructure as a way to reduce emissions. The materials identify power to gas (i.e. hydrogen) and renewable energy (including, apparently, RNG) as part of Enbridge Gas' "long term future". The materials identify "top issues for [gas distribution]" to be "navigating a challenging carbon policy environment" and "accelerated development of low-carbon business platforms". All of these issues, highlighted for Enbridge Gas' leadership seven years ago, are at the core of the energy transition discussion in Concentric's cost of capital report in this proceeding.

45. Despite these ongoing energy transition considerations, EGI says that it did not raise the capital structure issue in the consolidation application because it was not a rebasing application and so not the time to put forward *"base-rate adjustments of this kind"*.[25] Of course, the choice to seek a rebasing deferral at the time of the merger was the choice of EGI. If it had significant concerns with its then current and imminent ability to raise capital and otherwise finance its ongoing operations it could have brought a rebasing application then, or soon thereafter. Or it could have filed separately for a review of its capital

---

[23] Exhibit M8, page 21, line 15 to page 22, line 8.
[24] Exhibit JT7.23, Attachment 1, pages 46 *et seq.*
[25] Transcript 8, page 53, lines 9-15.

structure, which would be a prudent course in the face of a genuine concern for continued ability to attract and retain capital on reasonable terms.

46. Instead EGI requested a 10 year rebasing deferral, apparently contemplating that its capital structure could and would remain as is for many years to come.

47. Unless there has been an unforseen sea change in energy transition risk to EGI since 2019, the notion that there is urgency to increasing EGI's equity thickness in 2024 would seem out of step with EGI's recent regulatory conduct.

48. In this proceeding, it is EGI's evidence that while energy transition is coming, there is no significant imminent risk during the proposed 2024 through 2028 rate plan period.

49. EGI has continued to achieve stable earnings at or above its approved ROE.

50. Dr. Hopkins considers EGI's historical ability to earn at or above its allowed returns, and concludes that *"the figures show that EGI and its predecessor companies have consistently achieved stable returns that are higher than the allowed returns."*[26] Dr. Hopkins explains the relevance and significance of this fact as follows:[27]

> *The fact that EGI and both of its precedent parts exceeded their allowed returns every year since at least 2007 indicates that investors considering the near-term risk facing EGI should not expect their returns to fall below the allowed level, and that return will generally fall in a relatively narrow band above the allowed level.*

51. Dr. Hopkins further concludes that the lack of indication of any change in operational or volatility-related business risk over the period from 2007 to the present as reflected in consistent utility earnings performance *"is consistent with the addition of new variance and deferral accounts to manage new sources of volatility that have arisen over this period"*.[28]

52. Dr. Clearly engaged in a similar consideration of EGI's (and its predecessor companies') history of earned ROE consistently exceeding allowed ROE as demonstrating that:[29]

> *… EG (and its predecessor companies) operates in a low risk environment that enables it to earn attractive returns – i.e., since it is consistently able to earn its*

[26] Exhibit M8, page 16 bottom to page 18.
[27] Exhibit M8, page 18, lines 12-16.
[28] Exhibit M8, page 18, lines 9-12.
[29] Exhibit M6, pages 13-14.

> *allowed ROEs or higher. This can be the* ***strongest indication that EG possesses low total risk****.* [Emphasis in original.]

53. Dr. Clearly elaborates on the instructiveness of this consideration in the following exchange with Mr. O'Leary on behalf of EGI:[30]

> *MR. O'LEARY: Would you agree with me, Dr. Cleary, that the fact that Enbridge has historically achieved its authorized ROE doesn't tell us anything about the company's ability to continue to do so in the energy transition future?*
>
> *DR. CLEARY: I would disagree with that. I think the track record and the fact that they have been able to do it for – what is that now, oh my gosh, 32 years? So the fact that they have been able to do it demonstrates a few things. They operate efficiently. They are in a strong economic region. They also have strong regulatory support.*
>
> *And, as an investor, I would look at that and say that one of the first things in, you know, equity analysis – and I have taught it for several years and run funds where students are investing in equities, so I live in that world for a lot of my time – is you are going to look at the track record. And the track record says something about the business stability. It also says something about the management, it says something about the environment they operate in.*
>
> *So if I look at a company that is consistently earning above what it is allowed, and then I look at others – and I don't want to point out cases, but there are some other companies that do not consistently earn at or above. I would say those ones have some – they are facing some risks, or they have some operational or management issues that are preventing them from doing that.*

54. We note that following this exchange Mr. O'Leary went on to attempt to demonstrate that the Alberta Utilities Commission (AUC) has ruled differently, though Dr. Cleary was able to explain that the excerpts from the AUC referred to by Mr. O'Leary related to setting ROE (not equity thickness) on a generic basis, and that in respect of equity thickness the AUC absolutely does consider earned vs. allowed ROE.[31]

55. Dr. Cleary elaborated on his views of the significance of consistent historical earnings in a subsequent exchange with Commissioner Moran, as recorded at pages 71 through 73 of Volume 10 of the hearing transcript.

56. Rating agencies seem to consider consistency in earnings as well.

---

[30] Transcript 10, page 50, line 19 to page 51, line 17.
[31] Transcript 10, page 51, line 18 to page 55, line 16.

57. EGI filed as part of Exhibt K8.2 a July, 2023 Standard & Poors (S&P) credit rating report for EGI. Like other credit rating reports preceeding it, this considers S&Ps expectation that EGI will continue to *"generate stable and predictable cash flow"* from its operations (see report page 2 under the "Outlook" heading), and specifically that *"EGI will earn close to its authorized return on equity"* (see "Base Case Scenario" assumptions set out in the shaded box on page 3, 4th bullet). Mr. Coyne agreed that volatility in earnings, or lack thereof, is an *"important"* indicator of business risk (though distinguishing that from what he referred to as "total risk" noting that lack of earnings volatility would be a consideration, but less so, in an overall business risk assessment).[32]

58. In support of the foregoing evidence, it seems intuitive that anyone considering investing in any business would consider a business that always earns at or above an "expected return," and with low volatility in these earnings, to be less risky than one that does not do so consistently - and that displays greater volatility in their earnings. One does not need to be an expert to draw this conclusion.

59. ***There is no indication that EGI faces any near term operational or volatility business risks.***

60. In respect of capital recovery risk, EGI has confirmed that it does not have actual stranded asset costs for the 2013 to 2022 period and is not forecasting any stranded asset costs from 2023 to 2028 related to its distribution, storage or transmission assets.[33] EGI does not face near-term capital recovery risk.

61. Dr. Hopkins' work demonstrates that Concentric has not shown that EGI's capital risk has actually increased since 2012:[34]

> *Concentric has pointed to various indicators but not connected those indicators to any concrete scenarios or circumstances in which EGI's shareholders or bondholders would actually fail to recover all of their invested capital, with a fair return. Neither Concentric, EGI, nor any other firm working for EGI has conducted empirical analysis of any of the wide variety of claimed factors that Concentric cites in its report as evidence that EGI faces increased capital risk, or what the impacts on EGI, its investors, or customers would be if the identified risks become manifest.*

[32] Transcript 8, page 89, lines 9-15.
[33] Exhibit I.1.10-OGVG-1.
[34] Exhibit M8, page 32, lines 12-20.

62. In respect of the Guidehouse pathways report, Dr. Hopkins concludes:[35]

> *The Posterity Group and Guidehouse analyses are scenario analyses, but they look only at the external characteristics of Ontario's energy system and ignore the state of EGI as a company within this context. They do not include analysis of the totality of EGI's capital investments or retirements, rate base, depreciated assets, system operations, operations and maintenance costs, rates, or returns to investors in their scenarios. As such, neither analysis is capable of answering the business-specific questions that are necessary for quantifying and understanding business risk for EGI and its mitigation by EGI.*

63. Dr. Hopkins opines, and IGUA agrees, that:[36]

> *To rigorously argue that energy transition creates capital risk for EGI, some kind of analysis of actual risk facing EGI itself is necessary.*

64. Both the Concentric cost of capital report and the Guidehouse pathways work describe general conditions for EGI and for its industry at large. They do not identify or conduct any analysis that even attempts to examine the future of EGI and its specific business or financial parameters under different approaches to energy transition, either approaches internal to the utility, or external approaches in terms of Ontario's pathway.

65. London Economics Inc. (LEI) has recommended an increase in EGI's equity thickness to 38% as a result of *"a modest increase in overall business risk (primarily due to energy transition risk)"*, agreeing with Concentric that EGI *"is riskier today compared to 2012 (and 2017)."*[37] However, like Concentric, Posterity and Guidehouse, LEI has not done any analysis of EGI's specific capital risk nor of the prudent and appropriate operational and/or regulatory response to any risk ultimately demonstrated. Like the expert reports tendered by EGI, LEI's report examines only external factors and provides no EGI specific analysis that could support a determination that <u>EGI's</u> business risk has in fact significantly changed beyond the ability of EGI to prudently manage.

66. In contrast, all of the rating agency reports tendered in this application, including the most recent S&P report filed by EGI at the hearing as part of Exhibit K8.2, maintain an A-/Stable credit rating and an "Excellent" business risk rating for EGI. Ratings since 2019 have been unchanged, and have been consistently the same or better than ratings of the constituent

[35] Exhibit M8, page 38, lilnes 14-19.
[36] Exhibit M8, page 38, lines 10-12.
[37] Exhibit M1, page 51, first paragraph.

utilities prior to 2019.[38] S&Ps most recent "Financial Risk" rating for EGI as "Significant" is also unchanged since at least 2017, and reflects not the energy transition but rather *"Negative discretionary cash flow due to increasing capital expenditure (capex) activities indicat[ing] external funding needs."*[39]

67. ***In respect of capital risk, Dr. Hopkins concludes, and IGUA agrees, that:***[40]

> ***The OEB should reject EGI's argument that it requires a greater equity thickness because of energy-transition-related capital risk until such time as EGI presents quantitative analysis of the risk it faces (and which it cannot mitigate while acting prudently), in the context of Ontario's pathway to net zero emissions. When such analysis is presented and withstands intervenor and OEB scrutiny, it can be the basis for just and reasonable decisions regarding equity thickness.***

68. The analysis that could and should be undertaken by EGI to demonstrate its business risk and the extent to which such risk can and should be mitigated is described in detail in Dr. Hopkins written evidence and summarized in the previous section of this argument.

"Fair Return Standard"

69. Having concluded that EGI's business risk has significantly increased, Concentric goes on to the second stage of analysis and provides a fulsome "fair return standard" analysis in support of the appropriateness of its recommended equity thickness for EGI of 42%. Dr. Cleary brings some basic common sense to this regulatory cost of capital analysis by considering the facts behind the numbers.

70. EGI laments that is has the lowest equity thickness ratio of all investor owned gas utilities in North America.[41] Of course, many of these comparators are in the U.S. (more on that below). In respect of Canadian comparators, EGI says, it is lower than the average.[42]

71. Size matters when it comes to assessing "fair return", as acknowledged by Mr. Coyne, with larger utilities having lower risk, all else equal. [43] The reasons were explained in

[38] Exhibit M8, page 30, Table 1.
[39] Exhibit K8.2, S&P Ratings July 14, 2023 report, page 1 under *"Key risks"* heading.
[40] Exhibit M8, page 47, lines 19-24.
[41] EGI AIC, paragraph 578.
[42] EGI AIC, paragraph 579.
[43]Transcript 8, pages 72 through 76.

evidence filed by Concentric before the New Brunswick Energy and Utilities Board in 2021[44]. That evidence indicates that (our emphasis):

> ***Credit rating agencies consider small size as a distinguishing risk factor.*** *Moody's for example, considers the size and diversity of utility operations to be a distinguishing factor that makes some utilities risker than others. In discussing its rating methodology for regulated electric and gas utilities, Moody's states:*
>
> > *We also consider diversity of utility operations (e.g., regulated electric, gas water, steam) when there are material operations in more than one area.* ***Economic diversity is typically a function of the population, size and breadth of the territory and the business that drives its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry.***

72. Concentric's conclusion in the New Brunswick case was that for smaller utilities *"investors would require a substantial risk premium in relationship to the larger and more diversified proxy group utilities"*.

73. For larger and more diversified utilities, the opposite should be true. Both EGI and Concentric acknowledge that size and diversity (of customer type, density, climate patterns) tend to reduce business risk, both absolutely and relative to comparators.[45]

74. Since the last time that the Board examined equity thickness for Ontario's gas distributors in detail, they have effectively become larger and more diverse. EGI is now the largest gas distributor in Canada, and among the largest in North America. Not only is it now larger, and more diverse, it is also more efficient, having adopted the *"best of both worlds"* from its predecessor utilities' systems and processes.[46]

75. While Mr. Coyne indicated that Concentric began its risk analysis for EGI with *"a detailed risk analysis of the amalgamated Enbridge Gas"*, there is no mention in Concentric's report of the amalgamation related factors that serve to <u>reduce</u> EGI's business risk.

76. The Concentric analysis also fails to adjust for the fact that EGI is by far the largest Canadian gas distributor, which given Mr. Coyne's previously expressed expert opinion

[44] Exhibit M6, Attachment C, pages numbered 60-63.
[45] Transcript 8, page 67, line 14 through page 71, line 11.
[46] Transcript 8, page 70, line 10 through page 71, line 1.

that larger utilities generally offer less risk, should dictate that EGI's equity thickness should at least be positioned at the lower end of the Canadian range, and probably even below that. The next largest Canadian comparables in Concentric's Canadian operatiing company proxy group (Mr. Coyne agrees that operating companies are the best proxies for EGI) are Atco Gas (with 23.9% of EGI's annual revenue), Energir (with 27.1% of EGI's annual revenue) and FortisBC Energy (with 35.0% of EGI's annual revenue). These companies are all much smaller than EGI. The other 7 Canadian operating companies in Concenctric's proxy group each have ~5.5% or less annual revenue as compared to EGI.[47] Dr. Clearly reasons that if these proxies were to be considered "similar risk" utilities a properly applied proxy analysis would indicate equity ratios no greater than 38%, <u>before</u> considering the vastly greater diversity and size of EGI.[48]

77. Similar size considerations were articulated recently by the Régie de L'énergie (Régie) in its October, 2022 decision on cost of capital for 3 Quebec gas distributors, a translation of which was filed by EGI as Exhibit K8.2, at page 50 (paragraph 198) through page 51 (paragraph 199) of the translation.

78. In testimony in chief Mr. Dane of Concentric states that adopting LEI's recommendation that EGI's equity ratio be increased to 38% *"would continue to place Enbridge Gas near the bottom of its peers, which is inconsistent with the fair return standard"*. No explanation is offered as to why placing the largest Canadian natural gas distributor, by far, with a consistent history of earning above its allowed ROE (indicating stability and low risk) *"near the bottom of its peers"* would be inconsistent. Again, looking behind the numbers to the facts is not only warranted, but required, for a proper evaluation of relative risk and appropriate regulated capital structure.

79. EGI and Concentric assert that Ontario electric utility business risk cannot be higher than that of EGI *"considering the vast and foundational impact energy transition has on natural gas distribution"*.[49] In fact, there is no evidence in this proceeding of the business risks faced by Ontario electricity distributors as compared to that faced by EGI. While it is instinctively clear that the energy transition will affect EGI and Ontario's electricity LDCs very differently, that doesn't mean that the electricity LDCs do not and will not face future risks (leverage, cash flow, municipal governance, extreme weather impacts, load forecast

[47] Exhibit M6, pages 23 through 26.
[48] Exhibit M6, page 26, lines 20-27.
[49] Transcript 8, page 65, lines 2-9.

risk, to name but a few obvious ones). On the other hand, if recent policy emphasis on electrification has in fact decreased the business risk of Ontario's electricity distributors, it may be that their current 40% equity thickness is, upon reconsideration, too high.

80. In any event, EGI now serves effectively the entire province of Ontario as a regulated, franchised distributor. Comparisons of EGI's business risk to that of dozens of electricity distributors each serving limited geographic areas of the province, all of whose capital structures were set a number of years ago by the OEB on a generic basis as a matter of regulatory efficiency are, with respect, of limited value in determining a fair return standard for EGI.

81. Mr. Coyne also acknowledged that single jurisdiction operation and regulation is standard fare for regulated gas distributors, and that Ontario's regulatory framework is stable and supportive, an important business risk consideration.[50] Mr. Goulding of London Economics International (LEI) offered a similar assessment[51], and Mr. Reinisch for EGI acknowledged the same point.[52] Despite this agreement, Dr. Cleary was criticized by Mr. Dane in his direct testimony for in turn disagreeing with S&P's concerns regarding EGI's *"lack of geographic and regulatory diversity"*. It is submitted that Dr. Cleary was simply exhibiting independent thinking, and common sense, as well as expert thinking in highlighting this icongruous statement on S&P's part.

82. Regarding comparison of EGI to U.S. utilities, it is Dr. Cleary's view that such comparisons are of limited value, though <u>not</u> that they can't be considered. Rather Dr. Cleary maintains, and IGUA agrees, that like all comparators consideration must be given to the particular business, jurisdictional and regulatory circumstances applicable to any particular utility being compared to EGI.

83. The Régie's October, 2022 cost of capital decision filed as Exhibit K8.2 also expresses the Régie's caution in considering the capital structure of U.S. gas distributors:[53]

> *Moreover, contrary to the opinion of Dr. Villadsen, the Régie is of the opinion that using the capital structures of US gas distributors requires caution. In this regard, it accepts Dr. Booth's testimony that the Alberta Utilities Commission recently ruled*

[50] Transcript 8, page 90, line 24 to page 91, line 11.
[51] Transcript 9, page 108, line 25 to page 109, line 18.
[52] Transcript 8, pages 99, lines1-3.
[53] Exhibit K8.2, page 51.

> *on this issue based on evidence filed by Concentric that US regulators do not determine capital structures using the same approach as Canadian regulators.*

84. When Mr. Coyne was asked in this proceeding about this statement he provided some rather cautious and, with all due respect, inconclusive testimony to the effect that *"it depends on the regulator"* and *"when you look at U.S. regulators, of course, you are looking at a multitude of states, and then the federal government, of course. So it is a broad swath."*[54]

85. Reference to the Alberta Utilities Commission's (AUC) 2018 Generic Cost of Capital decision is a bit clearer, including in respect of what Mr. Coyne previously said on the subject:[55]

> *656. With respect to the comparability of the deemed equity ratios as between Alberta and the U.S., the Commission agrees with the following submission from Mr. Coyne:*
>
> > *With respect to the differences in equity ratios, this is explained in part by the process U.S. regulators use for setting equity ratios versus their Canadian counterparts, where equity ratios are deemed. As such, I have not recommended an adjustment for the difference in equity ratios between the U.S. and Canada, as I believe the difference may be justified by the use of deemed equity ratios in Canada versus greater reliance by U.S. regulators on actual capital structures in comparison to peer companies.*
>
> *657. Mr. Coyne's observation is supported by DBRS in its analysis of the regulatory framework for utilities in Canada and the U.S. DBRS stated:*
>
> > *For some utilities, returns are based on the actual capital structure which is set within a range determined by the state regulator. Pennsylvania is an example, where the commission intervenes only if quarterly disclosed equity ratios fall outside a reasonable range.*
>
> *658. In the 2009 GCOC decision, the Commission found that the equity ratios in the U.S. are likely higher as a result of the ability of management in certain U.S. jurisdictions to set the capital structure within a range acceptable to the regulator. This is a differentiating point between regulation of U.S. and Canadian utilities and an indication that allowed capital structures for U.S. utilities should not be held up as representative of the capital structures required by Canadian utilities in order to satisfy the fair return standard. The Commission continues to be of this view.*

86. Dr. Cleary also indicated in discussion with Commissioner Elsayed[56] that the average U.S. utility does not earn its allowed ROE, which suggests that they face different risks than the

[54] Transcript 8, pages 92 through 95.
[55] AUC Decision 22570-D01-2018, page 133, paragraphs 656-658.
[56] Transcript 10, page 68, line 20 through page 71, line 4.

average Canadian operating utility. Dr. Cleary also commented on the different jurisdictional approaches in the U.S. relative to Canada. Dr. Clearly concluded on this point as follows:

> *And I think that you can look at U.S. utilities for some purposes, but you have to qualify it. And just blindly looking at their awarded equity ratios or allowed ROEs, which are a function of, you know, the structure of the board or commission, the market conditions at the time, what is going on in the jurisdictions they operate in, is not adequate.*

87. Such superficial averaging of cost of capital parameters from other jurisdictions also imports a circularity into the analysis that the AUC has recently recognized and eschewed in favour of more granular consideration of *"sound principles of finance"* in conducting a fair return analysis. As noted in the AUC's 2018 Generic Cost of Capital decision in reference to submissions by the Alberta Utilities Consumer Advocate (UCA)[57]:

> *The UCA noted the Commission's previously expressed preference for an approach to estimating cost of capital that relies on sound principles of finance, as opposed to simply looking to the awards of other regulators developed on the basis of different records under different circumstances. It noted and agreed with the observation of the chair of this proceeding that relying on the returns approved by other regulators necessarily imports circularity into the process. The UCA also agreed with the chair that the relevant consideration is the market expectation of the cost of capital, and not what other regulators are allowing.*

88. In his testimony in the current proceeding Mr. Goulding of LEI agreed:[58]

> *… I would hope that in each proceeding there was a thoughtful approach. I have expressed in previous proceedings my concern about circularity of cost of capital hearings in which everybody looks at each other in order to determine where they should be. And I think that, when we look at comparator analysis, it is always important to do so thoughtfully…*

89. Before leaving the topic of comparing EGI to U.S. utilities' historical capital structure, we would note Dr. Cleary's reasoned response to Concentric's suggestion that Canadian utilities are trading at a great discount than U.S. utilities today as compared to 2010. Dr. Cleary does not believe that is in fact the case, and this is yet another illustration of the peril of superficial numerical comparator analysis without reference to relevant underlying circumstances. Dr. Cleary explained that Concentric:[59]

---

[57] AUC Decision 22570-D01-2018, page 132, paragraph 655.
[58] Transcript 9, page 11, lines 5-16.
[59] Transcript 10, lines 17-26.

> *... fail to account that overall market movements, where the Canadian market – equity reutrns and the Canadian market were 57 percent lower than in the U.S. over that period, while the returns to Canadian utilities were only 20 percent lower. So, if anything, the Canadian utilities fared better relative to the U.S. utilities.*

90. Dr. Cleary summarizes his concerns with Concentric's proxy group comparisons at Transcript 10, pages 8 and 9. We won't repeat that testimony in full here, but commend it to the Hearing Panel.

91. In contrast to the backward looking nature of tabulating comparator cost of capital parameters determined by other regulators in other jurisdictions at other times, sometimes several years in the past, Concentric and Dr. Cleary agree that debt and equity analysts look forward in time in assessing risk. Instructively, none of these reports question EGI's continuing or anticipated financial integrity or its ability to continues to attract capital on reasonable terms.

92. Concentric has criticized Dr. Cleary for relying on debt rating agency reports to asses equity investor sentiment. When asked whether S&P's express consideration of historical stable and predictable cash flows and earning close to authorized ROE was relevant to the cost of capital analysis, Mr. Coyne responded:[60]

> *It is also the case, and this is meaningful here, that this is a debt-rating agency and they are focused on the ability for the underlying company to meet its debt obligations. And that is important from a credit-rating perspective, but if you are looking at it from the perspective of an equity investor, they are looking at much more than this in terms of a total risk analysis of the company.*

93. Despite this criticism, Concentric does acknowledge that the OEB has included credit ratings, debt terms, and financial results in factors to consider in cost of capital analysis.[61] Concentric itself includes a section in its analysis on credit ratings and credit metrics (see pages 58-64), and Mr. Coyne acknowledges the appropriateness of this to the analysis[62]:

> *MR. MONDROW: Is it important to look at a particular company's credit metrics in evaluating both comparators and that own company's business risk?*
>
> *MR. COYNE: We look at credit ratings as a screen, and then we also look at credit. And credit metrics is a source of comparison in our report, so I would say yes.*

---

[60] Transcript 8, page 89, lines 18 through 24.
[61] Exhibit 5, Tab 3, Schedule 1, page 57, quoting from EB-2011-0254, *Decision on Equity Ratio and Order*, February 7, 2013 at page 16.
[62] Transcript 8, page 97, lines 1-6.

94. Dr. Cleary responded to Concentric's criticism as follows:[63]

> *Another thing they [Concentric] mentioned in their direct was my focus on debt reports and debt yield, and that I ignore equity investors. And they insinuate that they operate in two parallel universes; equity investors and debt investors. I find that totally untrue. Both equity and debt investors look at forward-looking information, try to assess the future cash flows of a company, and growth opportunities, and risks facing the company. I will agree that they do have different focuses, with debt investors focusing more on the downside. Equity investors focus on the downside, but also more emphasis on the upside, but they use the same kind of information. They assess the risk of the parties.*
>
> *And, also, I would point out that the OEB formula to estimate allowed ROE is supposed to proxy the cost of equity, and it includes, essentially, changes in the cost of debt. Because the first component is the risk-free rate – the government yields, if you will – and the second component is the A-rated utility yield spread. If you add the two together, that is the A-rated yield; the government yield plus the A-rated spread. So the fact that the OEB recognizes that the cost of equity goes up or down, with changes in the cost of debt to the utility, reflects that close relationship between the cost of debt and cost of equity.*

95. Dr. Cleary summarized this opinion even more clearly and succinctly in response to questions from Mr. O'Leary on behalf of EGI[64];

> *So equity investors and debt investors look at the same types of information from a different perspective. So there is no way that a debt rating can guarantee that an equity ratio is either right or wrong, but the fact that they [EGI] maintain that credit rating and are able to borrow on favourable terms is a good indication that it is adequate.*

96. The continuation of this exchange is worth highlighting as well:[65]

> *MR. O'LEARY: Sorry, Dr. Cleary. Let me understand. Is your recommendation therefore that the Board should wait for a credit rating downgrade before Enbridge Gas's equity cost of capital is reconsidered? Is that what you are suggesting?*
>
> *DR. CLEARY: That's not my suggestion. My suggestion is that, at the current rates, their ratings are solid, which means their cost of equity is also solid; and the forecast credit metrics, which enable them to maintain those credit ratings and to borrow at those rates, are forecast to get stronger, not weaker, at a 36 percent equity ratio. So the suggestion that we need to bump it up now, again, that will put extra income in EGI's pockets, but, again, at the price of the consumers. And it's fine if it was deemed necessary, or proven necessary, but it has not been proven necessary.*

---

[63] Transcript 10, page 10.
[64] Transcript 10, page 47, line 25 through page 48, line 2.
[65] Transcript 10, page 48, lines 8 through 23.

97. We would also observe that as EI is the issuing entity in our circumstance, there is no direct observability into EGI equity value, unlike EGI debt terms which are easily observable. In that respect, Dr. Cleary notes that EGI borrows at slightly below A-rated utility average yield, which he believes shows that EGI has no problem attracting capital.[66]

98. IGUA submits that this is a market-determined indicator that EGI satisfies the capital attraction standard (i.e., is able to attract incremental capital on reasonable terms and conditions). The fact that EGI is able to borrow in public markets at "market rates" is because it earns returns on capital that investors could earn on comparable risk investments (i.e., the comparable investment standard). Bond market investors determine the yields they require on EGI's debt based on public debt ratings and likely even more so based on their own internal "forward-looking analysis."

99. Concentric also criticized Dr. Cleary for analyzing the ROEs of Concentric's holding company proxy group as compared to operating utility ROEs (the book value issue). In the vein of throwing stones in glass houses, Dr. Cleary responded to this criticism as follows, illustrating once again that context matters:[67]

> *And I do recognize that there are issues there, particularly the accounting issues in comparing the ROEs of operating companies to holding companies. And I recognize that. And, if anything, that supports my opinion that holding companies are poor comparator.*
>
> *The second thing is they seem to have not the same concern when they look at the credit metrics, because, as mentioned, in their credit metrics, 13 of the 20 companies they look at are, in fact, holding companies. So they seem to disregard the accounting differences when they are looking at the credit metrics, so I am not quite sure why it's an issue when looking at the ROEs and not when looking at the others.*

100. Dr. Cleary also explained that while the time period for the ratings reports relied on by all of the experts in their cost of capital analyses are 2-3 years from the report date, the longer-term view that equity investors take is factored into these analyses:[68]

> *I do acknowledge the importance of the long term, as do capital providers. And I totally acknowledge that point. The point that Concentric fails to recognize is that the capital providers, the debt markets, and the equity markets also have already looked at the long term, and those are reflected in today's current rate-borrowing rates for Enbridge Gas, so it's reasonable to assume that they have considered*

[66] Transcript 10, page 9, line 26 through page 10, line 2.
[67] Transcript 10, page 12, lines 1-14.
[68] Transcript 10, page 11.

the energy transition risk and that it is already reflected in Enbridge Gas's cost of debt.

101. This opinion is consistent with that put forward by the Canadian Gas Association and American Gas Association through a joint report filed in this proceeding as Exhibit K8.4, the conclusions of which are summarized in the report as follows (see page 3) and which EGI's Ms. Ferguson agreed with[69]:

(a) *Gas utilities are stable low risk investments if they have a positive year-over-year rate base and customer growth* [which EGI does and which EGI expects will continue].

(b) *Natural Gas remains essential for energy security, as there are no other low-cost options available to replace it at scale.*

(c) *Gas utilities with diversification plans into clean fuels (i.e., RNG) are viewed positively.*

(d) *Transparent and consistent year-over-year rate setting methodology by commissions* [is valued by investors, and applies to EGI].

102. ***Considered in its totality, the evidence in this proceeding simply does not support a conclusion that at its current 36% equity thickness EGI is compromised in its ability to finance its ongoing business operations, or that the "fair return standard" is not being met. Properly considered, the weight of the evidence is that it is not necessary to increase EGI's equity ratio for reasons of financial integrity or the ability to attract capital. These conclusions are based on an examination of EGI's business risk, its ability to earn its allowed ROE, as well as an examination of debt ratings, debt rating reports, EGI's cost of debt relative to comparable utilities, and credit metric analysis. The fact that the market-determined yield on EGI's debt is slightly below the average yield on Canadian A-rated utilities demonstrates that EGI satisfies the comparable investment standard based on its current equity ratio.***

103. EGI's evidence is that a lower equity thickness will result in a lower revenue requirement and, instructively, while the debt to equity ratios will of course change depending on approved equity thickness, the cost rate for the debt was not forecast to change depending on the equity thickness determination.[70] Those debt costs were accepted by EGI as part of the Settlement Agreement.

[69] Transcript 8, page 99 *et seq.*
[70] Exhibit 5, Tab 3, Schedule 1, page 5; Transcript 8, page 119, line 7 to page 121, line 9.

104. Further, even with maintaining a 36% equity thickness, all of EGI's credit metrics are forecast to improve in 2024 relative to 2023.[71]

105. Mr. Coyne agreed that EGI's response to the energy transition will have an influence on investors' appetite for investing in EGI.[72]

106. Mr. Goulding agreed that a utility that is aware of a risk but has not analyzed how to respond to it would be acting imprudently.[73] (In fairness, we do note that Mr. Goulding also cautioned that getting too far ahead of policymakers in a circumstance of uncertainty would also be ill advised, and further his opinion was that imprudence and setting a fair capital structure were separate considerations and the former should not influence the latter. Dr. Hopkins takes the opposite view, as outlined above. IGUA supports Dr. Hopkins' view on this point. In any event, Mr. Goulding does seem to endorse the ability of the OEB to require EGI to do more energy transition related planning than it has, if the Commission is persuaded that would be prudent; see Transcript 9, page 120, line 15, *et seq.*)

107. Dr. Cleary noted that, while it seems that capital providers and S&P agree that at this point in time the energy transition *"hasn't posed a huge, sudden, existential risk"*, as the paths towards transition are better defined, financial markets (i.e. analysts, lenders and investors) *"will be asking more pressing questions about that and looking for details on those plans [by EGI] for the transition"*.[74]

108. As detailed above, development of that response is, at best, nascent. Pending more work by EGI to particularize the risks to its operations posed by the energy transition and develop particular mitigation strategies and plans to prudently and proactively respond to those risks, it would be unjust and unreasonable to allow EGI to increase its equity thickness and increase customer costs by $260 million. This would be tantamount to customers paying once to cover those unmitigated risks and then paying again when those unmitigated risks and associated costs crystallize.

109. EGI has requested 42%. LEI has recommended 38%, based on a resulting forecast improvement in credit metrics.[75] Dr. Cleary maintains that 36% remains appropriate, and

[71] Exhibit M6, page 29, table 5; Transcript 8, page 121, line 10 to page 122, line 16.
[72] Transcript 8, page 124, lines 13-17.
[73] Transcript 9, page 113, lines 12-14.
[74] Transcript 10, page 30, line 12 through page 31, line 10.
[75] Exhibit M2, page 55.

in particular demonstrates that EGI's credit metrics are forecast to improve in 2024 while maintaining its current 36% equity thickness.[76]

110. ***IGUA supports Dr. Cleary's recommendation.***

111. However, if the OEB nonetheless determines it to be important to send the financial market a signal that as EGI's regulator it is live to the risks posed to EGI by the energy transition, then, as Mr. Goulding acknowledged, a directional determination (i.e. allowing a lesser increase to 37%) could itself be taken by the market as a positive sign, in particular in conjunction with further direction on an ensuing process for more careful examination of the potential energy transition impact on EGI and EGI's available responses thereto.[77]

[76] Exhibit M6, pages 28-29.
[77] Transcript 9, page 121, line 8 through page 125, line 3.

DEPRECIATION

112. Under the currently approved depreciation policies for legacy Enbridge Gas Distribution (EGD) and Union Gas (UG), the 2024 depreciation provision would be $737.1 million.[78] EGI has proposed a 2024 depreciation provision of $879.0 million, which is a $141.9 million (16%) increase relative to currently approved depreciation methodologies.[79] Over the course of the proposed 5 year rate plan, EGI's proposal would result in an increase in depreciation expense relative to currently approved policy of over $700 million, prior to escalation, and an increase in rates[80] of over $1 billion.

113. Enbridge Gas does not have actual stranded asset costs for the 2013 to 2022 period and is not forecasting any stranded asset costs from 2023 to 2028 related to its distribution, storage or transmission assets.[81]

114. LEI is of the view that natural gas policy in Ontario does not appear to have crystallized to the point where it is obvious that natural gas assets will need to be retired prematurely.[82]

115. Dr. Hopkins' work reflects proper consideration of depreciation as a tool to address energy transition risks, including re-evaluation of depreciation approaches for each type of utility asset, including differentiation among assets that serve different types of customers that may have different long-term usage patterns.[83]

116. The depreciation experts Messers Madsen and Bowman recognize that depreciation policy can play a role in response to the energy transition, but as further articulated below do not believe that the blunt depreciation acceleration approach now advocated by Concentric and EGI is the way to do it.

---

[78] J16.5, page 3, line 68; J.16.7. Note that OEB Staff's Submission at page 98 sets out, in Table 17, column B, the figure for 2024 of $899.6 million, in reference to Intergroup's transcript undertaking J17.12. There is a plethora of depreciation figures offered by various witnesses under various combinations of depreciation parameters. For the purposes of this argument we have used the figures provided in EGI's Undertaking Responses, which we believe to be directionally indicative of the impact of various positions, and taking comfort that EGI will ultimately produce a draft rate order calculated in accord with whatever direction in respect of, *inter alia*, depreciation the OEB makes.
[79] Exhibit J.16.7.
[80] Exhibit J17.11, page 5, line 5.
[81] EGI Exhibit I.1.10-OGVG-1.
[82] Exhibit J10.1.
[83] Exhibit M8, see for example studies being undertaken in other jurisdictions as synopsized at pages 40-42 and Dr. Hopkins' planning recommendations at page 53.

117. There are two candidate procedures which have been advanced in this proceeding; Average Life Group (ALG, currently in use for legacy EGD assets and most other North American gas utilities[84]) and Equal Life Group (ELG, proposed by EGI).[85] Of the two, both are justified as a matter of general depreciation practice, though one (ELG) has a materially higher near term cost for customers. EGI has not justified the adoption of the ELG procedure either as a practically superior depreciation method nor as an appropriately nuanced and transparent approach to addressing energy transition asset recovery risk where it might ultimately be demonstrated to exist (i.e. in respect of which assets) and in appropriate measure.

118. IGUA agrees with OEB Staff, as do the depreciation experts from Emrydia and Intergroup, that deployment of a depreciation response to energy transition concerns should not be conflated with, or obfuscated by, adoption of the ELG rather than the ALG depreciation procedure. Neither of these procedures is an appropriately nuanced tool to properly address energy transition concerns.

119. IGUA further submits that several of Concentric's life curve recommendations, its CDNS calculations, and its proposed net salvage calculation discount rate all merit critical examination and adjustment, as particularized below.

ELG or ALG

120. Some $84 million or so[86] (~60%) of the proposed depreciation provision increase for 2024 can be attributed to EGI's proposal to adopt the Equal Life Group (ELG) depreciation procedure as compared to the Average Life Group (ALG) depreciation procedure currently approved for EGD and recommended by both Emrydia and Intergroup for EGI.

121. To start with, adopting ELG rather than ALG is <u>not</u> an appropriate response to the energy transition.

122. Despite consistent reference by various EGI witnesses through the course of the oral hearing to a depreciation proposal which responds to the energy transition, and the Concentric witnesses' repeated reference to the responsiveness of ELG to energy

---

[84] Exhibit I.4.5.Staff-173(d).
[85] Two additional depreciation tools; an Economic Planning Horizon and a Units of Production approach, have also been discussed but how they would be implemented has not been fully evidenced.
[86] OEB Staff Submission, page 98, Table 17.

transition concerns, Concentric's depreciation report does not address energy transition considerations as input to its depreciation recommendations.

123. The only reference in Concentric's report in connection with discussion of the ALG or ELG procedures to anything remotely relevant to the energy transition is found in two sentences at page 3-3 of Concentric's 451 page report (Ex4/T5/S1/Att1). At page 3-3 Concentric states:

> *With potential changes in the utility industry, future users of the facilities may be different from the current system users. This lack of stability may magnify the inter-generational inequity of the ALG procedure.*

That's it.

124. Concentric does, at pages 3-3 through 3-7 of its report, go on to actually discuss the energy transition, in the context of brief consideration of the potential to move to an Economic Planning Horizon (EPH) approach to actually addressing energy transition concerns through depreciation policy. Concentric proceeds to reject such approach at this time, without any mention of preferring its proposed ELG procedure as an alternative to addressing energy transition.

125. It is simply not credible to maintain that in advancing its depreciation recommendations Concentric took any real consideration of the energy transition.

126. While Concentric's Ms. Nori ultimately testified that in making some of her judgements regarding expected life curves she *"considered"* the energy transition, she also confirmed that such considerations were not in fact articulated anywhere in Concentric's report or interrogatory responses, and she was unable to provide any further explanation of how or when such considerations were taken.[87]

127. At its highest, while not a primary driver for Concentric's recommendation to adopt ELG, energy transition seems to be considered by Concentric as a justification for adopting ELG as it effectively pulls depreciation expense recovery forward in time, increasing near term recovery of invested capital.

[87] Transcript 17, pages 47-48.

128. It does this by breaking major asset classes into subgroups of assets, and assigning service lives to subgroups rather than averaging the service lives of a broader grouping of assets to obtain an average service life for the larger class and assigning a depreciation life curve thereto. Concentric says that this approach fosters better generational equity by more accurately allocating the costs of assets in service to those customers being served by them. Because subgroups of shorter lived assets are depreciated based on their shorter average lives compared to other subgroups of longer lived assets, the result in EGI's case is to accelerate the recovery of sunk capital.

129. It is not surprising that EGI takes Concentric's recommendation, the effect of which is to accelerate its shareholder's recovery of invested capital by some $80 million plus a year. As noted at the outset of this argument, EGI's primary response to energy transition concerns to date has been to seek to recover more from customers more quickly.

130. The argument that ELG is a more accurate approach to matching recovery of asset costs to customer usage of those assets than ALG is, in theory, a compelling one. In practice, however, the theoretical attraction of the position loses its lustre.

131. First, as acknowledged by Mr. Kennedy[88], despite theoretical purity assets in any group don't behave as predicted on average. Some will be retired sooner than their "average life" expectancy. Some later. This practical dynamic itself renders the theory that ELG is able to match asset cost recovery with asset use unattainable in practice. In fact, segregating assets within a class with shorter expected lives from those with longer expected lives would lengthen the recovery period for the latter group of assets relative to not segregating them. If energy transition were a consideration, this could exacerbate the problem of asset stranding in respect of such longer lived assets. For example, accelerating depreciation on plastic services that may be in use beyond their currently estimated expected useful life risks raising costs to current customers, exacerbating intergenerational equity, and causing additional customers to leave the system further exacerbating the problem.

132. Second, rate making is not solely about mathematical purity. If it was we would have individual rates for each customer, or each neighbourhood. Of course we do not. There is inevitably some subsidy between customers of regulated utility services. Properly done, however, ratemaking results in benefits and burdens averaging out. In the case of

[88] Transcript 16, page 148, line 28 through page 150, line 8; page 151, line 28 to page 153, line 23.

depreciation, ALG has been accomplishing just and reasonable assignment of asset cost recovery to customers for decades. There is nothing broken with legacy EGD's current depreciation policy that requires immediate attention. Starting with a robust depreciation policy and taking the time to consider, transparently and thoughtfully, energy transition response including in respect of depreciation policy, would be a better course than deploying an overly-blunt "directional" change in a premature fashion.

133. Concentric asserts that adoption of ELG provides for better continuity with historical depreciation policy, because ELG better matches the Generation Arrangement approach historically used by Union Gas. As OEB Staff's Submission points out[89];

(a) Legacy EGD used ALG. In fact, legacy EGD had a marginally larger rate base than Union Gas at the time of the merger[90], so under this argument ALG would in fact be the preferred approach.

(b) Mr. Bowman from Intergroup clarified during the hearing that Generation Arrangement is not an alternative to ELG or ALG, rather it is a method to organize assets for analysis, and Union in fact applied ALG to those assets once so organized.[91]

134. Third, as a rate making matter, moving from ALG to ELG will create significant upward rate pressure. Indeed, similar magnitude anticipated rate impacts when driven by EGI's proposal to increase its equity thickness are proposed to be phased in over 5 years, yet in respect of the proposed move to ELG no such consideration for rate impacts has been taken. Mr. Kennedy's evidence is that it was not Concentric's job to consider rate impacts.[92] Their job was to propose a depreciation methodology. It is, however, the Commission's job, and to some extent should also be EGI's job. As noted immediately above, continuity with past practice and achieving rate making practice continuity would dictate harmonizing the legacy depreciation procedures into ALG for the upcoming rate plan term.

135. It must also be remembered that depreciation is in fact booked to the individual assets that are, from an accounting perspective, actually depreciating.[93] Depreciation policy for ratemaking purposes is about equitable and timely recovery of depreciation expense and

---

89 OEB Staff Submission, page 82, first paragraph.

90 Exhibit 2, Tab 1, Schedule 1, page 4, lines 5 and 12. ~53% of the combined utility's rate base was legacy EGD rate base.

91 Transcript 18, pages 18-22.

92 Transcript 16, page 125, lines 5-12.

93 Transcript 16, page 145, line 20 to page 147, line 3.

not directly and exclusively about actually depreciating, from an accounting perspective, individual assets. Like other aspects of rate making, setting a depreciation policy for ratemaking purposes includes consideration of an appropriate balance between shareholder and customer interests.

136. It is in this context that the merits of ALG and ELG should be considered and compared. All of the depreciation experts opined that ALG is a valid, indeed the most commonly accepted, rate making depreciation methodology. Its application will ultimately result in recovery from customers of EI's invested capital over time, in a manner which matches depreciation expense with the operative regulatory system of accounts asset classes. In the case of ALG depreciation averages the entire asset class, while in the case of ELG subclasses are defined and averaged before being rolled up into a depreciation provision for the class as a whole. Both are valid approaches. Both recover capital. Both result in accounting depreciation of assets and asset classes.

137. In some ways the broader averaging entailed in the ALG procedure could be said to soften the inevitable, real life mismatch between the useful lives of individual assets and their average expected lives, as discussed above. For assets that in fact last longer than their expected average service life, which mathematically would be expected to be half of the assets in any asset class <u>or</u> sub-class grouping, ALG may better match, on a forecast basis, cost recovery from customers with the service provided by the assets. It must be further borne in mind that normal depreciation practice includes periodic review of account balances and depreciation rates, regardless of choice of procedure, to ensure that those estimates continue to be valid, and assess any advisable changes, so that if something gets materially out of balance it can be corrected.[94]

138. EGI's proposal to move to ELG rather than ALG would entail an acceleration of cost to customers by almost $1 billion over the proposed 5 year rate plan term, at a time when by all accounts there is increasing uncertainty about what path the energy transition will open for EGI, and which assets and delivery customers are likely to be more or less affected.

139. IGUA agrees with OEB Staff, as do the depreciation experts from Emrydia and Intergroup, that deployment of a depreciation response to energy transition concerns should not be conflated with, or obfuscated by, adoption of the ELG rather than the ALG depreciation

[94] Transcript 16, page 138, lines 4-17.

procedure. Neither of these procedures is an appropriately nuanced tool to properly address energy transition concerns.

140. In response to Commissioner Moran's inquiry both Mr. Madsen and Mr. Bowman explained how depreciation might take into account concerns regarding avoidance of stranded costs, were that determined to be an appropriate way to address such concerns.[95] Both of these experts described a targeted, informed approach to addressing expectations for truncated life curves for specific types of assets, to the extent that conventional depreciation policy did not already yield results within the range of expectations. Dr. Hopkins alludes to similar types of more targeted depreciation considerations in response to energy transition concerns in his written evidence.[96] The common thread in all three of these opinions is that properly addressing energy transition concerns through depreciation policy requires a much more targeted approach based on data and nuanced consideration of risks associated with particular categories of assets.

141. In contrast, EGI asserts[97] that *"[w]here there is a range of average service lives, in light of energy transition issues, the depreciation expert should err on the side of moderation and caution and propose an average service life at the shorter end of the range or apply a more modest increase if the data so warrants."* This approach would only be appropriate if there was evidence of a need to shorten. Absent that evidence, the better approach is to pick the best life estimate or if that is not clear then the mid-point. Erring on increasing depreciation expense risks creating more problems and inequities if there is no evidence of the need. Neither EGI nor Concentric have provided any such evidence beyond a general, untested, and un-nuanced assertion regarding some generic, unparticularized future asset risk.

142. ***OEB Staff has recommended a study of how depreciation policy could be engaged in response to the energy transition.[98] IGUA endorses this recommendation.***

143. In the interim, the objective of determining a harmonized depreciation policy for EGI should be to determine a robust depreciation policy premised on sound depreciation principles and ratemaking policy considerations as a starting point.

---

[95] Transcript 18, page 100, line 18 through page 105, line 22.
[96] Exhibit M8, page 53, line 22 to page 54, line 3.
[97] EGI AIC, paragraph 517.
[98] OEB Staff Submission, page 99.

144. ***EGI has not justified the adoption of the ELG procedure either as a practically superior depreciation method nor as an appropriately nuanced and transparent approach to addressing energy transition asset recovery risk where it might ultimately be demonstrated to exist (i.e. in respect of which assets) and in appropriate measure. EGI's proposal to abandon the historically and broadly accepted ALG depreciation policy in favour of ELG should be rejected.***

145. To the extent that considered modifications to a conventional depreciation approach are appropriate to address particular energy transition concerns for particular asset classes and/or customer types, such should be transparently, thoughtfully and directly applied. The recommended study will provide much more robust information on how depreciation policy, as part of a potentially broader package of regulatory responses, could be reasonably, equitably and productively (rather than potentially counter-productively) deployed to address energy transition concerns.

Service Lives/Survivor Curves

146. Concentric acknowledges that the choice of survivor curves and service lives is a matter of professional judgement.[99] Mr. Madsen refers to determination of depreciation expense as *"both art and science"*, noting that *"it is a complex exercise, and depreciation experts may not always agree."*[100]

147. As OEB Staff has submitted[101];

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

148. While Concentric's report provides data and graphs for each of its recommended survivor curves and service lives[102] it provides only very limited narrative of the reasoning applied for each account, in contrast to the detailed discussion provided by the other depreciation experts in their reports.

---

[99] Transcript 16, page 134, lines 15-16.
[100] Transcript 18, page 69, lines 23-27.
[101] OEB Staff Submission, page 88, 2nd full paragraph; Exhibit M1, pp. 28-45; Exhibit M5, pp.34-68.
[102] Exhibit 4, Tab 5, Sechedule 1, Attachment 1, pages 42-154.

149. As noted above, Ms. Nori of Concentric did indicate that her judgement on appropriate survivor curves and service lives was coloured by energy transition considerations, but she could not particularize how or in what instances. Concentric's written report is silent on this point, lacking even a generic statement to this effect.

150. Mr. Madsen's evidence (Exhibit M5) indicates that he reviewed all of the service life and survivor curve recommendations provided by Concentric, and was generally supportive of most of those recommendations. Mr. Madsen concluded that in most cases, Concentric's recommendations aligned with the underlying retirement data, peer analysis and reported management discussions.[103]

151. In certain cases, however, where Concentric appeared to have exercised significant judgement, Mr. Madsen disagreed with Concentric's recommendations. In each of these cases Mr. Madsen's written evidence provides a detailed, specific and carefully reasoned analysis of the applicable underlying retirement data, peer analysis and reported management discussions, and the reasons for his disagreement with Concentric's judgement, and also provides his own recommendations directly and expressly based on his fully articulated analysis.

152. ***Based on this record, IGUA endorses the service life recommendations of Mr. Madsen as summarized in the following table*** (with reference in each case to Mr. Madsen's articulated reasoning):

ASSET ACCOUNT	EMRYDIA RECOMMENDED SERVICE LIFE/SURVIVOR CURVE	EMRYDIA EXPLANATION (Ex M5)
466: Transmission–Compressor Equipment	37-R4	Pages 39-44
473.01: Services-Metal	50-L1	Pages 44-49
473-02: Services Plastic	60-S3	Pages 49-53
475.21: Mains -Coated & Wrapped	65-R3	Pages 53-57
475.30: Mains- Plastic	70-R2	Pages 57-61
478: Meters	25-L1.5	Pages 61-66

153. The Intergroup evidence (Exhibit M1) observes that Concentric proposed that most accounts retain their current approved life and dispersion parameters, or be subject to

[103] Exhibit M5, page 39, paragraph 1.

modest changes generally supported by the underlying data disclosed and updated retirement history. However, Intergroup found:

> *There are several accounts where the proposed life estimates by Concentric do not reflect the best matching of parameters to observed life characteristics. Other life and dispersion combinations provide better estimates for these accounts. There are also accounts where Concentric's recommendation are [sic] not generally aligned with peer utilities range.*

154. As did Mr. Madsen's, Intergoup's report provides a detailed, specific and carefully reasoned analysis for each of these several accounts of concern, including express discussion and consideration of the applicable underlying retirement data, peer analysis and reported management discussions, based on which consideration Intergroup provided its own recommendations.

155. ***Based on this record, IGUA endorses the following additional service life recommendations of Intergroup*** (with reference in each case to Intergroup's articulated reasoning):

ASSET ACCOUNT	INTERGROUP RECOMMENDED SERVICE LIFE/SURVIVOR CURVE	INTERGROUP EXPLANATION (Ex M1)
452: Underground Storage–Structures and Improvements	45-R1.5	Pages 29-31
456: Underground Storage–Compressor Equipment	44-R4	Pages 31-35
457: Underground Storage–Regulating and Measuring Equipment	40R2.5	Pages 35-37
465: Transmission Plant-Mains	70-R4	Pages 37-41

156. In addition to these 4 accounts, Mr. Madsen and Intergroup both considered the following two accounts, and advanced different recommendations in respect thereof:

ASSET ACCOUNT	EMRYDIA RECOMMENDED SERVICE LIFE/SURVIVOR CURVE & EXPLANATION (Ex M5)	INTERGROUP RECOMMENDED SERVICE LIFE/SURVIVOR CURVE & EXPLANATION (Ex M1)
475.21: Mains-Coated & Wrapped	65-R3 (Pages 53-57)	70-R3 (Pages 41-43)
475.30: Mains-Plastic	70-R2 (Pages 57-61)	65-R3 or 70-R4 (Pages 43-45)

157. ***In respect of Account 475.30: Mains-Plastic, given that both experts accept, on a fully articulated basis, the reasonableness of a 70 year service life, IGUA endorses this service life for this account.***

158. In respect of account 475.21: Mains-Coated & Wrapped;

(a) Intergroup's analysis highlighted that EGI's operational staff and Concentric indicated their consideration that peer Canadian pipeline utilities' services lives for this asset class ranged from 55-80 years. However, Intergroup further noted that there are no utilities that report a life estimate of 55 years for this account, and the current span for this account is actually 65-80-years, much longer life estimates than that proposed by Concentric.[104]

(b) Mr. Madsen in his report considered peer group reported service lives of between 55 and 80 years, though as noted by Intergroup this reported range should actually have been 65-80 years, and further noted that in the 2021 depreciation study EGD is reported as having a 61 year service life for this account, however in the peer range table EGD is listed as having a 70 year service life for this account.[105]

(c) Intergroup further notes in respect of this account that Gannett Fleming in their 2016 draft report for EGD recommended a 70 year average service life as reasonable.[106]

159. ***In light of this record, either Mr. Madsen's 65 year recommended service life or Intergroup's recommended 70 year service life seem more reasonable than Concentric's recommended 55 year service life.***

160. Given the various parameters in play in respect of the impact of different depreciation approaches and assumptions, despite various cuts at quantifying impacts of various judgements and policy choices there is no precise record on the impact of the foregoing group of recommendations regarding survivor curves/service lives. An order of magnitude impact can however be inferred to be in the range of the ~$45 million indicated in Column D at Table 17 of OEB Staff's Submissions, which apply the Intergroup life parameters to an ALG derived depreciation provision.

161. Combined with the ~$80 million impact of adopting ALG rather than ELG, we estimate that adopting the Emrydia and Intergroup survivor curve/service life recommendations would

[104] Exhibit M1, page 42, paragraph 2.
[105] Exhibit M5, page 56, lines 6-10.
[106] Exhibit M1, page 41.

address ~$125 million of the ~141 million increase in 2024 that would result from adopting Concentric's depreciation recommendations.

162. Mr. Madsen's evidence (Exhibit M5, pages 69-74) also identifies a particular concern with Account 474 – Regulators, which is one of Concentric's proposed amortization accounts. In discussion with Mr. Bowman, Mr. O'Leary described EGI's proposal clearly.[107] EGI is proposing to transfer regulators that EGD had recorded in account 473.01 to account 474, where Union had recorded regulators. At the same time, as Mr. Madsen's evidence explains, EGI is proposing to adopt Concentric's recommendation to apply a 25 year service life for regulators (as compared to the 20 year service life that Union had applied to them in the past). Because those transferred regulators are coming from an EGD account that had a much longer service life, EGI's proposal results in a very significant increase in depreciation in 2024. As Mr. Bowman explained, much of this increase results from recalculation using a much shorter service life for the historical EGD regulators than was the case in the past, which results in a large unrecovered cost from the past period. Combined with a prospective shortening of the service lives of these assets upon transfer to account 474, and proposed recovery of the historical shortfall over the much shorter prospective service life, the result, as Mr. Bowman put it[108];

> *… just compounds to a massive impact. So that, on a – you know, as I said, it's a half a billion dollars…*
>
> *… the impact of cleaning up that old balance ends up being a huge part of the cost impact of doing this, and it is trying to clean up that old balance on this shorter life.*

163. Mr. Bowman goes on in his testimony on this point to agree with Mr. Madsen that this account may merit some transition provisions[109], as Mr. Madsen has proposed[110]. Commissioner Duff followed up on this issue with Mr. Madsen during the oral hearing, regarding the potential to isolate the roughly $300 million of "old" regulators which EGI proposes to move from account 473.02 to account 474, which Mr. Madsen then suggests could continue to be depreciated at the historical rate (45 years per EGI account 473.01[111]) under which these assets had been depreciated.[112]

---

[107] Transcript 18, page 37, line 27 through page 38 line 9.
[108] Transcript 18, page 40, line 27 to page 41, line 6.
[109] Transcript 18, page 41, lines 9-14.
[110] Exhibit M5, page 72, lines 12-18.
[111] EGI AIC, paragraph 519.
[112] Transcript 18, page 93, line 7 through page 94, line 27.

164. An alternative which Mr. Madsen has proposed in his prefiled evidence was to apply a longer service life to account 474 into which these legacy regulators are to be transferred. In its AIC EGI has criticized that proposal as unsupported by any evidence. This criticism misses the point regarding “the mess” (as Mr. Bowman referred to it) created by EGD’s legacy treatment of these assets.

165. ***IGUA supports separate treatment of the legacy regulators so as to moderate the impacts of recovering the historical depreciation shortfall that would result from adoption of Concentric’s recommended 25 year service life for regulators going forward. IGUA submits that in respect of these legacy assets, EGI should continue to apply the 45 year service life under which they have been depreciated to date. IGUA also agrees with Mr. Madsen that tracking these assets under a separate sub-account would ensure visibility going forward.***

CDNS

166. While all of the depreciation experts endorse the use of a Constant Dollar Net Salvage (CDNS) procedure to accrue and recover future expected asset retirement costs as a component of depreciation expense, Mr. Madsen and Intergroup are both convinced that the CDNS model used by Concentric is broken, and yields inappropriate results.

167. Mr. Kennedy and EGI have criticized the Madsen/Intergroup recommendations, including in particular their position that a weighted average cost of capital (WACC) discount rate for net salvage represents an appropriate reflection of the value to future customers of the contributions to net salvage costs of current customers[113], on the basis that when run through Concentric’s CDNS model those recommendations result in an absurdly low net salvage provision in 2024.[114] Careful review of the Intergroup report[115], as bolstered by Mr. Bowman’s oral testimony on the topic[116], indicates that this absurd result is in fact driven by errors embedded in the Concentric CDNS model, and not by the depreciation parameters recommended by Mr. Madsen and Intergroup.

[113] Exhibit M1, page 53, last paragraph; Exhibit M5, page 85, lines 1-8.
[114] Exhibit J16.6. Concentric reports that the resulting net salvage accrual to be $325,472, using the ALG procedure and a WACC discount rate of 6.03%.
[115] Exhibit M1, pages 52-53.
[116] Transcript 17, page 179, line 23 through page 180, line 22.

168. The Intergroup report (Exhibit M1) explains the problems with Concentric's approach to the CDNS calculations at pages 49 to 53. This evidence indicates that:

(a) Concentric does in fact "double inflate" historically derived net salvage figures, which already embed an inflation factor but are then inflated again in Concentric's calculations.

(b) Concentric inappropriately derives a *"single flat percentage"* for CDNS, which fails to reflect that CDNS accruals are designed to change with the vintage make-up of the account, and with time.

169. Mr. Bowman proceeds in Intergroup's report to describe a proper approach to apply CDNS (see page 51 of that report). Mr. Bowman then applies his approach to calculate a proper 2024 net salvage provision, noting that such a provision is ~$3 million higher in 2024 than the provision calculated by Concentric. The result of the faults in Concentric's model is that Concentric under-accrues net salvage provisions.

170. Mr. Bowman also points out that his proper approach to calculating net salvage is not overly sensitive to the use of ALG rather than ELG, but that Concentric's improper approach is.[117] This explains why Concentric derives an absurdly low CDNS provision using the Madsen/Intergroup depreciation proposals. Fixing the CDNS model as Mr. Bowman does would yield a much more instinctively appropriate result, even using a WACC based discount rate (as illustrated in Intergroup's Table 7 at page 54 of its report).

171. EGI continues to maintain that there is no double inflating problem in the Concentric CDNS calculations.[118] The testimony through which Mr. Kennedy was led at the oral hearing indicates the contrary.[119] That testimony, and subsequent testimony by Mr. Bowman and Mr. Madsen[120], confirms that Concentric's calculations derive a net salvage ratio based on an asset investment/salvage expense history that embeds inflation, and then inflates that already future dollar net salvage requirement again before discounting the over-inflated result to derive a current net salvage provision.

[117] Exhibit M1, page 52, last full paragraph.
[118] EGI AIC, paragraph 504.
[119] Transcript 16, page 158, line 22 through page 170, line 2.
[120] Transcript 18, page 10, line 24 through page 14, line 19.

172. Further evidence from Mr. Madsen articulates the shortcomings in the over-simplified approach taken by Concentric to its CDNS calculations, and the somewhat more detailed but more appropriate approach to such calculations.[121]

173. The evidence is clear. There are problems with the Concentric CDNS model.

174. ***OEB Staff advocates using Intergroup's CDNS calculation methodology. For the purposes of setting rates in this proceeding, IGUA supports that recommendation.***

175. Should the OEB not be persuaded that this is the best solution, an alternative which IGUA would also support, would be to set the 2024 net salvage provision to cover the net salvage costs forecast to be incurred in 2024. This approach would ensure that the net salvage accrual to date (~$1.6 billion) would remain intact through the 2024 net salvage expenditure. EGI's forecast of net salvage costs for ensuing years indicates relatively stable net salvage expenditures forecast year to year. Setting the 2024 net salvage provision in line with the 2024 forecast net salvage expenditures would thus maintain the current accrued net salvage balance in the near term, pending further study and determination of an appropriate CDNS calculation methodology.

176. Intergroup has recommended altering net salvage estimates for several asset accounts. Mr. Madsen deferred review of those net salvage estimates to Intergroup[122] and IGUA defers on this topic to the submissions of OEB Staff.

177. ***Given overall net salvage cost uncertainty, however, Mr. Madsen did recommend, and IGUA endorses that recommendation, that the OEB direct study of EGI's largest asset accounts to assess appropriate net salvage parameters. In particular, Mr. Madsen recommended[123] that EGI be directed to report as follows in respect of EGI's 10 largest asset accounts:***

(a) ***The current approach to salvaging the assets in these accounts, including the approximate material and labour costs to salvage the assets.***

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

[121] Transcript 18, page 65, line 7 through page 656, line 25.
[122] Transcript 18, page 92, lines 6-10.
[123] Exhibit M5, pages 91-93.

(c) ***EGI's best estimate of the future costs to salvage the assets within each account, including the assumptions used to develop those estimates.***

178. Mr. Madsen explained the objective for this study as follows:

> *While this information will require significant judgement and thus be subject to significant uncertainty it will nevertheless provide parties with a better understanding of the potential magnitude and range of the future costs that may be incurred. The information outlined above will also provide more clarity into the best practices Enbridge may be able to employ to plan for, and perhaps mitigate or avoid a portion of, those costs. The information would also provide an additional data point to assist in developing future net salvage estimates and better inform decisions and recommendations around how current experienced levels of net salvage costs (i.e. -100%, -200%, or greater) may or may not be reflective of the future levels of expected net salvage.*

179. OEB Staff has supported such a study in its Submission.[124] ***In respect of the choice of accounts to study, IGUA supports OEB Staff's recommendations (see OEB Staff Submission, page 97).***

180. EGI has indicated it would not object to such a study[125], though a response added by Concentric cautions against the time and expense required for such work if it is to be accomplished by way of engineering studies. Concentric expresses concerns regarding studies that may cost in the millions, though we note that the context here is a net salvage provision accumulated to date of ~$1.6 billion and potential future net salvage costs in the ~$10 billion plus range.[126]

181. ***In any event, we respectfully suggest that it would be helpful for EGI in its reply argument to provide additional information on alternatives to how it might approach such a study and the cost, timing, and value implications of those alternatives.***

Segregated Net Salvage Fund

182. Mr. Madsen and Intergroup also considered the advisability of establishing a segregated net salvage fund at this time, and both concluded, as did Concentric, that at present the

---

[124] OEB Staff Submission, page 99.
[125] Exhibit J16.9.
[126] Exhibit M5, page 90, line 24 to page 91, line 6.

cons of such an approach outweigh the pros. Chief among these considerations for Mr. Madsen were[127];

(a) The lack of clear, near-term expectations for material asset retirements and consequent outflow of significant salvage costs.

(b) The effect from a segregated fund of shifting investment risk associated with that fund to customers.

(c) The relatively certain value to current and future customers of allowing EGI to continue to use net salvage proceeds as an offset to rate base and associated financing requirements (i.e. WACC).

(d) The ongoing recovery by EGI of net salvage provisions and consequent lack of any material, currently apparent risk to recoverability of salvage costs related to future retirement of assets.

183. At the same time, considering the current uncertainty regarding future retirement costs (see, for example, the exchange between IGUA counsel and Mr. Kennedy from pages 118 to 128 of the March 27, 2023 Technical Conference transcript), Mr. Madsen also suggests that in lieu of the establishment of a segregated net salvage fund at this time[128]:

> *… the OEB direct Enbridge to begin separately tracking and reporting the annual changes in the current net salvage liability. Specifically, the existing balance in the account inclusive of any approved funding to the account and actual costs incurred should be reported as a separate requirement in future rate applications.*
>
> *…*
>
> *In my opinion, there would be significant benefit from Enbridge calculating and reporting the expected future net salvage cost liability based on two assumptions:*
>
> *i. The applied for net salvage rates.*
>
> *ii. The five-year average actual experienced net salvage costs for each account.*
>
> *I consider this information to be of significant value in providing transparency to all parties on the potential magnitude of a future salvage cost obligation. This information would also be of assistance in informing the positions of all parties in relation to net salvage costs in the future. …*
>
> *…*

[127] Exhibit M5, pages 87 through 91.
[128] Exhibit M5, page 90, lines 8-11 and 17-20.

> *This is particularly the case given Concentric's comments around potential future review of an economic planning horizon due to potential impacts from an energy transition, which will impact both depreciation and net salvage.*

184. EGI did not have specific objections to these recommendations, subject to consideration of *"frequency and timing of such reporting so that a balance can be struck between operational effectiveness and cost efficiency."*

185. ***IGUA invites EGI to elaborate in reply on which of the Mr. Madsen's particular recommendations give rise to concerns regarding "operational effectiveness and cost efficiency" (i.e. the more detailed recommended 10 largest account study, or these more regular reporting obligation proposals), and how EGI would propose to strike the appropriate balance.***

Discount Rate

186. Both Mr. Madsen[129] and Intergroup recommend use of EGI's weighted average cost of capital (WACC) as the appropriate discount rate for CDNS calculations. Intergroup describes the relevant considerations as follows (our emphasis)[130]:

> *Finally, the selection of the discount rate is a very significant factor in calculating the CDNS accrual in any given year. For example, adjusting the discount rate can change the annual accrual across a wide range, from 0% (effectively the traditional approach) to 2% (constant real dollars, i.e., only levelized for inflation), 3.75% (CARF, as proposed) up to 5.87% (the full weighted average return on rate base) as illustrated in Table 7. While the effects on annual costs are significant, the principle against which the rate is selected is a policy question regarding trade-offs between existing customers and future customers. There is no further definitive technical insight to guide this decision. However,* ***the approach that most directly recognizes the full value of the net salvage funds that will be collected from current ratepayers, which will be credited against the rate base in future rate cases, is the 5.87 discount rate.***

187. Throughout the hearing Mr. Kennedy and EGI challenged this approach on the basis that using WACC as a discount rate produced an absurdly low net salvage provision. As articulated above, however, the absurd result calculated by Concentric is driven not by the choice of discount rate, but rather by the broken Concentric CDNS model.

[129] Exhibit M5, pages 79-85.
[130] Exhibit M1, page 53.

188. OEB Staff's Submission indicates (see Table 17 at page 98) that the 2024 depreciation impact of moving to an updated credit adjusted risk free rate (CARF) of 4.48% from the CARF of 3.75% used in Concentric's evidence, and using Intergroup's corrected CDNS calculations, yields a net salvage provision reduction in 2024 of $4.1 million. Moving from this CARF to a WACC of 5.87%[131] would reduce the 2024 depreciation provision calculated by Intergroup ($727.6 million) by another $8.4 million. While a material reduction, hardly an absurd result.

189. ***IGUA thus recommends application of a CDNS discount rate equal to WACC.*** Using WACC as the discount rate reflects that the value to future customers of the net salvage contributions by current customers is the avoided EGI rate base.

190. We note that despite the updated evidence on CARF currently being 4.48%[132], EGI maintains in its Argument in Chief its proposed discount rate of 3.75%[133]. EGI asserts that this rate remains appropriate given that the Canada Energy Regulator has recently used a rate of return of 3.25% in setting contribution requirements for regulated segregated retirement funds. As Mr. Kennedy acknowledged during examination[134], the purpose of setting a discount rate to determine contributions to a segregated fund to ensure sufficient future accruals to meet an expected expenditure is a particular exercise, distinct from setting a discount rate to present value recoveries on account of future expenses which recoveries will not be set aside. What the CER has specified to ensure that the actually segregated fund is sufficiently capitalized in order to yield a particular future sum is a different question than what policy basis the OEB should consider in determining an appropriate balance between current and future customers' contributions to net salvage costs added on to ongoing depreciation expenses.

191. To that end, if the OEB determines that CARF (rather than WACC) is an appropriate discount rate to use to derive CDNS provisions for EGI in 2024, which is what Concentric and EGI advocated in the first place, then CARF, and not some different (and lower) figure should be used. As of the time of closing of the record in this proceeding, CARF is 4.48% (which is also closer to the evidenced WACC of 5.87% and thus, from IGUA's perspective,

131 Exhibit J17.11, Attachment 1, page 1, line 4.
132 Exhibit J17.5.
133 EGI AIC, paragraph 506.
134 Transcript 16, page 175, line 18 to page 176, line 25 and page 178, line 23 to page 179, line 28.

a more appropriate alternative to what we nonetheless maintain is the appropriate discount rate to apply, for the reasons articulated above).

CONCLUSION

192. This is an important case, and a complex one.

193. To rebase rates for Canada's largest natural gas distributor after 10 years and an intervening merger is complex enough.

194. To do so against the backdrop of a real yet still uncertain energy transition amplifies the complexity of the case, and its importance.

195. The extent to which one's view of the future of the gas distribution business tempers conventional rate making considerations such as depreciation policy, capital structure, capital plans, cost responsibility for new connections, and a host of other matters underscores the oft quoted observation that *"the devil is in the details"*.

196. IGUA retained Dr. Asa Hopkins of Synapse Energy Economics, Inc. in the context of EGI's proposal to increase its equity thickness in response to energy transition posed business risk, but beyond that to share learnings from his work in various North American jurisdictions on exploring the details applicable to the future of gas utilities in the face of deep decarbonization.

197. Dr. Hopkins' primary recommendation is that EGI should start now to construct and run proper modelling of its potential futures, and to develop a detailed business plan for managing the utility in the changing public policy and competitive environment in which it operates:[135]

> *That plan should identify and quantify risks and opportunities, including when they would manifest in impacts on the company as well as what their impacts would be. This plan should include a comprehensive assessment of electricity and gas utility roles in decarbonization, gas load forecasts, infrastructure needs, gas price forecasts, analysis of customer counts and consumption patterns by customer type, and the availability and costs of alternative fuels. Developing such a plan would reduce uncertainty regarding the company's future business, and thereby lower investor risk. Such a plan should also inform analysis of, and selection of, additional mitigating actions.*

198. Dr. Hopkins evidence provides synopses of work in this direction being done now in other jurisdictions, and lessons learned[136]. It also provides illustration of the type of modelling

[135] Exhibit M8, page 53, lines 6-14.
[136] Exhibit J5.2.

that can and should be done by EGI, and the sort of information and insight that such modelling could provide.

199. IGUA does not support waiting until 2028 to bring these issues back for further consideration. The evidence in this case, including the illustrative modelling performed by Dr. Hopkins[137], shows how small changes in assumptions can have significant customer impacts, either way.

200. Further, as Dr. Hopkins puts it[138]:

> *…regulatory attention to energy transition issues reduces uncertainty and lowers risk. OEB consideration of EGI's plans in the context of the Ontario Ministry of Energy's Cost-Effective Energy Pathways Study will similarly reflect the transparent, consistent, and predictable regulatory process in Ontario, which is a key component of S&P's evaluation of EGI's business risk as "Excellent."*

201. ***IGUA submits that the OEB should, in its Phase 1 decision in this case, direct EGI to commence such work, and signal its interest in considering progress and early results from that sooner than 2028. The precise timing for such consideration could be the subject of deliberation as part of Phase 2 of this application.***

202. Despite the lack of detail in EGI's work on energy transition to date, the imminence of the transition has been cited by EGI and its external consultants at Concentric to justify an across the board acceleration in return of its shareholder's capital through depreciation expense and an increase in its shareholder's earnings through increased equity thickness. When the diaphanous veil of energy transition that has been presented by EGI in this case is stripped away;

(a) The evidence of Dr. Cleary illustrates that a properly and thoughtfully considered application of the cost of capital "fair return standard" does not support providing EGI's shareholder with greater equity thickness.

(b) EGI's proposed shift in depreciation policy is itself unnecessary and the alternatives proposed by Mr. Madsen of Emrydia and OEB Staff's experts from Intergroup provide a more robust approach to depreciating EGI's assets in the manner that standard regulatory depreciation policy intends.

[137] Exhibit M8, pages 43-47 and Attachment 4.
[138] Exhibit M8, page 27, line 25 – page 28, line 3

203. IGUA appreciates having had the opportunity to contribute to the OEB's review of this important application, and hopes that its purposeful approach will prove of assistance to the Commission in its upcoming deliberations.

ALL OF WHICH IS RESPECTFULLY SUBMITTED by:

GOWLING WLG (CANADA) LLP, per:
Ian A. Mondrow
Counsel to IGUA

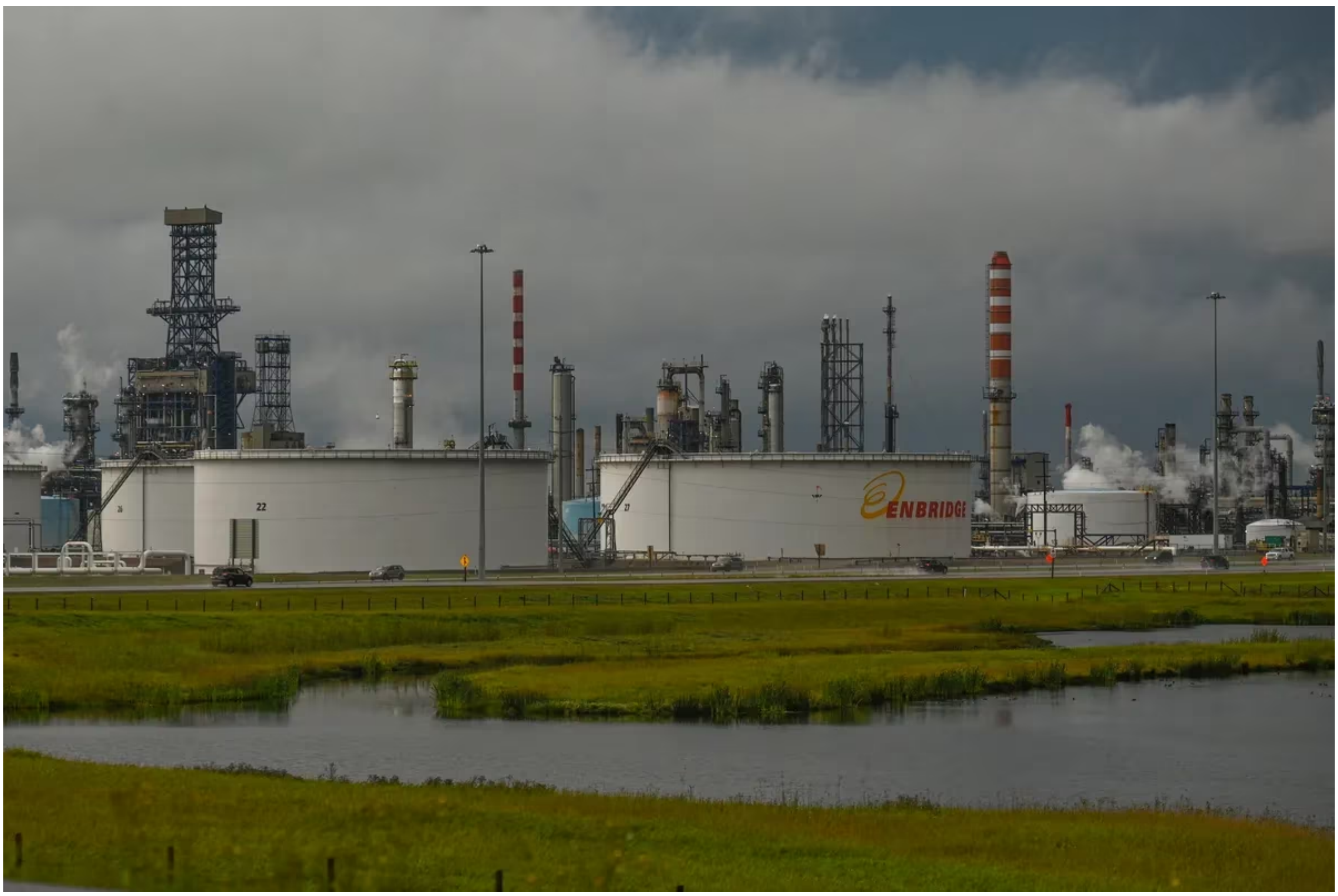
September 21, 2023

58551020\2

Enbridge bets big on natural gas with $9.4-billion acquisition of three U.S. utilities

EMMA GRANEY > ENERGY REPORTER
TIM KILADZE >
BRENT JANG >

PUBLISHED YESTERDAY
UPDATED 3 HOURS AGO
FOR SUBSCRIBERS



The Enbridge Terminal and Pipelines next to the Suncor Energy Refinery on Aug. 23, in Sherwood Park, Alberta.

ARTUR WIDAK/REUTERS

Canadian pipeline giant Enbridge Inc. ENB-T (/investing/markets/stocks/ENB-T/) -5.86% ▼ is betting big on the long-term value of natural gas in the energy transition as the world seeks to shift away from more polluting forms of fuel, buying three U.S. utilities for US$9.4-billion to create the continent's largest natural gas utility.

The Calgary-based company announced Tuesday it has entered into three agreements with Dominion Energy Inc. to acquire the East Ohio Gas Co.; Questar Gas Co. and its related Wexpro companies; and Public Service Co. of North Carolina Inc. The deal comprises US$9.4-billion in cash, plus US$4.6-billion of assumed debt.

Enbridge plans to fund the deal through a combination of debt and equity, and on Tuesday, the company launched one of the largest share sales in Canadian history.

The acquisition represents a "generational opportunity" for Enbridge, the company's chief executive Greg Ebel said on a conference call.

"We remain firmly of the view that all forms of energy will be required for a safe and reliable energy transition. This transaction helps to achieve greater balance and gives us increased exposure to natural gas, which is and will continue to be the critical fuel to help realize our lower carbon aspirations," Mr. Ebel said.

Canadian fossil-fuel producers maintain that natural gas will play a crucial role in the power grid as countries move to reduce greenhouse-gas emissions, and proponents want to see it displace more carbon-intensive coal for generating electricity in other countries. Critics argue that burning gas isn't that much better, as it releases large amounts of methane – a powerful greenhouse gas – into the atmosphere.

Enbridge lining up support for B.C. natural-gas pipeline plans

The Enbridge expansion will split the company's earnings before interest, taxes, depreciation and amortization 50-50 between its U.S. and Canadian operations, by beefing up an American presence that grew rapidly when Enbridge bought Spectra Energy Corp. in 2016.

It will also significantly diversify the company's geographical footprint into Ohio, Utah, Wyoming, Idaho and North Carolina. Those jurisdictions come with two major benefits, Enbridge says: supportive regulatory regimes for natural gas; and projected population growth that far exceeds the U.S. average.

Mr. Ebel said the utilities also have long lives and have each committed to achieving net-zero greenhouse-gas emissions by 2050.

“This is, without question, a historically rare opportunity; we are acquiring high quality growing gas utilities upscale for an attractive price,” he said.

Ade Allen, a senior analyst at Rystad Energy, said Enbridge’s announcement demonstrates how confident the company is in the long-term prospects for natural gas in North America.

While solar and wind power are crucial intermittent suppliers in the energy transition, natural gas will still play an important role in providing a steady base load, he said in an interview Tuesday from New York.

“There is intermittency in some of these alternatives, whereas natural gas tends to show up when we need it the most,” Mr. Allen said.

Enbridge has also been keen to participate in exports of liquefied natural gas. The company acquired a 30-per-cent stake last year in Woodfibre LNG, which is scheduled to begin construction later this month at a site near Squamish, B.C.

Woodfibre LNG announced Tuesday that BP Gas Marketing Ltd. will be buying the vast majority of the LNG to be produced at the Squamish-area facility that is slated to start exports in 2027.

Tuesday’s acquisition of U.S. assets is expected to close next year following regulatory approvals.

The $4-billion share sale Enbridge also announced Tuesday is one of the largest ever in Canada. Previous deals of this size include TC Energy’s TRP-T (/investing/markets/stocks/TRP-T/) -3.07% ▼ record $4.4-billion share sale in 2016 – which was followed by another $3.5-billion share sale later that year – and Barrick Gold Corp.’s ABX-T (/investing/markets/stocks/ABX-T/) +0.02% ▲ US$4-billion share sale in 2009, which was used to eliminate the bullion producer’s fixed-price gold contracts.

Enbridge shares are being issued at $44.70 a piece, a sizeable 7.2-per-cent discount to where they closed on Tuesday. When markets are hot, share sales are usually priced at a tight 2-per-cent discount to their last traded price, but Canada has endured a drought of financings in 2023.

As of July 31, total financings raised by companies listed on the Toronto Stock Exchange came to $5.8-billion, according to TMX Group, down 54 per cent from the same period in 2022 and plummeting 81 per cent from the same period in 2021.

The deal is another major splash for Enbridge in the United States, after the Canadian energy giant bought Houston-based Spectra Energy Corp. for $37-billion in an all-share deal in September, 2016.

At the time, Enbridge was heavily weighted to oil, but the crude market was enduring a multiyear rut after Saudi Arabia flooded the global market with supply, sending oil prices plummeting. To pivot, Enbridge's then-CEO Al Monaco laid out a plan to expand in power production and natural-gas transmission.

Enbridge ultimately bought Spectra, which had 27,520 kilometres worth of long-haul natural-gas pipelines. Spectra also had midstream assets – or natural-gas processing plants – in British Columbia's Montney formation.

Crucially, though, the company's pipelines ran through the Northeast U.S. That location was notable because in early 2016, Canadian rival TC Energy – then TransCanada Pipelines – bought Columbia Pipeline Group for US$10.2-billion. Columbia specialized in transporting gas from the booming Marcellus shale formation in the U.S. Northeast.

Following Enbridge's acquisition, Spectra CEO Greg Ebel became chair of Enbridge's board of directors, and in January, he succeeded Mr. Monaco as Enbridge's new CEO.

On Tuesday, Enbridge's shares closed at $48.16, 7 per cent below their trading price before the blockbuster Spectra deal was announced.

Skip to content Skip to footer

Main Menu Button

ENBRIDGE

Enbridge Announces CDN$4.0 Billion Bought-Deal Offering of Common Shares

September 5, 2023

CALGARY, AB, Sept. 5, 2023 /CNW/ - Enbridge Inc. (TSX: ENB) (NYSE: ENB) ("Enbridge" or the "Company") today announced that it has entered into an agreement with a syndicate of underwriters led by RBC Capital Markets and Morgan Stanley, and including BMO Capital Markets, CIBC Capital Markets, National Bank Financial Markets, Scotiabank, and TD Securities (the "Underwriters") under which the Underwriters have agreed to purchase, on a bought deal basis, 89,490,000 common shares of the Company ("Common Shares") for aggregate gross proceeds of CDN$4 billion at an offering price of CDN$44.70 per Common Share (the "Offering").

Enbridge intends to use the net proceeds from the Offering to finance a portion of the cash consideration payable by it for the purchase of local distribution company gas utilities in the United States from Dominion Energy, Inc., the details of which were announced today in a separate news release issued by Enbridge (the "Acquisitions").

The Common Shares will be offered to the public in all of the provinces of Canada through the Underwriters and their affiliates by way of a Canadian prospectus supplement (the "Canadian Prospectus Supplement") to Enbridge's short form base shelf prospectus dated September 5, 2023 (the "Canadian Prospectus"). The Common Shares will be offered to the public in the United States pursuant to Enbridge's registration statement, including a prospectus (the "U.S. Prospectus"), filed with the U.S. Securities and Exchange Commission (the "SEC"), and a prospectus supplement (the "U.S. Prospectus Supplement") to the U.S. Prospectus. Before investing, prospective purchasers in Canada should read the Canadian Prospectus Supplement, the Canadian Prospectus and the documents incorporated by reference therein, and prospective purchasers in the United States should read the U.S. Prospectus, the U.S. Prospectus Supplement and the documents incorporated by reference therein for more complete information about Enbridge and the Offering in Canada and the United States, respectively. Common Shares may also be offered on a private placement basis in other international jurisdictions in reliance on applicable private placement exemptions.

The Offering is expected to close on or about September 8, 2023. Pursuant to the agreement, the Underwriters have an option to purchase up to 15% in additional Common Shares by providing notice to Enbridge at any time until the date that is 30 days after the closing of the Offering, to cover over-allotments, if any. If the over-allotment option is exercised in full, the aggregate gross proceeds from the Offering will be approximately CDN$4.6 billion.

A copy of the Canadian Prospectus for the Offering is, and a copy of the Canadian Prospectus Supplement will be, available on SEDAR+ (http://www.sedarplus.ca) and a copy of the U.S. Prospectus is, and a copy of the U.S.

Prospectus Supplement will be, available on the SEC website (http://www.sec.gov). Potential investors can request copies of the Canadian Prospectus and Canadian Prospectus Supplement from RBC Dominion Securities Inc., 180 Wellington Street West, 8th Floor, Toronto, ON M5J 0C2, Attention: Distribution Centre, or via telephone: 1-416-842-5349, or via e- mail at Distribution.RBCDS@rbccm.com and the U.S. Prospectus and U.S. Prospectus Supplement from RBC Capital Markets, LLC, 200 Vesey Street, 8th Floor, New York, NY 10281-8098, Attention: Equity Syndicate, phone: 877-822-4089, Email: equityprospectus@rbccm.com or Morgan Stanley & Co. LLC - Attn: Prospectus Department - 180 Varick Street, 2nd Floor - New York, NY 10014.

The closing of the Offering is not conditional upon the completion of the Acquisitions. In the event that any or all of the Acquisitions are not completed, Enbridge may use the net proceeds from the Offering to reduce its outstanding indebtedness, finance future growth opportunities including acquisitions, finance its capital expenditures, or for other general corporate purposes.

This press release shall not constitute an offer to sell or the solicitation of an offer to buy any securities, nor will there be any sale of these securities, in any jurisdiction in which such offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of any such jurisdiction.

FORWARD-LOOKING INFORMATION

This news release contains both historical and forward-looking statements within the meaning of Section 27A of the U.S. Securities Act of 1933, as amended, and Section 21E of the U.S. Securities Exchange Act of 1934, as amended, and forward-looking information within the meaning of Canadian securities laws (collectively, forward-looking statements). Forward-looking statements have been included to provide potential investors with information about Enbridge. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "believe", "estimate", "expect", "forecast", "intend", "likely", "plan", "project", "target" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements included in this news release include, but are not limited to, statements with respect to the following: the closing of the Offering, the use of proceeds of the Offering and the Acquisitions.

Although Enbridge believes these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future events and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual events to differ materially from those expressed or implied by such statements.

Enbridge's forward-looking statements are subject to risks and uncertainties, including, but not limited to the possibility that the Offering does not close when expected, or at all, because conditions to closing are not satisfied on a timely basis, or at all, the possibility that the Acquisitions do not close when expected, or at all, because required regulatory approvals and other conditions to closing are not received or satisfied on a timely basis, and those other risks and uncertainties disclosed in Enbridge's other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by applicable law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this news release or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on its behalf, are expressly qualified in their entirety by these cautionary statements.

ABOUT ENBRIDGE INC.

At Enbridge, we safely connect millions of people to the energy they rely on every day, fueling quality of life through our North American natural gas, oil or renewable power networks and our growing European offshore *wind portfolio. We're investing in modern energy delivery infrastructure to sustain access to secure, affordable energy and building on two decades of experience in renewable energy to advance new technologies including wind and solar power, hydrogen, renewable natural gas and carbon capture and storage. We're committed to reducing the carbon footprint of the energy we deliver, and to achieving net zero greenhouse gas emissions by 2050. Headquartered in Calgary, Alberta, Enbridge's common shares trade under the symbol ENB on the Toronto (TSX) and New York (NYSE) stock exchanges.*

FOR FURTHER INFORMATION PLEASE CONTACT:

Enbridge Inc. – Media	**Enbridge Inc. – Investment Community**
Jesse Semko	Rebecca Morley
Toll Free: (888) 992-0997	Toll Free: (800) 481-2804
Email: media@enbridge.com	Email: investor.relations@enbridge.com

SOURCE Enbridge Inc.

Enbridge Announces the Closing of CDN$4.6 Billion Common Equity Offering Inclusive of Underwriters' Over-Allotment

September 8, 2023

CALGARY, AB, Sept. 8, 2023 /CNW/ - Enbridge Inc. (TSX: ENB) (NYSE: ENB) (Enbridge or the Company) today announced it has closed its previously announced public offering (the Offering) of common shares by a syndicate of underwriters led by RBC Capital Markets and Morgan Stanley, together with BMO Capital Markets, CIBC Capital Markets, National Bank Financial Markets, Scotiabank, TD Securities as joint bookrunners. Enbridge issued 102,913,500 common shares inclusive of 13,423,500 common shares issued pursuant to the full exercise of the underwriters' over-allotment option. Gross proceeds from the Offering are approximately CDN$4.6 billion.

Enbridge intends to use the net proceeds from the Offering to finance a portion of the aggregate cash consideration payable for the purchase of local distribution company gas utilities in the United States from Dominion Energy, Inc. (the Acquisitions), the details of which were announced in a news release issued by Enbridge on September 5, 2023.

The exercise of the over-allotment option by the underwriters reduces, and further de-risks, Enbridge's future financing requirements to fund the Acquisitions.

This press release shall not constitute an offer to sell or the solicitation of an offer to buy any securities, nor will there be any sale of these securities, in any jurisdiction in which such offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of any such jurisdiction.

A copy of the Canadian Prospectus and the Canadian Prospectus Supplement is available on SEDAR+ (http://www.sedarplus.ca) and a copy of the U.S. Prospectus and U.S. Prospectus Supplement is available on the SEC website (http://www.sec.gov). You can request copies of the Canadian Prospectus and Canadian Prospectus Supplement from RBC Dominion Securities Inc., 180 Wellington Street West, 8th Floor, Toronto, ON M5J 0C2, Attention: Distribution Centre, or via telephone: 1-416-842-5349, or via e- mail at Distribution.RBCDS@rbccm.com and the U.S. Prospectus and U.S. Prospectus Supplement from RBC Capital Markets, LLC, 200 Vesey Street, 8th Floor, New York, NY 10281-8098, Attention: Equity Syndicate, phone: 877-822-4089, Email: equityprospectus@rbccm.com or Morgan Stanley & Co. LLC - Attn: Prospectus Department - 180 Varick Street, 2nd Floor - New York, NY 10014.

About Enbridge Inc.

At Enbridge, we safely connect millions of people to the energy they rely on every day, fueling quality of life through our North American natural gas, oil or renewable power networks and our growing European offshore wind portfolio. We're investing in modern energy delivery infrastructure to sustain access to secure, affordable energy and building on two decades of experience in renewable energy to advance new technologies including wind and solar power, hydrogen, renewable natural gas and carbon capture and storage. We're committed to reducing the carbon footprint of the energy we deliver, and to achieving net zero greenhouse gas emissions by 2050. Headquartered in Calgary, Alberta, Enbridge's common shares trade under the symbol ENB on the Toronto (TSX) and New York (NYSE) stock exchanges.

Forward Looking Statements

This news release contains both historical and forward-looking statements within the meaning of Section 27A of the U.S. Securities Act of 1933, as amended, and Section 21E of the U.S. Securities Exchange Act of 1934, as amended, and forward-looking information within the meaning of Canadian securities laws (collectively, forward-looking statements). Forward-looking statements have been included to provide potential investors with information about Enbridge. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "believe", "estimate", "expect", "forecast", "intend", "likely", "plan", "project", "target" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements included in this news release include, but are not limited to, statements with respect to the following: the use of proceeds of the Offering and the purchase of local distribution company gas utilities in the United States from Dominion Energy, Inc.

Although Enbridge believes these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future events and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual events to differ materially from those expressed or implied by such statements.

Enbridge's forward-looking statements are subject to risks and uncertainties, including, but not limited to the possibility that the Acquisitions do not close when expected, or at all, because required regulatory approvals and other conditions to closing are not received or satisfied on a timely basis, and those other risks and uncertainties disclosed in Enbridge's other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by applicable law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this news release or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on its behalf, are expressly qualified in their entirety by these cautionary statements.

FOR FURTHER INFORMATION PLEASE CONTACT:

Enbridge Inc. - Media	**Enbridge Inc. - Investment Community**
Jesse Semko	Rebecca Morley
Toll Free: (888) 992-0997	Toll Free: (800) 481-2804
Email: media@enbridge.com	Email: investor.relations@enbridge.com

SOURCE Enbridge Inc.

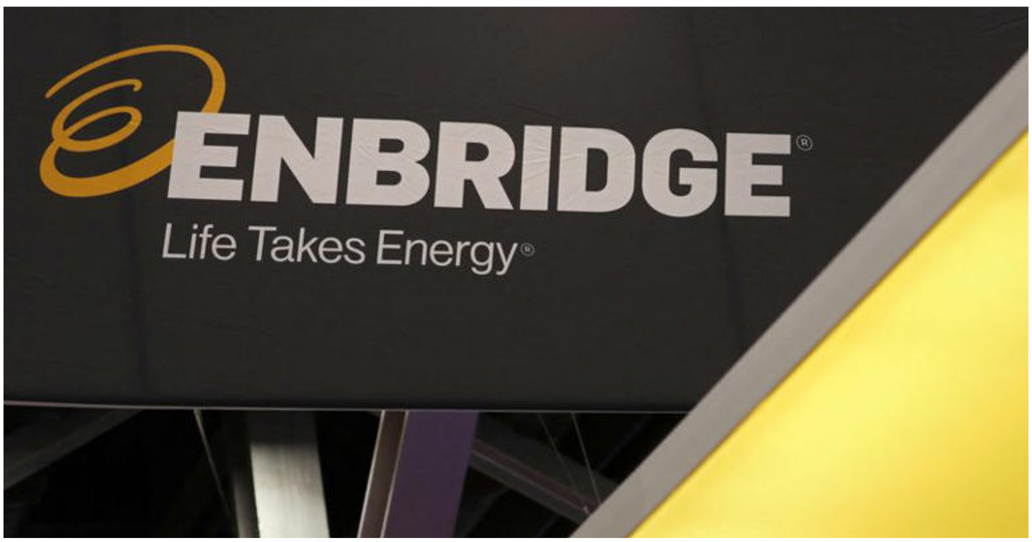
Reuters Follow

Enbridge dives as $14 billion Dominion deal sparks debt concerns

Story by By Mrinalika Roy • 18h

IN THIS ARTICLE ···

ENB ▼ -0.36% D ▼ -0.20%



© Thomson Reuters

By Mrinalika Roy

(Reuters) -Enbridge shares tumbled nearly 7% to an over four-year low on Wednesday, as investors fretted over the Canadian pipeline operator's debt load from the surprise $14 billion bid for three natural gas distribution companies from Dominion Energy.

The move to acquire East Ohio Gas, Questar Gas, and Public Service Co of North Carolina would double Enbridge's gas distribution business and make it the largest gas utility by volume in North America, with the unit accounting for a bit less than a fourth of the company's overall business mix.

The deal announced on Tuesday is seen as a bet on the future of natural gas in a regulated market even as energy companies and consumers transition to a greener future by phasing out fossil fuels.

Analysts, however, were surprised at the timing, the scale and impact such a deal would have on the company's already leveraged balance sheet.

president of Newhaven Asset Management, which holds shares in Enbridge.

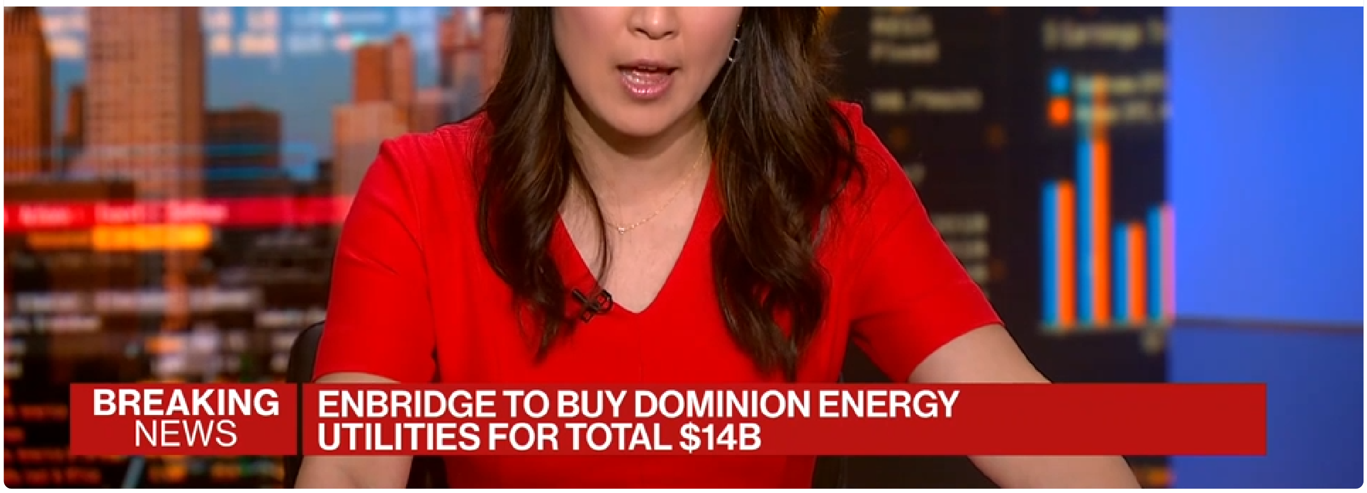
"I don't see how you can keep piling more issuance - debt and equity - on this company at these rates. The market is clearly telling them they don't have a strong currency to do so."

'OFF GUARD'

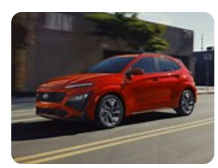
Related video: Enbridge Buying Three Dominion Natural Gas Utilities (Bloomberg)

Bloomberg

Enbridge Buying Three Dominion Natural Gas Utilities



Enbridge announced the deal just over a month after CEO Greg Ebel told analysts the company saw "tuck-in" acquisition opportunities "across the board."



"I do think the market was caught a bit off guard, as this wasn't on my bingo card," Morningstar analyst Stephen Ellis said. "Management had a realistic approach towards allocating capital, so a smaller transaction (perhaps a deeper investment in Canadian LNG?) would have been more expected," Ellis said.

Credit rating agencies S&P Global Ratings and Moody's cut their outlook on Enbridge following the announcement.

S&P estimates Enbridge's debt to EBITDA ratio - a measure of company's ability to repay debt - to rise to about 4.9, which leaves limited cushion for Enbridge to execute its funding plan "without relying on more than our assumed proportion of debt."

At the end of 2022, the ratio was at 4.7, and Enbridge's guidance is to keep it in a 4.5 to 5.0 range.

Enbridge is raising about C$4 billion by selling new shares at a discount of 7.2% to its Tuesday close to part-fund the transaction, while rest of the funding would come from debt, sale of non-core assets and others.

Feedback

growth expectation over the medium term unchanged, which suggests that the earnings contribution is "replacing weaker results on the liquids side of the business."

Enbridge shares provisionally closed down 5.9% at C$45.31, while the benchmark Canadian share index was off 0.9%. Rival TC Energy dropped 2.2%.

"While Enbridge paid a reasonable price, high leverage and funding gap could act as overhang," Wells Fargo analysts said in a note.

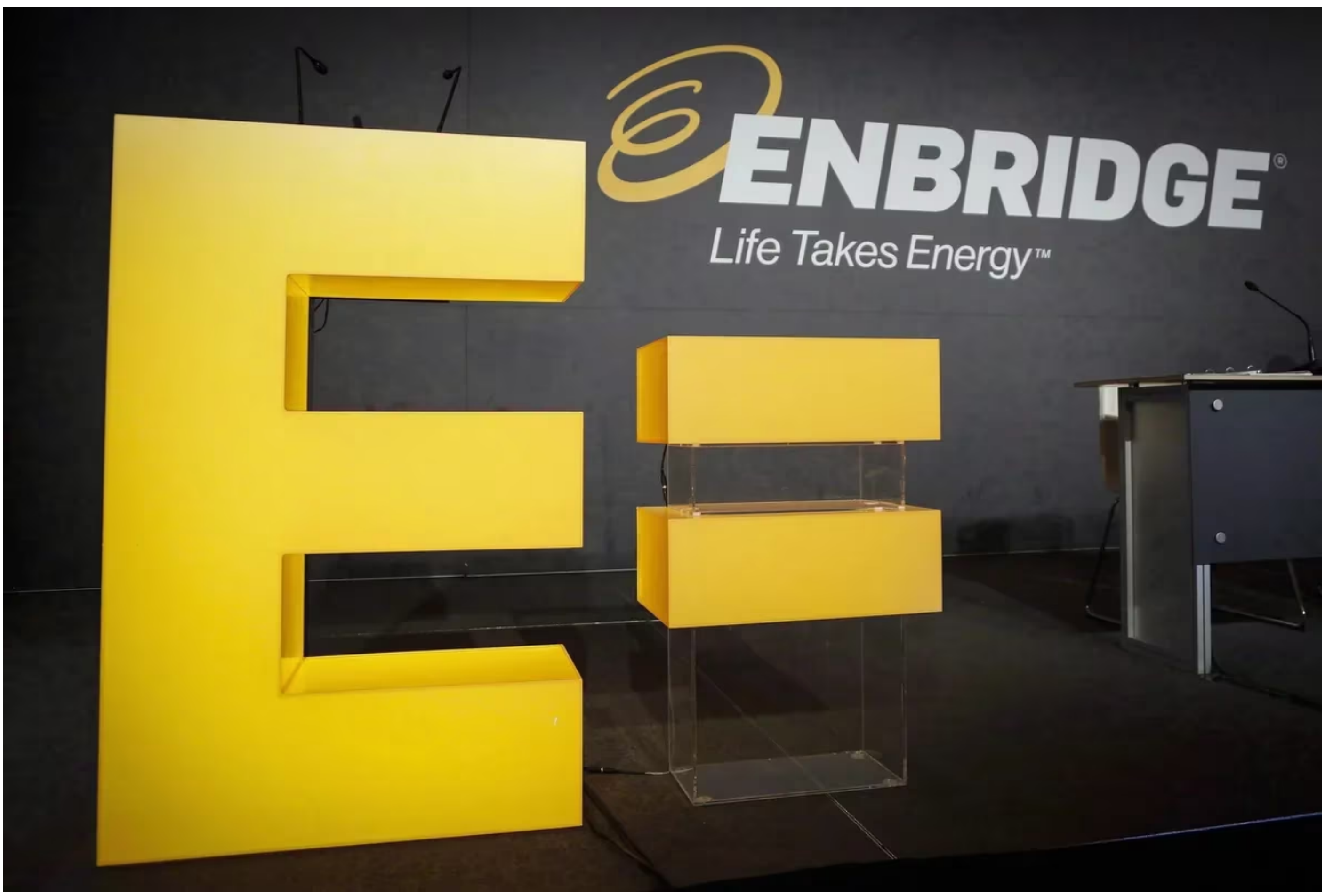
Separately, pipeline operator Williams Companies CEO Alan Armstrong said at the Barclays CEO Energy-Power Conference in New York that the company was not interested in the three utilities Enbridge has offered to buy as the return rate would be too low.

(Reporting by Mrinalika Roy in Bengaluru; Additional reporting by Nia WilliamsWriting by Denny ThomasEditing by Anil D'Silva, Alexandra Hudson, Devika Syamnath and Marguerita Choy)

Enbridge's big U.S. acquisition comes with a trade-off: Prioritizing revenue mix over debt load

EMMA GRANEY ENERGY REPORTER
TIM KILADZE
PUBLISHED YESTERDAY

FOR SUBSCRIBERS



Enbridge's logos on display at the company's annual meeting in Calgary, Thursday, May 12, 2016.
JEFF MCINTOSH/THE CANADIAN PRESS

Enbridge Inc.'s ENB-T (/investing/markets/stocks/ENB-T/) +0.09% decision to double-down in the United States with another blockbuster acquisition pits newly minted chief executive Greg Ebel's diversification strategy against the potential for more debt drama.

After announcing plans Tuesday to purchase three U.S. natural gas utilities from Dominion Energy Inc. for US$9.4-billion in cash, plus US$4.6-billion of assumed debt, Mr. Ebel preached the benefits of having multiple revenue streams.

Consumers want to be able to access energy from different sources, whether it's oil, gas or renewables, he told media Wednesday. Enbridge will cater to this by creating an organization that is akin to a "three-legged stool," he said, with one leg for each stream so it can quickly react to energy market changes.

A decade ago, Enbridge generated 75 per cent of its revenue from its oil pipeline division, and it was widely seen as a Canadian business. After a string of deals, including the one this week, the Calgary-based company's earnings before interest, taxes, depreciation and amortization (EBITDA) will be split 50-50 between its U.S. and Canadian operations, and oil has dropped to half of its total profit.

"I just think it's a more balanced approach to energy infrastructure, which is really in response to what industry and consumers are looking for in terms of an all-of-the-above approach," Mr. Ebel said on the call with reporters.

While diversifying, Enbridge must also consider what the new deal will mean for its balance sheet – and some early feedback has been more negative than positive.

Credit rating agencies Moody's Investors Service and Standard & Poor's both reaffirmed Enbridge's investment grade rating after the latest acquisition was announced, but they also put the energy giant on a negative watch, meaning the company has a better chance of being downgraded than upgraded at this point in time.

Although Enbridge sold $4-billion of new shares to cover some of the deal's US$9.4-billion price tag, "the negative outlook reflects uncertainty about the nature and timing of the remainder of the financing plan and credit metrics, which leave limited cushion to the company's downgrade trigger of at-or-above 5 times debt to earnings before interest, taxes, depreciation and amortization," S&P wrote in its ratings update on Wednesday.

Before the acquisition, Enbridge projected that it will keep its debt-to-EBITDA multiple within a range of 4.5 to 5 times for the near future, and even suggested the multiple will be closer to the lower end. After the acquisition, S&P is now projecting debt-to-EBITDA of 4.9 times in 2024.

In its own ratings update, Moody's directly addressed the added diversification, with earnings from local gas distribution jumping to 22 per cent of Enbridge's total, up from 12 per cent currently. While the rating agency welcomes this increase, it is more focused on the growing debt concerns.

"Although Enbridge's business risk profile improves modestly with the transaction, it is not enough to offset ongoing pressure on the company's financial profile," vice-president Gavin MacFarlane wrote.

There are many reasons to worry about debt. For one, Enbridge got itself into balance-sheet trouble not so long ago, resulting in a debt downgrade by Moody's in 2017. After purchasing Houston-based Spectra Energy Corp. in 2016 for $37-billion, Enbridge's total debt burden had swelled to more than six times its EBITDA. (Enbridge's current CEO, Mr. Ebel, used to run Spectra.)

To win back investors and restore confidence from rating agencies, Enbridge ultimately sold $5.7-billion worth of assets in 2018, and another $2.1-billion in 2019.

More recently, some rival pipeline companies and utilities have faced the wrath of investors who are worried about debt loads. In July, Canadian rival TC Energy sold 40 per cent of Columbia Pipeline Group, a major division that focuses on natural gas transmission in the U.S. Northeast, to a private equity firm at a much lower multiple than what TC paid to buy it in 2016.

And in a somewhat ironic twist, the reason Enbridge was able to buy the new batch of U.S. assets is because the seller, Dominion Energy, is facing its own debt troubles and had to sell assets. Dominion has been struggling because of a costly offshore wind production project and regulatory changes in Virginia, where it makes the bulk of its money, that will affect the rates it charges. Dominion's shares are down 44 per cent over the past year.

While Enbridge's balance-sheet composition is not triggering a ratings downgrade, equity investors are particularly focused on debt loads now that interest costs on new borrowings and refinancings are much more expensive.

Historically, Enbridge could override some of these concerns by enticing retail investors with a large dividend yield. That isn't always enough any more, and before the acquisition was announced, Enbridge's shares were down 9 per cent this year despite yielding more than 7 per cent.

Asked about the trade-off between debt and diversification Wednesday, Mr. Ebel said the opportunity to buy the assets was simply too good to pass up. When he took the reins of Enbridge on Jan. 1, he never even considered that such a deal would be available.

A package of gas assets of this nature hadn't come to market for more than a decade, he said, and Enbridge is "one of the few players that can make a move of this size and magnitude in one fell swoop." He also repeatedly stressed that the deal will strengthen and stabilize the company's balance sheet over the long-term.

In terms of how Enbridge will now market itself to investors – as a pipeline operator with utilities? Or a utility operator with pipelines? – Mr. Ebel said he doesn't think it has to be one or the other.

"I would say you should look at us as an energy infrastructure player that actually has a balanced approach to transporting, delivering for customers and industry on all of the above energy opportunities," he said.

Top financials at a glance