September 19, 2023

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street
P.O. Box 2319
Toronto, Ontario
M4P 1E4

Dear Ms Marconi:

EB-2022-0200 – Enbridge Gas Inc. – 2024-2028 – Rates - Final Argument of the Consumers Council of Canada

Please find, attached, the Final Submissions of the Consumers Council of Canada pursuant to the above-referenced proceeding.

Please feel free to contact me if you have questions.

Yours truly,

Julie E. Girvan

Julie E. Girvan

CC: All parties

FINAL ARGUMENT OF THE CONSUMERS COUNCIL OF CANADA

RE: EB-2022-0200

ENBRIDGE GAS INC. – RATES 2024-2028

1. INTRODUCTON

On October 31, 2022, Enbridge Gas Inc. (EGI) filed an Application with the Ontario Energy Board (OEB) for rates for the period 2024-2028. The Application seeks approval to set rates for 2024 using a cost of service approach and an incentive ratemaking mechanism (IRM) for the years 2025-2028. EGI is seeking to increase rates to recover a gross 2024 test year deficiency of $186.3 million[1].

EGI requested that the OEB consider hearing the Application in phases. The OEB in its Procedural Order No. 1 determined that it is appropriate to hear the application in phases recognizing that the ability to set rates for 2024 on an interim or final basis will not require every issue raised by the Application to be decided by January 2024[2].

An Issues Conference was held on January 9, 2023 to discuss a draft issues list and produce a proposed issues list for the OEB's consideration. Some issues were disputed and a provision was made for parties to make submissions on the disputed issues. On January 27, 2023, the OEB approved an Issues List for the proceeding and the extent to which the issues would be considered in Phase 1 or Phase 2 of the proceeding.

A Technical Conference was held from March 22, 2023 to March 31, 2023.

A Settlement Conference was held from May 29, 2023 to June 9, 2023. The parties reached a Partial Settlement which was filed with the OEB 0n June 28, 2023. On June 16, 2023, EGI filed Capital Update Evidence which among other things provided a revised capital budget for 2023 and 2024. The oral proceeding was held over 18 days between July 13, 2023 and August 11 2023. On August 18, 2023 EGI filed its Argument-in-Chief.

These are the submissions of the Consumers Council of Canada (Council) regarding EGI's Application. The Council does intend to comment on all unsettled issues, as we are relying on the submissions of other intervenors who have taken the lead on those issues.

2. BACKGROUND AND CONTEXT

[1] Argument-in-Chief, p. 11

[2] Procedural Order no. 1, dated December 16, 2022, p. 5

This is the first cost of service “rebasing” proceeding for Enbridge Gas Inc. since the merger of Union Gas Limited (Union) and Enbridge Gas Distribution Inc. (EGD) which was effective January 1, 2019. Union last rebased its rates in 2013 and EGD in 2014. It has effectively been 10 years since the OEB has had an opportunity to comprehensively assess the underlying cost structures, policies, methodologies and programs for the now combined utility that serves 3.8 million residential, commercial and industrial customers in Ontario.

Although the Partial Settlement Agreement was successful in resolving a number of important issues there remain many issues that will significantly impact the rates that are ultimately set by this OEB panel. In addition, as determined by the OEB, important issues will be further addressed in Phase 2 of this proceeding. Furthermore, another Phase will deal with cost allocation and rate design issues for the period beyond 2024, including various potential scenarios involving rate harmonization across the franchise area.

The Council acknowledges that the energy landscape has changed since the legacy utilities last rebased. It has also changed since the OEB approved the merger of the legacy utilities with the establishment of EGI. “Energy Transition”, “Electrification”, “Net Zero”, and “Decarbonization” are at the forefront of any discussions regarding energy policy and energy regulation across the globe. These issues provide context for the OEB’s consideration of EGI’s Application. Energy Transition has been considered throughout the proceeding. The Council will set out its perspectives regarding energy transition in Section 3 below. However, it is important to provide the energy transition developments that have occurred over the last few years in Ontario that are in our view are relevant to the OEB’s consideration of EGI’s Application.

The Government of Canada has committed to reducing GHG emissions by 40% below 2005 levels by 2030 and to net zero emissions by 2050. The Government of Ontario has committed to reducing GHG emissions to 30% below 2005 levels by 2030.[3]

The federal carbon charge has been included on customer bills since August 2019 and will continue to increase annually. This is partially offset by climate action incentive payments.

The Government of Ontario established in November 2022 the Electrification and Energy Transition Panel (EETP) to help Ontario’s economy prepare for electrification and the energy transition. The panel was struck to advise government on high-value, medium and long-term opportunities in the energy sector. This includes opportunities to:

- Help enable investment and job creation in Ontario by keeping energy rates low;
- Create a more predictable and competitive investment environment;
- Build on the government’s work to meet energy needs and ensure a reliable, affordable and clean electricity supply; and

[3] Ex. 1/T2/S1/p. 13

- Strengthen Ontario's long-term energy planning process by better coordinating the fuels and the electricity sectors.[4]

To support the work the Ministry of Energy also commissioned an independent Cost-Effective Energy Pathways Study to better understand how Ontario's energy sector can best support electrification and the energy transition.

On December 15, 2022, the Independent Electricity System Operator (IESO) released its Pathways to Decarbonization Report. The report explores the Minister of Energy's request to evaluate a moratorium on new natural gas generating stations in Ontario and to develop an achievable pathway to decarbonization in the electricity system.[5]

On April 11, 2023, the OEB released its "OEB Energy Transition Roadmap". That document sets out a Schedule of initiatives that map out the work of the OEB within the broader context of its 2023-2026 Business Plan. Among "Potential Future Initiatives" included in the roadmap are:

- Framework for Integrated Natural Gas and Electricity Planning
- Align Cost-effectiveness Test for IRP and Gas Expansion
- Natural Gas Stranded Assets and Risk Review[6]

On June 30, 2023, the OEB submitted its Report of the Ontario Energy Board to Ontario's Electrification Panel. The OEB provided advice to the EETP regarding its role as the economic regulator for the electricity and natural gas sectors. With respect to natural gas the OEB set out the following:

- Energy Regulators are being asked to address a broader range of outcomes beyond price reliability and quality of service. Although the statutory objectives as set in the OEB Act are broad, updates could be made to include a specific reference to reducing GHG emissions or to net zero to provide greater clarity and predictability for the sector;

- Compared to the OEB's broad authority in relation to electricity the OEB has more limited authority in relation to natural gas. Given the impact of the energy transition there may be merit in broadening the OEB's powers with respect to natural gas to align its authorities more closely to those the OEB has for electricity, which could ensure the OEB has a broader basis on which to protect natural gas customers during the energy transition;

- Just as the electricity sector is evolving, the natural gas sector is also experiencing change as a result of the energy transition, and some natural gas utilities are considering the role their resources and infrastructure can play in a net zero future.

[4]

[5] Pathways to Decarbonization Report, IESO, December 15, 2022, p. 2

[6] OEB.ca, Energy Transition

The OEB and natural gas distributors will need to remain open to different business trajectories amid energy sector uncertainty, while ensuring investments are prudent and meet the needs of customers;

- The OEB is exploring what more we can do to support the work of natural gas and electricity utilities in their efforts to inform their customers about the energy transition;

- Coordination and planning alignment between the natural gas and electricity sectors is critical given the multitude of change and infrastructure development that will be required to support the energy transition. The purpose of a coordinated energy planning framework is to support a cost-effective energy transition that ensures that investments in energy resources align with long-term goals and deliver sustainable and affordable energy. Any new planning framework must give careful consideration of the roles of all energy sector participants, in particular the Ministry of Energy, the IESO, the OEB, natural gas and electricity utilities. While getting to an end state may take time and iteration, there are steps that can be taken now to advance Ontario towards this goal.[7]

The OEB also highlighted in its Report that any changes to the OEB's objectives should not detract from the OEB's role as an economic regulator or minimize the OEB's existing mandate to protect the interests of consumers with respect to prices, reliability and service quality. These changes would, from the OEB's perspective, provide an additional lens through which the OEB would consider the merits of emissions reducing investments with an eye to their cost effectiveness and potential impacts on reliability, resilience and affordability[8].

On July 30, 2023, the Government of Ontario released its Powering Ontario's Growth report In that report the government stated that, "natural gas will continue to play a critical role in providing Ontarians with a reliable and cost-effective fuel supply for space heating, industrial growth and economic prosperity. With developments in energy efficiency and low carbon fuels such as RNG and low-carbon hydrogen, the natural gas distribution system will help contribute to the province's transition from higher carbon fuels in a cost-effective way."[9]

Energy transition is clearly at the forefront of work being undertaken by the Federal Government, the Ontario Government, the IESO, the OEB and others. A common theme highlighted by the OEB itself is the need for coordination and planning alignment between the natural gas and electricity sectors. The EETP Report to the Government is expected in late 2023. It remains unclear how long it will take the Government of Ontario to respond. Given the submissions made by the OEB and others, legislative changes may be required in many areas, but specifically with respect the OEB's objectives and its powers over the natural gas sector.

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[7] Report of the Ontario Energy Board to Ontario's Electrification and Energy Transition Panel, June 30, 2023, pp. 2-4

[8] Ibid, p. 15

[9] Powering Ontario's Growth, July 10, 2023, p. 30

This OEB panel must determine whether EGI has appropriately responded to the fact that energy transition is coming and the extent to which energy transition should impact its rates for 2024 and beyond. In addition, the OEB will need to be clear as to its expectations as to how EGI should respond in the future, once Ontario policies regarding energy transition are known.

3. ENBRIDGE AND ENERGY TRANSITION

EGI acknowledges that the nature and pace of how energy transition will unfold in Ontario is unclear, but also acknowledges that energy transition is underway as the energy landscape has shifted since its rates were last rebased[10]. In its Argument-in-Chief (AIC), EGI set out why it believes that it has been "prudent and thoughtful in developing its Energy Transition Plan (ETP) in a moderate and measured manner, considering evolving government policies and varied interest and perspectives of many different stakeholders."

In developing its ETP, EGI undertook the following initiatives:

- Energy Transition Scenario Analysis (Posterity Group)
- Pathways to Net Zero Emissions for Ontario (P2NZ) (Guidehouse)

The Posterity Group study was undertaken to help EGI understand the impact of energy transition and associated climate policies on natural gas demand and EGI's system over the next 20 years.[11]

EGI engaged Guidehouse to undertake the following:

To evaluate two different scenarios that achieve net zero emissions for Ontario by 2050, and to chart GHG reduction pathways in terms of overall feasibility, energy system capacity, system reliability and resiliency, GHG emissions reductions and cost. The objective of the analysis was not to determine the best or most likely pathway to net zero for the entire energy system. Rather, this analysis was meant to examine how Ontario's energy systems can support the achievement of net zero emissions in Ontario by 2050, including identifying what investments in electricity, hydrogen and methane supply capacity, storage, infrastructure would be required. This report does not contemplate how future technology innovations could change the identified investment requirements.[12]

Essentially the comparison was between a "diversified scenario" that includes a targeted approach to electrification tied to the deployment of low or zero carbon gases, including renewable natural gas (RNG), hydrogen and natural gas with capture and an "electrification

[10] AIC, pp. 12-13
[11] Tr. Vol. 1, p. 81
[12] Ex. 1/T10/S5/p. 1

scenario" which focusses on electrification of all sectors with low and zero carbon gas use limited to cases where no reasonable alternative energy source exists.[13]

Guidehouse concluded that the diversified approach is the most cost effective and resilient method to achieve net zero emissions in Ontario. In the original evidence the cost savings differential between the two scenarios was $181 billion over the period 2020-2050, but after Guidelhouse updated its analysis the differential was reduced to $41 billion.[14]

At the hearing Ms. Rozell from Guidehouse summarized her view on what pathway studies are intended to do:

> Pathway studies are intended to compare future potential scenarios, but not predict a specific future. Many variables across the scenarios are varied to model distinct and different potential futures. The scenario definitions of this analysis represent two different perspectives of what the future state of the energy system could look like and are not predictive or exhaustive of all possible scenarios.[15]

EGI essentially agreed with Ms Rozell stating that, "the P2NZ Study is important in the context of the case as information about the potential impact of various plausible and relevant scenarios. However, the P2NZ Study is not meant to be a prediction of the future, a probability or a likelihood of ether scenario occurring was not assigned or ever intended to be implied."[16]

The Guidehouse P2NZ analysis was the subject of considerable scrutiny in this proceeding though interrogatory process, at the Technical Conference and again at the hearing. The criticism was comprehensive. Energy Futures Group (EFG), in its evidence, provided a detailed critique which even after Guidehouse made a number of corrections, concluded that "a number of significant problems remain, many if not all of which are likely to bias results against electrification and in favor of gaseous fuels. Thus, the study remains fundamentally flawed and its conclusions remain highly misleading."[17] The EFG evidence set out a comprehensive list of areas where they disagreed with the underlying assumptions included in the P2NZ analysis. According to EFG, "there are numerous instances in which optimistic leaps of faith are made about equipment and systems necessary to make continued use of gaseous fuels look economically viable while much more conservative assumptions are made about electric alternatives."[18] EFG also took issue with the fact that the scenarios analyzed by Guidehouse were developed by or with EGI.

The Council is aware that other intervenors will be providing further critiques of the Guidehouse P2NZ analysis and that they accept the conclusions advanced by EFG that major

[13] Ex. 1/T10/S5/pp. 1-2
[14] Ex. KT 9.2, Figure ES-2
[15] Tr. Vol 1, p. 71
[16] AIC, p. 16
[17] Ex. M9, p. 26
[18] Ex. M9, p. 39

declines in peak and annual gas demand are likely in the future as efforts to decarbonize the Ontario economy accelerate.

The Council accepts that the move toward further electrification and decarbonization is coming. However, the pace of change is completely uncertain at this point. The outcome of the Guidehouse analysis is interesting as are the critiques. However, as both Guidehouse and EGI have agreed it does not represent a prediction of the future, they are not predictive or exhaustive of all possible scenarios.

The path and pace that Ontario will take toward net zero will depend upon a number of factors. Government policies, both provincial and federal will provide guidance, and understanding the implications of that guidance will be important. The Council is hopeful that the EEFT Report later this year will be instrumental in assisting the Government of Ontario in determining how to facilitate energy transition, but it will not be determinative. Market forces, choices by consumers, potential changes in legislation and the ability of the electricity system to accommodate further electrification will all come into play. Work by the Government of Ontario, the IESO and the OEB will hopefully be undertaken (as they have both advocated) to assess a whole range of issues that cut across both the natural gas and electricity sectors. As noted by the OEB itself in its submissions to the EEFT, "Coordination and planning alignment between the natural gas and electricity sectors is critical given the multitude of change and infrastructure development that will be required to support the energy transition." The pace of further electrification is uncertain and the capacity of the electricity sector to respond has not been comprehensively analysed.

So, we know that energy transition is coming. We are yet unclear as to pace and the form of transition in terms of the level of diversification. EGI has a view, as do others. EGI sees a continuing role for the gas distribution system which minimizes the risks of assets that are not used and useful.[19] Others do not see a continued role for the natural gas system and are justifiably concerned with putting assets in the ground today that will not be used and useful in the future.

What are the implications of all of this for the current application before the OEB? As set out above, this OEB panel must determine whether EGI has appropriately responded to the fact that energy transition is coming and assess the extent to which energy transition should impact its rates for 2024 and beyond. In addition, the OEB will need to be clear as to its expectations as to how EGI should respond in the future, once Ontario policies regarding energy transition are known.

EGI has taken the position that it has proactively taken critical first steps to study, consider and integrate energy transition in the company's business and into this application. That work from EGI's perspective was an important first step in what will be an ongoing and evolving process and one that will carefully consider changing market trends, stakeholder input, government

[19] AIC, p. 8

plans and changing policies that could come as a result of the EETF report and the pathway study commissioned by the Government of Ontario.[20]

In the pre-filed evidence and throughout the proceeding EGI referred to its "safe bets." EGI defines a safe bet as an action that can and should be taken now, as it is required regardless of whether or not a diversified or electrification pathway unfolds in Ontario.[21] The safe bets that EGI identified are:

a) Maximizing energy efficiency
b) Increasing the amount of energy in the gas supply
c) Reducing GHG emissions from the industrial and transportation sector
d) Integrating gas and electric system planning; and
e) Supporting consumer choice and the energy transition journey[22]

It is EGI's view that its energy transition plan (ETP) which is based on its safe bets and objectives and the associated rebasing application proposals are prudent as they support continued progress towards a net-zero future despite current policy uncertainty, but do not overinvest in a particular pathway prior to the Ontario government defining its energy transition plans.

Despite the fact that the Government of Ontario has not established a clear policy direction with respect to energy transition the Council believes it was incumbent for EGI to establish a more robust ETP. The safe bets are either things that EGI is currently doing or is required to do arising from previous OEB Decisions like demand Side Management (DSM), Integrated Resource Planning (IRP), the Natural Gas Vehicle (NGV) program etc. With respect to several of EGI's safe bets it simply has no proposal at this time to undertake them like optimizing energy system planning (gas and electric), the low carbon energy project, industrial fuel switching, RNG upgrading etc. EGI has admitted that it has made very few adjustments to its application to reflect energy transition. Ms Wade on behalf of EGI, at the Technical Conference confirmed this, "I think we note in the evidence that, yes, we have assumed energy transition assumptions and we don't expect to have large material impacts in the rebasing period."[23]

Although EGI has made few adjustments to reflect energy transition in its rate plan budgets and forecasts, the entire deficiency and corresponding rate increases are driven by its proposals to increase its equity thickness and introduce a new depreciation methodology. In effect, in the near-term, energy transition is not impacting its business, yet at the same time there is an immediate need to increase both its equity level and its depreciation expense – driven, in large part, by energy transition. This is patently unfair to its ratepayers.

[20] Tr. Vol. 1, p. 80
[21] Tr. Vol 1, p. 87
[22] Ex. 1/T10/S6/p. 14
[23] TC Tr. Vol. 2, p. 75

Given the state of the energy landscape today and the government initiatives underway, the Council does not believe that the OEB should approve rates for EGI for the full rate plan term 2024-2028. The Council recognizes that the rate plan term is an issue for Phase two of this proceeding, but believes it is important to set out, at this time, why the full five-year term is not appropriate. Five-year rate plans are most appropriate in a relatively steady state environment. The Council is of the view that it will take some time for energy policy in Ontario to be more defined. As noted above, many initiatives are being undertaken that could potentially impact EGI and its rates in the future.

The Council submits that EGI should be required to file a rate application in early 2026 for rates effective January 1, 2027. At that time there will be more policy certainty in Ontario. In addition, it will allow EGI to prepare a number of critical studies that will look at future scenarios, related risks and potential regulatory tools to mitigate those risks. If the OEB approves a 5-year rate plan there is a greater risk that EGI will put assets in the ground that may ultimately become stranded.

The Council does not believe that the OEB should, in setting rates for 2024 and the two years following take drastic measures because of energy transition. Moving to an accelerated depreciation approach today, for example, will have a short-term negative impact on rates. Adjusting depreciation solely to react to energy transition would not, in our view be prudent. In addition, the Council does not see the need, at this time, to increase EGI's equity thickness, solely on the basis that energy transition is emerging. EGI has made very few adjustments to the 2024 revenue requirement to reflect energy transition and has conceded that the risks of stranded assets are not a factor in the near term.

EFG has provided a detailed critique of the Guidehouse work. In addition, they have recommended that EGI do the following work:

- Immediately assess and report back to the OEB by 2024 on the near-term and longer-term rates, cost of capital, affordability and inter-generational equity impacts of alternative depreciation approaches. This should include among other things a Units of Production approach, which could account for declining annual sales, and thus promote better intergenerational equity and help to ensure affordability as demand declines.

Dr. Hopkins from Synapse produced evidence to analyze the business risk facing EGI as presented by EGI and Concentric. He concluded that EGI has not shown that its business risk is higher than it was in 2012. He also recommended that the OEB require EGI to conduct a detailed business analysis along the lines of illustrative examples provided in detail in his evidence following the conclusions of the EETF to inform its capital and operational plans. Furthermore, EGI should be required to bring that analysis and associated plans to bear in developing its next rebasing application.[24]

[24] Ex. M8, pp. 4,6

Dr. Hopkins, in his testimony describes what types of analysis EGI should be required to do once the Ontario Government provides further policy direction:

> The first essential step is for the utility to develop a business plan for managing the firm in the changing public policy and competitive context in which it operates. The 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[25].

He also recommended additional mitigating actions:

- Detailed and careful examination of any choice to invest in new gas system infrastructure including the useful life of that infrastructure and the options for economic non-pipeline alternatives;

- 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;

- Developing partnerships with electric utilities to cost-effectively meet winter peaking needs through the gas system subject to regulatory approval and provincial plans;

- Evaluation of low-carbon fuels such as green hydrogen or biomethane.

Dr. Hopkins acknowledged that the Posterity and Guidehouse studies could provide the foundation on which to build a risk analysis that would evaluate scenarios for the likelihood and consequence of capital risk events. However, he recommended that the Ontario pathways study now underway should be the foundation for EGI's decision-making or modelling. He added that EGI's preliminary work on renewable natural gas and hydrogen could provide some important information to reduce uncertainty.[26]

Upon a request from Commissioner Elsayed Dr. Hopkins agree to provide further evidence in an undertaking regarding lessons learned from other jurisdictions with respect to energy transition. The undertaking provides details regarding his recommendations in the following areas which should assist the OEB in directing EGI to undertake further study regarding energy transition:

- Substantively engage stakeholders;

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[25] Ex. M8, p.53

[26] Ex. M8, pp. 53-55

- Avoid competing models;
- Incorporate customer perspectives;
- Integrate regulatory and pathway analyses;
- Integrate electric and gas analyses;
- Seek policy clarity; and
- Recognize that time constraints drive the need to act in the face of uncertainty[27].

The Council submits that EGI should be required to undertake the analysis proposed by EFG and Dr. Hopkins. This work can be started now. When the Government of Ontario policy objectives regarding energy transition are clearer, the ability to complete that analysis will be enhanced. As noted above, EGI should then file a new application in early 2026 for rates effective January 1, 2027.

4. RATE BASE (Issues 6, 7, 8)

The Settlement Proposal dealt with a number of issues related to rate base. As set out in the Settlement Proposal the following issues were agreed to by all parties:

- Parties agree to accept the methodology presented by EGI for the determination of working capital and rate base. Final 2024 amounts will be subject to the determination of the other unresolved issues;

- 2024 opening rate base is agreed to subject to the following: (i) the inclusion of EGI's integration capital from the deferred rebasing term in opening rate base for 2024; and (ii) the additions to 2024 opening rate base resulting from 2023 changes;

- Parties accept EGI's rate base up to and including 2022 subject to (i) agreement to remove the forecast residual net book values of the overspend on the WAMS project and 25% of the overspend on the Enbridge Gas Distribution Inc. GTA Reinforcement Project from opening rate base for 2024 and; (ii) the appropriateness of including any integration capital costs in rate base. The impact of these adjustments to 2024 rate base is $41 million;

- Parties also agree that EGI will not include any amounts in the 2024 opening rate base for the Dawn to Corunna project which has been approved by the OEB. The determination of the allowed recovery for, and method for recovery of the Dawn to Corunna costs will be made in Phase 2 of the proceeding. Parties agree that the impacts of the OEB's decision on the rate base treatment of the Dawn to Corunna project will be recoverable from ratepayers as if it were included in 2024 rate base when final rates are set following Phase 2 of the proceeding;

[27] Ex J5.2

- Parties agree that the acceptance of the overhead capitalized amounts in Incremental Capital Module (ICM) projects being included in 2024 opening rate base is without prejudice to the rights of parties to argue in the future, including in Phase 2 of this proceeding when the proposed IRM plan is reviewed and in any future Leave to Construct (LTC) proceedings, that overhead capitalized amounts should not be included, in whole or in part, in ICM amounts. Parties are free to refer to and rely on any information and evidence on previous ICM projects, notwithstanding their acceptance of those amounts in opening rate base.[28]

The Council will address the following issues related to rate base that remain unsettled;

A. Customer Attachment Policy
B. Overhead Capitalization (Issue 8)
C. 2024 Capital (including Integration Capital)

A. Customer Attachment Policy

Energy transition has been a constant theme throughout the proceeding. In its Procedural Order No. 6 dated June 23, 2023, the OEB identified matters of particular interest to it in the context of energy transition. This included the following:

- Whether EGI's application of the revenue horizon parameter established in E.B.O. 188 continues to be appropriate in light of energy transition.[29]

EGI, in its AIC, points out that the while there is no specific issue directed to the customer attachment policy, the topic does have implications for energy transition, rate base and the 2024 capital budget. EGI is seeking approval of its harmonized customer attachment policies effective January 1, 2024. In addition, EGI has requested approval of its proposed extra length charge (ELC) which is one of the Miscellaneous Service Charges included in the Application.

In January 1998 the OEB established guidelines for assessing customer connections and system expansion projects through its E.B.O 188 Decision. As described by Mr. Macpherson at the hearing:

> The OEB guidelines are designed to streamline the approval process for system expansion projects and achieve a commonality of approach between utilities, while ensuring that ratepayers are protected against financially inappropriate system expansion. Through the prescribed portfolio approach, using an investment portfolio approach, and rolling project portfolio, the OEB developed the guidelines to balance several competing interests of existing and new customers of all types, to achieve the

[28] Partial Settlement Proposal, pp. 24-25
[29] Procedural Order No. 6, dated June 23, 2023

> public interest of providing natural gas distribution services in a financially responsible manner[30].

The E.B.O. 188 guidelines have been codified in the Gas Distribution Access Rule (GDAR) as set out in Section 2.2.2. which states, "A rate regulated gas distributor shall assess and report on system expansion in accordance with E.B.O. 188"[31].

The OEB in its Generic Proceeding on Community Expansion reaffirmed the use of E.B.O. 188 while making provisions for "stand-alone" rates for new communities:

> The OEB considers it appropriate to allow proponents to apply for rates that are geared toward the costs of the individual projects, or groups of projects where they have similar cost drivers. There is no need to modify the parameters or depart from the principles embodied in E.B.O 188 to facilitate expansion parameters[32].

The Council was largely supportive of the OEB's findings in the Generic Community Expansion proceeding as it established a way for new gas customers to fund their expansions through the stand-alone rates (SES and TCS).

According to the parameters set out in E.B.O. 188, customer attachments and system expansion are subject to a feasibility analysis. Project revenues and costs are discounted using the company's after-tax weighted average cost of capital. A profitability index (PI) is determined which measures the value of the project's revenues over the life of the project. If the PI is less than 1 EGI's customers are required to pay either a contribution in aid of construction (CIAC) or as approved in the Generic Proceeding, a volumetric surcharge or temporary connection surcharge.

The current revenue horizon is 40 years and EGI applies this consistently for all residential customers "because this is what E.B.O 188 requires". From EGI's perspective there is no discretion allowed or prescribed. [33] The Council submits that within the context of E.B.O. 188 the 40-year revenue horizon and the customer attachment horizon of 10 years are set as maximum amounts, giving the natural gas utilities flexibility in their application. EGI is not required to use a 40-year revenue horizon.

EGI's implies that because E.B.O. 188 was the result of a lengthy and comprehensive proceeding, which involved a great deal of evidence commencing with a Report of the Board, third party expert evidence, a common submission by all gas utilities and an ADR process, it should not be changed as it presupposes future government policy and could result in wide ranging impacts including much higher connection costs for customers. EGI has submitted that

[30] Tr. Vol. 10, p. 78
[31] Ex. K10.2, p. 138
[32] Ex. K10.2
[33] Tr. Vol 10, p. 80

if the OEB is inclined to change the revenue horizon it should do so through a measured approach.[34]

EGI has proposed that if a change is required, a 30-year revenue horizon is appropriate as it is based on the assumption that about half of the newly attached customers will maintain gas appliances at the time their furnace reaches end of life[35]. The Council does not believe this assumption has been substantiated with any detailed analysis.

EGI provided a schedule setting out the customer connections capital and the (CIAC) required under a full range of revenue horizons. The 40-year revenue horizon (as proposed) will result in $1.3 billion in customer connections capital during the 5-year rate term. Moving to 20 years will bring that number down to $.972 billion. Moving to 10 years will bring that number down to $.460 billion. The CIAC required assuming a 20-year revenue horizon is $1,774 and assuming a 10-year horizon it would be $4,428.[36]

EGI submitted that moving to a 25-year revenue horizon (or less) to align with the Distribution System Code (DSC) would make new connections more expensive for customers, increasing the CIAC significantly. In addition, EGI argues that different assets and different asset lives support a different approach.[37]

EGI also set out what it views as amendments to its connection policy if the revenue horizon was to be changed:

a) It would impact the Government of Ontario mandated Community Expansion Program. More funding might be required or that program be subject to different attachment guidelines;

b) The proposed extra length charge may no longer be appropriate;

c) The SES and TCS rates may make continued use of thee rates unlikely;

d) A variance account may be required to cover the uncertainty around the number of customer connections and associated capital costs;

e) The Company's deprecation proposal may have to be changed as it assumes a 40-year revenue horizon; and

[34] AIC, p. 99
[35] AIC, p. 100
[36] Ex. J111.1
[37] AIC, p. 100

f) EGI would require some time to fully implement a change given existing commitment for new customer and required systems changes. Any new changes should be done on a prospective basis.[38]

EGI has also added that the OEB should assess whether there is a full and sufficient record in this proceeding to make changes to E.B.O 188. EGI notes the Decision in the recent Elexicon Energy Inc. proceeding where the OEB concluded that it does not lightly depart from established rules such as those set out in the DSC and must take the current government into account.[39]

The Council is of the view that a change to the E.B.O. 188 revenue horizon may well be justified. Although there is no clear policy direction regarding energy transition, further electrification assumes that at some point more customers will be moving off gas. It has been 25 years since the E.B.O. 188 Decision was issued. The Council submits that now is the time for a comprehensive review of E.B.O. 188. Although the original parameters for the revenue horizon were based on the life of the assets, that approach is likely no longer appropriate in the context of energy transition.

The Council does not believe it is appropriate in this proceeding to make a change to one component of the customer attachment policy. The connection policies are guided by many components including the method of feasibility assessment, the minimum profitability standard, the portfolio approach, the feasibility assessment inputs, the CIAC collection, cost allocation and a refund policy.[40] The Council submits that it is timely to have a wholesale look at the policy and all of the underlying methodologies and inputs used to assess economic feasibility and cost allocation. Going forward, as a part of that review, the OEB may well determine that the revenue horizon should be shortened. Rather than doing it now, it can do so in the context of a comprehensive process that considers all aspects of the attachment policy.

The Council submits that the review of the E.B.O. 188 parameters should be done in conjunction with a review of the connection policies in the DSC. Although the policies should not necessarily be aligned in all respects it may be appropriate to align them to the extent possible in order to ensure fairness to all customers. In addition, once the Government of Ontario policies are more established regarding energy transition the OEB may choose to use these policies as tools to promote further electrification if directed to do so. The energy landscape has clearly changed since 1998. It would be prudent for the OEB to undertake a review of the E.B.O 188 guidelines, GDAR and the DSC. This would be consistent with the statement set out in the OEB's submission to the EETP, "Coordination and planning alignment

[38] AIC p. 101
[39] AIC, p. 106
[40] Ex. 1/T15/S1/p. 1

between the natural gas and electricity sectors is critical given the multitude of change and infrastructure development that will be required to support the energy transition."[41]

The Council urges the OEB to undertake this review as soon as possible. It would allow for a wholesale review of the customer attachment policies, allow for broad participation by all interested stakeholders, with proper notice, and would ensure that the OEB's determination at the end of the day would be based on tested evidence. The Generic Proceeding on Community Expansion was successful in seeking input from a broad group of stakeholders and allowing for evidence, and that evidence to be fully tested. EGI has indicated that if the OEB makes a change arising out of this current proceeding, it would take time to implement and could not be done before January 1, 2025.[42] Under the current legislation applicable to the OEB's powers, rule changes are under the purview of the OEB's Chief Executive Officer (CEO). The Council submits that the most appropriate tool for reviewing the attachment policies would be a generic hearing, much like the Generic Proceeding on Community Expansion. Rule changes could be made by the CEO following the hearing.

The Council submits that the viability and the appropriateness of the Ontario Government's mandated Natural Gas Expansion Plan should also be considered in this proceeding. The treatment of customers within those committed expansion projects will be a matter for consideration by the Board when considering the merits of the overall attachment policy. To what extent should some customers benefit from that program whereas other customers may be asked to subsidize existing customers?

The Council adds that within the context of a generic review the OEB should consider the extent to which changing the revenue horizon and the CIAC required for connections would allow access to natural gas for some, while discriminating against those who cannot afford the higher cost. In addition, the OEB should consider the costs and benefits of treating new and existing customers on a different basis and the extent to which new customers may be required to subsidize existing customers.

If the OEB does not accept that there is a need to review E.B.O. 188, GDAR and the DSC expansion policies, the Council would support a move to 20-year revenue horizon. 20 years is consistent with the projected life of a furnace. In addition, moving to a 20-year revenue horizon would represent a measured approach relative to 10 years or an approach that simply eliminates the revenue horizon, requiring new customers to pay the full CIAC.

B. Overhead Capitalization (Issue 8)

There was no agreement on the proposed overhead capitalization methodology in the Settlement Proposal.

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[41] Report of the Ontario Energy Board to Ontario's Electrification and Energy Transition Panel, June 30, 2023, pp. 2-4

[42] AIC, p. 117

EGI is seeking approval of its Overhead Capitalization methodology (OCM) and the resulting capitalized overhead amounts for the 2024 test year. The harmonized methodology was implemented on January 2020. For 2024 EGI is requesting inclusion of $292 million of overhead capitalized amounts. This represents $15.4 million more as compared to the previous methodologies used by Enbridge Gas and Union.[43] It is EGI's view that if the OEB approves its capital budget there would be no need to change the net OM&A amount of $821 million which was included in the Settlement Agreement. EGI asserts that if, however the full $292 million of proposed overhead capitalized amounts is not approved for inclusion in the approved capital budget, the difference will be added to the net O&M total of $821 million.[44]

EGI retained EY to provide advice and recommendations regarding the review and development of overhead capitalization. They did not undertake an independent review, but rather helped EGI develop its policy.[45]

The Council does not take issue with EGI's proposed overhead capitalization methodology for the purpose of setting rates in 2024. However, we acknowledge there are legitimate concerns with the approach as advanced by SEC in its Final Submissions. The Council does believe there is merit in ordering EGI to undertake a full independent review of its policy to be brought forward in its next rebasing hearing. This should include a review of methodologies used by other utilities. In addition, it should include a review of the appropriateness allocating overheads for Incremental Capital Module (ICM) projects.

C. 2024 Capital (Issues 6, 7)

EGI seeks the following approvals:[46]

- 2024 Test Year capital expenditures and resulting in-service capital additions
- 2024 Rate Base (inclusive of 2023 additions and integration capital)
- Levelized rate treatment for PREP

2024 Test Year Capital Expenditures, In-Service Capital Additions & 2024 Rate Base

EGI seeks approval of 2024 rate base of $16,212.3 million, 2024 Test Year expenditures of 1,470.3 million[47] and in-service additions of $1,313.6 million[48], which includes integration capital and the impacts of the Capital Update filed on June 16, 2023 described below.[49]

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[43] Ex. K15.4, p 19
[44] AAIC, p. 121
[45] E. 2/T4/S2/ Attachment
[46] EGI AIC , paragraph 840
[47] Ex. 2/1/2/p. 5 Table 2
[48] I.2.5-SEC-108
[49] Total capital expenditures excludes PREP amounts of $34.2M in 2022, $22.7M in 2023 and

As part of the Capital Update EGI excluded the capital expenditures and in-service additions[50] related to the Panhandle Regional Expansion Project (PREP) and proposed a levelized approach to cost recovery over the term, which the Council does not support. When PREP is added back to the forecast, EGI forecasts to spend $1,665.2 million in capital in 2024.[51] This reflects an increase in requested capital of $174 million or 12% compared to the original 2024 forecast[52] of $1,491.30 million.

Table 1: Impact of Capital Update

Capital	2023 As Filed Oct '22	2023 Update Jun '23	2024 As Filed Oct '22	2024 Update Jun '23
Capex (J14.5)	1,605.70	1,427.20	1,491.30	1,470.30
Add PREP		22.70		194.90
Total	1,605.70	1,449.90	1,491.30	1,665.20
In-Service Additions				
ISA (I.2.6-SEC-108)	1,611.50	1,369.10	1,456.50	1,313.60
Add PREP				252.00
Add CWIP (J11.7)		59.00		
Total	1,611.50	1,428.10	1,456.50	1,565.60

Overview of Capital Expenditures

In 2013, the last time the two predecessor utilities (Enbridge and Union) rebased, the OEB approved total combined capital expenditures of $797.6 million and a total utility rate base of 7,896.5 million.[53] In 10 years, EGI's capital budget has increased by 84%.[54] Rate base has increased by 105%,[55] or more than doubled over the same period.

For the 5-year period 2018 to 2022, EGI spent $5,775 million in capital (Table 2) with an average spend of $1,155 million including PREP. Over the forecast 5-year period, 2024 to 2028, EGI forecasts to spend $7,374 million in capital including PREP (Table 3), an increase of 28% over the recent 5-year period of actuals.

$194.9M in 2024
[50] Total In-service additions excludes PREP: $252M in 2024 and $6.8M in 2025
[51] Corresponding in-service additions of $1,565.6 million
[52] October 2022 Capital Plan
[53] Ex. 2/1/1/p. 4 Table 1
[54] (1470.3-797.6)/797.6 = 84.3%
[55] (16212.3-7896.5)/7896.5 = 105%

Table 2: Utility Capital Expenditures by Asset Class 2018 to 2022 (No Overheads in Asset Classes)[56]

No.	Particulars ($ millions)	2013 OEB	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Estimate	2024 Test Year	Total 2018-2022	Average 2018-2022
1	Compression Stations		10.6	18.3	26.5	34.4	53.4	22.6	23.7	143.2	28.6
2	Compression Stations - LTC						31.8	226.0	12.7	31.8	6.4
3	Customer Connections		151.1	190.4	178.7	211.7	237.1	221.1	238.7	969.0	193.8
4	Distribution Pipe		139.6	149.5	147.9	251.1	292.9	157.5	212.4	981.0	196.2
5	Distribution Pipe - LTC		0.2	25.6	44.9	112.9	89.6	26.2	68.3	273.2	54.6
6	Distribution Stations		38.1	39.7	61.4	74.2	77.6	52.1	65.7	291.0	58.2
7	Fleet & Equipment		15.3	26.3	20.2	21.7	24.4	6.9	24.8	107.9	21.6
8	Growth - Distribution System Reinforcement		25.9	31.3	19.3	34.8	55.5	38.1	44.5	166.8	33.4
9	Growth - Distribution System Reinforcement - LTC		10.5	108.6	50.8	4.8	0.4	4.6	22.3	175.1	35.0
10	Real Estate & Workplace Services		21.2	42.0	38.3	57.2	51.3	48.6	49.3	210.0	42.0
11	Technology Information Services (TIS)		56.6	48.9	22.7	18.5	22.4	36.4	80.2	169.1	33.8
12	Transmission Pipe and Underground Storage		17.9	20.0	32.5	38.7	48.3	31.0	48.2	157.4	31.5
13	Transmission Pipe and Underground Storage - LTC		0.6	0.3	0.9	26.0	2.3	30.3	6.2	30.1	6.0
14	Utilization		75.2	99.3	62.9	65.6	78.8	124.3	119.8	381.8	76.4
15	Extended Alliance Fixed Overhead		15.8	17.8	19.5	25.4	27.0	25.6	39.8	105.5	21.1
16	Capitalized Overheads		207.0	215.2	220.9	235.0	271.8	305.9	277.5	1149.9	230.0
17	Integration Capital			21.7	39.8	71.1	22.8	15.4		155.4	31.1
18	Community Expansion - LTC		4.1	17.1	20.9	17.4	14.2	20.6	11.2	73.7	14.7
19	GTA - LTC									0.0	
20	WAMS									0.0	
21	CPT - LTC		156.1	11.4						167.5	33.5
22	Other		0.2	3.9	(0.9)	10.5	1.1	34.3	124.6	14.8	3.0
23	Union Unregulated		(13.4)							-13.4	-2.7
24	Sub-Total	797.6	932.60	1,087.40	1,007.20	1,310.80	1,402.90	1,427.20	1,470.30	5,740.90	1,148.18
25	Add PREP (Transmission Pipe & U/G Storage)						**34.20**	**22.70**	**194.90**		
26	TOTAL (w/PREP)		932.60	1,087.40	1,007.20	1,310.80	1,437.10	1,449.90	1,665.20	5,775.10	1,155.02

[56] J14.5 Attachment 1

Table 3: Utility Capital Expenditures by Asset Class 2024 to 2028 (No Overheads in Asset Classes)[57]

No.	Particulars ($ millions)	2024 Test Year	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	Total 2024-2028 Forecast
1	Compression Stations	23.7	29.8	37.5	95.7	13.9	200.6
2	Compression Stations - LTC	12.7	20.9	0.1			33.7
3	Customer Connections	238.7	195.4	192.9	188.9	181.6	997.5
4	Distribution Pipe	212.4	231.8	206.7	186.5	229.8	1067.2
5	Distribution Pipe - LTC	68.3	94.6	5.4			168.3
6	Distribution Stations	65.7	89.1	78.8	59.1	84.5	377.2
7	Fleet & Equipment	24.8	27.9	30.1	34.1	38.0	154.9
8	Growth - Distribution System Reinforcement	44.5	34.9	24.7	34.4	7.5	146.0
9	Growth - Distribution System Reinforcement - LTC	22.3	122.6	7.8			152.7
10	Real Estate & Workplace Services	49.3	48.3	69.1	23.9	40.9	231.5
11	Technology Information Services (TIS)	80.2	61.4	53.4	33.4	39.3	267.7
12	Transmission Pipe and Underground Storage	48.2	54.4	47.6	63.1	123.4	336.7
13	Transmission Pipe and Underground Storage - LTC	6.2	59.6	103.0	138.0		306.8
14	Utilization	119.8	126.1	129.5	113.2	122.3	610.9
15	Extended Alliance Fixed Overhead	39.8	40.8	41.9	43.0	23.2	188.7
16	Capitalized Overheads	277.5	323.0	329.5	329.6	332.1	1591.7
17	Integration Capital						0.0
18	Community Expansion - LTC	11.2	19.6	20.5	21.5	7.3	80.1
19	GTA - LTC						0.0
20	WAMS						0.0
21	CPT - LTC						0.0
22	Other	124.6	43.9	28.3	28.0	35.7	260.5
23	Union Unregulated						0.0
24	Sub-Total	1,470.30	1,623.80	1,406.70	1,392.30	1,279.50	7,172.6
25	Add PREP (Transmission Pipe & U/G Storage)	**194.90**	**6.70**				
26	TOTAL (w/PREP)	1,665.20	1,630.50	1,406.70	1,392.30	1,279.50	**7,374.2**

[57] J14.5 Attachment 1

Levelized rate treatment for Panhandle Regional Expansion Project (PREP)

PREP is a large project with a cost of $358 million inclusive of overheads. As part of the Capital Update EGI changed the timing of PREP from a forecast in-service date of 2023 to 2024.

Enbridge Gas is proposing a levelized approach to cost recovery for PREP. This approach will exclude in-service additions for the project from 2024 rate base.

Subject to OEB approval of the PREP LTC application, a separate unit rate, based on an average of the five-year net revenue requirement for the project, will instead be calculated and applied for cost recovery during the 2024 Test Year and each year of the incentive rate mechanism term (2025-2028). The forecast average annual net revenue requirement for the project is $7.3 million. Enbridge Gas proposes to establish an associated variance account, the PREP Variance Account (PREPVA), that would capture any variance between the project's actual net revenue requirement and the actual revenues collected through the average unit rate that would be in place over the IR term.[58]

As PREP has yet to receive Leave to Construct approval, Enbridge Gas believes that separate treatment of the project is warranted.[59] The Council does not accept EGI's proposal as many other projects are subject to LTC over the 2024 to 2028 period and EGI has not requested separate treatment for these projects.

The removal of the revenue requirement impacts for PREP in 2024 results in a revenue deficiency of $14.4 million,[60] which benefits customers. The Council has reviewed the draft submissions prepared by SEC and agrees with the following points:

- When PREP was scheduled to go in-service in 2023, and Enbridge would have benefited from the sufficiency, it did not propose a levelized approach;

- Now that the project is going into service in 2024, and there is a negative revenue requirement in the test year[61], EGI proposes a levelized approach;

- The Dawn to Corunna project is of a similar size to PREP and has a negative revenue requirement of $30.6M in its first year, yet EGI is not proposing a levelized approach for this project.[62]

The Council submits EGI is being selective in its rate making approach when it benefits EGI. The PREP project should not receive special treatment as it is not sufficiently unique, and capital

[58] Ex. 2/5/2 p. 30-33
[59] Ex. 2/5/2 p. 30
[60] Ex. 2/5/4 p. 35
[61] first year of the project has a negative revenue requirement as a result of a combination of the half-year rule and the high CCA rates applied for tax purposes
[62] J13.2

costs should be included in 2024 rate base. In addition, the Council supports SEC's proposal that a LTC variance account should be established to capture outcomes if the PREP project or any other projects is denied LTC.

<u>Inclusion of Integration Capital</u>

Enbridge Gas expects to incur $189.0 million in capital expenditures related to integration efforts over the deferred rebasing term.[63] This represents a reduction of approximately $63.2 million relative to Enbridge Gas's original forecast. The primary driver for the change in capital expenditures is the deferral of the GTA East and GTA West facility integration projects.

The total undepreciated integration capital amounts that EGI proposes to include in 2024 rate base is $119 million.[64] The Council submits $119 million should not be included in rate base as doing so would be inconsistent with the MAADs Handbook and the MAADs Decision approving the amalgamation of Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union). The undepreciated balance of capital expenditures related to the merger should not be recovered from customers.

The MAADs Handbook states "Incremental transaction and integration costs are not generally recoverable through rates."[65] As part of the OEB's Decision on the merger, the OEB approved a deferred rebasing period of five years.[66] The OEB found that five years provides a reasonable opportunity for the applicants to recover their transition costs. The OEB further stated its "policy of permitting a deferred rebasing period of up to ten years was adopted to incent the consolidation of electricity distributors". The OEB noted that during the last rate setting frameworks[67], both Union Gas and Enbridge Gas earned more than the OEB-approved return as evidenced by the earnings sharing mechanisms for both utilities. Customers will not benefit from any efficiency gains from this previous period until the end of the rebasing period. [68] Overearnings prior to the merger factored into the OEB's decision to set a five-year deferred rebasing period as a reasonable timeframe.

EGI overearned by $231.1 million above the OEB approved ROE over the 2019-2022 period.[69] 2023 is yet to be determined. This is in addition to the overearnings during the period prior to the merger 2014-2018. The Council submits EGI has achieved sufficient earnings during the rebasing period to cover $119 million in transition costs, as predicted by the OEB in its MAADs Decision.

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[63] Ex. 1-9-1 p. 20
[64] I.1.9-VECC-3
[65] Handbook to Electricity Distributor and Transmitter Consolidations January 19, 2016 p. 8
[66] Decision and Order EB-2017-0306 and EB-2017-0307 p.22
[67] 2014-2018
[68] Decision and Order EB-2017-0306 and EB-2017-0307 p. 22-23
[69] Ex. J14.10

The two GTA East and GTA West facility integration projects (GTA East – New Build – Peterborough ($14.7 M) & GTA West – New Build – Halton Hills ($43.2 M))[70] with previous in-service dates of December 2023[71] were deferred and added to the AMP Appendix A: Investments > $10 million.[72] These projects were previously identified as integration as they align operations across the legacy utility boundaries.[73] The Council submits these projects should continue to be identified as integration projects and should not be recovered in rate base regardless of when they are in-service.

EGI has identified Records Management Technology Obsolescence ($23.6 M) and Contract Market Technology Obsolescence ($69.8 M) in future plans.[74] Had these projects been undertaken during the deferred rebasing term, EGI indicates they might have been identified as "Integration Capital" as they address applications used by both legacy utilities.[75]

EGI further indicates the General Service Rebasing Changes project ($17.9M) is required to implement rate harmonization as a result of the merger.[76] The New London Site project ($49.5M)[77] [78] is similar to the GTA East and GTA West facility integration projects. The Council submits these additional projects should continue to be identified as integration projects and should not be recovered from customers, consistent with the OEB's MAADs policy that incremental transaction and integration costs are not generally recoverable through rates.

Summary of Position on Capital

For the reasons discussed below, the Council submits that EGI's proposed level of forecast capital expenditures in 2023 and 2024 reflect a substantial increase compared to previous years, that are not justified or reasonable, and a capital reduction in 2023 and 2024 is appropriate:

- The Updated Capital plan was derived from an accelerated and rushed budgeting process that did not follow EGI's established asset management process, i.e. EGI did not re-run the project portfolio optimization using Copperleaf[79] as was done in the original capital plan resulting in a sub-optimal plan and 12% higher forecast expenditures in 2024 as a result of the update;

[70] Investment #739714 & Investment #739715
[71] Ex. 1-9-1 Attachment 1
[72] J13.12
[73] J14.13
[74] I.2.6-CCC-71 (i)
[75] J14.13
[76] 14 Tr.
[77] 14 Tr.
[78] I.2.6-CCC-71(g)
[79] Ex. 2/5/1/p. 4

- EGI's capital plan includes a large proportion of projects with negative net value scores which is not prudent and reflects poor project prioritization;

- EGI underspent on its capital plan for the historical years 2019 to 2022 and is forecast to underspend in 2023;

- Productivity savings have not been built into the capital plan;

- There are potential savings that have not been accounted for in the plan.

The Council submits the OEB should approve a level of capital spend in 2023 and 2024 related to base capital that does not exceed the average historical spend for the years 2018 to 2022.

<u>The Updated 2023-2032 Capital Plan was not optimized using Copperleaf</u>

Following the clarification of interrogatory responses at the Technical Conference in March 2023, it became apparent that there were significant changes in EGI's overall capital requirements from the October 2022 Capital Plan and subsequent March update, as a result of project deferrals, emerging needs and inflationary pressures, resulting in the need for a capital update.

As part of the 2024 budget process EGI identified project deferrals in 2022, and deferrals in 2023 into 2024 or beyond, and 2024 investments were deferred or cancelled from the 2023 to 2032 Capital Plan. Certain 2024 investments subject to Leave to Construct (LTC) applications were deferred and/or cancelled.[80] As part of the normal budgeting process plans may change within a spending envelope and priorities may shift from one year to the next but the magnitude of the changes in EGI's capital plan since October is concerning. A capital update was not contemplated in EGI's original capital plan.

EGI filed its Capital Update on June 16, 2023.[81] In 2023 alone, a preliminary list of projects that were deferred or cancelled, reflects 387 projects totaling $277 million.[82] In addition, the PREP project, which was not on the list, was delayed from 2023 to 2024 with an additional capital spending deferral of $208.3 million in 2023.[83] [84]

47 material projects >$10 million included in the AMP Appendix A, valued at $2.13 billion (excluding overheads) were included in the original capital plan. As a result of the capital update, 14 material projects were removed[85] and 13 material projects were added resulting in a

[80] I.2.6-SEC-117
[81] Associated changes to evidence, interrogatory responses and undertaking responses were filed on July 6, 2023.
[82] J5.2
[83] Ex. 2/6/2/p. 203
[84] The years 2028 to 2032 were not updated as part of the Capital Update (J12.2)
[85] Removed; forecast<$10M, replaced with another investment

total of 46 Projects valued at $2.27 billion (excluding overheads).[86] A number of projects requiring mandatory treatment with respect to timing changed within the portfolio. Three material Compliance investments >$10 million, typically treated as fixed costs, were removed in the update.[87] [88] Four of the 17 projects originally prioritized through EGI's Risk Management Process[89], which addresses more complex investments are no longer included in the 2024 budget.[90] This level of extreme change in such a short amount of time shows inherent uncertainty regarding which projects are required to be done in 2023 and 2024.

EGI's budgeting process is underpinned by the Asset Management Plan (AMP).[91] EGI's AIC explains its established Asset Investment Planning and Management (AIPM) Process including how it uses Copperleaf, an asset investment planning tool, to create a multi-year investment plan and optimize the overall portfolio.[92] [93]

EGI followed this process to create the October[94] Capital Plan but in the preparation of the June[95] Capital Update, EGI did not re-run the Copperleaf portfolio optimization component of its budgeting process.[96] EGI explains that they did not rerun the optimization because they were focused solely on getting the 2024 update corrected. EGI's intention is to start the process of updating its asset management plan for the next 10-year envelope, and part of that process (to be completed by October of next year) is to take those investments, and any new investments that are identified, and go back through an optimization cycle. It is not clear which of the original projects will be included in the next optimization cycle.

Copperleaf's portfolio optimization is important because it allows for comparison of dissimilar investments and helps to ensure transparent investment decisions. EGI's decision to not re-run the Copperleaf optimization leaves a significant gap in analysis and undermines the confidence the OEB requires to assess and determine the right capital spend in 2023 and 2024 and beyond. EGI has not followed what it describes as its "rigorous asset management planning and capital budgeting process" given this key step in the process has been omitted. In its Examination-in-chief, EGI stated "While our practice is to follow the corporate budget process, the capital update was completed on an advanced, sorry, on an accelerated timeline compared to what we would typically do, to ensure that we had the information available in time for the hearing."[97]

[86] J13.12
[87] Ex 2.6-SEC-149
[88] mandatory investment–must be addressed within their required time frame
[89] timing is confirmed outside of Copperleaf optimization
[90] I.2.6-CCC-48
[91] Ex. 2/6/2
[92] AIC Paragraph 394-401
[93] By varying the net direct capital per year, highlighting the effects of project timing, option selection and value.
[94] October 2022
[95] June 2023
[96] Tr. Vol. 11, p. 122
[97] Tr. Vol. 11, p. 94

EGI appears to have rushed the 2024 budget process and update, and relied on manual manipulation of excel spreadsheets to do the prioritization and reforecasting for 2023 and 2024.[98]

In 2024, EGI's updated forecast capital spend is $1,665.1 million including PREP, is the highest of any of the five years in the 2024 to 2028 forecast (See Table 2). The AMP talks about the portfolio of projects prior to optimization stating, "Prior to optimizing, an initial portfolio representing the preferred option and timing of investments is captured. This typically results in an inconsistent spend profile over the 10 years, with a much larger proposed spend in earlier years." EGI's unoptimized plan is consistent with this finding: EGI's capital plan reflects higher capital spending in 2024 and 2025, the earlier years, compared to 2026 to 2032.

The impact of optimization can be seen in the outcome of EGI's October 10-year capital planning process that included running Copperleaf. Optimization of the plan resulted in a project portfolio that was 93% of the spend of the pre-optimized portfolio. The pre-optimized value of the 2023 to 2032 plan was $14.3 billion compared to $13.3 billion after optimization, a reduction of $1 billion or 7%. In total, 3,401 investments were included in the optimization of the 10-year October Capital Plan. Of the 3,401 investments 3,087 investments (90.7%) were included in the final optimized capital plan for 2023-2032.[99]

In addition to a significant number of projects deferred or cancelled as part of the update, many projects were added to the project list. Comparing the list of 3,087 projects in 2.5-CCC-50, which details spending in each of the years 2023 to 2032, to the updated interrogatory response, the capital plan now has 3,418 investments.[100] The number of capital investments in 2024 has increased from 660 to 755, an increase of 15%.[101] It is concerning that the prioritization and urgency of so many projects has changed in such a short amount of time.

In response to a request for EGI to comment on EGI's interpretation of its asset management plan EGI states "Enbridge Gas's Asset Management Plan (AMP) describes asset management activities related to core utility assets within the company's regulated operations. The AMP is optimized to ensure effective allocation of the approved capital envelope dollars."[102] By not optimizing the capital update through iterative scenarios to determine an optimal spend profile, the OEB cannot be confident that EGI has put forward an effective allocation of capital envelope dollars for 2023 and 2024.

Copperleaf Value Framework

98 Tr. Vol. 13, p.134
99 I.2.6-CCC-47
100 I.2.6-CCC-47 (d)
101 I.2.6-CCC-47 (f)
102 J12.4

EGI sorts the proposed investments into three investment categories that impact timing: Mandatory, Compliance and Value Driven.[103] Mandatory refers to an investment that is required to address a risk or opportunity.[104] Compliance refers to an investment required to adhere with applicable laws and regulations, industry codes, standards and internal policies. Both Mandatory and Compliance investments must be addressed within their required timeframe. The timing of Value-Driven investments is based on the value it brings to the ratepayer and the organization.

Copperleaf quantifies an investments' value, expressed in thousands of dollars using value measures.[105] Value measures are investment attributes that are evaluated objectively based on risk or opportunity to determine how the investment delivers value to Enbridge and the ratepayer. These value measures are placed on an economic scale to assist in optimization. An investment's net value is used to determine both its independent merit and its standing among other investments in a constrained optimization process.

Investments identified as Mandatory, Compliance, or Value-Driven using the Risk Management process[106] are automatically slotted at the required time rather than using risk and cost to determine optimal timing. Other Value-Driven investments are free to shift within the optimization time frame. Using Copperleaf, the EGI portfolio is optimized and analyzed by varying the net direct capital per year, highlighting the effects of project timing, option selection and value.

In J14.6, EGI provided the list of projects in JT5.13 ranked according to their net value. The project net value scores range from 294,938 to (60,709).[107] A large proportion of the projects in the portfolio have a negative net value including many investments in 2023 and 2024. During the Capital Update, 86 projects, all with net value scores greater than zero were removed and EGI prioritized other projects with scores of zero or less than zero.[108] Many of the projects removed had some of the highest net value scores. This is concerning and suggests when manually determining the 2023 and 2024 forecasts, EGI did not appropriately analyze the value scores.

EGI's own guidelines to help determine the relative value of the investment state "An Investment with a net value less than zero, is an investment in which all the benefits specified for the Investment have a present value less than the present value of the cost. Investments with a net value less than zero should be reconsidered and re-evaluated for other value

[103] Ex. 2/6/2/p.46
[104] Exceeding an established risk upper threshold; Third-party relocation; Program work with sufficient history and risk to warrant continuation; Projects that meet the economic feasibility tests in EBO 188 and EBO 134
[105] Ex. 2/6/2/p.47
[106] Using EGI's Risk Management process, EGI's significant operational risks are reviewed quarterly and revised as required.

[107] K11.2 p.52, 76
[108] J14.6

opportunities. A lower value Investment may be delayed in lieu of other, more urgent Investments, or may ultimately be deemed unnecessary".[109]

The Council's view is that it is not prudent for EGI to prioritize and pursue projects with a negative net value as it has done, especially given these investments are competing for resources that would be better allocated to investments with a net value greater than zero which bring more value to the organization.

The Council submits EGI has not selected the best value driven projects for the 2023 and 2024 capital plan.

Other Considerations

Historical Spending Trends

Even if the OEB approved EGI's capital forecast as is, EGI will be challenged to complete the work if past performance is applied. Over the period 2019 to 2022, EGI's actual capital expenditures were 4% lower than forecast, and for 2023 the variance is 9.7%.[110] EGI consistently accomplishes less capital work than it forecasts.

Table : 2019 to 2022 Forecast vs Actual Capital expenditures[111]

Utility Capital Expenditures ($ M) - Forecast vs. Actuals						
	2019	**2020**	**2021**	**2022**	**Total**	Ref
Forecast	1,085.70	1,081.00	1,428.10	1,444.30	5,039.10	I.2.5-CCC-43 e
Actual	1,084.70	1,007.20	1,310.80	1,437.10	4,839.80	2-5-3 p.14 Table 6 Updated
Variance $					199.3	
Variance %					4.0%	

Customer Engagement

With respect to customer engagement, there were no customer engagements done with respect to the capital update including the proposed treatment of PREP.[112] Accordingly, customers cannot be seen as endorsing the Updated Capital Plan and increased level of spending in 2024.[113]

Lack of Productivity Savings in Capital Plan

[109] JT5.10 Attachment 1, p.14

[110] 2023 Estimated Actual = $1,449.90 vs. $1,605.70 Forecast = 9.69% (See Table 1)

[111] 2022 Actuals includes PREP

[112] Tr. Vol. 13, p.132

[113] $1665.20 including spending on PREP

EGI provided productivity savings of $128.6 million it has achieved since 2019 through to the end of the test year.[114] All the productivity savings are O&M savings.[115] At the Oral Hearing, EGI confirmed they don't do a very good job of quantifying where there may be capital savings, [116] and although known efficiencies at the time of capital budgeting are built into the capital plan,[117] they do not have any embedded incremental productivity levels forecast in the capital forecast.[118]

EGI plans to spend on average $1,465 million[119] over the next five years and should be continuously striving for ways of executing its capital plan better. The Council submits EGI's capital budget should have included an allowance for additional savings that have not yet been identified, similar to its O&M budget, to offset the significant cost increases. The OEB should take into consideration EGI's lack of embedded productivity savings in its capital budget when determining an appropriate level of capital spend for 2023 and 2024.

Potential Savings Through Initiatives

The Distribution Integrity Management Program (DIMP) and Transmission Integrity Management Program (TIMP) identify system integrity and reliability risks with Enbridge Gas's pipeline assets, which are then prioritized based on risk to determine the timing of investments. The outcomes of the DIMP and TIMP assessments determine the need to maintain or replace pipeline assets. EGI has also introduced the Enhanced Distribution Integrity Management Program (Enhanced DIMP) with the goal of providing more detailed pipeline condition assessments. EGI has not included any deferrals or delays as a result of EDIMP in the asset management plan or the 2024 budget, yet there could be some.[120] The OEB should consider the potential for reduced capital needs in 2024 as a result of EDIMP in setting the appropriate level of spending in 2024.

Conclusions

In considering the above factors, the Council submits EGI's capital forecast for 2023 and 2024 is too high and reflects a sub-optimal capital plan with respect to prioritization, optimal project timing and spending levels. The Council submits its above analysis provides the necessary support for the OEB to make the required capital reductions while maintaining safe and reliable gas service during the rate term.

The Council's position is that the forecast of base capital for 2023 and 2024 should not exceed EGI's average historical base capital spend for the years 2018 to 2022 of $940 million (Line 1). The Council proposes reductions to base capital of $39 million and $254 million in 2023 and

[114] I.1.9-SEC-90
[115] I.ADR.23
[116] Tr. Vol. 11, p.178
[117] Tr. Vol.11, p. 181
[118] Tr. Vol 11, p.180
[119] Including PREP ($7,374.2/5 =$1,465 million)
[120] Tr. Vol 12 p.191

2024), respectively, relative to EGI's request (Line 1). This results in total capital expenditures of $1,388.4 million in 2023 and $1,216.28 in 2024 (excluding PREP) (Line 5). The Council's reductions to base capital reflects the unique nature of the projects included under the Special Initiative, Integration Capital and Other which in the Council's view should be excluded from the analysis.

Table 4: Utility Capital Expenditures by Category of Spend[121] [122] [123]

Line No	($ millions)	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2018-22 Average	2023 Bridge Year	2024 Test Year	2023 Reduction	2024 Reduction
1	Base Capital	776.3	900.1	836.9	1,036.4	1,150.2	940.0	978.8	1,194.00	39	254
2	Special Initative	156.2	144.5	110.4	183.5	210.9	161.1	373.6	140.5		
3	Integration Capital		21.7	39.8	63.0	26.5	30.2	20.0	0		
4	Other		21.0	20.0	27.9	15.3	16.8	54.9	135.8		
5	Total	932.5	1,087.4	1,007.2	1,310.8	1,402.9	1,148.2	1,427.2	1,470.30	1,388.4	1,216.28

Approximately 40% of the investments in the updated capital plan are Value-Driven as opposed to Mandatory or Compliance.[124] Value-driven investments are free to shift within the optimization time frame.[125] Based on the need for the capital update, EGI's response and the level of value driven investments, EGI has demonstrated it has the necessary flexibility within the timing of its capital portfolio to accommodate the Council's proposed capital reductions.

Future Capital Planning in the Context of Energy Transition

In the context of Energy Transition, there is a risk that assets with a long asset life will be underutilized or potentially stranded. EGI indicates the utilization or stranded asset element is considered within the demand forecast.[126] The Council submits EGI needs to do more and should formally incorporate an analysis of asset utilization in its capital planning process, given the pace of Energy Transition.

EGI acknowledges that many assets have a life span of about 40 to 60 years and beyond,[127] yet

[121] JT14.5
[122] Special Initiative Projects include CPT, Leave to Construct and ICM
[123] Other reflects community expansion, RNG, CNG
[124] J12.2
[125] Ex. 2/6/2 p.55
[126] Tr. Vol 14. P. 96
[127] Tr. Vol. 11, p.151

EGI has never seen the circumstance where an asset would be underutilized.[128] When asked to confirm that EGI has no measures within the Copperleaf system that prioritize EGI's value-driven projects, that look at what is the future utilization or the future possibility of underutilization of an asset, EGI responded, "if the tool is there, we don't have any experience using it,"[129] and "it's not something that we're doing actively, right now."[130]

In the St-Laurent Decision, the OEB discussed the need to look at the possibility of future underutilization of the assets stating, "…for future similar applications, the OEB urges Enbridge Gas to provide more details about life-cycle costs, including abandonment costs and the probability of future underutilization." [131]

EGI has several value measures linked to its strategic priorities. None of the existing value measures in its Copperleaf asset investment planning tool specifically address asset utilization. The Council submits the OEB should require EGI to improve upon its Asset Investment and Planning and Management (AIMP) process in the future and include a way to identify the potential for stranded or underutilized assets and assess the risk and value. EGI should then report back at its next cost of service application as to how it has incorporated asset utilization in its AIMP process and the experience gained including lessons learned.

5. OTHER REVENUE (ISSUE 10)

Property Dispositions

As part of the Settlement Proposal,[132] there was no agreement as to whether and/or how amounts related to proceeds from EGI dispositions of property in 2024 and subsequent years should be included in other revenue forecast or otherwise credited to ratepayers. The OEB determined that this issue would be dealt with in writing only.[133]

EGI is requesting OEB approval of its proposed forecast of other revenue to exclude any forecast of property disposition gains or losses, i.e., EGI has forecast property disposition proceeds as equal to the net book value of these capital assets for 2024.[134] There is no impact on the proposed 2024 revenue requirement if the OEB accepts the manner in which EGI has proposed to account for property dispositions.

The forecast timing of property dispositions is provided below. The number of property dispositions in 2024 was updated as part of the Capital Update from four to one, with estimated capital proceeds decreasing from $31 million to $6.3 million.

[128] Tr. Vol. 11 p.152
[129] Tr. Vol. 11, p. 150
[130] Tr. Vol. 11, p. 151
[131] EB-2020-0293 Decision
[132] Ex. O1/1/1/p.29
[133] PO#6 p5
[134] EGI Argument-in-Chief, paragraph 714

	Exhibit I.2.6-SEC-137 (Original response, filed March 8)	Exhibit I.2.6-SEC-137 (Capital Update, filed July 6)
2024	4 dispositions; $30-31 million proceeds	1 disposition; $6.3 million proceeds
2025-2026	3 dispositions; $38.5-42.1 million proceeds	no change
2027	2 dispositions; proceeds dependent on market conditions at future time of sale	no change

EGI is proposing the following:[135]

- Any gains or losses on land dispositions be shared with ratepayers in accordance with any sharing mechanism approved by the OEB as part of an earnings sharing mechanism (ESM) beyond 2024;

- For 2024, EGI has forecast property disposition of any properties as equal to the net book value of these capital assets; and

- In the event that the OEB determines that proceeds from gains on land disposed of in 2024 should be shared with ratepayers, EGI proposes that this be done by way of a deferral account.

OEB staff supports EGI's proposal to exclude amounts related to property disposition gains or losses in the 2024 other revenues forecast and recommends the establishment of a deferral account to record proceeds from sales over the proposed rate term. Consideration of the method of disposition and the allocation of amounts would be conducted in the future when there are entries into the account and the nature of the properties and reasons for the sales can be reviewed.[136]

The Council supports the submissions of OEB Staff. The Council agrees with respect to property dispositions, there are many uncertainties related to timing of dispositions, amount of proceeds and allocation of proceeds between land and buildings. The Council supports EGI's proposal to not include any amounts related to property disposition gains or losses in its 2024 other revenues forecast (and therefore revenue requirement). Absent detailed information and actuals on what properties have been sold and why, the Council agrees it is not possible at this point to recommend what treatment might be appropriate for any particular property.

6. OPERATING EXPENSES

Depreciation Expense (Issue 15)

[135] EGI Argument-in-Chief, p.255-263
[136] OEB Staff Submission p. 72-73

EGI has requested a 2024 depreciation expense of $879 million which represents a variance of $141.9 million assuming the existing methodology stays in place.[137] This is a significant driver in the determination of the overall revenue deficiency and the proposed rate increases.

EGI engaged Concentric Energy Advisors to provide expert evidence regarding the appropriate approach to determining the depreciation expense.

OEB Staff engaged Intergroup Consultants Ltd. (Intergroup) to assess the evidence provided by EGI and Concentric. IGUA engaged Ermydia Consulting Corporation (Ermydia). The main disagreement between Intergroup and Ermydia and Concentric is the move from the Average Life Group approach previously used by Enbridge Gas Distribution to the Equal Life Group approach. In addition, Ermydia and Intergroup questioned the application of the Constant Dollar Net Salvage method used by Concentric. The difference between the ELG and ALG methodologies in the 2024 is $83.4 million[138].

EFG on behalf of ED and GEC recommended that EGI be required to immediately assess and report back to the Board by 2024 on the near-term and longer-term rates, cost of capital, affordability and intergenerational equity impacts of alternative asset deprecation approaches.[139] The Council supports this approach.

Mr. Neme has specifically recommended that his analysis be undertaken under the following scenarios: 1) maintaining the currently proposed ELG method; 2) adopting an Economic Planning Horizon (EPH) for new assets; 3) adopting an EPH for all assets and 4) switching to a Units of Production (UOP) method of asset depreciation[140]. The Council submits that the analyses should also include the approaches advanced by Ermydia and Intergroup in this proceeding.

The Council is not, at this time, supporting one specific depreciation methodology over another. The Council has recommended elsewhere in these submissions that EGI be required to come back to the OEB in early 2026 with a new rate application for 2027. This would allow EGI to undertake the required analysis recommended by Dr. Hopkins and EFG. It would also allow for Phase 2 and potentially Phase 3 of this proceeding to be completed. This timing would further allow for the Government of Ontario to better crystalize its perspectives and proposals regarding energy transition.

7. COST OF CAPITAL

Equity Thickness (Issue 20)

[137] AIC, p. 175
[138] AIC, p. 185
[139] Ex. M9 – GEC-ED, pp. 5, 44
[140] Ibid

EGI has requested an increase to its equity thickness from 36% to 42%, but has proposed a phased-in approach. The proposal is for an increase to 38% for 2024 and a 1% increase for each after for the period 2025-2028. The proposal is to make an annual rate base adjustment in the years 2025-2028 of $13.6millon[141]. A 2% increase in 2024 contributes $26.1 million to the deficiency.[142]

The current capital structure was approved by the OEB for both Union Gas and Enbridge Gas in their 2013 rate proceedings. The common equity component of 36% has been in place since that time. EGI filed its own evidence and also retained Concentric Energy Advisors to prepare a report on the reasonableness of the capital structure approved by the OEB and to determine if its risk profile has significantly changed since 2012. Concentric concluded that EGI's overall risk has significantly increased since 2012 and warrants a reassessment of its equity ratio.[143] Concentric recommended a move from 36% to 42%:

> Our recommended equity ratio for Enbridge Gas in the upcoming rate setting period is consistent with the result of our analysis, which indicate that an increase in equity thickness is warranted. This is particularly important as the Company will need to maintain financial strength to continue accessing the debt and equity capital it needs to manage the Energy Transition under a variety of economic and capital market conditions, while providing safe reliable service to its customers."[144]

Under Concentric's assessment EGI's risk profile has increased significantly as compared to its risk profile in 2012 and the most material factor contribution to the increase is energy transition which Concentric has characterised as "a broad-scale transformation from a primary reliance on fossil fuels to a primary reliance on more renewable resources."[145]

Concentric also looked at volumetric risk, financial risk, operational risk and regulatory risk concluding that that the risk profile of EGI has increased in all of these areas.

OEB Staff retained London Economics Group to assess EGI's cost of capital evidence and provide an independent analysis. LEI recommended an increase in the equity thickness to 38% for the period 2024-2028. LEI concluded that EGI's business risk had increased since the last cost of capital reviews of the predecessor utilities in 2012, but that increase in risk was partially offset by the amalgamation of the two utilities.

The Industrial Gas Users Association (IGUA) retained Dr. Sean Cleary from Queen's University. Dr. Cleary's main recommendation was to maintain the equity ratio at 36%. He concluded that Concentric had simply failed to provide any compelling evidence that it should be increased. Concentric has not provided meaningful support for its assertion that there has been a

[141] AIC, p. 211
[142] J17.1, p. 5
[143] Ex. 5/T3/S1/pp. 2-3
[144] Ex. 5/T3/S1/Attachment 1/p. 3
[145] Ibid, p. 1

significant increase in EGI's risk profile that would warrant any increase in its equity ratio let alone the significant increase requested[146].

During the oral hearing Dr. Cleary highlighted his concerns with Concentric's analysis:

- Concentric relies on looking at equity ratios that are awarded in other jurisdictions without considering the record at the time, the risk facing the utilities, the operations of those utilities and market conditions.[147]

- There are flaws and different risk characteristics in all of their proxy groups relative to EGI. In particular, the first three are much riskier. Their fourth group, includes 10 companies but seven of them are so much smaller than EGI that they require an adjustment for that risk, as has been argued by Mr. Coyne in the New Brunswick proceedings.

- Concentric ignores the fact that EGI borrows at slightly below the A-Utility average yield which definitely shows that they have no problem attracting capital and that they are on par with comparable investments. [148]

- Concentric has claimed Dr. Cleary ignores equity investors. He states that this is untrue.[149]

- Concentric has claimed the Dr. Cleary only focuses on the short-term and not the long-term. Concentric fails to recognize that the capital provider, the debt markets, and the equity markets also have already looked at the long term, and those are reflected in today's current borrowing rates for EGI, so its reasonable to assume that they have considered the energy transition risk and that it is already reflected in EGI's cost of debt.

- Concentric suggests that because a company earns above its allowed ROE, which EGI has done consistently, it does not indicate anything about the risk to the company. They suggest that does not mean they are less risky than a company that consistently earns less. Dr. Cleary takes issue with that, concluding that any investor would recognize that a business that continually earns above the expected return would be less risky than one that continually earns below the expected return.[150]

In summary Dr. Cleary concluded:

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[146] Ex. M2-IGUA p. 3
[147] Tr. Vol. 10, pp. 8-9
[148] Tr. Vol. 10, pp. 9-10
[149] Tr. Vol. 10, p 10
[150] Tr. Vol. 10, p. 12-13

> In contrast to Concentric's simple reliance on historically awarded equity ratios, I would argue my evidence is forward looking, based on available financial market information, and my analysis suggests that it is not necessary to increase EGI's equity ratio of 36% which comfortably satisfies all three legs of the fair return standard.[151]

As discussed above, EGI itself does not see energy transition as an immediate risk as very few elements of the rate application are in response to energy transition. To change the capital structure to reflect an increased risk resulting from energy transition would not be appropriate at this time.

EGI has consistently earned above its ROE. EGI has had no trouble attracting capital. Any potential risks associated with energy transition are not expected to materialize during the rate plan period, particularly in the first three years. The Council has reviewed the detailed submissions of IGUA regarding Concentric's analysis and Dr. Cleary's evidence. The Council supports IGUA's view that it is not necessary, at this time, to increase EGI's equity ratio of 36%.

8. DEFERRAL AND VARIANCE ACCOUNTS (Issue 33)

Volume Variance Account

Prior to the amalgamation, Enbridge Gas had an Average Use True-up Variance Account and Union Gas had a Normalized Average Consumption Account. To replace those two accounts EGI is proposing a Volume Variance Account (VVA) The new VVA will record the revenue impact, exclusive of gas costs, of the volumetric variance resulting from actual average use per customer and weather experienced during the year for the general service rate classes.[152]

It is EGI's position that the introduction of this account is consistent with the longstanding approach of the former Union Gas and Enbridge Gas to keep the utility and ratepayers whole from the impacts of changes in average use. Without the account EGI loses its incentive to maximize DSM results, because the resulting reduced volumes from DSM lead to revenue declines that are not credited back to the utility. From EGI's perspective this would also address changes resulting from increasingly efficient appliances, hybrid heating, changes to building costs and other efficiency related change that the OEB encourages[153].

The Council is not opposed to continuing with an account that keeps the shareholders and the ratepayers whole from the impacts of changes in average use. This was the purpose of the Lost Revenue Adjustment Mechanism (LRAM) which was eliminated with the introduction of the two previous accounts.

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[151] Tr. Vol. 1o, p. 13
[152] E. 9/T1/S2/p. 26
[153] AC, p. 238

EGI has indicated that the new account provides a similar de-risking of fixed cost recovery to the straight fixed variable with demand (SFVD) proposal to be considered in Phase 3 of this proceeding.[154]

The Council finds it ironic that EGI is seeking a significant increase in its equity thickness at the same time it is seeking to eliminate its weather risk. The Council supports the establishment of the account without capturing variances due to weather. This would be consistent with the accounts approved in the past which were primarily established to account for variances related to DSM activities. The existence of these accounts led to the elimination of the LRAM. The OEB is going to consider EGI's proposal for a SFVA rate design n Phase 3 of this proceeding. It is at that time the OEB should consider whether EGI should be effectively sheltered from the weather impacts on its revenue. If the OEB accepts the account as proposed, this should be considered in the context of EGI's request to significantly increase its equity thickness.

9. OTHER

Regulated Treatment of NGV (issue 34)

EGI has requested regulatory treatment of the Natural Gas Vehicle (NGV) Program. EGI is requesting approval to:

a) Continue the NGV Program as a utility activity;
b) Expand the current NGV Program for the EGD rate zone to all EGI franchise areas; and
c) Remove the requirement to impute revenue in any fiscal year that the NGV's annual rate of return (RoR) does not meet or exceed the required RoR[155].

As set out in the pre-filed evidence the NGV Program has been operating within the EGD rate zone since the mid-1980s. The current program supports the use of natural gas as fuel for Company vehicles, encourages growth and development of natural gas as a substitute for gasoline and diesel fuel in transportation markets, and coordinates natural gas supply for public and private refuelling stations. The three components of the NGV program are Compressed Natural Gas refuelling facilities, NGV fuel cylinders and Vehicle Refueling Appliances and CNG tube trailers. There is no comparable NGV program in the Union rate zones although Union did begin to reintroduce NGVs into their fleet of utility service vehicles to reduce fuel costs and emissions. Union does own and operate one refuelling station for the City of Hamilton.[156] Since 1997 the NGV Program has been operating as an "unregulated ancillary business that is complementary to the core utility business". It is subject to fully allocated costing for rate treatment purposes.[157]

[154] Ex. 9/T1/S2/p. 27
[155] Exhibit 1/T14/S2/p. 1
[156] Exhibit 1/T14/S2pp. 2-3
[157] Argument in Chief, p. 266

EGI has characterized NGV as one of its “safe bet” opportunities for the utility and Province from both a transportation fuel switching perspective and also in terms of increasing RNG content in transportation fuels. EGI expects NGV growth to expand on the basis of the environmental benefits, the recently announced Government of Canada Clean Fuel Regulation (CFR) Program, price competitiveness, and technology improvements. [158]

EGI is proposing to expand the NGV Program throughout its franchise area and modify the current regulatory approach of imputing revenue. It is unclear how expansive this will be. The program will be funded by monthly service rates charged to participating customers over the life of the program. EGI intends to report on the NGV Program at its next rebasing proceeding.

The relevant NGV amounts included in EGI’s 2024 revenue requirement are:

- Rate base $21.4 million
- Other Revenue $4.3 million
- O&M $.9 million[159]

The net capital additions forecast for 2024 is $7.6 million[160]. The net utility investment in the NGV program is $40.3 million.[161] EGI is earning a return on that investment.

EGI has argued that its NGV Program differs from unregulated activities conducted within or outside of its regulated operations because there is still no fully functioning competitive market for turnkey NGV solutions. EGI is concerned that if the OEB were to deny the requested relief the market would receive this as a negative signal about the importance of EGI’s role as facilitator to continue stimulating and growing the market[162].

It is EGI’s view that ratepayers will, going forward, be protected by cost recovery from the NGV customers through specific charges and credits checks. However, EGI has confirmed that if the NGV program cannot meet the RoR in any given year non-participating customers will be subsidizing the NGV Program.[163]

It remains unclear to the Council why the NGV Program should remain an “unregulated ancillary business” operated within the utility. If the NGV Program economics are viable the Council questions why it cannot be operated outside the utility. If it can only operate successfully within the utility – as an unregulated activity - we question whether it is being cross-subsidized by utility ratepayers. Union Gas discontinued its NGV activities in 2000 because of declining revenues. The only other NGV program is in B.C. The benefits to existing

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[158] Exhibit 1/T14/S2/p. 4-8
[159] Argument in Chief, p. 264
[160] Ex. I-1.14-CCC-34
[161] Exhibit 1/T14/S2/Attachment 1
[162] Exhibit I.1.14-STAFF-43
[163] Ex. I-1.14-CCC-34

ratepayers are not clear and in the absence of clear benefits the NGV Program should be removed from utility operations.

EGI mentions that CNG cube trailers have been identified as an IRPA initiative, but acknowledges this would be outside the NGV Program. EGI has provided little evidence as to how this represents a viable IRPA initiative and why maintaining the NGV program within the utility would be required.

The Council accepts that NGV could represent a viable alternative to gasoline and diesel, but is of the view that activities like NGV should not be structured as an "unregulated ancillary business within the utility". Why should there be an unregulated competitive activity within the utility? We also question the extent to which EGI should be ramping up its NGV activities while there is a push to promote electric vehicles. If the OEB supports continuation of the NGV Program, ratepayers should be fully protected from any adverse impacts should the extensive rollout to the entire franchise area occur.

Earnings Sharing (ESM) for 2024 (Issue 37)

EGI has not proposed, and does not support an ESM for 2024. EGI has proposed an ESM for the period 2025-2028 that would share utility earnings in excess basis points above the OEB-approved return on equity (ROE) in a 50/50 basis with ratepayers.[164] This was an issue that the OEB determined would be considered through a written hearing process.

EGI has argued that the ESM is not required for the test year 2024 as there is already the protection for ratepayers from excessive earnings through the extensive reviews of the test year forecast that have taken place in this cost of service proceeding[165].

The Council has been a long-time advocate of earnings sharing. Earnings sharing provides an important protection mechanism for ratepayers. Although it may not be the standard in all cost of service rebasings, many Ontario electricity utilities have agreed to an ESM for their base year. It is especially important for larger utilities. It is also particularly important for EGI as it consistently overearns. The Council sees no downside in requiring an ESM.

The Council proposes an ESM for EGI for 2024 that shares earnings with its ratepayers on a 50:50 basis for all earnings 100 basis points above its allowed return.

SQRs (Issue 40)

EGI is requesting a partial exemption under Section 1.5.1 of the OEB's GDAR related to three service quality requirement (SQR) performance measures. The requested SQRs are a s follows:

[164] Ex. 10/T1S1/p. 12
[165] AIC, p. 272

a) Meter Reading Performance Measurement (MRPM) – the number of metered with no read for four consecutive months or more divided by the total number of active meters to be read. The current target is .5% and EGI is seeking a target of no more than 2% of meters with consecutive estimates for four months or more;

b) Call Answer Service Level (CASL) – the percentage of calls reaching the general inquiry number including IVR calls that are answered within 30 seconds. The current target is yearly 75% with a minimum monthly standard of 40%.EGI is seeking approval to achieve 65% of calls reaching the general inquiry number answered within 30 seconds;

c) Time to Reschedule a Missed Appointment (TRMA) – the distributor must contact the customer to reschedule the work within 2 hours of the end of the original appointment time. The current target is 100% and EGI is seeking approval for the TRMA target to be an attempt to contact customers requiring a scheduled appointment within one business day of the original appointment 98% of the time[166].

EGI is also seeking a generic review of GDAR in order to consider codifying the SGR performance standards proposed in this Application.

In the merger proceeding the Applicants committed that the new entity would continue to maintain the safety, reliability and quality of service to Enbridge Gas and Union Gas customers, both in-franchise and ex-franchise. The OEB was satisfied that the proposed transaction would not lead to any adverse impact with respect to the reliability and quality of service, and concluded that the "no harm" test was met in this regard. The OEB accepted the Applicants' position that, efficiencies can be gained without compromising the ability of Amalco to maintain current levels of reliability and quality of service."[167]

EGI was unable to meet the performance standard for each of the three performance standards in 2021. In addition, the performance standard for MRPM was not met in 2019 and 2020.[168] In effect, EGI's performance has degraded since the merger.

EGI cites four factors that have contributed to EGI not meeting its SQR targets that it claims were outside its control:

a) COVID-19 pandemic
b) Staffing issues
c) System integration
d) Extreme weather

[166] AIC, p. 282-283
[167] EB-2017-0306/EB-2017-0307 Decision and Order, dated August 30, 2018, pp. 12-13
[168] Ex. 1/T7/p. 2

The Council does not support an exemption from the MRPM and CASL SQR performance measures. There was an expectation on the part of the OEB and EGI's customers that the merger would at a minimum maintain, and potentially enhance, customer service levels. Changing the performance measures now, simply because EGI cannot meet them is not appropriate. While it is understandable that the ability of EGI to meet the targets was compromised during the COVID-19 pandemic and the consolidation of the billing systems, circumstances have changed and EGI should be capable of meeting the measures as it did prior to the merger. In recent years EGI has had significant problems with its billing and meter reading. EGI needs a strong incentive ensure its billing and meter reading follow best practices.

The Council is not opposed to the change to the TRMA as it is consistent with the target for electricity distributors as set out in the DSC. It is not unreasonable to expect it may take one full business day to contact and reschedule a missed appointment with a customer.

10. RATE IMPLEMENTATION

Rate Implementation Proposal

The Council is supportive of a January 1, 2024, effective date for rates.

All of which is respectfully submitted.