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Sept. 19, 2023

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Marconi,

RE: EB-2022-0200 – Enbridge Has Inc. 2024 Rebasing - London Property Management Association Submissions

Please find attached the Submissions of the London Property Management Association in the above noted proceeding.

Yours very truly,

Randy Aiken

Digitally signed by Randy Aiken
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Date: 2023.09.19 15:08:09 -04'00'

Randy Aiken
Aiken & Associates

c.c. EGI Regulatory Proceedings (e-mail only)
Intervenors & Interested Parties (e-mail only)

EB-2022-0200

ONTARIO ENERGY BOARD

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

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

**SUBMISSIONS
OF THE
LONDON PROPERTY MANAGEMENT ASSOCIATION**

INTRODUCTION

These are the Submissions of the London Property Management Association ("LPMA") related to unsettled issues in Phase 1 of an application by Enbridge Gas Inc. ("EGI") to approve rates for the sale, distribution, transmission and storage of gas commencing January 1, 2024.

EGI filed its 2024 rates application and most of its supporting evidence on October 31, 2022 with the remaining evidence filed on November 30, 2022.

EGI has also applied for the approval of an incentive rate-making mechanism ("IRM") for the years from 2025 to 2028. In the Decision on Issues List and Expert Evidence and Procedural Order No. 2 dated January 27, 2023, the Ontario Energy Board ("Board" or "OEB") confirmed that the IRM related issues to a Phase 2 of the application that was originally proposed by the Board in Procedural Order No. 1 dated December 16, 2022. This was to ensure that rates for 2024 could be put in place, at least on an interim basis, in a timely manner.

In Procedural Order No. 1, the Board made provision for the submission of interrogatories, a technical conference and a settlement conference. A nine day technical conference took place from March 22 through March 31, 2023 as well as on April 27, 2023. The settlement conference was held from May 29 to June 9, 2023 and EGI and intervenors were able to reach a partial settlement on a number of issues.

LPMA is not making any submissions with respect to the IRM related issues or any other issues that have been moved to Phase 2 by the Board or to a Phase 3 as proposed in the Partial Settlement Proposal updated on July 12, 2023 and approved by the Board in the Decision on Settlement Proposal dated August 17, 2023. However, LPMA notes that some of the issues that have been deferred to later phases of the application may impact the resolution of some of the Phase 1 issues.

EGI filed its Argument In Chief ("AIC") on August 18, 2023 and Board Staff filed their Submission ("Staff Submission") on September 12, 2023. LPMA has found both EGI's AIC and the Staff Submission to be very useful in setting out the background to the unresolved issues in Phase 1 of this proceeding and LPMA will not repeat that background in its submissions that follow.

OVERVIEW

Much of the time spent in this proceeding dealt with energy transition. On the first day of the oral hearing, the Presiding Commissioner indicated that the Board panel was looking forward to understanding the range of perspectives represented by the parties and receiving submissions on what the path forward should look like.

LPMA submits that it is too early to be determining what the path forward should look like. In the absence of any government policy that sets a path to net zero the only thing that can be concluded is that there is no clear evidence in this proceeding with respect to any path forward. Before you worry about which path to take, you need to know where your ultimate destination is and how soon you need to get there. In the absence of detailed energy transition laws, regulations, directives and other information for gas distributors everything at this point is just conjecture. The Board should not be making decisions that have significant impacts on gas distributors based on conjecture.

The Board should not be making significant energy transition decisions without knowing how consumers will react. Consumers will want to know, with some level of confidence, about the costs for space and water hearing if they are being encouraged to shift from natural gas to electricity. These costs include not only the ongoing costs associated with electricity and natural gas delivered to their homes and businesses but also the up-front costs associated with the move.

Consumers will want information on the reliability and resilience of the energy system that delivers the energy to their homes and businesses. How will electrical outages due to storms and fires be handled given the increase in frequency and severity that is being felt around the world? Will customers want to pay to remain connected to a natural gas system that only provides backup heat on a very limited number of days in the winter? There are no studies or research on consumer behaviour in this proceeding.

There is also, in the view of LPMA, no real evidence related to energy transition in this proceeding. There are two pathways provided by EGI consultants and alternatives provided by consultants on behalf of intervenors. But as parties recognize, there are an infinite number of pathways to an unknown destination or destinations in an unknown amount of time. The material provided, while interesting, is more conjecture and opinion depending on the views of the parties providing the material.

As an example, EGI spent a lot of time in the oral hearing talking about how the natural gas system could be repurposed to provide reliability and resilience to the provincial energy system through renewable natural gas, hydrogen blending and hybrid furnaces and heat pumps among others. This is an interesting potential pathway to get from here to somewhere in the future. But it does not go far enough into the 'what if' of scenario analysis. Would customers opt for a hybrid furnace that would keep them warm but still leave them in the dark when electricity delivery is interrupted? Or would customers prefer a gas powered standby generator that comes on automatically when the supply of electricity is interrupted that not only keeps you warm with the lights on, but also keeps the refrigerator and freezer cold and keeps the sump pump running to avoid flooded basements. These types of generators are already used by many customers in Ontario where electricity delivery can be interrupted frequently and for long durations.

Even further down the rabbit hole of possibilities is that gas powered generators can run on not only natural gas, but also propane, gasoline, and hydrogen. Hydrogen can be produced in many different places, and like propane can the trucked and stored on site. Propane can also be used for hybrid furnaces, eliminating the need for customers to pay to remain connected to the natural gas system.

Until Enbridge and other parties, including the Board, have time to understand what future government policies, directions and legislation mean, LPMA submits that it is not appropriate for the Board to start down any path related to energy transition. Rather the Board should direct EGI to be prepared to come back to the Board at some time subsequent to the release of Government of Ontario policies, directions and legislation. The Board should require EGI to review its asset management plan, capital budget, depreciation methodology, customer and volume forecasts and methodologies, peak day and peak hour forecasts and methodologies and anything else that may be impacted once energy integration policies of the government can be analyzed and assessed.

In the meantime, EGI should be encouraged to continue to investigate what it calls ‘safe bets’. These safe bets, which LPMA supports, do not lead to any particular path, but they provide information that could be useful in the future when the paths become more defined.

The Board should also not be making decisions that impact energy transition trajectories in the absence of detailed evidence on the impact of electricity distributors, transmitters and generators. To do so would be like walking up a cliff in the fog and not knowing where the edge of the cliff is.

The Board should initiate a generic energy transition proceeding immediately upon the release of the Government of Ontario policies, directions and legislation related to energy transition. This proceeding should involve all gas distributors, electricity distributors, electricity transmitters, and electricity generators in Ontario. It should also include upstream and downstream transmission systems that supply or take supply from Ontario. It should also include associations that can deliver other energy services in Ontario such as propane, hydrogen, distributed generation, battery and other forms of energy storage, HVAC dealers and heating equipment and appliance manufacturers. It needs to include a broad range of customer representatives as well as municipalities. It needs to result in a truly Integrated Energy Resource Plan (“IERP”) that deals with all aspects of any needed transition, focusing on, but not limited to, timing, regional approaches, utility preparedness, regulatory innovations, stranded assets, stranded customers and allocation of risk between utilities and customers.

At the beginning of the oral hearing Mr. Kitchen, on behalf of EGI, stated that *"it is important to recognize that the primary purpose of this application is to set rates effective January 1, 2024."* (Tr. Vol. 1, page 4). Mr. Kitchen then continued on, saying that *"Any decision on 2024 rates must be made in the context of current energy policy. At this time, there is no government policy that sets a path to net zero. That said, however, the Government of Ontario recently released the Powering Ontario's Growth report, indicating that natural gas will continue to play a critical role in providing Ontarians with a reliable and cost-effective source of energy for space heating, industrial growth, and economic prosperity."*

LPMA supports this position. Phase 1 of this proceeding is about setting rates to be effective January 1, 2024 and should be based on known government policy as it currently exists. Any impacts related to or from energy transition in 2024 should be dealt with as part of this phase of the hearing. Other aspects of the application such as the IR mechanism, cost allocation, rate design (including harmonization of rates) and a number of other specific issues will be dealt with under Phase 2 and Phase 3 of the proceeding.

LPMA's submissions with respect to the remaining outstanding issues follow below and are focused on the determination of the 2024 revenue requirement. This includes submissions, where necessary, on the impact of energy transition, or lack thereof, in the test year.

THE REMAINING ISSUES

1. Are the proposed rates and service charges just and reasonable?

As currently requested, LPMA submits that the proposed rates and service charges are not just and reasonable. As summarized in the response found in Exhibit J17.11, Attachment 1, page 3 of 5, EGI has calculated a delivery revenue requirement of $3,019.5 million and total delivery revenue at existing rates of

$2,833.2 million, resulting in a delivery revenue requirement deficiency of $186.3 million. This represents an increase in cost of just under 6.6%.

This increase does not include the potential addition of $22.5 million to the revenue requirement associated with the deferral of the Dawn to Corunna project to Phase 2 (Exhibit J17.11, Attachment 1, page 5 of 5, line 9) or the proposed levelized deficiency amount of $7.3 million for the Panhandle Regional Expansion Project ("PREP") (Exhibit J17.11, Attachment 1, page 3 of 5, Note (1)).

Adding the deficiencies associated with the Dawn to Corunna project and PREP, the deficiency balloons to more than $216 million, or an increase of more than 7.6% in the revenue requirement over revenue at existing rates.

LPMA submits that an increase of this magnitude is not just and reasonable. In the issues that follow, LPMA provides suggestions for significant reductions in the deficiency through changes to the equity component of rate base, the treatment of PREP, capital additions to rate base and the calculation of depreciation.

2. Have the customer benefits identified in the amalgamation proceeding EB-2017-0306/0307 been realized having regard to the five-year deferred rebasing term that was approved?

With the exception of the issue of the treatment of integration capital included in rate base, LPMA makes no submissions with respect to this issue. LPMA deals with the issue of the inclusion of integration capital in the 2024 rate base under Issue 6.

3. Has Enbridge Gas appropriately considered energy transition and integrated resource planning in relation to such things as a) load forecast; b) deemed capital structure; c) depreciation rates; d) forecast capital expenditures; e) allocation and mitigation of risk, to determine new rates

that will be effective January 1, 2024, considering relevant government policies and legislation?

LPMA submits that EGI has adequately considered energy transition and integrated resource planning – at this time – considering the relevant government policies and legislation that exist at this time. LPMA notes that this submission that EGI has adequately considered energy transition and integrated resource planning is limited to the determination of new rates that will be effective January 1, 2024.

While LPMA does not agree with the EGI proposals related to some of the items noted in the issue, this disagreement is not related to either energy transition or integrated resource planning.

LPMA submits that not only has EGI adequately considered both energy transition and integrated resource planning for the determination of 2024 rates, it also submits that EGI has appropriately considered both of these issues with respect to 2024 rates.

EGI has put forward a number of "safe bets" which it is investigating and/or moving forward with while waiting for the Government of Ontario's energy transition work and policy directions. LPMA supports this approach. As EGI states in its AIC (para. 100), their proposed safe bets are required regardless of the pathway that is ultimately taken. This provides EGI the flexibility to adapt to future directions, while maintaining a safe and reliable gas system.

It would be foolish, in the view of LPMA, if EGI were to spend vast amounts of ratepayer money at this time given the level of uncertainty in Ontario due to the current lack of policy direction. This spending could lead EGI toward the wrong path. As well, it is doubtful that all intervenors would agree with whatever path EGI was headed towards. There is no need at this time to try and predict what government policy will be and when that policy will be implemented. To try and do so now would not be prudent in the view of LPMA. It would only be controversial and costly.

Once the Government of Ontario's energy transition work and policy directions are known, then all parties, including EGI and the Board can get to work to implement those policy directions. That is when decisions related to the future of gas distribution systems should be made.

5. Has Enbridge identified and responded appropriately to all relevant OEB directions and commitments made from previous proceedings?

EGI provided a Directive and Commitment Response Summary in Exhibit 1, Tab 13, Schedule 1 where it listed more than two dozen directive/commitments, along with a cross-reference to the evidence that deals with each item. LPMA submits that EGI has responded adequately to each of the directive/commitments and has no further submissions on this issue.

6. Is the 2024 proposed rate base appropriate?

There are a number of sub-issues with respect to the appropriateness of the proposed 2024 rate base. LPMA provides submissions with respect to the ones of concern to it.

i. <u>Use of Actual 2022 Data</u>

As part of the Settlement Proposal that was accepted by the Board, parties accepted EGI's rate base up to and including 2022, with some adjustments that were outlined in the Settlement Proposal. The 2022 rate base was based on estimated values that were available to parties at that time. EGI proposes to update the rate base calculation for 2022 to reflect actual rate base that underpinned the capital update that was filed. LPMA supports this proposal from EGI because it believes the actual 2022 rate base is the appropriate starting point upon which to layer on the 2023 and 2024 capital activity (i.e. in-service additions and retirements). LPMA further notes that EGI has stated that the 2022 actual rate base values result in a lower 2022 ending net property, plant and equipment balance that is carried forward into 2023. This benefits ratepayers as the rate base values in each of 2023 and 2024 are lower as a result of using the actual 2022 ending value.

ii. Panhandle Regional Expansion Program ("PREP")

As part of its capital update filed in June, 2023, EGI has excluded the forecast expenditures and 2024 in-service additions related to PREP and has instead proposed a levelized recovery mechanism for the project. (Exhibit 2, Tab 5, Schedule 4, pages 30-33).

EGI has proposed that PREP be treated differently than other capital expenditures and in-service additions in 2024 because it is a large project and is subject to leave-to-construct ("LTC") approval application. LPMA notes that this LTC application (EB-2022-0157) is well underway with interrogatory responses from EGI expected in early October, 2023.

EGI has removed the costs associated with PREP from the determination of the base 2024 cost of service revenue requirement. The justification for this is that if the project is not approved, or the timing is different, or the costs are different, then no adjustment to base rates or revenue requirement would be necessary.

EGI proposes to separately calculate the forecast net revenue requirement of the project for the 2024 test year and each year of the proposed IR term of 2025 to 2028 for inclusion in rates in a levelized manner. This would result in a cost to ratepayers in each of those years, including the cost-of-service 2024 test year of $7.3 million, which would be recovered through an average unit rate over these years.

Moreover, EGI states that its proposed treatment is similar to the treatment of prior ICM projects, and the proposed prospective treatment of future ICM projects. As a result, EGI is also proposing a variance account 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. In other words, EGI wants to eliminate any risk to itself associated with this project.

EGI's proposals with respect to PREP are summarized in paragraphs 433 and 434 of its AIC.

LPMA strongly opposes the EGI proposal to remove the PREP project from inclusion in the 2024 revenue requirement and use a levelized approach to recover the costs. This approach, if approved by the Board, would cost ratepayers in excess of $100 million over the 2024 to 2028 period.

As shown in Attachment 2 to Exhibit 2, Tab 5, Schedule 4, Attachment 2 filed 2023-06-16, the 2024 revenue requirement associated with the PREP project if it was included in base rates is a sufficiency of $14.4 million. The creation of a sufficiency in the first year that an asset is placed into service is driven by the large capital cost allowance deduction, as shown in the attachment, and is not unusual for capital additions. EGI confirmed this to Mr. Rubenstein (Tr. Vol. 12, page 28):

> MR. RUBENSTEIN: As I understand it, the negative revenue requirement in the first year is not a phenomenon that is specific to the PREP project, correct?
>
> MR. VINAGRE: That's correct.
>
> MR. RUBENSTEIN: You, for many of your large projects, you have year 1 revenue requirements, or I would say maybe most of them, that are a lot -- that are negative. Do I have that right?
>
> MR. VINAGRE: That's correct. In the year in service, that is the general.

The difference between the traditional approach of including forecast in-service additions in a cost-of-service application (sufficiency of $14.4 million) and EGI's approach of a levelized cost of $7.3 million is $21.7 million in 2024. Over the course of the proposed 5-year IR term, the removal of the $14.4 million sufficiency in 2024 results in the increase in costs paid by ratepayers of $72 million ($14.4 x 5), with a further increase of $36.5 million ($7.3 x 5) associated with the levelized charges proposed by EGI. The ultimate impact on ratepayers of the EGI proposal is an increase in costs over the 2024 through 2028 period of $108.5 million.

In its AIC, EGI argues that the inclusion of an earnings sharing mechanism should not apply to the year where rates are set based on a cost-of-service application, consistent with current practice (AIC, para. 761). EGI then goes on to state in paragraph 766 of its AIC that:

> Enbridge Gas's proposal is consistent with OEB policy, the regulatory process associated with cost-of-service proceedings and past practice for both EGD and Union. The ESM is not required for the test year 2024 as there is already 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.

Unfortunately, EGI does not want to be consistent with OEB policy or the regulatory process associated with cost-of-service proceedings or past practice of both EGD and Union when it comes to the PREP project. EGI wants to treat PREP as an ICM that comes into service in a cost-of-service proceeding. The reason for this is obvious: EGI does not want the revenue requirement to be reduced by $14.4 million in the 2024 base year because it would have to live with that reduction in 2024 base rates for the remainder of the IR term.

This point was hammered home by Mr. Rubenstein (Tr. Vol. 12, pages 28-29):

MR. RUBENSTEIN: So when you filed your application of PREP

-- sorry, when you filed your original application and PREP was included in the 2024 opening rate base, you -- and you had originally proposed a 2023 in service, there would have been a negative revenue requirement associated with that in 2023. Correct?

MR. VINAGRE: In 2023, yes. It was originally forecast in that manner.

MR. RUBENSTEIN: And you weren't proposing at that time to levellize the spending. So customers got the benefit of that negative revenue requirement in 2023. Correct?

MR. VINAGRE: That's a fair statement.

MR. RUBENSTEIN: And with respect to a whole host of other 2023 capital additions, same thing? There are many projects that have negative revenue requirements in the first -- in that year. You are not proposing to give customers the benefit of that, correct, with a levellized approach in 2024?

MR. VINAGRE: Not in a similar manner to the PREP project.

MR. RUBENSTEIN: So the benefit of that negative revenue requirement in 2023, that would have [audio dropout], to the benefit of the shareholder, correct?

MR. VINAGRE: Are we speaking to the original? Is that what you are asking about?

MR. RUBENSTEIN: To any project in 2023 that had a negative revenue requirement.

MR. VINAGRE: Ultimately, with all the puts and takes, yes, overall.

In summary, EGI was happy to have the tax benefit flow to its shareholder when PREP was scheduled to be in-service in 2023 and under IRM, but now that it has been delayed to 2024, the benefit should not be shared with ratepayers under cost of service. LPMA submits that the EGI proposal that impacts the 2024 revenue requirement is not consistent with OEB policy, the regulatory process associated with cost-of-service proceedings or past practice for both EGD and Union and other regulated distributors.

EGI further couches its justification for this proposal in that if the project is not approved, or the timing is different, or the costs are different, then no adjustment to base rates or revenue requirement would be necessary. LPMA submits that this is extremely misleading and disingenuous. If a project that is forecast to proceed in a test year does not actually proceed, or if the actual costs are different from the forecast costs, or if the project is placed into service before or after the forecast of when it was to be placed into service, there is no adjustment to either base rates or the revenue requirement under a cost-of-service proceeding.

The risk associated with the possibilities noted above should be borne by EGI, just as it bears the risk of other projects being deferred, cancelled, or coming in at a different cost than forecast in a cost-of-service test year.

LPMA finds it astounding that EGI wants to burden ratepayers with the significant additional – but unnecessary – costs so it can avoid the risk of the project not proceeding or being delayed, while at the same time asking the Board for a substantial increase in the equity component of its rate base.

In summary, LPMA submits that the Board should reject EGI's proposal for the levelized approach to recovery for PREP and direct EGI to include the project as being in-service in 2024, as forecast by EGI, with the resulting revenue sufficiency of $14.4 million built into the 2024 base rates.

iii. Integration Capital

As stated in Exhibit I.1.9-VECC-3 (Updated 2023-07-06), in-service additions related to integration projects totaled $189 million, of which $70 million will be fully depreciated at the end of 2023, leaving a net book value of $119 million that is proposed by EGI to be included in the 2024 opening rate base. The revenue requirement impact for 2024 is $28 million as shown in Exhibit I.1.9-SEC-89, of which $15 million is depreciation (based on the revised depreciation rates) with the remainder of $13 million related to interest expense, taxes and return on capital. The updated interrogatory expense also indicates that if the existing depreciation rates were used, the revenue requirement would be $47 million.

LPMA submits that the MAADs policy is clear in that integration costs are generally not recoverable through rates. EGI could have amortized the integration capital that was placed into service in 2019 through 2023 over the remaining length of the deferred rebasing period. This is similar to the treatment of franchises and consents that are often amortized over the remaining life of the franchise. This would have resulted in a net book value of $0 at the beginning 2024 and eliminated the need for the recovery of these remaining costs in rates.

LPMA has had the opportunity to review the Staff Submission with respect to the inclusion of integration capital in the opening 2024 rate base. While LPMA believes that none of the integration capital costs should be paid for by ratepayers, LPMA recognizes that some of the integration capital costs were for projects that were already forecast by the individual utilities prior to amalgamation. These costs would have been paid for by ratepayers over their lives as is the normal course. Based on this, LPMA supports the Staff proposal to include 50%, or $59.5 million of the $119 million, in open rate base for 2024. This recognizes that a portion of the expenditures were integration related and not recoverable through rates and a portion of the expenditures were operations related and recoverable through rates.

iv. <u>2023 In-Service Additions</u>

Under Issue 7 below, LPMA makes a number of submissions with respect to reductions to 2024 capital expenditures and in-service additions. As is noted there, the impact of the capital expenditures and the corresponding increase in in-service additions, has a very minimal impact on the 2024 revenue requirement.

This, however, is not the case when it comes to the revenue requirement for 2024 associated with the 2023 capital expenditures and in-service additions. As shown in Exhibit J13.15, the 2024 revenue requirement associated with 2023 capital additions is $131.8 million, as compared to the revenue requirement in 2023 of ($5.6) million in 2023. This difference is primarily associated with the decrease in tax in 2023 and the timing of the additions to rate base in 2023, which generally occur near the end of the year.

As shown in Exhibit 2, Tab 1, Schedule 1, Table 2 (Updated 2023-07-06), EGI has forecast capital expenditures in 2023 of $1,427.2 million, just slightly lower than the forecast of $1,470.3 million for 2024. As illustrated above, the impact on the 2024 revenue requirement associated with 2023 capital additions is $131.8 million while the impact of the 2024 capital additions is $3.5 million (see Issue 7 below). In other words, the revenue requirement impact of the 2023 capital additions is 37 times more than the impact of the 2024 additions.

LPMA submits that if the Board makes a reduction in 2024 capital expenditures, it should make a similar reduction to the 2023 capital expenditures. As noted above, the total spending in both years is similar.

If the Board determines that it does not have enough evidence to support a reduction in 2023 capital expenditures, then LPMA submits that the Board should approve an asymmetric variance account to protect ratepayers from paying for in-service capital additions that are forecast to take place in 2023 but do not actually occur. In other words, ratepayers should be protected from bridge year stuffing to inflate rate base and thereby base rates for in-service additions that do not take place in the bridge year. Any amounts placed into this account would be used to reduce the 2024 revenue requirement and base rates before any IR mechanism, such as the proposed price cap would be applied to generate 2025 rates. This would eliminate the potential for inflated base rates to be carried on throughout the IRM term.

v. <u>2024 Capital Expenditures</u>

LPMA's submissions with respect to 2024 capital expenditures are included under Issue 7 below.

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

LPMA makes a number of submissions with respect to areas where it believes the capital expenditures and in-service additions in 2024 should be reduced. However, LPMA notes that the impact of any such reductions as may be approved by the Board on the revenue requirement are very minimal. In particular, as shown in Exhibit JT4.25, the 2024 revenue requirement associated with the 2024 in-service capital additions is only $3.5 million. Of this amount, $2.8 million is associated with capital projects that do not require leave-to-construct applications, while the difference of $0.7 million is associated with projects that do require leave-to-construct approvals.

i. <u>Customer Additions & E.B.O. 188</u>

LPMA supports the revisiting of the 40-year revenue horizon associated with EGI's customer attachment policies, but believes that the Board should deal with the potential for substantial changes within a generic proceeding and not within the context of this proceeding to set rates for 2024. The issue of the 40-year revenue horizon and the other components of E.B.O. 188, including the customer attachment horizon and other parameters used in the calculations, should dealt with in a generic proceeding that involves all natural gas distributors. It should also take place in the context of energy transition after further guidance is provided from the Government of Ontario.

This generic review should be coincident with a review of the customer connection feasibility parameters for electricity customers that are set out in the Distribution System Code ("DSC"). EGI submits in its AIC (para. 278) that the different assets and asset lives associated with connection assets for gas and electricity connections support a different approach. EGI may well be correct, but the Board can only make that determination based on evidence from both the gas and electricity sectors. Different assets and asset lives are not likely to be the only factors that may impact the E.B.O. 188 and/or DSC parameters included in customer attachment policies. Customer attachment policies also hold the potential to move potential new customers in the direction that may come out of government policies related to energy transition.

In the meantime, LPMA supports the reduction of the revenue horizon to 30 years. This reduction from 40 years to 30 years reduces the capital expenditures related to customer additions in 2024 by $75 million from $304 million to $229 million (Exhibit J10.11), or a reduction of nearly 25% of the customer addition capital.

Reducing the revenue horizon has a more significant longer-term impact. As seen in the response to Exhibit J10.11, over the course of 5 years (2024-2028), the reduction in the revenue horizon from 40 years to 30 years is a reduction in capital expenditures of $124 million of the customer addition capital over this period.

These reductions would reduce the amount of potential stranded assets that may result from energy transition once government policies are known. If the Board were to determine that the risk for EGI has increased and that the equity component of the capital structure should be increased beyond 38%, then LPMA submits that the Board should shorten the revenue horizon even further in order to offset at least some of the perceived increase in risk and keep the increase in the equity component of rate base to 38%.

Assuming an equity component of rate base of 38% or less, LPMA cannot support the reduction in the revenue horizon to anything less than 30 years, <u>at this time</u>. While shorter periods will reduce capital expenditures by large amounts, the impact on potential new customers is not reasonable. For example, the increase in the contribution in aid of construction ("CIAC") from moving from 40 years to 20 years of revenue is an increase of $1,140 per customer (Exhibit J11.1). Such a significant increase or even larger increases associated with shorter revenue horizons, cannot, in the view of LPMA, be justified at this time given the lack of any concrete government policy that signals a significant change in energy policy within the province. Once the goal posts have been set by the government, the Board can review the customer attachment policies with respect to both natural gas and electricity with the goal of reaching the end zone within any time constraints imposed by the government.

ii. Natural Gas Expansion Program

EGI has proposed to include the original estimated net capital costs of its Natural Gas Expansion Program ("NGEP") funded projects what are forecast to be in-service by the end of 2024 in the 2024 rate base, regardless of the current estimated net capital costs. EGI states that in its view, this is consistent with the Board's decision in the EB-2020-0094 Decision and Order dated December 4, 2020. In that Decision and Order the Board stated:

"The OEB finds that inclusion of the forecasted capital costs in the rate base at the next rebasing before the end of the RSP is consistent with the ***Generic Decision's requirement for a Community Expansion Project and would achieve the desired goal that Enbridge Gas bear the risk of any capital cost overrun during the RSP****. The OEB also finds that the treatment of actual capital costs at the time of rebasing following the rate stabilization period is appropriately the jurisdiction of the panel reviewing the rate rebasing case."* (emphasis added).

LPMA agrees with the EGI position but only with respect to the NGEP projects where the most recent cost estimates or actuals exceed the original estimated net capital costs. In these instances, EGI will assume the risk of cost overruns and lower connection rates during the rate stability period.

However, the Selwyn project has an updated capital cost of $2.8 million, which is approximately $1.5 million less than the original net capital cost of $4.4 million

(Exhibit I.2.6-Staff-74, Table 2). This project is forecast to be in-service in 2024. EGI has included the original net capital cost of $4.4 million in the in-service additions to rate base in 2024 despite the updated and lower net capital cost.

On the face of it, this may appear that EGI is consistent with the Board's statement in EB-2020-0094 noted above. However, in proposing $4.4 million rather than $2.8 million to be included in rate base, EGI would recover costs that are not expected to be incurred during the rate stability period. EGI would be shifting the risk associated with the Selwyn project onto ratepayers. LPMA submits that this is not consistent with the Board's desired goal that EGI bear the risk of any capital cost overrun during the rate stability period.

LPMA submits that the Board should direct EGI to only include the current net capital costs of the Selwyn project of $2.8 in the 2024 rate base, a reduction of approximately $1.5 million from that proposed by EGI.

iii. System Reinforcement Costs

EGI is forecasting system reinforcement costs of $85.2 million, which includes $9.5 million associated with its hydrogen blending project (Exhibit 2, Tab 5, Schedule 2, page 8, Updated 2023-07-06).

LPMA submits that the remaining $75.7 million in system reinforcement costs should be reduced by 12.5% or $9.5 million. This reduction of 12.5% is one-half of the approximately 25% reduction in customer additions capital costs of moving from a 40 year to a 30 year revenue horizon noted above. LPMA believes some customers will not connect to the distribution system due to requirement to pay an increased CIAC. LPMA believes that a 12.5% reduction, one-half of the reduction in customer capital is a reasonable estimate.

LPMA further submits that if the Board directs EGI to reduce the revenue horizon for new customers to something below 30 years, then the reduction to the system reinforcement projects should be correspondingly higher than that proposed by LPMA.

iv. Compressor Stations

LPMA has reviewed the Staff Submission with respect to the recommendation of a reduction in 2024 capital expenditures related to compressor stations of $8.5 million. LPMA supports the rationale for this reduction and submits that the $8.5 million identified by EGI related to the Multi-Sector Air Pollutants Regulations that have been in place for several years should be absorbed in the capital budget.

v. Integrity Digs

LPMA has reviewed the Staff Submission with respect to integrity digs (pages 60-62) and is in general agreement with those submissions. In particular, LPMA submits that EGI has provided no evidence to support the increase in the 2024 budget as part of capital update to $100.9 million as compared to the original forecast of $73.2 million. Using the original forecast would result in a reduction in the capital expenditures of $27.7 million.

Staff submits that the amount included in the 2024 capital budget should be levelized at the average of the 2025 through 2028 period, which would result in a budget of $46.3 million. While LPMA supports a levelized approach for integrity digs, it is submitted that the original forecast for 2024 should be included in the average. The average of 2024 through 2028 would reduce the capital budget from $100.9 million to $51.7 million, a reduction of $49.2 million.

vi. St. Laurent

For the same reasons expressed above under Issue 6 related to the inclusion of PREP in rate base in 2024, LPMA submits that the forecasted St. Laurent in-service capital additions should be included in rate base and not recovered through the levelized treatment like PREP as recommended by Staff.

As noted by Ms. Dreveny (Tr. Vol. 12, page 25), the inclusion of the $75.7 million in-service cost of the St. Laurent projects in 2024 reduces the 2024 revenue requirement because the project has a sufficiency of $2 million in 2024. Staff's recommendation for the treatment of this project would result in customers paying more, not only for 2024, but for all of the IR years that follow. If the project goes ahead, as with other 2024 projects, it is added to rate base and the impact in 2024 is included in base rates (i.e. the sufficiency of $2 million). EGI should shoulder the risk of the project not being approved and base rates being set $2 million lower than they would otherwise be in base rates. Ratepayers should not be exposed to this risk.

vii. Summary

The following table shows the reductions to the 2024 capital expenditures as proposed by LPMA. Figures shown are in millions of dollars.

Customer Additions	75.0
Natural Gas Expansion Program	1.5
System Reinforcement Costs	9.5
Compressor Stations	8.5
Integrity Digs	49.2
Total	143.7

Based on the July capital update the forecasted capital expenditures for the 2024 test year are $1,470.3 million (Exhibit 2, Tab 5, Schedule 3, Table 6). The proposed capital reductions proposed by LPMA and summarized in the above table represent a decrease of just under 10%. LPMA submits that this is a reasonable reduction and that EGI should be able to maintain a safe and reliable distribution system with a capital expenditure budget that still exceeds $1.32 billion.

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

LPMA submits the Board should approve the overhead capitalization methodology as proposed by EGI. No other methodology has been sufficiently tested as part of this proceeding. LPMA does, however, submit that the Board should direct EGI to investigate other methodologies once the Government of Ontario has provided direction with respect to energy transition.

The overhead capitalized amount of $292 million is a significant portion of the capital expenditures and in-service additions that are added to rate base each and every year.

While much of the focus in this proceeding centered around the use of accelerated depreciation to reduce the growth in rate base in order to reduce the quantum of potential stranded assets as a result of some energy transition pathway, there was virtually no mention of how reducing capitalized overhead amounts could also result in the lessening of rate base and the reduction of potential stranded assets. This is an issue that should be reviewed in the context of energy transition when the Government of Ontario policy is known.

LPMA has had the opportunity to review the Staff Submission with respect to this issue and note that Staff do not oppose EGI's proposed harmonized capitalized overhead methodology, subject to two items.

The first Staff requirement is that the Board direct EGI to quantify, on a best-efforts basis, the indirect costs that would not be eligible for capitalization without regulatory approval as per US Generally Accepted Accounting Principles ("USGAAP") at its next rebasing application.

LPMA supports this requirement for two reasons. First, it would be useful for the Board and interested parties to know and understand the magnitude of the change if regulatory approval is not given in the future and EGI remains under USGAAP or if EGI can no longer use USGAAP in the future. Second, this information could also inform the Board and parties of another option to dealing with the potential of stranded assets once energy transition policy becomes clearer.

LPMA takes no position on the second proposed Staff requirement that a revision to the way the Operation Regions capitalization rate is determined. It is not clear to LPMA what the impact of this change would be, or whether it would be material.

LPMA's submissions with respect to the appropriate impact on operating and maintenance expenses of any change in the capitalized overhead amounts is provided below under Issue 12.

10. Is the 2024 other revenue forecast appropriate?

The unsettled issues with respect to other revenues are related to the dispositions of property in both 2024 and subsequent years and the appropriate treatment of the Natural Gas Vehicle ("NGV") Program. LPMA's submission with respect to the NGV program are provided below under Issue 34.

With respect to the disposition of properties, EGI proposes that other revenues should exclude any forecast of property disposition gains or losses. EGI did, however, propose that any proceeds from the sale of land that had been included in rate base would be included in other income and shared with ratepayers as part of any earnings sharing mechanism that is approved by the Board over the IRM period. Gains and losses on depreciable assets, such as buildings, are accounted for in adjustments to accumulated depreciation and are not included in other income.

LPMA notes EGI's comments with respect to the disposition of properties related to the uncertainties around timelines and property values that are in turn impacted by market conditions, availability of replacement sites, zoning, permitting and construction issues. This lack of certainty and changing timelines was evident in this proceeding as part of the capital update in June 2023 that reduced the number of property dispositions from four to one in the 2024 test year, with the proceedings dropping to $6.3 million from the original forecast of $31 million.

LPMA agrees with EGI that these are legitimate concerns and agrees with EGI that any property disposition gains or losses related to land should not be included in other revenue.

As noted in the Staff Submission (page 72), the extent to which the Board may consider the sharing of any proceeds from the disposition of property with ratepayers could be dependent on the details of the property that was sold.

LPMA supports the submission of Staff that the Board should establish a deferral account to track any proceeds from property sales over the course of 2024 and any approved IRM term. The disposition and allocation of any amounts in this account should be determined on a property-by-property basis in the future when EGI brings forward balances in the account for disposition.

12. Are the proposed 2024 Test Year operating and maintenance expenses appropriate?

As part of the Settlement Agreement, parties agreed to an overall operating and maintenance expense budget envelope. However, it was left open for parties to argue that a different capitalized overhead amount would be appropriate if a different overhead capitalization methodology was approved and/or if a different capital budget was approved.

The Settlement Agreement stated that in the event that the Board approves a capitalized overhead amount that is different from $292 million, all Parties agree that any resulting adjustment of the O&M budget being recovered as capitalized overhead is an item for Parties to argue and the Board to consider.

As noted above under Issue 8, LPMA submits the Board should approve the overhead capitalization methodology as proposed by EGI.

If the Board approves a different capital budget, EGI's position is that the total amount of capitalized overhead will not change (Tr. Vol. 15, pages 130-133). The allocation of the amounts to asset classes and individual projects will change, but the total will remain the same.

This position is premised on the total internal costs of EGI remaining the same regardless of the amount of capital projects to be completed in the year. While LPMA believes that this may be reasonable for a relatively small change in the level of capital projects, it may not be reasonable for a large change in capital expenditures.

If the Board determines that there should be a large change to the capital budget, LPMA submits that the Board should also determine whether it is reasonable to assume that there would be no change in internal resources used by EGI or whether there should be a reduction in internal resources that mirrors the reduction in capital projects. This would result in less than 100% of the reduced capitalized overhead amount being added to the operating and maintenance expenses.

15. Are the proposed harmonized depreciation rates and the 2024 Test Year depreciation expenses appropriate?

As shown in Exhibit J17.11, EGI is forecasting a gross revenue deficiency of $186.3 million. This is despite a sufficiency of $57.8 million related to the deferred rebasing impact and a further sufficiency of $81.4 million related to settled issues.

The impact of the new depreciation study is a revenue deficiency of $187.5 million, or 101% of the total revenue deficiency forecast by EGI. In terms of the impact on ratepayers, the increase in the depreciation expense is the largest driver of the increase in rates.

Based on the existing depreciation rates and methodology, the 2024 depreciation expense would be $737.1 million (Exhibit J16.5, Att. 1). Based on the proposed methodology and rates, this rises to $879 million (Exhibit J17.1, Att. 1), for an increase of $141.9 million.

LPMA submits that this accelerated depreciation may be warranted to offset the potential for faster asset retirements due to energy transition. However, during the hearing, EGI has noted that the use of renewable natural gas, hydrogen blending, hybrid heat pumps and the use of the gas system to provide reliability and resilience in the provincial energy system would continue to require the assets to be utilized. In other words, in the energy transition envisioned by EGI, there would be no need for accelerated depreciation.

LPMA has had the opportunity to review the Staff Submission with respect to this issue. LPMA supports and adopts the Staff submission with respect to the use of the Average Life Group (“ALG”) instead of the Equal Life Group (“ELG”) proposed by EGI and Concentric.

LPMA notes that both InterGroup Consultants Ltd. (“InterGroup”) and Emrydia Consulting Corporation reviewed the EGI and Concentric proposals to move to ELG. Both experts did not support the change to ELG and recommended that the ALG approach be used.

EGI and Concentric have indicated that moving to the ELG methodology is a good first step in addressing energy transition as it results in a higher depreciation expense (and a lower net book value of assets). However, EGI's capital budget, for the most part, ignores energy transition with capital expenditures continuing to assume the status quo. EGI has indicated that it does not expect to see material impacts over the 2024 to 2028 period related to energy transition (Technical Conference, March 23, 2023, pages 74- 75):

> MR. SHEPHERD: That is non-responsive, sorry. The energy transition changes that you have assumed will have happened between now and 2028, none of them are material; is that right?
> MS. WADE: I think we note in our evidence that, yes, we have assumed energy transition assumptions and we don't expect to have large material impacts in the rebasing period.

Given that EGI does not expect large material impacts from energy transition over the next 5 years, and given that depreciation studies are reviewed as part of a rebasing application which is expected in 5 years, there is no need, in the view of LPMA, for a significant change in depreciation methodology and lives at this time.

LPMA also adopts the Staff recommendations for adopting the asset life parameters as proposed by InterGroup and the net salvage method and parameters based on the InterGroup calculation methodology of Constant Dollar Net Salvage.

Finally, LPMA submits that the Board should direct EGI to investigate other depreciation methodologies and asset lives should energy transition take a path not contemplated by EGI. These methodologies would include, but not be limited to, an economic planning horizon and a unit of production approach. LPMA further submits that such a study should only take place after EGI and other parties have had adequate time to understand the yet to be released government directions, policies and legislation related to energy transition.

16. Are the proposed 2024 Site Restoration Costs appropriate, and should the OEB establish a segregated fund for the Site Restoration Costs?

LPMA has reviewed the submission of EGI with respect to this issue at paragraphs 528 through 536 of the AIC and agrees with EGI that the Board should not establish a segregated fund for site restoration costs.

As noted in the AIC, none of the depreciation experts in this proceeding advocated for the use of a segregated fund at this time.

LPMA notes that as indicated in Exhibit J17.10, establishing a segregated fund would increase costs to ratepayers by $93 million in 2024 and that this cost would increase in subsequent years.

LPMA further notes that the current approach to net salvage costs in the depreciation study appear to be adequate to ensure that removal costs are covered, with EGI accumulating an additional $1.6 billion of net site restoration costs. LPMA also notes that if site restoration costs increase significantly or if assets are retired and removed faster than anticipated, these changes will be accounted for and reflected in, the next depreciation study. LPMA submits that the Board should direct EGI to file an updated depreciation study as part of its next rebasing application.

Finally, LPMA notes that EGI has indicated that it could not find any example of other utilities using segregated funds for site restoration costs and that the net salvage approach is commonly used by many utilities across North America.

For all of the above reasons, LPMA does not support the establishment of a segregated fund for site restoration costs at this time.

17. Are the proposed 2024 income and property tax expenses appropriate?

LPMA has no issues with the methodology used by EGI to calculate income and property tax expenses for 2024. The amount of the tax expenses cannot be determined until the Board issues its decisions related to other matters that are to be determined, such as the equity component of rate base and in-service capital additions.

LPMA submits that EGI should provide sufficient information for the Board and interested parties on the calculation of the tax expenses as part of the Draft Rate Order ("DRO") so that the parties can verify the calculations and the amounts.

18. In relation to the 2024 Test Year gas cost forecast, f) Is the 2024 Test Year Parkway Delivery Commitment Incentive (PDCI) Forecast appropriate?

LPMA has reviewed the Staff Submission (pages 101-105) with respect to this issue and adopts that submission as its own. In particular, LPMA submits that the Board has sufficient evidence on this issue to make a determination that it should not make any adjustments to the 209 to 2023 PDC/PDI costs that have been recovered from ratepayers.

20. Is the proposed 2024 Capital Structure, including return on equity, appropriate?

EGI currently has an equity component of rate base of 36% and proposes to increase that to 42%. LPMA submits that the Board should approve an equity component that is no higher than 38%.

EGI's proposal of 42% was supported by the evidence filed by Concentric. Concentric concluded that energy transition was the most important factor increasing the business risk of EGI and recommended a minimum equity thickness of 42%.

Board Staff retained London Economics International LLC ("LEI") to assess the EGI and Concentric cost of capital evidence and provide an independent assessment of that evidence and to provide a recommendation for a deemed equity thickness. LEI recommended an increase in the deemed equity thickness to 38%.

IGUA retained Dr. Cleary as its cost of capital expert who also provided an independent assessment of the EGI and Concentric evidence. Dr. Clearly concluded that there was no increase in EGI's business risk and recommended that the equity thickness remain at the current level of 36%. IGUA also retained Dr. Hopkins to perform an independent assessment of the impacts of energy transition on EGI's financial metrics and business risk. Dr. Hopkins concluded that EGI's business risk had not increased, in part due to the uncertainties related to energy transition.

Much of the evidence provided by EGI and Concentric – which indicated in its analysis that energy transition was the most important factor increasing the business risk of EGI – is not actually supported by the EGI witnesses.

The following exchange between Mr. Shepherd (SEC) and Ms. Wade (EGI) at the technical conference summarizes the evidence in this proceeding with respect to energy transition and the impact of energy transition between now and 2028 (Technical Conference, March 23, 2023, pages 74-75):

> MR. SHEPHERD: Thank you. I want to make sure that I don't miss any of these things from yesterday. I want to turn now to -- I may come back to some of these. I want to turn now to some of the interrogatory responses, and starting with SEC -- I.1.2-SEC 1.
>
> This is a question for Enbridge.
>
> Your application does not assume the changes in the energy market that are in the Guidehouse study, right?
>
> MS. WADE: Cara-Lynne Wade, Enbridge Gas. Our

> application assumes the energy transition changes that will occur over the rebasing period.
>
> MR. SHEPHERD: And you're assuming that there are none or not material until after 2028; is that right?
>
> MS. WADE: The energy transition assumptions are -- we have considered them and they are included within the evidence, yes.
>
> MR. SHEPHERD: That is non-responsive, sorry. The energy transition changes that you have assumed will have happened between now and 2028, none of them are material; is that right?
>
> MS. WADE: I think we note in our evidence that, yes, we have assumed energy transition assumptions and we don't expect to have large material impacts in the rebasing period.
>
> MR. SHEPHERD: Thank you.

In addition to stating that energy transition is not expected to have a large material impact in the rebasing period, EGI noted a number of reasons why it expected that the gas system would continue to be utilized for the foreseeable future. These reasons include the increased use of renewable natural gas, the inclusion of hydrogen blending into the gas supply and the potential of moving to 100% hydrogen.

LPMA also notes that EGI spoke often about the resilience and reliability benefits provided by the gas system relative to the electricity system. Ms. Giridhar stated (Tr. Vol. 10, page 179):

> MR. RUBENSTEIN: Well, that was 2050. I'm talking 2064. We're talking about the 40-year connection horizon. Is it your expectation that customers who connect in 2024 will be on the system in 2064?
>
> MS. GIRIDHAR: They could be. I think, as we have -- we are very clear that the unabated use of natural gas has to decline to meet climate goals, and we are also very clear that non-emitting electricity would play a very significant role. So,

> while we have modelled -- while Guidehouse modelled these two scenarios, you know, there is myriad scenarios in between, but one that we actually think could play out, depending on government policies, is that people stay connected to the gas system. It becomes a reliability and resilience play. At that point, obviously, the amount of energy that is used is vastly lower than what is used today, because of a combination of energy efficiency, high-efficiency appliances, and so on. And the need for the gaseous fuel on the occasions that it is used is addressed through low-carbon fuels, but it would be a much lower number than what is being used today. So we see that as entirely possible.

Ms. Giridhar continued to express the view that EGI would transform itself based on the ability to provide reliability and resilience (Tr. Vol. 17, page 11):

> As you've heard me say repeatedly in the course of this proceeding, Enbridge Gas sees itself transforming into an entity that delivers -- I mean, it will go from delivering energy to today to largely delivering energy, when needed, in support of the entire energy system; so the points that I've made about reliable and resilience, and so on.

On behalf of EGI, Ms. Wade made a similar statement, indicating that EGI believes that it would be able to leverage its system as it is today to continue to provide value to customers (Tr. Vol. 11, page 167):

> MR. RUBENSTEIN: And, as I heard from earlier panels, including the customer connection panel, the company doesn't know its future perfectly, with either RNG or hydrogen, as Ms. Giridhar mentioned, essentially as a backup on the coldest winter days. Do I have that correct?
>
> MS. WADE: I would say, at this point in time, we are not entirely sure if it would just be a backup from a resilience play, for example, if customers have electrified and are maintaining it for

resilience and/or for backup for, say, a hybrid heating perspective, that's right.

MR. RUBENSTEIN: And in each of those scenario, the hydrogen-RNG scenario or the hybrid heating scenario that you're talking about, as I understand it is still going to involve lots of pipes and lots of capital assets. Correct?

MS. WADE: It would be leveraging our system as we have it today. That's correct.

Finally, in the exchange between Mr. Mondrow, Ms. Dreveny and Ms. Giridhar (Tr. Vol. 16, pages 95-97), EGI confirmed that it did not see large retirements of its assets as a reasonable possibility in either the near or medium term. With respect to the longer term, Ms. Dreveny indicated that it would depend on how energy transition unfolds in Ontario, but at this time, EGI believed the diversified pathway was the best way forward to manage this. Ms. Dreveny concluded that with respect to the longer term, there was not necessarily an immediate concern there either.

LPMA submits that EGI's evidence with respect to the potential impact of energy transition is clear. EGI may have to pivot from delivering natural gas to delivering reliable and resilient energy to Ontario customers. However, this would be done using the system as it is today. Clearly, EGI is not concerned with the potential for stranded assets as the result of energy transition.

LPMA agrees with the submission of Staff that the amalgamation of Union Gas ("Union") and Enbridge Gas Distribution ("EGD") has reduced the risk of EGI since the last time that the cost of capital was reviewed for the predecessor utilities. Not only is EGI larger in terms of the number of customers than the three largest electricity distributors in Ontario, as noted in the Staff Submission (page 109), it also has other benefits over the electricity distributors.

EGI benefits from significant diversity relative to the electricity distributors in Ontario. This diversity includes geographic diversity and economic diversity.

Each of these factors play an important role not only in comparison to electricity distributors but also with the predecessor utilities.

The geographic diversity of EGI combines significantly different regions of Ontario that were previously served by Union and EGD. While EGD was centered around the large cities of Toronto and Ottawa, the Union franchise encompassed northern Ontario, eastern Ontario and southwestern Ontario. These areas are more rural in nature than that of EGD and have a more industrial and manufacturing focus as compared to the commercial focus of EGD. Combined, EGI now has a more diversified customer base than either of the predecessor utilities, reducing the impact on EGI of a slowdown in one industry or one region of the province.

With respect to the electric distributors, only Hydro One has a geographic diversity comparable to EGI and even then, Hydro One lacks the large metropolitan areas served by EGI.

As we have seen in recent past, the impact of weather on electric distributors can be significant with significant outages and the need to replace significant assets as the results of storms in both the summer and winter. At the same time, given that most of its assets are shielded from storms, EGI faces significantly less weather-related risk in terms of its assets. As noted above, EGI spoke often about the resilience and reliability benefits provided by the gas system relative to the electricity system. Commissioner Moran and Mr. Dane spoke about this in some detail (Tr. Vol. 9, pages 47-48).

Under Issue 32 below, LPMA provides submissions with respect to the proposed volume variance account that would provide EGI revenue protection from not only differences in average use per customer between the forecast and actual levels but also driven by variances in the weather from that forecast. This account would apply to all general service customers, which makes up the vast majority of EGI's distribution revenues. LPMA has submitted that the volume variance account, if approved by the Board, should continue to cover only differences in average use, as is currently the case. This would result in no additional business risk for EGI. LPMA opposes the inclusion of weather risk in that variance account for the reasons stated in Issue 32. LPMA submits that if the Board were to approve an equity thickness in excess of 38% it should not approve the inclusion of the weather risk in the account.

For all of the reasons noted above, LPMA submits that there is no evidence in this proceeding that supports assertion that EGI's business risk has increased. As a result, LPMA submits that the equity thickness should remain at 36%. However, if the Board determines that EGI's risk has increased, then the Board should approve an equity thickness of no more than 38%.

22. Is the proposed phase-in of increases to equity thickness over the 2024 to 2028 term appropriate?

EGI has proposed a phase-in based on their request of an increase in equity to 42%, starting at 38% in 2024 and increasing by 1 percentage point per year through 2028. If the Board determines that an increase of up to 38% is appropriate, then LPMA submits that there is no need for the phase-in.

On the other hand, if the Board approves an increase in the equity component to more than 38%, then LPMA submits that a phase-in to the increase may be needed. If the bill impacts that result from the overall findings of the Board in Phase 1 are significant enough to require mitigation, a phased-in approach may be necessary. If the Board approves an increase in the equity component to more than 38%, then LPMA submits that the Board should require EGI to make a proposal with respect to rate mitigation on the overall bill impacts from the

Board's decision in its draft rate order. The Board should then ask interest parties for their input on what, if any, phase-in is necessary.

23. Is the proposed 2024 Test Year Revenue Deficiency calculated correctly?

In the absence of a Board decision on a number of Phase 1 issues that have the potential to impact the calculation of the 2024 test year revenue deficiency, LPMA can only comment that the methodology used by EGI in the updated evidence to calculate the revenue deficiency is appropriate.

LPMA submits that EGI should submit sufficient detail as part the DRO to allow parties to verify the calculation of the test year revenue deficiency, and the allocation of that amount to the various rate classes.

29. Are the proposed miscellaneous service charges, including Rider G and Rider M, appropriate?

LPMA is providing submissions with respect to the proposed Extra Length Charge ("ELC") proposed by EGI for residential services beyond 20 metres in length. This proposal would harmonize the different rates currently charged in the Union and EGD rate zones. LPMA supports the proposal to move to a harmonized policy.

LPMA understands that the level of charge per metre beyond the initial 20 metres may need to change from that proposed by EGI if the Board changes the customer revenue horizon to be used in the customer attachment policy, which is dealt with under Issue *7.*

LPMA submits that if the Board does make a change to the customer attachment policy, it should direct EGI to provide the necessary information and alternatives in the draft rate order for the Board to determine the appropriate level of the charge.

32. Is the proposal to close and continue certain deferral and variance accounts and establish new ones appropriate?

i. Volume Variance Account

EGI currently has an Average Use True-Up Variance Account for the EGD rate zone and a Normalized Average Consumption Account for the Union rate zones. Both of these accounts record the revenue impact, exclusive of gas costs, of the difference between the forecast average use per customer for the general service rate classes and the actual weather normalized average use experienced during the year. Neither of these accounts recorded any amounts related to the revenue variance due to weather.

EGI proposes to close both of these accounts and replace these existing variance accounts with a new account for the merged utility. This Volume Variance Account would record the revenue impact, again exclusive of gas costs, of the volumetric forecast variance resulting from actual average use per customer and weather experienced during the year for the general service rate classes as compared to what is included in the forecast.

LPMA submits that the Board should approve the closure of the existing average use true up accounts. LPMA submits that the Board should approve a new volume variance account that only records the revenue variance due to differences in normalized average use between the forecasted amounts and the actual amounts. In other words, the weather forecast risk would remain with EGI, as it currently is.

In a cost-of-service application, rates are set on a forward-looking forecast basis. This forecast includes the cost of capital, customer attachments, operating and maintenance costs and volume forecasts based on a heating degree forecast.

EGI is at risk for their forecasts for all of these elements that flow into the traditional cost-of-service and the Board should not remove weather from that list.

LPMA further submits that the inclusion of weather risk is tied to the level of the equity component in rate base. Elimination of the weather risk for all general service customers results in a significant reduction in revenue risk to EGI. If the Board does give EGI the volume variance account as proposed that eliminates the weather risk, then LPMA submits that the Board should take this risk reduction into account when determining the appropriate equity component for EGI.

ii. Panhandle Regional Expansion Project Variance Account

As noted under Issue 6 above, LPMA is opposed to the treatment of the PREP costs proposed by EGI. This levelized approach significantly increases costs to customers, reduces risk to EGI and is not consistent with cost-of-service applications.

If the Board agrees with LPMA and directs EGI to include the PREP project in rate base in 2024, then LPMA submits that this proposed account is no longer required.

iii. Short-term Storage and Other Balancing Services Account (Union rate zones)

This account, which has been in place for the Union rate zones before and during the deferred rebasing term, records the actual net revenues for short-term storage and balancing services, less a 10% shareholder incentive to provide these services, and less the net revenue forecast for these services approved by the Board for rate-making purposes.

The Settlement Proposal indicated that matters related to gas storage would be determined in Phase 2 of the current proceeding and that EGI would maintain its current levels of market-based storage.

In its AIC (para. 671), EGI indicated that it had inadvertently failed to include the need to continue this account for the Union rate zones and that there would continue to be excess utility storage space in the legacy Union rate zones until at least a determination on storage is made by the Board in Phase 2 of this proceeding.

EGI has requested the continuation of this account. LPMA supports the continuation of this account, at least until a determination on storage matters is made in Phase 2 of this proceeding.

33. Is the proposal to dispose of the forecast balances in certain deferral and variance accounts appropriate?

i. <u>Tax Variance Deferral Account ("TVDA")</u>

The balance in this account, which is associated with the integration capital projects that were completed during the deferred rebasing term has a credit balance of $7.3 million (Exhibit J15.1). EGI is proposing to clear the balance in this account to ratepayers. This is based on EGI's proposal to include the undepreciated cost of the integration capital projects in the opening 2024 rate base. The net book value of these integration capital projects is $119 million with a revenue requirement impact of $28 million in 2024.

LPMA submits that if the Board accepts the EGI proposal to include all of the remaining undepreciated capital costs in rate base, then the balance in the TVDA should also flow in its entirety to ratepayers. Similarly, if the Board determines that no portion of the remaining undepreciated capital cost should be include in the 2024 rate base, then the balance in the account should accrue to EGI. In the event that the Board determines that only a portion of the remaining undepreciated capital cost should be included in the 2024 rate base, then LPMA submits that the TVDA balance should be split in the same proportion between ratepayers and EGI.

ii. Accounting Policy Changes Deferral Account ("APCDA")

LPMA's submissions with respect to the APCDA are limited to the pension and OPEB expense related to the unamortized pre-2017 actuarial losses and prior service costs. This account represents a cost to ratepayers of $156.0 million in the APCDA, with all the other components in the account totaling a credit to ratepayers of $15.8 million.

Included in the $15.8 million credit is a credit of $36.5 million for overhead capitalization. LPMA notes and supports the Staff comment that if the Board approves a change to EGI's proposed overhead capitalization methodology which was implemented in 2020, then this change should be reflected in the overhead capitalization amount in the APCDA.

With respect to the pension and OPEB amount of $156.0 million, LPMA has had the opportunity to review the detailed submission of Staff related to this issue (Staff Submission, pages 124-127), and adopts those submissions. In particular, LPMA supports the recovery of $75.8 rather than the $156 million proposed by EGI. EGI has over-recovered $80.2 million over the 2019 through 2013 period, as shown in Table 22 of the Staff Submission.

34. Is the proposed regulatory treatment of the Natural Gas Vehicle Program appropriate?

As set out in its AIC (para. 742), EGI proposes regulatory treatment for the NGV program that would i) continue the NGV program as an ancillary activity for the utility; ii) expand the NGV program to all EGI franchise areas and iii) modify the current regulatory treatment to remove the requirement to impute revenue when the achieved annual rate of return does not meet or exceed the required rate of return. This would mean that the NGV program is funded solely by the monthly service fees charged to participating customers.

EGI supports these proposals based on two main assertions. First, the NGV program is funded entirely by participating customers and there is no subsidization from other ratepayers. In 2024, the NGV program is forecast to produce a small revenue sufficiency. Second, EGI states there is no fully functioning competitive market for turnkey NGV solutions.

LPMA generally supports the continuation of the NGV program as proposed by EGI, but with a number of caveats.

The first caveat is that the Board should direct EGI to file with the OEB and interested parties a report setting out the annual revenue and costs, including the rate of return, of the NGV Program on an annual basis. This annual report would allow parties to assess the performance of the NGV program under EGI's proposed framework. In the response provided at Exhibit I.1.14-Staff-43, part (d), EGI indicated that it would be open to considering the filing of a mid-term report in 2026. LPMA does not believe this is adequate for a couple of reasons. First of all given that the term of the IRM period has not yet been determined as it is a Phase 2 issue, the concept of a mid-term report has no meaning at this time. Second, a report in 2026 would only show actual results for 2024 and 2025. LPMA submits that annual filings are important in order for parties to be able to review any trends or changes that may take place in the future on a timely basis so changes can be made, if necessary, to ensure that ratepayers do not subsidize the NGV Program participants.

Secondly, with respect to the EGI position that there is no fully functioning competitive market for turnkey NGV solutions, LPMA notes the response to part (f) of Exhibit I.1.14-ED-80 that there are competitive markets for fuel cylinders, VRAs and tube trailers in Alberta, Quebec and British Columbia, as well as competitive markets in Albert and Quebec for refueling facilities, while only British Columbia has a regulated market for these facilities. LPMA believes that the Board should direct EGI to investigate the potential for a competitive market for these NGV services in Ontario and report back to the OEB as part of its next rebasing application. The report would include any and all efforts made by EGI to facilitate a competitive market for its ancillary services. LPMA is concerned that the continuation of the regulated ancillary services may be a contributing cause to the lack of a competitive market in Ontario, when there is already competition in a number of other large provinces.

37. Is it appropriate to have an earnings sharing mechanism for 2024?

EGI argues that the Board should not approve an earnings sharing mechanism ("ESM") for 2024 and that no ESM deferral account is needed for 2024. This proposal is based on the fact that 2024 rates are being set on a cost of service basis and is consistent with the current practice of no ESM for a cost of service test year. EGI is proposing an ESM for the IR term from 2025 to 2028. Since this is a Phase 2 issue, LPMA is not providing any submissions with respect to an ESM for the IRM term.

With respect to the need for an ESM for the 2024 test year, LPMA understands the position of EGI, but strongly believes that there is a need for an ESM for the 2024 test year if the Board approves either an increase in the equity component of EGI's capital structure or the proposed levelized rate treatment for PREP then it should also approve an ESM for 2024.

If the Board determines that there is sufficient evidence to support an increase in the equity component of rate base for 2024 to a level above the current 36% level because of increased risk to EGI in 2024 (the only year for which rates are being sought in Phase 1 of the application) then LPMA submits that this increase in risk for EGI is also an increase in risk for ratepayers.

Despite the lack of evidence to support an increase in risk to EGI from energy transition in 2024, if the Board were to determine that there is an such an increase, then the risk to ratepayers in 2024 also increases because EGI is being granted additional revenues for risks that may not actually come into existence or even during the proposed IRM term through 2028. As noted above in Issue 22, EGI's own evidence states that they do not expect energy transition to have any large material impacts in the rebasing period. LPMA submits that to reward EGI with a larger equity component of rate base for potential changes in risk without providing ratepayers a safety net from paying for excess amounts in rates is neither just nor reasonable.

EGI also argues that consistent with current practice, there should be no ESM for the 2024 test year. However, EGI is proposing to break with current regulatory practice by not including PREP in rate base for 2024 even though that is when their own forecast expects it to be placed into service. In fact, EGI is proposing to treat PREP in a similar manner to an ICM project, despite the project being forecast to enter rate base in the 2024 test year (AIC, para. 665). Clearly this is not consistent with current practice, and as noted in Issue 6, above, this results in a significant increase in costs to ratepayers in both 2024 and in any IRM term that follows. Again, should the Board determine that it is appropriate for EGI to deviate from the current practice of adding this project to rate base in the test year as is the norm, then it should also deviate from the current practice of not establishing an ESM for a cost-of-service test year.

If the Board does establish an ESM for 2024, then LPMA submits that the associated deferral account should be asymmetric so that only earnings above a deadband would be refunded to ratepayers. The deadband should be set at 150 basis points if the approved equity component is 39% or less and 100 basis points if the approved equity component is above 39%. This provides additional protection to ratepayers if the Board were to approve a higher equity component for 2024 than if it approves a lower figure.

38. How should Dawn Parkway capacity turnback risk be dealt with?

The Dawn Parkway system connects the Dawn Hub to eastern parts of Ontario, Quebec and the U.S. northeast. The utilization of the Dawn Parkway system has increased over the last decade, but there is concern on the part of some parties that the utilization of this system may decline. Much of this concern is centered around ex-franchise customers not renewing their contracts for capacity with the result that in-franchise customers would be left with a higher allocation of costs associated with a system that is underutilized.

As shown on line 1 of Table 1 in Exhibit 2, Tab 7, Schedule 1, the total Dawn Parkway system capacity is 7,981 TJ/d, and the peak demand on the system is 7,892 TJ/d, leaving the difference of 89 TJ/d as surplus capacity.

As explained by Ms. Mikhaila (Tr. Vol. 7, pages 178-179), the full cost of the Dawn Parkway system (including the cost associated with the 89 TJ/d of surplus capacity) is included in the 2024 test year revenue requirement. The rates proposed for 2024 are derived on demands that are less than the full capacity of the system. In other words, ratepayers are paying for the entire system, including the surplus capacity.

Ms. Mikhaila went on to explain the consequences in 2024 and the remainder of the IRM term if the surplus capacity of 89 TJ/d were used by EGI to generate revenue or if there was additional capacity turnback to EGI.

LPMA submits that if EGI is able to generate revenue from the forecasted 89 TJ/d of surplus capacity, the Dawn Parkway System Surplus Capacity Deferral Account ("DPSSCDA"), which was approved as part of the Settlement

Agreement, will capture the revenue generated by the surplus capacity. LPMA submits that this is appropriate protection for ratepayers to have since they are paying for the surplus capacity in their rates.

On the other hand, if there is additional unforecasted turnback of capacity, the cost associated with the lost revenue would be borne by EGI. This is because the 2024 revenue requirement would not be changed to reflect the loss in revenue. There would not be any impact on the rates paid by ratepayers in 2024 or during the IRM term.

LPMA also notes that EGI, supported by the ICF Report, stated that the risk of turnback in 2024 through the IRM term (tentatively set as 2028) was very low (Tr. Vol. 7, pages 87-88) and Mr. Rosenkranz, who filed on behalf of FRPO, agreed that the risk of turnback over this period was small (Tr. Vol. 8, page 32).

The issue of concern to some parties appears to be the longer-term utilization of the Dawn Parkway system, especially if EGI were to expand the system and add capacity over the IRM term. Since the assets have a life of 40 to 50 years and are based on contracts that are much shorter in duration, there is a possibility of significant surplus capacity beyond 2028 that would be paid for by whomever was left on the system. This was discussed in detail by Mr. Rubenstein and Mr. Hagerman (Tr. Vol. 7, pages 84-90).

While LPMA is concerned about the potential for stranded surplus capacity that would result in higher rates for customers that remain on the system, it does not believe that this is an issue that can be dealt with in this proceeding, and in particular, in the setting of 2024 rates in Phase 1 of this proceeding. LPMA agrees with EGI the issue of any turnback risk should be dealt with when EGI brings forward an application to build a specific asset to meet an increase in demand.

40. Should the OEB grant Enbridge Gas's request for a partial exemption for 2024 from the Call Answering Service Level, Time to Reschedule a Missed Appointment and Meter Reading Performance Measurement targets set out in GDAR?

LPMA submits that the Board should not grant EGI's request for a partial exemption for 2024 for the call answering service level, the time to reschedule a missed appointment and the meter reading performance measurement targets as set out in GDAR.

Each of these metrics are customer focused. EGI is essentially requesting that the Board approve a reduction in outcomes that impact customers directly, despite continued increases in the cost paid by ratepayers to have gas delivered to them.

LPMA submits that EGI has not provided any real evidence to suggest that the easing of performance metrics should be considered by the Board, without a full review of GDAR. LPMA believes that any changes in target levels of performance should only be done in the context of a full review of all metrics included within GDAR. EGI should not be able to pick and choose which metrics it wants to reduce simply because they are having trouble meeting the existing requirements.

EGI has put forward evidence with respect to the ongoing savings that have been achieved through the merger, but in the view of LPMA, the value of these savings has been reduced due to the deterioration in the levels of customer service.

41. How should the OEB implement the approved 2024 rates relevant to this proceeding if they cannot be implemented on or before January 1, 2024?

EGI is requesting approval of interim rates for 2024 based on the Board's Phase 1 decision to be effective January 1, 2024. As set out in Procedural Order No. 2

and in the Settlement Proposal, decisions related to some of the Phase 2 issues may require adjustments effective January 1, 2024.

In its AIC (para. 830), EGI proposes that if 2024 rates cannot be implemented on January 1, 2024, it will implement them at the earliest possible date. EGI further indicates that it seeks full recovery of the approved interim revenue requirement for 2024. As part of the DRO, EGI indicates that it would include a revenue adjustment rider for the period between the effective date of January 1, 2024 and the implementation date. Given that the implementation date may not be known until after the DRO is approved, LPMA would like EGI to elaborate on how the revenue adjustment rider would be calculated in the DRO and over what period(s) and to provide further information in its Reply Argument. In addition, it is not clear to LPMA whether this rate rider would be a one-time charge based on the volumes between the effective date and the implementation date, or a charge that would continue on for a few months or until the end of 2024.

LPMA supports the EGI proposal, with two caveats. First, the Board should direct EGI to file sufficiently detailed information as part of the DRO that would allow the Board and intervenors the ability to verify not only the amounts but also the allocation of the amounts to the various rate classes.

Second, LPMA submits that assuming rates cannot be in place by January 1, 2024, but can be in place before April 1, 2024, (the effective date for the April QRAM), the Board should direct EGI to implement the rates as quickly as possible rather than wait for April 1. The winter months are high volume consumption months for most customers and delaying the change in rates to April 1 would have the potential to levy significant additional costs onto customers based on their historical consumption. LPMA submits that if rates can be implemented prior to April 1, 2024, this would increase transparency to ratepayers as to what they are paying.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

September 19, 2023

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