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Feb. 18, 2025

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

Dear Ms. Marconi,

RE: EB-2024-0111 – Enbridge Gas Inc. 2024 Rebasing & IRM – Phase 2 - 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
Date: 2025.02.18 13:57:33 -05'00'

Randy Aiken
Aiken & Associates

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

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 Phase 2 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 three unsettled issues in Phase 2 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 initial evidence for Phase 2 on April 26, 2024. The Ontario Energy Board ("OEB") issued Procedural Order No. 1 on the same date, followed by Procedural Order No. 2 on May 30, 2024 that set out the Issues List for Phase 2, and the processes to address the application up to and including a Settlement Conference.

Following the filing of interrogatories and their responses, a Technical Conference was held which was followed by a Settlement Conference that was held during September and October 2024. The Settlement Conference resulted in complete agreements on all issues, with the exception of three issues on which there were partial agreements.

The Settlement Proposal was filed with the OEB on November 4, 2024 and the OEB held a presentation day on November 18, 2024 to consider the Settlement Proposal. The OEB issued a Decision on November 29, 2024 approving the Settlement Proposal.

An Oral Hearing took place on December 17th through December 19th, 2024 during which the three remaining Phase 2 issues were discussed. These issues are:

a) The proposed change to the calculation of the Meter Reading Performance Measurement ("MRPM"), (the unsettled portion of Issue 8 from Procedural Order No. 2);

b) Are the specific proposals to amend the Voluntary RNG Program and to procure low-carbon energy as part of the gas supply commodity portfolio, appropriate? (Issue 17 from Procedural Order No. 2); and

c) Should the 2024-2028 Incentive Ratemaking Mechanism ("IRM") include a mechanism to decouple revenue from customer numbers? (related to Issue 7 from Procedural Order No. 2).

Environment Defence ("ED") and the Green Energy Coalition ("GEC"), which advanced the proposal to decouple revenue from customer numbers, filed a joint submission on this issue on January 27, 2025. EGI filed its Argument-In-Chief ("AIC") on February 6, 2025 in which it set out its proposal and supporting evidence for the MRPM and the low-carbon energy program, as well as its response to the ED/GEC submissions with respect to the proposal to decouple revenue from customer numbers.

OVERVIEW

While the three remaining issues in Phase 2 are discrete from one another, LPMA submits that they do have one thing in common. Each of them could result in significant impacts on ratepayers during both the remaining IRM term and well beyond that period.

In summary, LPMA submits that the OEB should:

a) Deny the EGI proposal to change the calculation of the MRPM, or at a minimum create a new scorecard performance metric related to inaccessible meters;

b) Deny the proposal to procure low-carbon energy as part of the gas supply commodity portfolio, ***at this time***, or at a minimum change the recovery of the incremental gas supply commodity costs so that small volume system gas customers do not shoulder the entire burden of the costs associated with RNG volumes not taken up by voluntary participants; and

c) Deny the ED/GEC proposal to decouple revenues from customer numbers, ***at this time***, and direct EGI to investigate such a mechanism, ***in conjunction with other measures***, to mitigate any impact of energy transition and report back as part of, ***or before***, its next rebasing application.

LPMA's submissions with respect to the three remaining issues follow below. LPMA has found both EGI's AIC and the ED/GEC submissions to be very useful in setting out the background to these remaining issues in Phase 2 of this proceeding and LPMA will not repeat that background in its submissions.

THE REMAINING ISSUES

a) The proposed change to the calculation of the Meter Reading Performance Measurement

In the Overview section of its AIC, EGI summarizes its rationale for changing the calculation of the MRPM (AIC, pages 2-3). EGI states that it has experienced difficulties in recent years in meeting the MRPM target of 0.5% on a yearly basis, due mainly to the rise in the number of inaccessible meters. While EGI indicates that will continue to make all reasonable efforts to reduce the number of unread meters, it believes that the rise in inaccessible meters is a "persisting unusual circumstance" beyond its control.

As shown in Table 1 of Exhibit I.1.7-VECC-2, the MRPM actual performance hit 5.00% in 2021, declining to 4.10% in 2022 and to 1.30% in 2023. Table 1 also shows that in 2019, EGI also failed to hit the 0.5% target. In Exhibit I.1.7.-Staff-2, EGI provided a forecast for 2024 of 1.06%. This forecast has been replaced by an anticipated result figure of 0.94% (AIC, page 5).

LPMA submits that EGI is making significant progress toward the current 0.5% target. This is reflected in the actual MRPM declines noted above from 5.00% in 2021 to 0.94% in 2024. LPMA submits that EGI is on the right trajectory and there is no need to change the calculation of the MRPM for the 2024 through 2028 period as proposed by EGI.

LPMA also submits that EGI has significant control over reducing the number of inaccessible meters, which it blames for the increase in the MRPM. In particular, it can install Encoder Received Transmitter ("ERT") on inaccessible meters. Installing an ERT makes the meter reading available. As noted in part (a) of the response to Exhibit I.1.7-VECC-4, inaccessible meters are targeted for replacement with ERTs. Moreover, as shown in Tables 1 and 2 of that response, EGI has significantly increased the number of ERTs that it is purchasing and installing. Those tables show that in the years where the MRPM was high (2020-2022), the number of ERTs purchased and/or installed was low. As the number of ERTs purchased and installed increased significantly in 2023, the MRPM fell significantly. In the response to Exhibit I.1.7-BOMA-1, EGI states that it has considered utilizing ERT meters as a long-term solution for inaccessible meters but that supply chain issues were making ERT meters a less attractive solution. However, as shown in Table 2 of Exhibit I.1.7-VECC-4, EGI was forecasting the purchase of 77,020 ERTs, more than the total for 2020 through 2023.

Given the significant increase in ERTs being purchased, LPMA submits that EGI can use this increase to target more inaccessible meters, leading to further reduction in the MRPM.

In EB-2022-0200, EGI requested an exemption to change the MRPM metric from 0.5% to 2.0% of meters. In denying EGI this exemption, the OEB stated (Decision and Order dated December 21, 2023, page 135):

The OEB denies the exemption request to change the MRPM target to 2.0% of meters. The current target of 0.5% of meters is maintained.

The OEB regards meter reading as a fundamental customer service provided by a gas distributor that directly impacts customer billing. While COVID issues may have existed in 2020 and 2021, the OEB is not convinced that Enbridge Gas invested sufficiently in its customer services to address and rectify this meter reading problem. It is too late now to change the experience for those customers affected. The OEB received many letters of comment in this proceeding regarding billing issues experienced by customers and the personal implications.

The OEB has considered the customer impact. This metric is based on estimating four consecutive bills. The result could be an unexpectedly large bill when an actual meter read takes place. From a customer's perspective, this is an unacceptable outcome, especially as the commodity cost of gas and the delivery cost have increased in recent years. Enbridge Gas needs to improve its performance rather than seek to change the metric. It is imperative that customers have accurate bills to manage their expenses, assess their energy costs and manage their energy activities accordingly. Changing the metric to 2% would lock in the adverse performance levels that occurred in unusual circumstances. The OEB finds that there are no unusual circumstances persisting in 2023, beyond Enbridge Gas's control.

LPMA submits that EGI is trying to circumvent the OEB decision noted above. The OEB found that there were no unusual circumstances persisting in 2023 (or beyond).

LPMA agrees with the OEB in the above noted Decision that from a customer's perspective changing the metric target or changing the calculation methodology as proposed by EGI is an unacceptable outcome.

LPMA also notes that there are no apparent adverse consequences to EGI of failing to meet the MRPM target of 0.5%. There is no justification for EGI to change the calculation just so it can meet the target for some of its meters and customers.

It is submitted that the OEB should deny the proposal to change the calculation of the MRPM. At the same time the OEB should direct EGI to report each year during the IRM term on its results based on the current methodology. EGI should also be directed to report on the number of inaccessible meters and the steps taken to reduce this number.

If the OEB were inclined to grant the relief sought by EGI, LPMA submits that it should then also create a new performance metric that shows the number of inaccessible meters each year, and include a performance target of a percentage reduction to be achieved each year. LPMA would suggest an annual reduction of 10% as the initial target that could be reviewed and modified, if necessary, when EGI reports all of its performance metrics in future proceedings.

b) Are the specific proposals to amend the Voluntary RNG Program and to procure low-carbon energy as part of the gas supply commodity portfolio, appropriate?

LPMA has serious concerns with regard to the specific proposals to amend the voluntary RNG program and to procure low-carbon energy as part of the gas supply commodity proposal, both in terms of the need for EGI to be involved, the limited number of customers that would have access to this gas, the recovery of costs not recovered from the voluntary participants, and the potential to saddle system gas customers with unnecessary gas supply commodity costs for years to come.

EGI has proposed a Lower-Carbon Voluntary Program ("LCVP") for the procurement of RNG as part of the gas supply commodity portfolio and to recover the incremental costs associated with the RNG through a proposed cost recovery mechanism, which is described below.

The LCVP would procure RNG starting at a target percentage of 0.25% of the gas supply commodity portfolio in 2026, but EGI would begin to make contractual obligations for the purchase of RNG in 2025. (Tr. Vol. 2, page 183). The percentage of RNG in the gas supply commodity portfolio would increase to a maximum of 2% in 2029, subject to a maximum bill impact to the average residential customer of $2 per month per target percentage point of RNG.

The LCVP would offer RNG to only large volume (more than 15,000 m^3 per year) system sales customers on a voluntary basis to achieve emissions reductions. EGI indicates that some of these customers have expressed an interest in using RNG and that this option exists in other jurisdictions.

Any RNG not taken on a voluntary basis by the limited number of customers eligible to take RNG through the LCVP would be included in the cost of gas supply commodity purchases resulting in all sales service customers having to pay for any excess RNG purchased by EGI.

LPMA submits that the OEB should deny this proposal, ***at this time***, for a number of reasons, which are detailed below.

i) <u>Federal Carbon Tax Offset & Economic Uncertainty</u>

The only financial benefit to ratepayers of the proposed LCVP would be a reduction in the federal carbon tax, which is not charged on RNG. However, as the OEB is aware, the possibility that the federal carbon tax, or the consumer carbon tax as some politicians now like to label it, will survive 2025 appears to be slim to none.

The removal of this carbon tax would significantly increase the net cost associated with RNG to ratepayers, including the large volume system customers for which the program was developed. As noted in paragraph 8 of Phase 2,

Exhibit 4, Tab 2, Schedule 7, Updated 2024-11-15, these customers made direct inquiries to EGI about RNG, and as noted during the hearing, EGI discussed the RNG option through customer events and customer meetings with the large volume customers (Tr. Vol. 2, page 182).

Given the turn in recent events with respect to the federal carbon charge, LPMA submits that EGI has no idea if large volume system gas customers (or large volume direct purchase customers) continue to have an interest in replacing some or all of their conventional natural gas purchases with RNG. The removal of the federal carbon charge, and the associated harmonized sales tax on it, increases the cost of RNG for these customers.

An analysis done by the Consumers Council of Canada shows that the net reduction in the net cost of the RNG proposal (net of the federal carbon charge) would be about $417.4 million over the 2026 through 2029 period (Exhibit K2.7, page 51). The same analysis shows that excluding the reduction in cost due to the federal carbon charge would raise the RNG cost by $155.9 million, or more than 37%, to $573.3 million. EGI did not dispute any of these figures. Clearly, the elimination of the federal carbon charge would have a significant impact in the cost of RNG.

This net increase in cost, combined with the on-going tariff threats from the United States, create a significant and extra layer of economic uncertainty for all ratepayers, especially large volume customers, but also small volume customers. What may have been an acceptable cost increase in 2024 is not likely to be even a consideration in 2025.

ii) <u>No Need for EGI to be Involved</u>

LPMA submits that there is no need for EGI to be involved in the procurement of RNG in Ontario.

When asked about other benefits to customers, other than the financial benefit of a reduced federal carbon charge, of the LCVP, Ms. Fife referred to three other benefits that EGI had identified (Tr. Vol 2, pages 188-189). These benefits were environmental, economic and societal. The societal benefits included community engagement on project development, Indigenous partnerships and public policy.

When asked which of those benefits would disappear if EGI was not involved in the development of RNG in Ontario, but was left up to someone like FortisBC – which is already purchasing RNG produced in Ontario, Ms. Fife stated that she did not think that the benefits would disappear. She then went on to express her opinion that those benefits would be enhanced if EGI was in the market because it would be further supporting the development of the market in Ontario. EGI has presented no evidence to support this statement. In fact, it could be argued that having too many parties trying to purchase a limited supply of RNG in Ontario could have the effect of increasing the price for RNG. The production and sale of RNG is not taking place in a regulated market; the laws of supply and demand are in effect in this market.

iii) <u>EGI Not Taking on Any Cost Risk, Putting All of the Risk on System Gas Customers</u>

EGI states that it wants to participate in the development of the unregulated RNG market, but it is not willing to take on any risks whatsoever with the higher commodity cost associated with RNG. All the costs associated with any RNG purchased by EGI over and above the amount taken by the voluntary large system gas customers would be shouldered by small volume system gas customers that are not eligible for the RNG program.

EGI would not commit to having its non-utility business voluntarily opt in to purchase any of the RNG gas at the premium price, confirming only that the allocation of the gas costs to both utility and non-utility businesses would be based on the reference price (Exhibit J2.10), which would include the spillover costs associated with any excess RNG purchased but not sold directly to voluntary participants. LPMA notes that if EGI would voluntarily commit to some RNG over and above what is in the system gas portfolio, which is what it is asking large volume system gas customers to do, there would be less costs that would need to be recovered from small volume system gas customers that are ineligible for the program. Clearly EGI wants 100% of the risk allocated to system gas customers and 0% allocated to its shareholder.

RNG production is clearly a competitive market. There are many sources of RNG, not only in Ontario, but across North America. There are many sources of RNG production ranging from landfills to agriculture waste and biomass. There are already numerous purchasers of RNG such as FortisBC and direct purchase customers as noted in EGI's evidence. LPMA submits that the risk of developing what is clearly a competitive market should not be put on the back of a subset (i.e. system gas customers) of EGI ratepayers.

iv) <u>The Cost is Too High for Small Commercial & Industrial Customers</u>

The maximum bill impact for a residential customer of $4 per month by 2029 was based on an annual consumption of 2,400 m^3 (Tr. Vol. 2, page 186). For a small commercial or industrial customer consuming 15,000 m3 per year, this translates into $25 per month or $300 per year. For a medium sized commercial or industrial customer consuming 30,000 m^3 per year this translates into $600 per year. LPMA submits that this level of increases is unacceptable, especially for small volume customers that are not eligible for the LCVP, but may end up paying more so that larger customers can take advantage of the program.

v) <u>Stranded Commodity Costs</u>

A lot of time has been spent in both Phase1 and Phase 2 of this proceeding dealing with the risk of stranded assets and what mitigation measures should be taken or examined in the context of energy transition. LPMA submits that the LCVP runs the risk of incurring stranded commodity costs.

As noted in the response to Exhibit J2.9, while EGI would do what it could to reduce costs if the LCVP was discontinued, the RNG volumes associated with contracts with remaining terms would be included in the gas supply commodity portfolio until the end of the contract terms or until other arrangements are made to end the contract. In other words, the system gas customers would be burdened with these additional costs.

LPMA submits that the OEB should not approve a program that may result in stranded gas commodity costs that may well exist beyond the current IRM term. For example, contracts signed in 2029 would be in effect well past 2029 (Tr. Vol. 2, page 147). EGI agreed that based on five-year contracts that system gas customers could end up paying $1.3 billion for the LCVP (Tr. Vol. 2, pages 147-148). This figure would be lower if there were any voluntary participation in the program, but LPMA notes that even if 50% of the volumes are passed through to voluntary participants, this would leave $650 million to be paid for by system gas customers.

The proposed program is based on long term contracts of five years (or more) for the purchase of RNG but only one-year terms for the consumption of RNG for voluntary participants. The risk inherent in this mis-match between contractual terms for buying and selling the gas falls inherently on system gas customers to backstop the associated risk of unsold volumes of RNG under the EGI proposal.

LPMA submits that there is no reason to subject system gas customers to a potential $1.3 billion stranded gas commodity risk.

vi) The Proposal is Too Narrowly Focused

LPMA submits that the LCVP proposal is focused too narrowly on only large volume system gas customers. As shown in the response to Exhibit J2.8, there are only 74,611 customers with an annual volume of 4,517,806 10^3 m^3 that are eligible for the program as proposed. These figures represent only 1.9% of the total customers and only 16.2% of distribution volumes.

By eliminating both direct purchase customers and small volume system sales customers, the potential volume for voluntary participants is severely limited, resulting in increased risk that small volume system gas customers will end up subsidizing the RNG program.

If the program was expanded to include large volume direct purchase customers, the number of eligible customers would increase by 11,464 to 86,075 (or 2.2% of the total), but more importantly, the eligible volumes would increase by 14,288,229 10^3 m^3 to 18,805835 10^3 m^3, or more than 67% of total distribution throughput. Any take up of RNG gas by any large volume direct purchase customer would decrease the burden left to be covered by small volume system gas customers.

Based on the following exchange (Tr. Vol. 2, page 182), it appears that there is interest by direct purchase customers in purchasing a portion of their gas requirements through the LCVP.

MR. PROCIW: So, in terms of direct inquiries, there is the focus on the system gas user. So that was the primary. But through customer events, customer meetings, there is an overall presentation on the proposed program, which would be -- it would be open to both DP and system gas users here. Yes.

MR. AIKEN: Are there any obstacles from Enbridge's point of view of offering this program to direct purchase customers so that they could purchase a portion of their gas from you that is RNG?

MR. PROCIW: At this point, we haven't evaluated the offering to the DP market, but that is something that could be further investigated.

LPMA submits that before EGI is allowed to proceed with its proposal or some variant of it, it should investigate, evaluate and report on offering the LCVP to the large volume direct purchase market.

In a similar vein, noting that direct purchase customers can already purchase RNG through a marketer, LPMA asked if a system gas customer could split their gas purchases into two parts: system gas and RNG gas through a third party, such as a marketer or directly from a producer (Tr. Vol. 2, pages 189-191).

MS. MIKHAILA: Sorry, Mr. Aiken, if there is a specific question it might be something we have to take away and explore a little bit more.

MR. AIKEN: Yes, I guess the question is: Are there, you know, obstacles, contractual or otherwise, that would prevent Enbridge from allowing large volume system gas customers to purchase a portion of their gas as RNG from a third party?

MS. MIKHAILA: Thank you for that. I think, as I am reaching far back into my memory, I believe the situation with the M9 customer is there is multiple contracts that we use to serve them and that is where I say the system limitations. On one contract I think you can only be system or direct purchase, but I think to accommodate that arrangement I think there is multiple customers in our system on different contracts, so we facilitate them as more than one customer for that arrangement.

Based on the response that EGI can accommodate customers in their system and facilitate them on different contracts as more than one customer, as it already does for an M9 customer, LPMA submits that EGI should offer this option to large volume customers. This would certainly increase competition for RNG as Enbridge, marketers and producers would now be competing with one another to supply the requested RNG. If large volume system gas customers could purchase a portion of their consumption as RNG from a third party (through a separate contract with EGI for delivery of that gas to their location) this would have the potential to reduce the amount of RNG to be purchased by EGI, thereby reducing the cost risk for small volume system gas customers that are ineligible for the program.

In summary, LPMA submits that the OEB should deny the proposal to procure low-carbon energy as part of the gas supply commodity portfolio, ***at this time.*** In the view of LPMA, there is too much uncertainty surrounding the program at this time. The OEB should direct EGI to defer the program for at least a year. EGI should re-evaluate customer interest in this program in light of potential changes to the federal carbon charge and the current economic uncertainty. It should also investigate how to allow large volume customers to be served by multiple contracts so that a customer can take some system gas and some RNG gas, whether from EGI or from a third party. The purpose of this deferral is to mitigate the potential stranded gas commodity costs that would accrue to the small volume system gas customers that are not eligible for the program.

vii) The Cost Recovery Mechanism is Flawed

If the OEB does approve the LCVP or some version of it, LPMA strongly submits that the OEB should **NOT** approve the **cost recovery mechanism** as proposed by EGI. While LPMA supports the cost recovery for the RNG from the voluntary participants as proposed by EGI, it cannot support the inclusion of RNG not elected through the LCVP in the cost of gas supply commodity purchases and recovered from all system gas customers.

There is no justification, in the view of LPMA, that small volume system gas customers should be saddled with increased gas supply commodity costs for a program for which they are not even eligible.

EGI rationalizes this approach by indicating that all sales service customers will receive the benefit of RNG with the certainty of a maximum bill impact and that the approach recognizes customers' interest in including lower-carbon energy without having to take specific action. LPMA disagrees. While this may be true for some customers, it is not true for the small volume system gas customers who do not want to pay up to $4 per month more for their gas. The miniscule take up of the Voluntary RNG (VRNG) Pilot Program of barely more than 4,000 customers as of October, 2024 (Phase 2, Exhibit 4, Tab 2, Schedule 7, Updated 2024-11-15, page 19) indicates that interest in RNG among small volume customers at an incremental cost of $2 per month (never mind $4 per month) is extremely low.

Furthermore, if there is a societal, environmental and/or economic benefit associated with the RNG proposal, the cost of this proposal should not fall on only one segment of EGI ratepayers. All ratepayers would benefit, not just small volume system gas customers. LPMA therefore submits that, if approved, the costs should be recovered from all customers, both small and large, both system sales and direct purchase.

Based on the response to Exhibit J2.8, which shows that sales service volumes make up about 47% of total distribution throughput, recovering the costs from all customers would reduce the maximum monthly charge from $4 to just less than $2. In the view of LPMA, this would be a more just and acceptable cost on all ratepayers.

In order to recover this cost over all customers rather than just system gas customers, LPMA submits that the incremental cost of the RNG not sold to voluntary participants over and above the weighted average cost of gas excluding the RNG should not be added to the gas commodity portfolio costs, but rather included in a market development charge account that would be recovered from all distribution customers, regardless of rate class, volume, or direct purchase status. This would result in more robust and fairer distribution of the risk associated with purchases beyond that taken up by the voluntary participants.

In summary, if the OEB approves the LCVP or some variant of it, LPMA submits that the OEB should direct EGI to change the recovery of the incremental gas supply commodity costs so that small volume system gas customers do not shoulder the entire burden of the costs associated with RNG volumes not taken up by voluntary participants. Environmental, economic and societal benefits should be paid for by all ratepayers, not just one subset.

c) Should the 2024-2028 Incentive Ratemaking Mechanism (“IRM”) include a mechanism to decouple revenue from customer numbers?

ED/GEC is proposing that the OEB implement a revenue decoupling mechanism that would result in EGI giving up some or all of the revenues from new customers during the IRM term. The apparent goal of this proposal would be to reduce potential stranded asset risk in the future by reducing or eliminating the incentive for EGI to connect new customers.

LPMA has had the opportunity to review the ED/GEC submissions on this issue, along with the EGI submissions (AIC, pages 23-45) made in reply to ED/GEC.

LPMA submits that the OEB should not approve the EF/GEC proposal of revenue decoupling for a number of reasons, including the seven high level categories noted on page 25 of the EGI submissions and further detailed in the remainder of the AIC. LPMA supports the submissions of EGI in each of the categories noted.

The ED/GEC proposal is based on little, if any, evidence and can best be described as flimsy. First of all, the proposal is not revenue decoupling in the traditional sense of the approved price cap IR mechanism that was approved by the OEB in Phase 1 of this application that decouples revenues from costs.

This proposal decouples revenues from customers, and specifically from customer additions. The proposal is unclear if this decoupling is from all customer additions or a variance from some forecast of customer additions during each of the IRM term years. The revenue withheld from EGI might be all, some or none of the revenue earned from these new customer additions or to the variance in customer additions, with any balance refunded or recovered from existing customers. No mention is made of whether or not new customer additions in one year of the IRM term would be considered existing customers in a subsequent year.

No analysis has been undertaken of the impact the ED/GEC decoupling of revenues from new customer additions that would impact the OEB approved price cap IRM mechanism. The price cap mechanism decouples revenues from costs, but the ED/GEC proposal (or at least one of them) contemplates tracking the net revenue from new customer additions (i.e. incremental revenues less incremental costs) and recovering or returning that amount to customers. Clearly this violates the principle underpinning the use of a price cap mechanism, as the revenues and costs for new customer additions have now been tied together.

No analysis has been undertaking on the impact of other components of the approved price cap IR mechanism, such as the off-ramp, the earnings sharing mechanism ("ESM") or the calculation of the materiality threshold of the incremental capital module ("IRM").

It is not clear to LPMA how the capital cost of adding new customers would be treated under the ED/GEC proposal. If the capital expenditures are added to rate base each year there will be an associated cost of debt (perhaps on 100% of the cost of the additions since EGI would not likely provide any equity financing for an asset it could not earn a return on) and depreciation expense associated with these assets. This could increase the potential for EGI to earn a return on equity that would fall below the off-ramp floor and it would impact the calculation of the ESM. Furthermore, the removal of revenues associated with new customer additions would reduce the growth rate of distribution revenues used in the calculation of the ICM materiality threshold. In particular, a lower growth rate would result in a reduction in the materiality threshold, resulting in more potential capital expenditures to be brought forward by EGI in ICM applications.

The ED/GEC proposal is made with the goal of reducing the potential for future stranded assets by creating a disincentive for EGI to attach new customers. This is based on two key, but erroneous, assumptions.

First, the proposal assumes that all assets associated with the addition of new customers are long lived assets of 50 to 60 years. While this may be true for many of the asset components, it is not true for significant cost components such as meters and regulators.

Second, the proposal ignores the equally long life of assets used for replacement of existing pipelines. The analysis provided in support of the proposal does not even mention the potential for EGI to shift capital expenditures to repairing and/or replacing existing lines more quickly than it would if it were earning revenues from new customers. In addition, under the guise of security of supply, EGI could move some of its capital expenditures from customer additions to "security of supply" projects such as adding second feeds into communities and subdivisions that only have one feed. These assets have the same long life that the ED/GEC proposal is attempting to limit.

The main driver of the ED/GEC proposal centers around stranded risks, but only related to new customer additions. As noted above, all new assets can have long lives. LPMA submits that focusing only on new customer addition capital expenditures is short-sighted and does not deal with the real issue of future potential stranded assets.

LPMA notes that the OEB considered the risk of stranded assets in the Phase 1 decision and directed EGI to implement a reduced capital budget. It also directed EGI to consider and address concerns about stranded assets in the next rebasing application. In particular, the OEB directed EGI to filed specific items for its next rebasing application including an Asset Management Plan that addresses the risk of under-utilized or stranded assets and identifying mitigation measures, options to ensure that its depreciation policy addresses the risk of stranded assets, a proposal to reduce any remaining capitalized overhead to zero, and perform a risk assessment and develop a plan to reduce the stranded asset risk in the context of system renewal. (EB-2022-0200 Decision and Order dated December 21, 2023, pages 140-141)

LPMA notes that there are other measures or regulatory constructs that could be used to mitigate stranded asset risk arising from energy transition. For example, an incentive mechanism could be developed that provides incentives to EGI to maintain or even reduce rate base, rather than growing it. Another example would be to shift the risk of under-utilization of or stranding of assets related to future capital expenditures from ratepayers to the shareholder. The ED/GEC proposal or others similar to it should also be investigated and reported on in the next rebasing application.

Mitigating stranded asset risks to mitigate any impact of energy transition is a large complex issue that is evolving with time. The ED/GEC proposal is only one small measure out of many that may reduce the risk of future stranded assets. LPMA submits that it would not be wise to proceed with only one measure ***at this time***. A comprehensive review of all measures and impact should be on the table, as they would be at the next rebasing. Unintended consequences of proceeding with only one measure could have significant unintended consequences on ratepayers in the long run.

LPMA submits that the OEB should direct EGI, in consultation with ratepayer groups, OEB Staff and other interested parties to investigate the impacts of the ED/GEC proposal and/or other similar measures of the impact on ratepayers and on EGI and part of the broader review due at the next rebasing application.

Further, LPMA submits that the OEB may want to consider directing EGI to provide the studies and reports that it has been directed to complete with respect to mitigating stranded asset risks ***prior to the filing*** of the rebasing application. Sufficient time should be given to all interested parties to review and understand what EGI may or may not be proposing. This would give parties time to provide feedback to EGI and time to start preparing their own evidence/response rather than waiting for the rebasing application to be filed.

In summary, LPMA submits that the OEB should deny the ED/GEC proposal to decouple revenues from customer numbers, ***at this time***, and direct EGI to investigate such a mechanism, ***in conjunction with other measures***, to mitigate any impact of energy transition and report back as part of, ***or before***, its next rebasing application.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

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