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February 18, 2025
Our File: EB20240111

Attn: Nancy Marconi, Registrar

Dear Ms. Marconi:

Re: EB-2024-0111 – Enbridge 2024-2028 Phase 2 – Submissions on Unsettled Issues

We are counsel to the School Energy Coalition. Pursuant to Procedural Order No. 10, these are SEC's submissions on the unsettled issues in Phase 2 of Enbridge Gas Inc.'s ("Enbridge") 2024-2028 rate application.

SEC's submissions address all three of the unsettled issues. They can be summarized as follows:

- ***Meter Reading Performance Measure Metric.*** The OEB should reject Enbridge's proposal to exclude customer-driven inaccessible meters from the Meter Reading Performance Measure ("MRPM"). Enbridge's proposal is not only unwarranted but also an improper indirect review of the OEB's Phase 1 Decision, which previously rejected a request to modify the metric's target for similar reasons.

- ***Low-Carbon Energy Program.*** The OEB should approve the proposed Low-Carbon Voluntary Program ("LCVP") but require significant changes to Enbridge's broader proposal to incorporate a substantial amount of Renewable Natural Gas ("RNG") into its system supply, funded by customers on a non-voluntary basis. The premium for RNG is considerable and does not meaningfully mitigate the risks faced by the energy transition.

- ***Customer Count Revenue Decoupling.*** Environmental Defence and the Green Energy Coalition ("ED/GEC") have proposed three different options for a customer count revenue decoupling mechanism. At this time, the OEB should not approve any of them, as each is flawed and fails to sufficiently address the long-term risk of stranded or underutilized assets. The OEB should require Enbridge to consider this issue as part of a broader review of its rate framework in the next rebasing application.

A. Meter Reading Performance Measurement Metric

The Gas Distribution Access Rule ("GDAR") sets out several service quality requirements and performance standards for natural gas utilities. One of those performance standards focuses on meter reading performance.[1] The MRPM metric is the percentage of total active meters that have not been read for four consecutive months. GDAR requires that gas utilities not exceed a target of 0.5%.[2] Enbridge requests that the OEB "interpret or amend the MRPM metric to exclude the impact of inaccessible meters" caused by or within the control of customers during the IRM term.[3] The OEB should deny the request.

As a preliminary matter, it is important to ensure the requested relief is properly framed. While the MRPM metric is included on Enbridge's OEB scorecard, which is at issue in Phase 2, it simply reflects the requirement under GDAR. Section 7.3.3.1 of GDAR defines not just the MRPM metric target but also how it is calculated.[4] Enbridge's relief is properly a request for a partial exemption under section 1.5.1 of GDAR.[5] A partial exemption is what was sought in Phase 1 when it proposed to change the MRPM metric target.

Regardless of how the relief is framed, SEC submits that it should not be granted for several reasons.

First, Enbridge is indirectly reintroducing an issue that the OEB denied in Phase 1. Post-merger, Enbridge's MRPM performance substantially declined, resulting in, among other things, the entering into an Assurance of Voluntary Compliance.[6] As part of Phase 1, Enbridge sought from the OEB an increase in the MRPM target (i.e. a decrease in required performance) from 0.5% to 2% through a partial exemption to GDAR.[7] The OEB denied the request, noting that the impact of bill estimation on customers could be significant and that the company "needs to improve its performance rather than seek to change the metric."[8] It also found that "there are no unusual circumstances persisting in 2023, beyond Enbridge Gas's control," and that the Advanced Metering Pilot Project, for which an update is to be provided in Phase 3, is a positive step in managing the metric.[9]

Since the OEB rejected Enbridge's request to adjust the target, the company now seeks to adjust how the metric is calculated by removing meters that it has the most trouble reading. This is nothing more than an indirect attempt to change the target. Both approaches have the same effect, reducing Enbridge's required performance without addressing the core problem.

Enbridge emphasizes the Phase 1 Decision's finding that the company has not demonstrated the continued impact of past unusual circumstances on its meter reading.[10] This issue is central to its Phase 2 evidence. Yet, the Phase 1 Decision made factual determinations on this matter, which Enbridge did not challenge in its review motion addressing other issues. The OEB did not invite the

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[1] Gas Distribution Access Rule, section 7.3.3
[2] Gas Distribution Access Rule, section 7.3.3.1
[3] Enbridge Argument-in-Chief, para. 20, 33
[4] Gas Distribution Access Rule, section 7.3.3.1
[5] Gas Distribution Access Rule, section 1.5.1
[6] EB-2022-0188, Enbridge Gas Inc. Assurance of Voluntary Compliance (September 12, 2022)
[7] *Decision and Order* (EB-2022-0200), December 21, 2023 ["Phase 1 Decision"], p.135
[8] Phase 1 Decision, p.135
[9] Phase 1 Decision, p.135
[10] Phase 2 Exhibit 7-1-1, p.13-14

company to file additional evidence or seek different relief as part of Phase 2, as it did for other issues.[11]

Second, Enbridge has still not demonstrated that the issue requires a change in the MRPM metric. SEC does not dispute that there has been an increase in inaccessible meters over the last few years due to changing customer attitudes following COVID-19. At the same time, the evidence shows that the number of customer-caused inaccessible meters has declined each year since 2022, when Enbridge began specifically tracking them.[12] The 2024 forecast is approximately 60% lower than the 2022 number.[13] As we move further from the pandemic, and as Enbridge continues working to improve its performance as directed in the Phase 1 Decision, the number should continue to fall.

Third, by removing inaccessible meters from the calculation, Enbridge significantly reduces its incentive to resolve the issue, as its performance would no longer be measured in any meaningful way. While the company has stated that it will report on the number of inaccessible meters, this is fundamentally different from the current system, where failing to meet the GDAR metric could result in compliance action. Not meeting the MRPM metric under GDAR constitutes a breach of an enforceable provision.[14]

Lastly, inaccessible meters are not a new issue for Enbridge. While the number may have increased in recent years, they have always been a factor that Enbridge was required to manage.[15] When the OEB initially set the 0.5% metric, it presumably reviewed past performance, which would have included some level of inaccessible meters that could not be read. If the MRPM metric is adjusted to remove inaccessible meters from consideration, then the target must be similarly reduced below 0.5% (i.e., Enbridge's required meter reading performance must increase accordingly).

This issue is particularly important for schools, as well as many other customers, primarily in the Union South rate zone, who have faced significant problems with estimated bills over the past few years. If Enbridge is permitted to remove inaccessible meters from the MRPM calculation without adjusting the target accordingly, then the company's required performance will, in effect, be lowered on this critical issue.

B. Lower-Carbon Energy Program

Enbridge is seeking approval for its proposed Lower-Carbon Energy Program ("LCE Program"). The LCE Program involves procuring RNG supply through an increasing annual target percentage of system supply each year (0.25% in 2026, reaching 2% by 2029).[16] Recovery of the cost premium will occur through two separate mechanisms.

First, Enbridge proposes to introduce a new Lower Carbon Voluntary Program ("LCVP"), beginning in 2027, which allows large-volume system supply customers, defined as those who use at least

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[11] Phase 1 Decision, p.140

[12] Phase 2 Exhibit 7-1-1, Attachment 2; Interrogatory Response 1.7-Staff-2; Interrogatory Response 1.7-SEC-2d; Tr.1, p.70

[13] Phase 2 Exhibit 7-1-1, Attachment 2

[14] *Ontario Energy Board Act*, section 3(1)

[15] Interrogatory Response 1.7-SEC-2d

[16] Phase 2 Exhibit 4-2-7, p.4

15,000m3 a year, to elect to have a share of their gas supply come from RNG and to pay the associated premium through a new rider.[17]

Second, any RNG costs not recovered through the LCVP will be recovered by all system gas customers[18] While the program sets an annual target percentage, Enbridge will cap RNG procurement when either the annual target is reached or the pre-determined annual bill impact for an average residential customer is reached, increasing each year ($6 in 2026 up to $48 by 2029).[19]

The OEB should not approve the proposed LCE Program as currently designed. SEC supports the LCVP, however, requiring all non-participating customers to pay significant premiums for RNG at this time is not warranted, and may do more harm than good.

Low Carbon Voluntary Program

SEC supports providing large-volume system supply customers with the option to procure a portion of their supply from RNG on a voluntary basis. For many large customers, including schools, RNG is a way to reduce emissions, and they may be willing to pay the premium over conventional fossil natural gas. The proposed LCVP is a well-developed program that allows these large-volume customers to access RNG as part of their supply without having to move to a direct-purchase arrangement. Enbridge may be able to leverage its size to offer a more attractive service than third-party arrangements, which often require customers to make substantial long-term commitments to include RNG in their supply portfolio.

RNG As Part of System Supply

The problem with the broader LCE Program is that non-participating LCVP system supply customers, including other large volume customers, are required to pay the costs of the procured RNG up to Enbridge's target. The cost difference is substantial.

While Enbridge's evidence and bill impact estimates focus on residential customers, for larger general service customers, such as schools, the increase in costs could reach several thousand dollars per year by 2029.[20] These are customers who have chosen not to pay the premium for RNG. Enbridge does not have a reliable estimate of how many customers are likely to enroll in the LCVP, and has not even provided a forecast. Although Enbridge's evidence suggests some interest from large-volume system supply customers, upon review, the level of interest and the actual volumes for interested customers appear to be very small. Enbridge's non-binding expression of interest process identified 75 customers with a total volume of 325 TJs[21], which reflects only 0.06% of the total system supply.[22]

If this level of interest reflects initial LCVP participation, nearly all RNG costs will be borne by all system gas customers. The premium over traditional fossil gas is substantial, amounting to an estimated $417

[17] Phase 2 Exhibit 4-2-7, p. 4, 11-13; 4.2-SEC-30

[18] Phase 2 Exhibit 4-2-7, p. 4, 13-15

[19] Phase 2 Exhibit 4-2-7, p. 5

[20] Interrogatory Response 4.2-SEC-29, Attachment 2

[21] Interrogatory Response 4.2-SEC-32, p.2; Tr.2, p.140

[22] Tr.2 p.140; Interrogatory Response 4.2-SEC-32, p.2

million through 2029, net of the reduced Federal Carbon Charge ("FCC").[23] If the FCC is eliminated, the incremental cost is projected to be approximately $574 million.[24]

The situation is also unfair to LCVP participants who choose to receive less than 100% of their supply from RNG. While they voluntarily pay the premium for their RNG volumes, they must also pay a premium on the remaining supply, just like all other non-participating customers.

RNG May Exacerbate Stranded Asset Risk

While RNG may play a role in the future of the natural gas system during the energy transition, the proposed LCE Program as proposed may act as a distraction from the fundamental transformation Enbridge must undertake to adapt to this transition.

The evidence is clear that RNG is not a cost-effective way to achieve emissions reductions compared to DSM, nor is it a cost-effective pathway for Ontario to meet its decarbonization obligations.[25] Based on Enbridge's own comparison, the cost per ton of emission reduction of RNG is approximately 7 times higher than DSM.[26] Furthermore, even if it were cost-effective, the evidence is that RNG can never be procured in sufficient quantities to fully (or even sufficiently) decarbonize the natural gas grid.[27]

In its Phase 1 Decision, the OEB recognized that the primary issue facing natural gas utilities like Enbridge, and, more importantly, its customers, is the increasing risk of stranded assets.[28] Requiring customers who do not voluntarily choose to pay the premium may be counterproductive. Raising the cost of natural gas only increases the likelihood that these customers will exit the system, accelerating customer decline and heightening the risk of stranded and underutilized assets. This is yet another factor contributing to the 'death spiral' risk that the OEB has already identified.[29]

Enbridge cites its customer engagement evidence, which suggests that surveyed customers are willing to pay a premium for RNG.[30] This is hard to reconcile with Enbridge's existing voluntary RNG program, which is targeted at residential customers, and has a very low uptake. This suggests that when given the opportunity, customers may not, in fact, be willing to pay the premium.[31]

Modified Proposal

A major challenge Enbridge seeks to address through the design of its proposed LCE Program is that developing the RNG market requires it to enter long-term commodity supply contracts, in contrast to typical short-term contracts.[32] As a result, Enbridge cannot simply offer the LCVP due to uncertainty in customer participation and volume commitments, which will fluctuate over time.

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[23] See CCC's forecasted costs K2.7, p.51

[24] *Ibid.*

[25] Tr.3, p.60-61; Undertaking J3.3

[26] See Undertaking J3.3. SEC compared the average DSM cost per ton of emission reduction for residential, commercial, industrial and large volume ($31.80), with the mid-point average across all four years of the RNG estimate ($258.55).

[27] Phase 1, Tr.4, p.162-169

[28] Phase 1 Decision, p.19-22

[29] Phase 1 Decision, p.20-21

[30] Tr.2, p.205

[31] Tr.2, p.205; 4.2-SEC-32

[32] Tr.2, p.202

To address this problem, SEC believes that it would be appropriate for system supply customers to act as a 'backstop' to the LCVP. Enbridge should be required to match its RNG procurement with a reasonable forecast of LCVP participation, and if it does not materialize exactly as forecast or declines over time, the costs (and environmental benefits) could be shared among all system supply customers.

Enbridge should also expand its existing voluntary RNG program to allow for system supply customers that are not eligible for the LCVP to increase their nominal share of RNG supply.

Customer Protection

SEC submits that if the OEB approves any RNG procurement, it should require enhanced protection to ensure that Enbridge does not favor its affiliates. The evidence shows that Enbridge has not developed a specific framework for selecting RNG projects for its supply.[33] Enbridge has stated that its procurement process will consider a number of factors beyond price, such as contract duration, Clean Fuel Regulations credit rights, feedstock type, and "other benefits or risks inherent to the project."[34] At the oral hearing, an Enbridge witness acknowledged that an affiliate is currently involved in the RNG project business.[35] Given that Enbridge is considering a broad range of factors in determining which RNG projects to contract with, there is a heightened risk of unfair favoritism or imprudent contracting with its affiliate, to the detriment of customers, which may be difficult to detect.

Enbridge should be required to submit a proposal in its upcoming five-year Gas Supply application, scheduled for filing in May, that would ensure that no advantages are granted to affiliates.[36]

C. <u>Customer Count Revenue Decoupling</u>

ED/GEC propose that Enbridge's approved price cap rate-setting framework be augmented with the introduction of a customer count revenue decoupling mechanism.[37] ED/GEC argue that such a mechanism would, among other benefits, reduce financial risk for existing customers, lower energy bills, and decrease the cost of decarbonization.[38] This proposal is driven by Enbridge's incentive, evidenced by its actions, to persuade developers to connect to the gas system while discouraging customers from exiting. ED has put forward three different mechanisms for the OEB to consider.[39]

SEC generally agrees with ED/GEC's view that there is a broad misalignment between Enbridge's interests and those of its customers as the energy transition progresses, creating significant financial risks for both existing and new customers. This risk was acknowledged in the Phase 1 Decision and incorporated into aspects of the approved Phase 2 settlement. SEC's Phase 1 Final Argument addresses this issue in detail, and we continue to believe that the company's response to the energy transition is inadequate.

However, SEC does not support implementing any of the three proposed decoupling mechanisms at this time. None effectively address the most significant risk facing both Enbridge and its customers,

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[33] Tr.2, p.203-204

[34] Interrogatory Response 4.2-CBA-1

[35] Ms. Mikhaila said in response to a question regarding Enbridge ever entering into a procurement contract with a facility owned by Enbridge or an affiliate that, "[i]t could be possible……[Enbridge] don't currently own and have no intentions of owning any facilities ourselves, but there are affiliates that do." (See Tr.2, p.203)

[36] OEB Letter, Enbridge Gas Inc. Five-year Gas Supply Plan, February 6, 2025

[37] ED/GEC Submission, p.3

[38] ED/GEC Submission, p.4

[39] ED/GEC Submission, p.17-18

that of stranded and underutilized assets due to the energy transition. Additionally, a customer count revenue decoupling mechanism cannot be considered in isolation from the broader rate-setting framework, which, as a price-cap mechanism, is already designed to decouple revenue from costs.

SEC acknowledges that a properly designed customer count revenue decoupling mechanism could be designed to better align the incentives of customers and Enbridge. The OEB should require Enbridge, as part of its next rebasing application, to consider such a mechanism within the broader rate framework, as part of its previous directive to develop a more effective plan for addressing the impacts of the energy transition.

Energy Transition Risk ED/GEC Proposed Mechanisms

The OEB's Phase 1 Decision discusses at length the issue of the stranded and underutilized asset risk driven by the energy transition and electrification. The OEB found, as SEC had argued, that Enbridge's proposal "is not responsive to the energy transition and increases the risk of stranded or underutilized assets, a risk that must be mitigated."[40] Based in part on this core finding, the OEB disallowed a number of proposed costs and required changes to the company's planning processes.[41]

At the same time, the OEB never stated, nor would SEC endorse, that potential customers should be denied the option to connect to the natural gas system or that Enbridge cannot recover its prudently incurred costs for connecting them.

The issue with ED/GEC's proposal is that their suggested decoupling mechanisms do not meaningfully address the risk of stranded or underutilized assets. Additionally, one of the mechanisms creates a direct disincentive for adding new customers by not providing Enbridge with any incremental revenue to support the associated costs during the IRM term.

The two ED/GEC revenue decoupling mechanism options that allow incremental revenue from new customer connections would only address short-term financial incentives during the IRM term. ED/GEC do not propose preventing Enbridge from recovering its full costs if prudently incurred at rebasing, when it seeks to include forecasted incremental O&M costs in its base year budget or add customer connection capital costs incurred during the IRM term to its rate base.

SEC is not convinced that limiting this short-term incentive during the IRM will significantly impact Enbridge's customer growth, either positively or negatively, given the lifetime revenue value of new customers and the return on connection assets. The OEB's primary concern should be the long-term incentive, rather than the short-term effects. Moreover, as currently structured, the proposed options would primarily shift risk from Enbridge to customers, a factor that was not accounted for in determining the company's equity thickness.

Option 1. ED/GEC's Option 1 would true-up revenues from actual customer count against the approved 2024 customer count. The option appears to be explicitly premised on the notion that company revenue from base rates, with a PCI adjustment, will be sufficient to allow it to fund new customer connections through the IRM term, and that the $256 million in forecast incremental revenues from new connections is not required.[42] This is unlikely, as there are both incremental O&M

[40] Phase 1 Decision, p. 20
[41] Phase 1 Decision, for examples p.2, 39, 42, 58
[42] ED/GEC Submissions, p.17

costs that would not be included in the 2024 OM&A budget and capital costs that may not be adequately funded through existing depreciation included in base rates.

ED/GEC are incorrect in suggesting that because Enbridge's 2024 base rates include funding for customer connections, those costs will necessarily continue to be funded in subsequent years, even if lower.[43] The capital additions that can be funded from base rates during the IRM term are not the same as the capital budget that formed the basis of those base rates. Rather, the capital costs that can be funded from base rates are primarily determined by the embedded ratio of rate base to depreciation. This is why the ICM threshold value formula is not simply based on the amount of capital additions approved in a utility's last cost of service test year but instead follows a more complex formula that accounts for this ratio.[44]

Option 2. ED/GEC's Option 2 would true-up revenues from actual customer counts against forecast customer counts.[45]

It is not clear how this option addresses ED/GEC's concerns as it involves a true-up of revenues from actual incremental customers during the IRM term against a forecast of incremental customers over the same period. Thus, the only incentive that could be a conceivable target is Enbridge's incentive to connect customers above and beyond what it has already forecasted to connect during the IRM term. In Option 2, Enbridge would receive the forecast $256 million from incremental connections, and what would be captured in a proposed variance account is any additional revenue received as a result of connecting more, or fewer, customers than forecasted. Option 2 does not alter Enbridge's incentives to meet its forecasted customer connections, only to exceed them.

The bigger concern is that Option 2 simply shifts the risk of Enbridge failing to meet its forecasted customer additions onto customers, a factor not considered when the OEB determined Enbridge's equity thickness in Phase 1. Given the potential for significant economic uncertainty resulting from changes in U.S. trade policy, which, all else being equal, is likely to lead to fewer connections than previously forecast, this risk could be significant and, under the ED/GEC proposal, would be borne entirely by customers.

Option 2 is particularly problematic because the forecasted customer count during the IRM period has not been tested. Under a price cap mechanism, a utility's load forecast (which includes customer count) is only approved for its initial test year. Enbridge was not required to submit detailed evidence on its customer count for 2025 to 2028. Instead, only its forecast has been provided, with no transparency on how it was developed. This is in contrast to the detailed evidence and discovery process conducted for the 2024 test year customer count.

Option 3. SEC is confused by what ED/GEC is proposing in Option 3. ED/GEC describes the mechanism both as a true-up between revenue from actual and forecasted customer counts, where Enbridge would retain 75% of the incremental revenue (a variation of Option 2)[46], but also a

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[43] ED/GEC Submissions, p.19

[44] See Supplemental Report: New Policy Options for the Funding of Capital Investments (Jan 22, 2016), p.12

[45] ED/GEC Submissions, p.17

[46] ED Submissions, p.18: "It would require that Enbridge calculate the difference in revenue from actual customers in a year against the forecast number of customers, subject to the percentage reduction. It would return the difference to ratepayers if customer growth was higher than expected or obtain additional revenue from customers if growth was less than expected."

mechanism where Enbridge would retain only a portion (75%) of the incremental revenue from all net customer additions, not just the variance from forecast (a variation of Option 1).[47]

If Option 3 is intended to function as the latter, which appears to be how Enbridge interprets the proposal, SEC sees some logic in an approach that limits the recovery of incremental revenues from new connections if the existing price cap mechanism, as currently designed, allows Enbridge to systematically earn above its allowed ROE on those connections during the IRM term. If ED/GEC intended the former, then similar to Option 2, it would have minimal to no impact and would merely shift risk onto customers.

Regardless, the core issue with Option 3 is whether 75% is an appropriate threshold. This percentage, intended as a middle ground, lacks supporting evidence regarding Enbridge's costs or net revenues.[48] Without a more thorough understanding of Enbridge's actual incremental costs and how they are recovered through incremental revenue under the price cap framework, it is impossible to assess whether 75% is a reasonable level for the company to retain.

Decoupling Mechanism Should Be Considered As Part of Next Rate Framework

ED/GEC's approach also reflects the challenge of proposing significant changes to one aspect of a price cap mechanism in isolation. The entire rate-setting framework is interconnected and designed to balance various risks and rewards for both Enbridge and its customers. A price cap is a rate-setting mechanism intended to decouple costs and revenues. By focusing on customer connections and limiting incremental revenue, ED/GEC is attempting to 'fit a round peg in a square hole', as this approach is, in many ways, contradictory to the price cap mechanism itself, particularly when compared to a revenue cap mechanism.

The Current Energy Group ("CEG") evidence and ED/GEC's perspective raise important issues and potential solutions that should be more appropriately addressed through a holistic review of Enbridge's rate-setting framework. This review is already expected to take place as part of Enbridge's next rebasing application, in line with many of the requirements set out in the Phase 1 Decision and approved Phase 2 Settlement. As part of this process, the OEB should require Enbridge to consider the issues and potential options raised by CEG and ED/GEC. Furthermore, that focus should be on the long-term misalignment of incentives that drive the significant risk of stranded and underutilized assets.

Additionally, ED/GEC's concerns about Enbridge's alleged anti-electrification and pro-gas bias, demonstrated through its planning processes[49], potentially deceptive marketing[50], or other means to inappropriately discourage customer exits[51] are real. The OEB should continue to use its existing tools and authority to effectively address these issues. This includes continuing to provide direction on

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[47] ED Submissions, p.18: "This options [sic] would allow Enbridge to retain only a portion of the incremental revenue it anticipated it would earn from net customer additions/exits (e.g. 75%)."

[48] SEC strongly disagrees with Enbridge's position that the $256 million in incremental revenue projected from new connections over the IRM term is insufficient to cover its incremental costs (See Answer to ED Motion Questions, Response to ED Question #3, Table 5). As explored during the oral hearing, Enbridge's analysis on this point is also fundamentally flawed (See Tr.2, p.95-99).

[49] ED/GEC Submissions, p.7-8

[50] ED/GEC Submissions, p.6

[51] ED/GEC Submissions, p.5-6

planning processes, as it did in the Phase 1 Decision[52], through Enbridge's leave to construct applications.[53] It also involves oversight of cost comparison materials and the IRP process, both of which will come before the OEB again in Phase 3[54], and ensuring that there is no inappropriate cross-subsidization or sharing of information with affiliates, such as Enbridge Sustain, as was agreed to in the Phase 2 Settlement.[55]

Decoupling Mechanism When Customers Decline Are Not A Forgone Conclusion

ED/GEC's proposal, which is being made in the context of a forecasted increase in customers during the IRM term, is also premised on the view that when Enbridge's customer count starts to decline (estimated to begin in 2034[56]), it "will almost certainly advocate to decouple revenue from customer counts as that would be necessary 'to keep the company whole'."[57] On that basis, ED/GEC believes the OEB should approve the mechanism now "while there is an opportunity to return some of the incremental distribution margin back to customers."[58]

SEC agrees that, even though Enbridge opposes the ED/GEC's proposal in this application, it is likely that it will propose some form of decoupling mechanism to protect its revenues during an IRM term when its total customer base declines. Mr. Kitchen admitted as much when asked, responding "I think we would have to look at it if it made sense at the time."[59]

The fact that Enbridge may request such a mechanism when customer counts decline does not mean it should be implemented now while customer counts are expected to increase. The OEB should not, as ED/GEC suggests, treat the future adoption of such a mechanism as inevitable. SEC submits it is not. A mechanism that insulates the company from the effects of a declining customer base is very problematic. Like any competitive business, a reduction in market share should naturally lead to lower revenues, necessitating cost adjustments. Enbridge must address this challenge directly to avoid increasing financial risk for both its existing customers and shareholders.

Implementation

If the OEB agrees with ED/GEC and approves a form of customer count revenue decoupling, several implementation issues would need to be addressed as part of Phase 3. These include, among other things, whether the true-up is done on a rate class/zone-specific basis or company-wide, the timing of its disposition, the interaction between any approved mechanism and the existing average use true-up account, and the appropriate baseline to be used for comparing actual customer counts and revenues.

[52] Phase 1 Decision, p.52; 57-58
[53] For example, see the submissions intervenors such as SEC have made in EB-2024-0200.
[54] Phase 2 Settlement Proposal, p.34, 35
[55] Phase 2 Settlement Proposal, p.36-37
[56] Tr.2, p.101
[57] ED/GEC Submissions, p.13
[58] ED/GEC Submissions, p.13
[59] Tr.2, p.101-102

Yours very truly,
Shepherd Rubenstein P.C.

Mark Rubenstein

cc: Brian McKay, SEC (by email)
Applicant and intervenors (by email)