EB-2024-0111

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.

COMPENDIUM OF THE SCHOOL ENERGY COALITION

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PERFORMANCE MEASUREMENT AND SCORECARD

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1. Enbridge Gas has updated this evidence to reflect the following issue that is being addressed in Phase 2 of this Application.

   58) Are the proposed scorecard Performance Metrics and Measurement targets for the amalgamated utility appropriate?

2. The purpose of this evidence is to establish the appropriateness of the current Enbridge Gas performance measures on its OEB Scorecard (scorecard). Enbridge Gas believes that the scorecard metrics are appropriate and believes that the methods for calculating the metrics are appropriate, with the exception of the Meter Reading Performance Measurement (MRPM) target. Enbridge Gas accepts 0.5% for the MRPM target, however, does not believe that inaccessible meters should be included in calculating the target. Enbridge Gas is proposing that inaccessible meters be excluded from the calculation of the MRPM starting in January 2024, as a result of ongoing and persisting meter access issues that are beyond the control of Enbridge Gas to remedy. Enbridge Gas has provided new data to support this proposal starting at section 2, Meter Reading Performance Measurement Proposal, of this evidence.

3. This evidence is organized as follows:
   1. Background
   2. Meter Reading Performance Measurement Proposal
   3. Mitigation Plan

1. Background

1.1 Performance Measurement Scorecard

4. Enbridge Gas's current scorecard was established during the MAADs proceeding[1] and has been reported annually to the OEB as part of the annual Utility Earnings and Disposition of Deferral & Variance Account Balances proceedings. As directed under the OEB's Filing Requirements for Natural Gas Rate Applications, Section 2.1.7, the scorecard includes measures in the following four categories:
    a) Customer Focus - which directs attention to service quality and customer satisfaction with measures to track Enbridge Gas's service appointments, billing accuracy and call centre activities.
    b) Operational Effectiveness - focuses on safety, system reliability, asset management and cost control where metrics are applied to address safety, system reliability, asset management and cost control for the customer.
    c) Public Policy Responsiveness - targets conservation and demand management, and connection of renewable generation which center on natural gas saving metrics.
    d) Financial Performance - looks at financial ratios, and includes interest charges, return on assets and equity.

5. The 20 measures spanning the four categories cover an extensive range of performance indicators, including a combination of Service Quality Requirements (SQRs) and best practice metrics that Enbridge Gas believes ensure the best possible experience for customers.

6. These categories are consistent with performance measures applied to EPCOR Aylmer and Southern Bruce operations along with electric utilities regulated by the

[1] EB-2017-0306/EB-2017-0307.

OEB including but not limited to EPCOR Electricity Distribution Ontario Ltd., London Hydro Inc., Toronto Hydro-Electric System Limited along with many others. However, the required annual metrics as defined by the OEB and set out in the Gas Distribution Access Rule (GDAR) are not consistent with the performance measures applied to the electric utilities, or specifically to the Electricity Distribution System Code (DSC). The DSC does not have a meter reading metric, given the use of automatic meter reading, and Call Answer Services Levels (CASL) are a minimum of 65% compared to GDAR's requirement of 75%.

7. 2023 is the fifth year that Enbridge Gas is presenting the scorecard for the amalgamated utility. Over the next IR term (2025 to 2028), Enbridge Gas will continue to provide the annual scorecard in the Utility Earnings and DispRosition of Deferral & Variance Account Balances proceedings.[2] Please see Enbridge Gas's historical scorecard results for 2014 to 2023 at Attachment 1. The years 2019 to 2023 are for Enbridge Gas, whereas 2014 to 2018 are presented separately for the pre-amalgamated utilities.

8. Enbridge Gas believes that the 20 performance measures across the four categories set out in the scorecard established during the MAADs proceeding continue to be appropriate, including the 8 measures that are prescribed by the GDAR, subject to Enbridge Gas's proposal for the MRPM in this evidence.

9. Enbridge Gas requests approval of the continued use of the existing scorecard, with the proposed modification to the calculation of MRPM as described in this evidence.

[2] EB-2023-0092.

1.2 Meter Reading Performance Measurement Target

10. In Phase 1 of the Application, Enbridge Gas requested a partial exemption for three performance standard metrics, one of which is the MRPM, beginning in 2024 for the rebasing period or until the OEB orders otherwise. Enbridge Gas proposed that no more than 2% of meters have a consecutive estimate for four months or more.

11. The MRPM is calculated as the total number of meters without a meter read for four consecutive months or more, divided by the total number of active meters to be read. This measurement shall not exceed 0.5% on a yearly basis. The metric does not consider why Enbridge Gas has not read a meter.

12. Enbridge Gas cited various reasons for not meeting the MRPM in EB-2022-0200 Exhibit 1, Tab 7, Schedule 1, page 10. In 2019, the main reasons for not meeting the target included extreme weather conditions and a key vendor exiting the meter reading market and ending its contract with Enbridge Gas. In 2020 and 2021, additional challenges tied to the pandemic prevented Enbridge Gas from meeting the MRPM, and this included public concerns about the safety of meter reading activities, closed businesses, increased customer sensitivities and access issues.

13. In the Phase 1 Decision, the OEB denied the exemption request to change the MRPM target to 2% of meters, maintaining the 0.5% target.[3] Further, the OEB noted, "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."[4]

[3] EB-2022-0200 Decision and Order, December 21, 2023, p. 135.
[4] Ibid.

14. With respect, Enbridge Gas's evidence shows that in fact, these unusual circumstances are persisting in 2023 and 2024 and they are expected to continue into the foreseeable future. This has and will continue to significantly impact the ability of Enbridge Gas to meet the MRPM target. Meter access issues are especially concerning as gaining access is beyond the control of Enbridge Gas where customers do not respond to Enbridge Gas's reasonable attempts to gain access or obtain a reading directly from the customers. Until these customers provide Enbridge Gas with access to the meter or service is discontinued at these premises, these inaccessible meters remain as part of the total number of unread meters. Unless the OEB allows Enbridge Gas to remove these inaccessible meters from the unread meter total, the effect is that Enbridge Gas will continue to be penalized for customer behaviour that is beyond the control of Enbridge Gas. This is neither fair nor appropriate.

15. Enbridge Gas anticipates that some parties may take the view that Enbridge Gas should have requested a review of the OEB's Phase 1 Decision with respect to the MRPM exemption. To the contrary, Enbridge Gas believes that it is more appropriate and efficient to make this updated proposal as part of Phase 2 of this proceeding, given the scope of the performance scorecard issue in Phase 2 and the fact that Enbridge Gas continues to experience extraordinary meter access issues despite its extensive mitigation efforts.

2. Meter Reading Performance Metric Proposal

2.1. Proposal

16. Enbridge Gas proposes to continue the current metrics and measurement targets from 2024 to 2028, with the exception of the calculation of the MRPM metric, which falls under the customer focus category. Enbridge Gas is not challenging the OEB's

Phase 1 Decision to maintain the 0.5% target, however, the Company does not agree that inaccessible meters should be included in the calculation of the metric. Enbridge Gas is proposing that all meters with access issues caused by or within the control of the customer to address be excluded from the MRPM calculation for the purposes of the scorecard measure. Enbridge Gas therefore defines inaccessible meters as those meters to which the Company has not been able to obtain access to read the meter for 4 or more consecutive months because of customer-driven conditions that are beyond Enbridge Gas's control.

17. Enbridge Gas acknowledges that in effect, this proposal could be viewed as an exemption request under Section 1.5.1 of the GDAR related to the MRPM. In this case, because evidence shows that the inaccessible meters are beyond the control of Enbridge Gas even through active mitigation efforts, it is appropriate for Enbridge Gas to make this request in relation to this issue in Phase 2. It is simply not fair for the OEB to hold Enbridge Gas accountable for customer behaviour that amounts to denying access to read the meter.

18. It is a term in the Enbridge Gas Conditions of Service for both rate zones that the customer shall provide access to Enbridge Gas to read the meter and failure to do so may result in the discontinuation of service.[5] It is within the authority of Enbridge Gas to discontinue service in these circumstances, subject to the disconnection requirements set out in the GDAR and the Conditions of Service. In some instances, it may be necessary for Enbridge Gas to eventually take this step. However, consistent with the OEB's restrictions related to service disconnection (e.g., disconnection ban during the winter season), Enbridge Gas will only resort to

[5] Enbridge Gas Inc. Conditions of Service. https://www.enbridgegas.com/Conditions-of-Service. Section 4.5, p.7.

service disconnection as a last resort and will provide clear communication to the customer prior. If the OEB were to take a very strict view of the MRPM and not accept Enbridge Gas's proposal to remove inaccessible meters from the calculation of unread meters, Enbridge Gas may need to conduct additional service disconnections just to have a better chance of meeting the MRPM. This would be inefficient at best and would not be in the best interests of customers.

2.2. Rationale

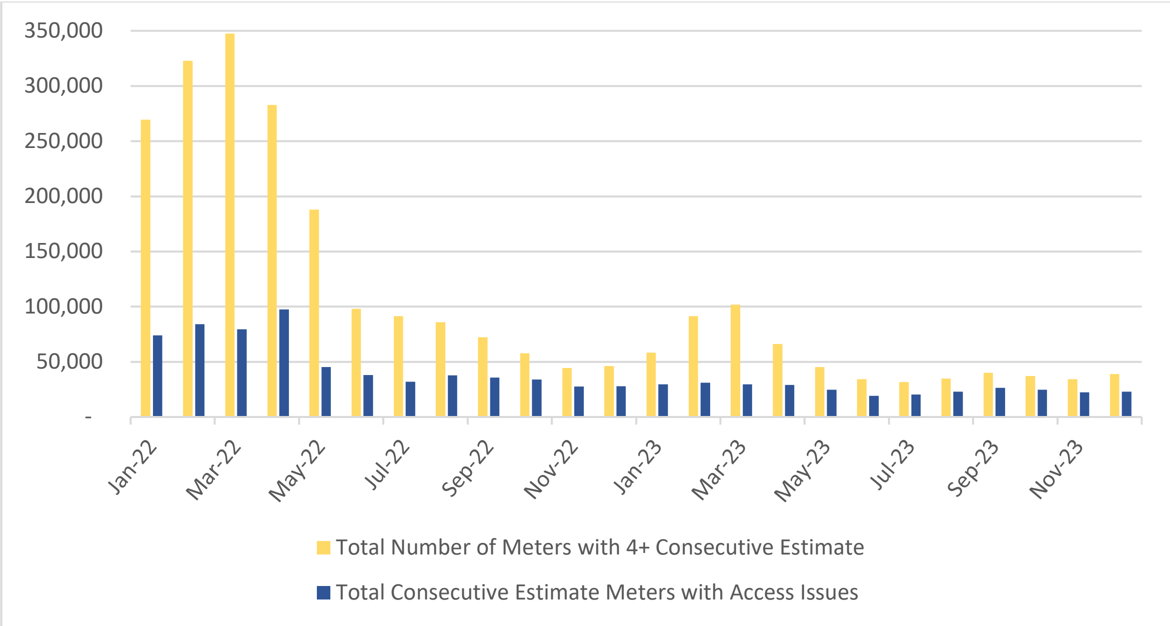
19. Enbridge Gas is inherently motivated to obtain actual customer meter reads on a regular basis and has taken all reasonable steps in striving to achieve the SQR target for MRPM on a consistent basis. Despite that, there continues to exist unusual persisting circumstances beyond Enbridge Gas's control that limit the ability for meter readers to access a certain proportion of gas meters to conduct consistent reads, which contributed to missing the target for the MRPM in 2022 and 2023.

20. While the number of overall consecutive meters not read continues to decrease, the number of those attributable to access issues, which are beyond Enbridge Gas's control, has risen. Attachment 2, page 1, column (d) and (j) show the number of consecutive estimate meters that are attributable to inaccessible meters from 2022 to 2023. Customer related access issues accounted for 49% of missed reads in 2023 as shown at Attachment 2, page 1, column (l), line (13), an increase from 32% in 2022 as shown in Attachment 2, page 1, column (f), line (13). With approximately 3.9 million customers, to meet an MRPM metric of 0.5%, no more than 19,000 meters can have 4 or more months of consecutive estimates, or the metric will not be achieved. If meters with access issues are removed from the MRPM calculation, the metric achieved for 2022 would be 2.78% instead of 4.10%,

and in 2023, the metric would be 0.66% instead of 1.31%.

21. Access issues are further compounded by seasonality. While Enbridge Gas has historically met the required MRPM while managing unpredictable winter impacts, when combined with the rising access issues, it is creating a situation in which Enbridge Gas cannot recover quickly enough to correct the metric throughout the remainder of the year. Figure 1 illustrates how seasonality compounds existing access issues. Historically, Enbridge Gas has been able to use the summer months to catch up on reads and correct the overall MRPM by year-end. However, as access issues increasingly account for the reasons for consecutive estimates in the summer months, the MRPM metric has become increasingly more difficult to achieve. As provided at Attachment 2, page 1, in summer months access issues accounted for 45% of consecutive estimates in 2022 and this increased to 66% in 2023, while in the winter months that is 19% and 37% respectively.

Figure 1: Impacts of Seasonality on Consecutive Estimates



22. Given that MRPM is a cumulative calculation, seasonal impacts combined with increasing access issues make it difficult to improve the metric year-over-year. The MRPM from the end of 2023 is carried into 2024 and Enbridge Gas will start the year at 1.3%. As the total number of unread meters fluctuates, some meters are read and subtracted from the totals, while other meters remain as unread from the previous month, and new meters reach their 4-month timeline and are added to the current consecutive estimate results. This means that even though a percentage of meters have successfully been read, Enbridge Gas will continue to have meters that have consecutive estimates. In addition, if Enbridge Gas experiences one or two challenging months for meter reading during a year, this makes the MRPM difficult to achieve, and it becomes impossible to catch up to the metric and meet the target for the remainder of the year. For example, readers have 3 days to read their routes within the billing cycle. When 1 reader is absent (illness or otherwise) they will miss routes for 2 to 3 cycles (5000 to 10,000 reads). Unread meters being carried into the next year compound the results when added to the external challenges such as access, customer sensitivity, and staffing issues.

23. Enbridge Gas's MRPM going into 2024 was 1.3%. The first quarter of 2024 has had favourable weather conditions which has allowed Enbridge Gas to reduce the overall MRPM to 1.2%.

24. Despite a 74% improvement in MRPM over the past two years, Enbridge Gas anticipates continued challenges in meeting the 0.5% GDAR requirement for 2024 given the persisting access issues caused by changes in post-pandemic customer behaviour and the cumulative calculation of MRPM. Even with inaccessible meters removed from the total unread meters count, Enbridge Gas anticipates the 2024 MRPM will be between 0.5% and about 0.6%. Meeting the 0.5% target is still a stretch for Enbridge Gas under known conditions. Attachment 2, page 2, is a 2024

Forecast of MRPM for Enbridge Gas. For the foreseeable future beyond 2024, Enbridge Gas expects that it will still require ongoing mitigation efforts and attention to approach and aim to meet the 0.5% MRPM target, even with inaccessible meters excluded from the total unread meter count. Accordingly, Enbridge Gas seeks to remove inaccessible meters for the entirety of the IR term.

2.3. Types of Access Issues

25. Below is a description of the various types of customer-related access issues that prevent Enbridge Gas from conducting regular meter reads including:

a) Locked gates and inside meters;
b) Customer sensitivity; and
c) Obstruction.

Attachment 3 contains images that illustrate access issues.

Locked Gates and Inside Meters

26. Meter readers experienced an increase in locked gates as a result of an increase in customer swimming pools during the pandemic. In 2021, Ontario saw an increase in swimming pool permits of 33%.[6] The increase in swimming pools resulted in an increase in locked fences, as required by the Swimming Pool Safety Act[7] and/or municipal by-laws. Since gas meters are usually located in backyards, the presence of pools and new fences prevent meter readers from accessing the gas meters to obtain meter reads. Customers are also adding locks to their gates as increasing

[6] Municipal Property Assessment Corporation. (2022 May 3). Backyard pools make a splash with Ontario property owners. MPAC. https://www.mpac.ca/en/News/OurStories/BackyardpoolsmakesplashOntariopropertyowners
[7] Office of Assembly. (2006). Bill 74, Swimming Pool Safety Act. Legislative Assembly of Ontario. https://www.ola.org/en/legislative-business/bills/parliament-38/session-2/bill-74.

crime rates are raising concern about personal safety and with an increase of dog ownership.

27. Enbridge Gas has seen a significant increase in business closures and the number of vacant properties, since 2021. Initially, this was related to the pandemic and lockdown measures, but the trend has continued to increase recently as a result of inflation.[8] Meter readers are not able to gain access to read meters inside of vacant premises.

Customer Sensitivity

28. Over the past few years, with increasing crime, customer presence (working from home) and installation of home cameras, Enbridge Gas has seen a rise in customers refusing access onto their property. This prevents Enbridge Gas from obtaining a meter read. More customers than ever before are calling the Enbridge Gas Call Centre to confirm the legitimacy of meter readers on their property or to request that readers refrain from entering their property. Toronto has seen a surge of 24.7% in auto thefts and 25.3% in property break and enters in 2023.[9] Enbridge Gas continues to try and educate customers on the meter reading process, but many customers still do not realize that Enbridge Gas meter readers need to physically see the meter to read it (and conduct a safety inspection). There is a misconception that the gas meter can be read remotely like water/hydro meters. Only 3.8% (143,000) of Enbridge Gas meters have an Encoder Received Transmitter (ERT) meter and can be read remotely. Further details on ERT meters can be found in paragraph 39 of this evidence.

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[8] Better Dwelling (2023 September 25). Canadian Business Closures Surge, Fewest Business Openings Since Lockdowns. https://betterdwelling.com/canadian-business-closures-surge-fewest-business-openings-since-lockdowns/

[9] Toronto Police Service Public Safety Data Portal. (2024 April 4). Data Analytics | Toronto Police Service Public Safety Data Portal I https://data.torontopolice.on.ca/pages/data-analytics

Obstructions

29. There has been an increasing presence of dogs since the beginning of the pandemic in Ontario.[10] Safety continues to be the top priority and a core value of Enbridge Gas and there have been increasing concerns around dog bites and the potential for dogs to escape when a reader tries to enter the yard. If a dog is present in the yard, and the reader does not feel safe entering, they will knock on the customer's door and ask that they put the dog in the house or provide a read themselves. An increase in the number of customers working from home post-pandemic has also led to a rise in the number of dogs outside during the day, when readers attempt to read meters. As readers encounter more dogs, there is a greater potential for dog bites. If a meter reader cannot enter the premise safely, the meter is unread as a result. Safety continues to be a core value for Enbridge Gas and its vendor partners. Together they mitigate any potential risk that may result in a reported safety incident. The Green Book,[11] enforced by the Ontario Ministry of Labor, provides a guideline for workplace environments that Enbridge Gas and its vendors must adhere to in order to ensure employee safety. Meter readers will not enter a premise when there is a situation that could result in injury.

30. Other types of obstruction to the meter include foliage, stored materials, tools, equipment, construction, excessive build up of garbage, and animal waste. During the pandemic, there was an increase in home projects overall, including structures that customers have built around gas meters that limit access such as decks, hot tubs, and sheds. There are also instances where a meter is inaccessible due to overgrowth of plants/foliage, shrubs, and trees, which could also be poisonous, or

[10] Veterinary Practice News Canada (2022 February 15). Canadians Adopted Three Million Pets Amidst Pandemic. Kenilworth Media. https://www.veterinarypracticenews.ca/canadians-adopted-three-million-pets-amidst-pandemic/
[11] Navigating the Green Book (OHSA). https://osg.ca/navigating-the-ohs-act-a-how-to-guide

gardens built around the gas meter. Ice and snow can obstruct access to the gas meter through either an unsafe path or by blocking the opening of a gate to a backyard. Gas meters are typically placed in discreet locations, exposing meter readers to safety risks of slips, trips, and falls. Snow can create additional hazards if it blocks gates or covers window wells next to gas meters. It is the customer's obligation to keep their gas meter free from obstruction according to the Conditions of Service.[12] Please see Attachment 3 for photos of obstruction captured by meter readers.

3. Mitigation

3.1 Past Mitigation Measures

31. It is in the best interest of the customer as well as Enbridge Gas to obtain meter reads. Customers taking a self-read and providing it to Enbridge Gas or allowing Enbridge Gas to access the meter and capture the read is how Enbridge Gas obtains reads currently. This process ensures that customers gas bills are accurate on a monthly basis. Enbridge Gas continues to send reminder communications to customers asking for access to read the meter or to provide their meter reading by phone or online. Over the past two years, Enbridge Gas has undertaken several extraordinary mitigation measures and incurred additional expense to counteract the meter reading constraints and potential impacts on customer billing. These include increased staffing and improvements in processes and technology. Enbridge Gas has also increased customer outreach and marketing communications to improve the MRPM results. Overall, these measures have led to reduction in MRPM of 74% from 5.0% in 2021 to 1.3% for 2023. Attachment 2, page 1, provides a breakdown of MRPM results for 2022 to 2023.

[12] Enbridge Gas Inc. Conditions of Service. https://www.enbridgegas.com/Conditions-of-Service. Section 4.5, p.7.

Staffing Increases

32. Enbridge Gas is involved in continuous review of staffing to ensure active hiring occurs wherever necessary to normalize staffing levels. Since March 2022, the number of meter reading staff has increased by 12.5%. In December 2019, the long-standing meter reading vendor in the Union rate zones terminated its contract with Enbridge Gas and a new vendor was acquired, with no prior experience reading meters. Over the pandemic, both vendors struggled to retain meter readers, given safety concerns and labour shortages. Since March 2022, meter reading staff for the new vendor has increased by 18%. This correlates to an improvement in MRPM for Union rate zones from 7.65% in 2020 to 1.68% in 2023. Overall attrition rates went from 40% in 2020 to 27% in 2022 with a further decrease to 23% in 2023.

33. Enbridge Gas has assisted meter reading vendors with recruitment activities and hiring practices. While hiring and attrition rates have improved over the past two years, this industry continues to struggle to find reliable resourcing, particularly in the winter months for rural, remote, and Northern areas. Incentives have been offered to meter readers for working extended hours during evenings and weekends.

Process Improvements

34. Enbridge Gas monitors the meter reading process daily to ensure all reads are captured and used for billing.

35. Enbridge Gas has regularly scheduled meetings with meter reading vendors to review performance, identify gaps and mitigate anticipated obstacles to improve MRPM. For the newer vendor, having these regular touchpoints have resulted in

meter reading improvements to the point that they are now performing at the same level as the long-standing vendor.

36. Additionally, Enbridge Gas has updated internal processes so that Call Centre agents review the meter reading history every time that a customer calls so that they can try to obtain a meter read (or schedule a read appointment if required) and address any potential access issues.

Technology Improvements

37. Enbridge Gas has created a new webpage[13] that allows customers to submit a meter read without requiring or accessing a MyAccount profile. Customers simply require their account number and postal code.

38. In late 2023, new handheld technology was implemented for use by the meter readers. The new handheld devices have real time upload capabilities resulting in extended reading hours. With the earlier model handhelds, meter readers had to physically be in an Enbridge/vendor office to upload the reads from the meter reading routes. The new ones allow the upload from anywhere, at anytime. They are also much lighter to carry and easier to use.

39. The meter reading team within Enbridge Gas has worked with the Operations team to target meter exchanges for installation of ERT meters, where appropriate. This includes installing ERT meters on specific properties that have historical access issues and replacing damaged and broken meters. ERT meters use a low powered radio frequency to communicate with the hand-held device used by meter readers

[13] Enbridge Gas Inc., Submit Meter Reading, https://myaccount.enbridgegas.com/My-Account/My-Gas-Meter

but must be read near the physical location of the meter. ERT does allow Enbridge Gas to obtain a meter reading within close proximity of the meter. However, as a result of the significant supply chain issues and cost implications, more wide-spread use of ERT meters is not practical. Additionally, Enbridge Gas requires access to the meter in order to install an ERT, meaning the access challenges pose a barrier to more extensive ERT installation.

40. Enbridge Gas is also considering Advanced Metering Infrastructure (AMI) for the meter reads. AMI uses a two-way signal that allows for real-time meter reads that can be obtained without a physical presence. As directed by the OEB in the Phase 1 Decision,[14] Enbridge Gas will file an update on the AMI pilot project in Phase 3.

Marketing/Outreach

41. Enbridge Gas increased its customer outreach activities to obtain a meter reading or schedule an appointment to attend the property. Outreach has included dialer campaigns and meter reading contests targeting customers with access issues related to overgrown vegetation, dogs, or locked gates. Enbridge Gas ran campaigns where Call Centre agents called customers over the weekend to schedule appointments to read meters.

42. Enbridge Gas has been running digital contests to increase the number of meter reads submitted by customers, which has been largely successful. The average number of monthly reads submitted by customers has increased by 115% from 2021 to 2023.

[14] EB-2022-0200, Decision and Order, December 21, 2023, p. 135.

Table 1

Number of Meters – Customer Read

Line No.	Particulars	2021	2023	Percentage Change
1	Agent entered customer read	2,905	3,114	7%
2	Customer submitted read (Interactive Voice Response)	5,245	7,887	50%
3	Customer submitted read (Web)	45,297	103,875	129%
4	Total	53,446	114,876	115%

43. Despite the effectiveness of these campaigns in obtaining meter reads, it has not significantly improved the MRPM target because the customers who are providing their own meter read through the campaigns are also the customers for whom Enbridge Gas meter reading vendors are able to obtain a reading. Customers with meter access issues have the same difficulty accessing the meter as meter readers. If there is a deck or a shed in front of the meter, the customers will not be able to obtain the read to submit it themselves.

44. Enbridge Gas is working on a plan to educate customers about the use of actual reads. There is a misconception that Enbridge Gas does not use a customer provided read because if the read is provided outside of the three-day meter reading window, the bills display ‘estimate’ read where an ‘actual’ meter read was obtained within the billing month. These reads are in fact used to adjust the account, as required, and are used to estimate the read that is within the reading window to generate the bill. Enbridge Gas is considering a process improvement to address how reads are utilized based on when they are received and how they are presented on the bill.

3.2. Mitigation Plan

45. Enbridge Gas is committed to providing excellent customer service to all customers and has developed mitigation plans for the performance measures not met in 2021. The mitigation plans outline the approach to improve metric performance: the mitigation plans for MRPM and CASL were provided to the OEB as part of the Assurance of Voluntary Compliance[15] dated September 2022 and the mitigation plans provided at EB-2022-0200 Exhibit 1, Tab 7, Schedule 1, Attachments 2 to 4 additionally included Time to Reschedule a Missed Appointment (TRMA) for 2022 and beyond.

46. The 2024 MRPM Mitigation Plan was developed by reviewing previous mitigation plans to determine which strategies implemented contributed to the improvements to the MRPM metric. The mitigation plan was developed by the Customer Care group with input from various internal groups such as Operations, Technology, and Marketing. Additionally, Enbridge Gas engaged meter reading vendors on a regular basis for further input to improve the MRPM. The 2024 MRPM Mitigation Plan provided at Attachment 4 was provided to OEB staff on March 8, 2024.

47. The MRPM Mitigation Plan for 2024 includes plans for continuous staffing improvements, marketing campaigns that include customer education about the use of meter reads and importance of ensuring clearance of the meter, process improvements, and technology updates that improve overall system functionality and use of meter reads.

48. Enbridge Gas is committed to continuous year-over-year performance improvement and has developed its mitigation plans to aid in achieving continuous

[15] EB-2022-0188, Assurance of Voluntary Compliance, September 12, 2022. https://www.oeb.ca/sites/default/files/EGI-Assurance-of-Voluntary-Compliance-20220912.pdf

progress. Despite its best efforts, Enbridge Gas remains concerned that the MRPM as it stands is simply not achievable even through extraordinary and consistent efforts from Enbridge Gas and its meter reading contractors. This should be acknowledged through acceptance of the above proposal to remove the burden of inaccessible meters from the unread meter count for the purposes of calculating the MRPM performance metric.

	Performance Measure	Target	Actual	Actual	Actual	Actual	Actual	Actual		Actual		Actual		Actual		Actual	
			2023	2022	2021	2020	2019	2018	2018	2017	2017	2016	2016	2015	2015	2014	2014
			EGI	EGI	EGI	EGI	EGI	EGD	UNION	EGD	UNION	EGD	UNION	EGD	UNION	EGD	UNION
#	CUSTOMER FOCUS (Service Quality & Customer Satisfaction)																
1	Reconnection Response Time (# of days to reconnect a customer) (# of reconnections completed within 2 business days/# of reconnections completed)	85.0%	99.3%	98.1%	96.9%	98.9%	98.1%	97.3%	90.7%	96.2%	90.5%	93.8%	86.2%	94.6%	90.1%	94.0%	91.9%
2	Scheduled appointments met on time (appointments met within designated time period) (# of appointments met within 4hrs of the scheduled date/# of appointments scheduled in the month)	85.0%	96.3%	95.4%	94.5%	98.8%	98.5%	94.7%	98.8%	94.3%	99.0%	94.8%	98.9%	95.2%	98.8%	95.1%	97.7%
3	Telephone calls answered on time (call answering service level) (# of calls answered within 30 seconds / # of calls received)	75.0%	89.5%	75.9%	64.3%	75.2%	79.0%	82.0%	77.6%	82.5%	79.2%	82.4%	80.1%	79.7%	79.1%	79.0%	73.6%
4	Customer Complaint Written Response (# of days to provide a written response) # of complaints requiring response within 10 days / # of complaints requiring a written response	80.0%	100.0%	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	95.5%	100.0%	100.0%	100.0%	93.3%	100.0%
5	Billing accuracy 'The requirement states that utilities should complete manual checks of their bills to verify data when a meter read demonstrates excessively high or low usage.'		331,489 manual checks completed as per QAP	390,246 manual checks completed as per QAP	384,858 manual checks completed as per QAP	427,524 manual checks completed as per QAP	429,386 manual checks completed as per QAP	224,316 manual checks completed as per QAP	218,700 manual checks completed as per QAP	494,330 manual checks completed as per QAP	167,075 manual checks completed as per QAP	453,326 manual checks completed as per QAP	171,381 manual checks completed as per QAP	478,248 manual checks completed as per QAP	173,132 manual checks completed as per QAP	462,936 manual checks completed as per QAP	154,888 manual checks completed as per QAP
6	Abandon Rate (# of calls abandon rate) (# of calls abandoned while waiting for a live agent / # of calls requesting to speak to a live agent)	10.0%	1.4%	7.1%	16.0%	5.4%	2.50%	1.9%	2.6%	1.8%	3.4%	1.8%	3.6%	2.4%	4.0%	1.9%	4.7%
7	Time to Reschedule Missed Appointments (% of rescheduled work within 2 hours of the end of the original appointment time)	98.0%[1]	97.8%	93.8%	97.0%	97.3%	97.0%	98.7%	99.8%	96.8%	99.9%	94.2%	99.8%	94.8%	99.8%	95.5%	99.9%
	OPERATIONAL EFFECTIVENESS (Safety, System Reliability, Asset Management & Cost Control)																
8	**Meter Reading Performance** # of meters with no read for 4 consecutive months / # of active meters to be read	0.5%	1.3%	4.1%	5.0%	4.4%	0.7%	0.5%	0.4%	0.5%	0.1%	0.4%	0.1%	0.5%	0.2%	0.7%	0.4%
9	**% of Emergency Calls Responded within One Hour** (# of emergency calls responded within 60 minutes / # of emergency calls)	90.0%	95.3%	94.1%	95.2%	96.7%	96.7%	96.6%	99.3%	96.8%	99.0%	96.1%	98.8%	96.7%	98.6%	96.9%	97.8%
10	**Compression Reliability** % reliable for transmission compression		100.0%	100.0%	99.7%	99.7%	99.9%	NA	99.8%	NA	99.9%	NA	99.7%	NA	99.8%	NA	99.9%
11	**Damages per 1000 locate requests**		2.10	2.31	1.95	2.22	1.97	1.85	2.28	1.83	2.17	2.19	2.41	2.46	2.56	2.49	2.67
12	**Total Cost per Customer** ($ / Customer)		745.7	683.2	643.9	658.2	653.6	530.7	756.7	513.9	730.3	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]
13	**Total Cost per km of Distribution Pipe** ($ / km of Distribution Pipe)		19,079.6	17,480.7	16,639.6	16,928.5	16,735.4	15,123.1	16,947.5	14,739.7	16,109.4	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]
	PUBLIC POLICY RESPONSIVENESS (Conservation & Demand Management & Connection of Renewable Generation)																
14	Total Cumulative Cubic Meters of Natural Gas Saved (Net) (Millions)		NA[3]	N/A[4]	1,707.5 [5]	1,632.2	2,075.9	807.5	1,124.5	787.2	1,182.7	837.1	959.4	826.2	1,750.8	719.8	1,889.5
	FINANCIAL PERFORMANCE (Financial Ratios)																
15	Current Ratio (Current Assets / Current Liabilities)		0.92	0.84	0.71	0.66	0.75	0.93	0.69	0.84	0.47	0.7	0.64	0.87	0.77	0.65	0.81
16	Debt Ratio (Total Debt / Total Assets)		0.39	0.42	0.41	0.40	0.40	0.49	0.51	0.47	0.49	0.47	0.47	0.47	0.48	0.49	0.45
17	Debt to Equity Ratio (Total Debt / Shareholders' Equity)		0.97	1.10	1.06	1.01	0.98	1.67	2.12	1.54	2.08	1.48	2.06	1.59	2.08	1.69	2.12
18	Interest Coverage (EBIT / Interest Charges)		1.75	2.54	2.55	2.34	2.53	2.52	2.69	1.96	2.42	2.07	2.33	2.18	2.33	2.3	2.46
19	Financial Statement Return on Assets (Net Income / Total Assets)		1.20%	2.03%	2.07%	1.97%	2.25%	2.98%	3.20%	2.27%	2.71%	2.26%	2.58%	2.38%	2.70%	2.60%	2.87%
20	Financial Statement Return on Equity (Net Income / Shareholders' Equity)		3.00%	5.37%	5.32%	4.96%	5.56%	10.20%	13.25%	7.39%	11.43%	7.17%	11.39%	8.00%	11.71%	8.99%	13.43%

[1] Time to Reschedule Missed Appointment target was 100% prior to the Phase 1 Decision
[2] 2014 through 2016 results are not available as the metrics were not historically tracked by EGD or Union
[3] 2023 is in draft
[4] 2022 results will be available in 2024
[5] 2021 results are audited and approved in the DSM Clearance Proceeding

Ontario Energy Board | Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2022-0200

ENBRIDGE GAS INC.

Enbridge Gas Inc. Application for 2024 Rates – Phase 1

BEFORE: **Patrick Moran**
Presiding Commissioner

Emad Elsayed
Commissioner

Allison Duff
Commissioner

December 21, 2023

In the event that the OEB requires an ESM for 2024, Enbridge Gas proposed to continue the parameters that were in place for the deferred rebasing term (i.e. 50:50 sharing for all earnings 150 basis points above OEB approved ROE for 2024), and which is proposed to be continued into the next rate term.

Findings

The OEB finds that an ESM for the 2024 Test Year is not required. The OEB has conducted a thorough review of all Phase 1 issues in this application which included extensive discovery and an oral hearing to test the evidence. The OEB is confident that the rates resulting from this Decision and Order are reasonable and appropriately reflect the costs to serve customers. Additional protection through an ESM is not necessary. An ESM for the IRM term will be considered in Phase 2 of this proceeding.

5.7 Exemptions From Certain Performance Metrics

Enbridge Gas is required to meet certain performance metrics as outlined in section 7 of GDAR. Section 7.2.1 requires a gas distributor to observe and track its performance with respect to certain service quality requirements (SQR). Enbridge Gas requested a partial exemption under section 1.5.1 of GDAR beginning in January 2023.

The current performance standards with the requested modified measures are set out below:

- Call Answering Service Level (CASL) – request to modify to achieve 65% of calls reaching the general inquiry number answered within 30 seconds, on an annual basis, with a minimum monthly standard of 40%. The current annual metric is 75% with a minimum monthly standard of 40%.
- Time to Reschedule a Missed Appointment (TRMA) – request to modify to attempt to contact customers requiring a rescheduled appointment within one business day of the original appointment window 98% of the time. The current metric requires customers to be contacted to reschedule an appointment within two hours of the original appointment window 100% of the time.
- Meter Reading Performance Measurement (MRPM) – request to modify to achieve no more than 2% of meters with consecutive estimates for four months or more. The current target is 0.5% of meters.

Enbridge Gas requested that these exemptions be applicable from January 2023 until the OEB orders otherwise.[194]

[194] Enbridge Gas, Argument-in-Chief, p. 284.

In September 2022, Enbridge Gas provided the OEB with an Assurance of Voluntary Compliance, wherein it paid $250,000 in penalties to the OEB and made certain commitments with respect to meeting its CASL, Abandonment Rate and MRPM targets for 2022.[195]

In certain years, Enbridge Gas has not met four SQR metrics related to the CASL, TRMA, MRPM and Abandonment Rate and in 2021, Enbridge Gas did not achieve any of these four SQR metrics. Enbridge Gas stated that it continues to take all reasonable steps to achieve the SQR targets.

Table 7
CASL Actual Performance to Target (2019 to 2022)

Target	Actual	Actual	Actual	Actual
	2022	**2021**	**2020**	**2019**
75%	75.9%	64.3%	75.2%	79.0%

Enbridge Gas explained that the CASL was impacted in 2021 by increased call volumes due to COVID-19 and the consolidation of Enbridge Gas's two legacy utility customer information systems in July 2021 which introduced 1.6 million Union rate zone customers to the new systems. As a result of COVID-19, Enbridge Gas also experienced staffing shortages. Enbridge Gas stated that the majority of calls to the call centre are complex in nature as more customers are choosing to resolve non-complex matters through self-serve options.

Enbridge Gas's mitigation plans to improve performance on the CASL include: (a) implementing an augmented planning process to better assess and mitigate impacts from events with customer-facing impacts; (b) increasing staffing; (c) continuous improvement of digital channels; and (d) continuous improvement in response to customer surveys and internal reviews.

[195] EB-2022-0188, Enbridge Gas Assurance of Voluntary Compliance, September 12, 2022.

A summary of Enbridge Gas's historic TRMA performance is provided below:[196]

Table 8
TRMA Actual Performance to Target (2019 to 2022)

Target	Actual	Actual	Actual	Actual
	2022	2021	2020	2019
100%	93.8%	97.0%	97.3%	97.0%

Enbridge Gas explained that it experienced challenges meeting the TRMA metric and Enbridge Gas and its predecessors historically have not met the metric. Enbridge Gas stated that this is despite its ongoing efforts to try and improve the results, and that the 100% target is unreasonable and impractical as it does not account for factors like emergency response (e.g., redirecting technicians to emergency calls), human error (e.g., record keeping errors) or technical error (e.g., telecommunication outages). Neither Enbridge Gas nor the legacy utilities have ever met the TRMA metric.

Enbridge Gas's mitigation plans to improve performance on the TRMA include:[197] (a) aligning existing process for identifying attempts to reschedule appointments; (b) leveraging technology to add additional customer contact options; (c) enhancing reporting of results and corrective action processes; and (d) ongoing communication of process to reschedule appointments.

A summary of Enbridge Gas's historic MRPM performance is provided below:[198]

Table 9
MRPM Actual Performance to Target (2019 to 2022)

Target	Actual	Actual	Actual	Actual
	2022	2021	2020	2019
0.5%	4.1%	5.0%	4.4%	0.7%

Enbridge Gas explained that it experienced challenges meeting the MRPM metric since 2019 for several reasons including COVID-19 resulting in closed businesses, increased customer sensitivity to contact with meter readers, access issues during periods of

[196] EB-2023-0092, Exhibit G, Tab 1, Schedule 1.
[197] Enbridge Gas's mitigation plans aim to achieve a standard of 98% of customer appointments rescheduled within one business day for TRMA.
[198] EB-2023-0092, Exhibit G, Tab 1, Schedule 1.

lockdown, staffing issues attributable to quarantine/isolation periods and labour resource shortages.

Enbridge Gas also lost a key meter reading vendor in 2019 resulting in the need to onboard a new vendor. Meter reading vendors experienced hiring challenges with the attrition rate and level of absenteeism for meter reading personnel being the highest Enbridge Gas has experienced. Enbridge Gas also stated that 27 weather events in the 2020 to 2021 period limited the ability to safely access meters.

Enbridge Gas's mitigation plans to improve performance on the MRPM include: (a) working with meter reading vendors to increase hiring and conduct meter reading campaigns; (b) educating customers of the importance of meter reading and providing assistance to read their own meters; (c) customer outreach on arranging for meter reads and submitting customer meter reads; (d) field operations to support meter access; and (e) continuous improvement to support meter reading attainment and efficiency processes.

Enbridge Gas stated that the OEB should grant its request for a partial GDAR exemption for the CASL, TRMA and MRPM for the following reasons:

- The performance standards were established more than 15 years ago and are not reflective of current customer behaviours and expectations. For example, customer calls are more complex in nature as customers can use web-self-service options and chatbot features for less complex inquiries.
- There is a lack of alignment with the Distribution System Code performance standards:
    - The Rescheduling a Missed Appointment measure is an attempt to contact the customer prior to the appointment and an attempt to reschedule within one business day compared to the TRMA requirement to reschedule within two hours of the end of the original appointment.
    - The Telephone Accessibility measure requires 65% of calls answered in 30 seconds compared to the CASL requirement of 75% of calls answered in 30 seconds.
    - The Distribution System Code contains a force majeure provision that allows a utility to be relieved of obligations for events beyond its reasonable control and the GDAR does not.
- There are continuing impacts of external factors such as residual pandemic-related issues, labour market shortages, extreme weather events, global energy and climate change dynamics and the economic environment.

- Planned activities to align systems and meet industry standards (such as for cyber-security, Green Button and harmonization of rates and services) may impact metric performance.

OEB staff did not oppose Enbridge Gas's request for a partial exemption from GDAR performance measures related to the CASL, TRMA and MRPM for the 2024 calendar year. However, OEB staff submitted that the OEB should not grant a perpetual partial exemption from GDAR requirements. If Enbridge Gas believes that a partial exemption of GDAR beyond the calendar year 2024 is necessary, OEB staff suggested that this should be accomplished through a generic review of the SQR-related GDAR requirements for gas distributors.

As the power to create or amend natural gas rules (such as GDAR) rests with the OEB's Chief Executive Officer, OEB staff submitted that any request to amend GDAR should be dealt with outside of the current proceeding (and no determinations with respect to amendments to GDAR are appropriate in the current proceeding).

If the OEB agrees with OEB staff's position that any changes to the SQR-related targets are best addressed in a GDAR amendment-related process, OEB staff suggested that Issue 58[199] (to be heard in Phase 2 of this proceeding) can be limited to any scorecard additions, removals, or changes that are not set out in GDAR.

Many intervenors (BOMA, CCC, FRPO, LPMA, Pollution Probe, SEC and VECC) submitted that the OEB should reject Enbridge Gas's request for partial exemption from meeting GDAR performance measures.

BOMA opposed Enbridge Gas's request for a partial exemption from meeting the MRPM target with respect to commercial buildings. BOMA submitted that Enbridge Gas should be required to conclude its Advanced Metering Infrastructure pilots and develop its strategy, budget and implementation plan for commercial buildings by March 31, 2024. BOMA also submitted that Enbridge Gas should implement advanced metering for 20% of commercial buildings by the end of 2025, and for all commercial buildings by the end of 2026.

CCC, FRPO and SEC noted that in the MAADs proceeding, Enbridge Gas committed to generate savings without impacting reliability and service quality. As the OEB relied on these commitments when approving the amalgamation, the OEB should hold Enbridge Gas to its commitment.

[199] Are the proposed scorecard Performance Metrics and Measurement targets for the amalgamated utility appropriate?

In particular, CCC opposed an exemption from the MPRP and the CASL performance metric. CCC noted that the OEB and ratepayers expected that after the amalgamation, Enbridge Gas at a minimum would maintain and potentially enhance customer service levels. CCC stated that it was not appropriate to change the performance standards simply because Enbridge Gas is unable to meet them. CCC argued that COVID-19 and consolidation of the billing systems should not be an issue anymore and Enbridge Gas should be capable of meeting the metrics.

FRPO was “surprised and disappointed” by Enbridge Gas’s response to service quality issues that have arisen since amalgamation. Unbeknownst to FRPO, the OEB had engaged Enbridge Gas regarding these issues culminating in an Assurance of Voluntary Compliance. Further, FRPO criticized Enbridge Gas for requesting lower performance standards at the same time requesting recovery of integration capital spent to create the systems.

LPMA submitted that the value of the savings achieved through the merger has been reduced due to a deterioration in the levels of customer service. LPMA noted that these are customer-focused metrics and Enbridge Gas is essentially requesting a reduction to outcomes that impact ratepayers directly. LPMA submitted that any changes to performance levels should be done in the context of a full review of all metrics included within GDAR.

Pollution Probe argued that it is not in the public interest to grant such exemptions and that such exemptions would dilute performance rather than ensuring that a certain level of performance is maintained or improved.

SEC was specifically concerned with the request for a partial exemption from the MRPM performance target. SEC noted that the OEB had received several complaints from customers regarding estimated meter reads and large bills to catch up with actual consumption. SEC added that a number of its member schools have been negatively impacted by the high number of estimated bills, particularly in the former Union South rate zone. Increasing the existing target from 0.5% to 2.0% of meters with no read for four or more consecutive months would only exacerbate the problem of estimated bills and would provide relief to the company for poor performance. Accordingly, SEC submitted that the OEB should send a clear message to Enbridge Gas and deny the request to lower its service quality obligations.

VECC maintained that Enbridge Gas’s problems related to system integration and the COVID-19 pandemic should not be considered as sustainable reasons for not meeting certain metrics. VECC submitted that there should no temporary exemptions for performance metrics that were previously attainable by the legacy utilities, but which have not been met recently due to either cost reduction measures or the inability of

Enbridge Gas to successfully integrate its systems. In reply, Enbridge Gas dismissed the claims by some intervenors that its underperformance relative to certain SQRs were within its control or caused by mismanagement of integration activities. In fact, the main factors for not meeting the SQRs are unrelated to the amalgamation and were outside the control of Enbridge Gas.

Enbridge Gas reiterated that despite its best efforts to meet SQRs through comprehensive mitigation plans, there remain ongoing challenges. Enbridge Gas noted that the residual impacts of the COVID-19 pandemic are continuing with respect to the labour market, specifically with respect to meter reading providers and call centre staff. In addition, customers working from home has increased access problems for meter readers. Enbridge Gas rejected FRPO's "naïve" assertion that Enbridge Gas should overcome access issues through customer service measures. Enbridge Gas submitted that despite its best efforts, access issues continue to account for approximately 1-3% of the total MRPM. While the more pronounced impacts of the pandemic have passed, Enbridge Gas noted that it continues to experience the residual impacts and this is expected to continue for the next several months.

Enbridge Gas claimed that the predecessor utilities have been unable to meet the TRMA and the 100% SQR target has always been unrealistic.

Enbridge Gas opposed BOMA's submission reiterating that it is conducting pilots for Advanced Metering Infrastructure but will not be in a position to bring forward a proposal for any group of customers within the next several months. Enbridge Gas further clarified that it does not track MRPM for different group of customers or for commercial buildings.

Enbridge Gas agreed with LPMA that a full review of GDAR is required. However, Enbridge Gas submitted that it needs a partial exemption in the interim period, otherwise it will not be in compliance with the OEB's GDAR requirements.

Findings

The OEB approves the partial exemption request to change the TMRA target metric to 98%. The OEB denies the partial exemption requests to change the CASL and MRPM target metrics.

In principle, a TRMA metric based on meeting a target 100% of the time appears impractical. Enbridge Gas's performance over the last four years is close to meeting the requested 98%, except in 2022 where the actual performance was 93.8%. The OEB is satisfied that setting the metric at 98% is appropriate and will continue to drive improvement in performance. The revised metric shall be in place until the OEB orders otherwise or until such time as the OEB conducts a review of GDAR SQR metrics.

The OEB denies the partial exemption request to change the CASL target metric to 65%. The OEB notes that Enbridge Gas has been able to meet the current metric of 75% over the last four years except in 2021, when COVID was a mitigating factor. There is no basis for changing this customer facing metric.

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.

In addition, the OEB believes that the Advanced Metering Infrastructure pilot project is a positive step in managing this metric in the future. Enbridge Gas is required to provide an update on this pilot project in Phase 3 of this proceeding.

7 SERVICE QUALITY REQUIREMENTS PERFORMANCE AND MEASUREMENT

7.1 General Provisions

7.1.1 The purpose of this section is to establish performance standards and measurements for the natural gas industry in Ontario.

7.2 Identifying Service Quality Requirements

7.2.1 A gas distributor must observe and track its performance with respect to the following list of service quality requirements:

a) Telephone Answering Performance;
b) Billing Performance;
c) Meter Reading Performance;
d) Service Appointment Response Times;
e) Gas Emergency Response
f) Customer Complaint (Written) Response; and
g) Disconnection/Reconnection.

7.3 Definitions and Performance Measurements

7.3.1 Telephone Answering Performance

Telephone Answering Performance is a service quality indicator that is based on a centralized facility established or outsourced to handle calls and other inquiries from customers. The measurement of this requirement will include the following categories of calls: billing; collections; emergencies; and meter appointments.

Data for the call answer performance measures shall be obtained by monitoring calls on the distributors’ telephone systems including the Interactive Voice Response (IVR) system.

7.3.1.1 Call Answering Service Level

The percentage of all calls to the general inquiry phone number, including IVR calls that are answered within 30 seconds. This measure will track the percentage of attempted calls that are satisfied within the IVR or successfully reach a live operator within 30 seconds of reaching the distributor’s general inquiry number. The operator must be ready to accept calls and to provide information.

This measurement will be calculated as follows:

Number of calls reaching a distributor's general inquiry number answered within 30 seconds
Number of calls received by a distributor's general inquiry number

The yearly performance standard for the Call Answering Service Level shall be 75% with a minimum monthly standard of 40%.

7.3.1.2 Abandon Rate

The abandon rate means the percentage of callers who hang up while waiting for a live operator. This measure will track the percentage of callers that hang up before they reach a live operator. This measurement will be calculated as follows:

Number of calls abandoned while waiting for a live agent
Total number of calls requesting to speak to a live agent

The performance for this standard shall not exceed 10% on a yearly basis.

7.3.2 Billing Performance

The billing performance standard is a quality assurance standard. The standard requires gas distributors to have a verifiable quality assurance program in place. No specific metric is attached to this requirement.

7.3.2.1 Audits

Distributors must audit their billing data for accuracy. Manual checks must be done to validate data when meter reads fall outside criteria, as set out in the quality assurance program, for excessively high or low usage. In addition, the quality assurance program must include random audits of data quality and billing accuracy.

7.3.3 Meter Reading Performance

A distributor may choose to estimate the meter read for various reasons which may include limited access (e.g., a customer has an inside meter or the access to the meter is restricted) and the expense of actual meter reads. It is cost prohibitive to get actual meter reads each month. As a result, the following measurement is put in place to set out the minimum requirements for meter reads.

7.3.3.1 Meter Reading Performance Measurement

The meter reading performance measurement requirement will measure the percentage of meters with no read for four consecutive months.

Callers who call in their meter reads will be considered to have had their meters read. The measurement will be calculated as follows:

$$\frac{\text{Number of meters with no read for 4 consecutive months or more}}{\text{Total number of active meters to be read}}$$

This measurement shall not exceed 0.5% on a yearly basis.

7.3.4 Service Appointment Response Time

A distributor will ensure that appointment times are scheduled and, if requested, a customer shall be given an appointment time with a four hour window (i.e., morning, afternoon, or evening). This measurement will track the accuracy of response to these appointment times. Only the appointments that require the customer's presence will be included in this measurement.

7.3.4.1 Appointments Met Within the Designated Time Period

This measurement will identify the percentage of appointments, including meter related or other customer related work, that are met within their 4 hour scheduled time/date as arranged with the customer. This includes appointments for installations, meter reads and reconnection appointments (not including those due to non-payment). This measurement will be calculated as follows:

$$\frac{\text{Number of appointments met within the 4 hour scheduled time/date}}{\text{Total number of appointments scheduled in the reporting month}}$$

The minimum performance standard for this measurement shall be 85% averaged over a year.

7.3.4.2 Time to Reschedule a Missed Appointment

This measurement tracks the time taken to contact the consumer to offer to reschedule a missed appointment. This includes appointments for meter related customer requests or other customer requested work such as installations, meter reads and reconnection appointments not due to non-payment. At minimum, the distributor must contact the customer to reschedule the work within 2 hours of the end of the original appointment time.

The minimum performance standard shall be that 100% of affected customers will receive a call offering to reschedule work within 2 hours of the end of the original appointment time.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

EB-2022-0200, Decision and Order, p. 135

Question(s):

In Phase 1, the OEB denied Enbridge Gas's exemption request to change the MRPM metric to 2.0% of meters (from the current 0.5% metric).

In that decision, the OEB stated:

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.

Please describe how Enbridge Gas has considered the OEB's decision in Phase 1, related to the MRPM exemption request, in its current proposal to exclude inaccessible meters from MRPM calculations.

Response:

Enbridge Gas has considered the Phase 1 Decision and is actively working towards meeting the target of 0.5% for the Meter Reading Performance Measure (MRPM). Since initially implementing the Company's 2022 MRPM Mitigation Plan to improve meter reading performance, the MRPM results have significantly improved from 5.0% in 2021 to 1.3% for 2023, as described at Phase 2 Exhibit 1, Tab 7, Schedule 1, paragraph 31. The Mitigation Plan can be found at Phase 2 Exhibit 1, Tab 7, Schedule 1, Attachment 4. Enbridge Gas's commitment to all aspects of the mitigation plan has resulted in more accurate billing for customers, which is evident in the reduction in customer escalations in 2024. The number of billing related complaints decreased from 330 cases in 2023 to 104 cases in 2024, when comparing the January to May period.

Even with the MRPM Mitigation Plan in place, Enbridge Gas cannot meet the MRPM target and therefore requests approval to exclude inaccessible meters from the MRPM target calculation.

Enbridge Gas recognizes that customer behaviour has fundamentally changed since the pandemic. The unusual circumstances that began during the pandemic are now the standard environment in which Enbridge Gas must operate to gain access and read meters. Please see Phase 2 Exhibit 1, Tab 7, Schedule 1, paragraph 13 and 14 for further information. The supporting data can be found at Phase 2 Exhibit 1, Tab 7, Schedule 1, Attachment 2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

[1-7-1]

Question(s):

With respect to the Enbridge's Meter Reading Performance Measurement (MRPM) proposal:

a) [p.7] Please provide the definition of "inaccessible meter" for the purpose of the MRPM metric.

b) Please explain how Enbridge will ensure that its staff do not improperly classify meters that are not read as "inaccessible".

c) [Attachment 2] Please provide a similar table that provides information between 2014 and 2021.

d) Please confirm that there were meters that were similarly inaccessible before issues arose in 2020.

e) Please explain why, if the OEB is to remove inaccessible meters from the MRPM calculation, which are not new, it should not also increase the target performance (i.e. reduce the target below 0.5%).

Response:

a) Please see Phase 2 Exhibit 1, Tab 7, Schedule 1, page 5, paragraph 16 for the definition of inaccessible meters.

b) Enbridge Gas will ensure that staff do not improperly classify meters that are not read as 'inaccessible' through process controls and quality assurance measures. When meter readers are unable to read a meter, they have to enter a skip code on their handheld device. A skip code is essentially the reason for not reading the meter. These codes are quantified by Enbridge Gas and used to identify the reasons for why a meter has had consecutive estimates. Skip codes include inaccessibility but also other reasons like meter malfunctions and road closures. Meter readers are thoroughly trained to accurately use the correct skip codes that reflect varying situations. Enbridge Gas also relies on the meter readers accuracy for later conversations with the customer to discuss why the customer's meter is not read. Customer feedback is leveraged to validate the correct use of skip codes. In addition, Enbridge Gas also conducts field audits, this includes random site visits to confirm the accuracy of the skip codes used on the consecutive estimate list.

c) Please see response at Exhibit I.1.7-STAFF-2, part c).

d) Enbridge Gas expects that there were meters with inaccessible issues before 2020, however this information was not tracked until 2022. Please see response at Exhibit I.1.7-STAFF-2, part c).

e) Enbridge Gas believes the MRPM target is appropriate and is not proposing in Phase 2 to change the MRPM metric of 0.5%. Even with inaccessible meters removed, the 0.5% target continues to be challenging to meet and will continue to require ongoing mitigation efforts and attention to approach, as described in Phase 2 Exhibit 1, Tab 7, Schedule 1, pages 9, paragraph 24.

Exhibit M2

Incentive Ratemaking for Capital Cost Containment and Energy Transition Risk Reduction

Evidence for Ontario Energy Board Docket EB-2024-0111

Submitted August 12, 2024

Overview and Recommendations

The Current Energy Group has been asked to recommend adjustments to the proposed incentive rate-setting mechanism for Enbridge Gas aimed at improving capital cost containment and mitigating financial risks to customers associated with the energy transition. This evidence begins with a discussion of the evolving gas utility sector and the increased need for cost containment in light of the energy transition. The evidence then outlines a number of opportunities to better align Enbridge's financial incentives with customer interests through the following recommendations:

Recommendation 1 – Differentiated ROE: The OEB should reduce the return on equity (ROE) on growth-related assets as they are at a greater risk of becoming stranded and are more amenable to non-pipeline alternatives, including assets related to increasing system capacity or connecting new customers. This would benefit customers by reducing the incentive to build assets that are riskier and easier to avoid. A 1% reduction would be a reasonable starting point. A fair return can be assured by reducing risk (e.g. through revenue decoupling) and/or with a corresponding ROE increase for other capital assets, as detailed below.

Recommendation 2 – Revenue Decoupling: The OEB should extend revenue decoupling to make Enbridge Gas indifferent to the number of customers that it connects to its system. This will benefit customers by reducing the incentive to connect new customers, which requires significant capital outlays that increase rate base and energy transition risks.

Recommendation 3 – Efficiency Carryover Mechanism and Capex Efficiency Sharing: The OEB should implement an efficiency carryover mechanism to resolve a flaw in the standard price-cap approach whereby utilities lose the incentive to implement cost-containment measures near the end of the rate term (because they have fewer years remaining, if any, to benefit from cost-containment). This mechanism functions by allowing the utility to benefit from savings that are carried over into the new rate term. In addition, a calibrated efficiency carryover mechanism that includes capex efficiency sharing could operate to mitigate Enbridge Gas's capital expenditure investment preference.

Recommendation 4 – Remove Bias Against CIACs: The OEB should eliminate or at least reduce the incentive for Enbridge to include connection assets in rate base (on which they earn a return) versus contributions in aid of construction (CIACs), on which they earn no return. The OEB could achieve this by allowing Enbridge to earn a margin on CIACs if the generic revenue horizon is lowered or if Enbridge applies a lower revenue horizon for a customer-specific reason (e.g., revenue risk associated with a specific large-volume customer). This would benefit customers by reducing Enbridge's incentive to have connection costs included in the rate base, which is a major contributor to rate base growth and to stranded asset risk.

Recommendation 5 – Share Gas Supply Risk: The OEB should require that Enbridge share a modest portion of the gas supply volatility risk to encourage it to manage gas supply costs carefully. Cost containment is particularly important with the prospect of rate increases due to declining customer counts and the need for revenue to be allocated to the accelerated depreciation needed to reduce rate base.

Recommendation 6 – IRPA Shared Savings Mechanism: The OEB should implement an incentive structure for non-pipeline alternatives now, rather than waiting for the first IRPA application, so that Enbridge can plan and make the case for IRPAs internally. A shared savings mechanism would be a good approach.

About the Authors

Matthew McDonnell has a wealth of experience with incentive rate-setting mechanisms. This includes his work as Commission Counsel with the Hawaii Public Utilities Commission, where he led the development of the first comprehensive performance-based regulation framework in the United States. He has also supported regulators, utilities, and ratepayers in his roles with Navigant and Strategen, including as the Executive Vice President and Head of Consulting for Strategen before founding the Current Energy Group. Mr. McDonnell's current focus areas include the modernization of regulatory frameworks for gas utilities in an era of decarbonization – a topic he has consulted and presented on extensively.

Brad Cebulko also has a strong background in both incentive rate-setting mechanisms and energy transition issues. As a senior policy advisor with the Washington Utilities and Transportation Commissioner, he led efforts to initiate the development of a new performance-based regulatory framework. He continues to work on that project, now as a consultant. He also advises clients with a focus on gas energy transition issues, including approaches to integrated gas planning proceedings as well as advanced regulatory frameworks to inform the future of gas.

Introduction + Context

An Evolving Gas Utility Sector

Market, technology, and policy changes have made it clear that demand for natural gas can no longer be expected to continue rising. The Canada Energy Regulator forecasts that Ontario's natural gas demand will annually decline by 1.07% from 2023 to 2030 in a "Current Measures" scenario where Canada takes limited action to reduce its greenhouse gas (GHG) emissions.[1] If Canada's energy demand is consistent with achieving net-zero GHG emissions by 2050, as enshrined by the Net-Zero Emissions Accountability Act, then Ontario's natural gas demand will decrease by 14% by 2030.[2] Regardless of Canada's current or net-zero trajectory, natural gas demand – with or without supplemental hydrogen supply – will steadily fall for residential, commercial, and industrial customers through 2050.

As discussed further in the section that follows, under the existing regulatory financial incentive structure, even stagnant demand for gas will cause financial challenges for gas utilities and, by extension, impact customers who bear much of the risk of imprudent investments today. There is reason to believe, however, that current long-term projections overestimate gas demand from residential and commercial customers and possibly industrial customers as well, as efficient electric space and water heating technologies such as heat pumps become more widespread. Under the traditional regulatory model, it is the customers who primarily bear the risk of this transition. While regulators typically determine an investment's prudence shortly after it is put into service, the utility recovers the costs of the investment over many years, often for as many as 40 to 60 years. If there is widespread adoption of electric heating, it is the remaining gas customers — not the utility — who are typically obligated to continue paying for the entirety of a system that was not sized according to the needs of a shrinking number of customers.

Canada's energy transition will be supported by the increasing cost-effectiveness and accelerated adoption of electric heating equipment, such as heat pumps. At Canada's

[1] Canada Energy Regulator. Canada's Energy Future 2023. Exploring Canada's Energy Future Data. Available at: https://apps2.cer-rec.gc.ca/energy-future/?page=by-sector&mainSelection=energyDemand&yearId=2023&sector=ALL&unit=petajoules&view=&baseYear=&compareYear=&noCompare=&priceSource=&scenarios=Current+Measures&provinces=ON&provinceOrder=YT%2CSK%2CQC%2CPE%2CON%2CNU%2CNT%2CNS%2CNL%2CNB%2CMB%2CBC%2CAB&sources=BIO%2CCOAL%2CELECTRICITY%2CGAS%2CHYDROGEN%2COIL&sourceOrder=BIO%2CCOAL%2CELECTRICITY%2CGAS%2CHYDROGEN%2COIL

[2] Id.

most recent forecasts, heat pump costs will decline between 7%-15% by 2030, and up to 40% by 2050, representing significant potential cost savings for electrification across both net-zero and "status quo" scenarios.[3] A recent study found that electrifying building heat is the lowest-cost way to achieve net-zero emissions across Canada and that the cost-optimal path to decarbonization will involve massive declines in gas use.[4] Even in Canada's colder climates, heat pumps can achieve high efficiencies at low temperatures, thereby allowing virtually all Ontario residents to benefit from heat pump usage year-round.[5] This aligns with accepted testimony by Chris Neme of Energy Futures Group, on the reasonable customer economics of electrification.[6] In his testimony, Mr. Neme projected that a full electrification of a residential Toronto home using gas in 2023 would achieve 37% cost savings in its first year, and 46% cost savings over the expected 18-year life of a residential heat pump.[7] For these reasons, Enbridge should expect declining gas usage for residential and commercial customers.

While the gas and electric systems have never operated in isolation, the ongoing energy transition is increasing the interdependence between the two systems. This will require correspondingly increased attention from regulators to ensure that costs are controlled as gas-to-electric fuel switching accelerates. The misalignment between traditional utility financial incentives to expand their systems and the expected impacts of the energy transition will also require updated regulatory toolkits, including innovative approaches to realigning those incentives with evolving market trends and policy goals.

The current trajectory of market transformation trends holds real import for Enbridge Gas and remains starkly at odds with forecasts suggesting increasing customer demand and an ever-expanding distribution network. This long-term decline of Ontario's gas utility customer base is primarily based on three exogenous risks that Enbridge will struggle to forecast, let alone control:

[3] Canada Energy Regulator. Canada's Energy Future 2023. Exploring Canada's Energy Future Report. P. 33. Available at: https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/canada-energy-futures-2023.pdf. (p. 36 of PDF).
[4] Canadian Climate Institute. Heat Exchange: How today's policies will drive or delay Canada's transition to clean, reliable heat for buildings. June 2024. Available at: https://climateinstitute.ca/reports/building-heat/.
[5] Phase 1 Exhibit J18.7. Natural Resources Canada. Heating and Cooling With a Heat Pump. Available at: https://natural-resources.canada.ca/energy-efficiency/energy-star-canada/about/energy-star-announcements/publications/heating-and-cooling-heat-pump/6817#d2
[6] Ontario Energy Board. Enbridge Gas Application for 2024 Rate – Phase 1 Decision and Order. EB-2022-0200. P. 38.
[7] Chris Neme. Enbridge Gas 2024 Rebasing Testimony. Exhibit M9-GEC-ED Energy Transition. EB-2022-0200. May 2023. P. 23

1. The growth of public and market actors mandating the reduction of greenhouse gas (GHG) emissions and fossil fuel use to combat climate change and reduce local health and environmental hazards.[8]
2. The interconnected risks of geopolitical instability, such as the ongoing war in Ukraine, that shock natural gas prices with immediate and long-term impacts.[9]
3. The clean energy transition makes electric water and space heating more cost-effective options relative to natural gas appliances and infrastructure.[10]

These growing risks reflect a growing misalignment between Enbridge Gas's proposed investment decisions and its customers, where Enbridge's capital plan is predicated on 40,000 new customers each year for the next decade, in a market environment where its customers have increasingly cheaper and cleaner alternatives that will limit or end their natural gas usage.[11] Ontario's regulatory framework has traditionally incentivized the continued expansion of the gas distribution system, giving gas utilities like Enbridge the ability to invest in assumed growth that will impact ratepayer bills over the next 60 years of operation and depreciation. However, the Ontario Energy Board (OEB) has increasingly recognized that natural gas utility investments focused on gas system growth– whether through new business growth or capacity expansion – risk becoming stranded assets to a declining amount of Enbridge customers. As Enbridge's gas demand declines from customers switching to electrified sources of heat and power, the remaining customers will share a greater cost burden of Enbridge's gas distribution system. This is a major risk and Enbridge currently does not have the incentives it needs to appropriately mitigate those risks.

This report highlights some specific opportunities to improve the proposed elements of Enbridge Gas's Price Cap Incentive Rate-Setting Mechanism (Issue #2) to better align Enbridge Gas's financial incentives with customers' interests in an era of flat or declining gas sales. This report also examines ways in which Enbridge Gas could be incentivized to implement economic alternatives to gas infrastructure and how the recovery of its costs should be treated (Issue #7).

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[8] Enbridge Gas. Sustainability. https://www.enbridge.com/about-us/our-values/sustainability.
[9] Yi Jin et. al, Geopolitical risk, climate risk and energy markets: A dynamic spillover analysis, International Review of Financial Analysis, Volume 87, 2023, 102597, https://doi.org/10.1016/j.irfa.2023.102597.
[10] Brattle Group. The future of Gas Utilities Series. August 2021. https://www.brattle.com/wp-content/uploads/2022/01/The-Future-of-Gas-Utilities-Series__Part-1.pdf.
[11] Enbridge Gas. Table 2- Customer Attachments (Before and After Energy Transition). Exhibit I.2.6-ED-94. EB-2022-0200. Updated 2023-07-06. P. 4.

Limitations of the Traditional Regulatory Framework

Most gas (and electric) utilities operate under what is known as a traditional cost-of-service regulatory (COSR) framework. In this framework, regulators review a utility's capital investments to ensure that they are prudent and in the public interest and then allow utilities to earn a return on these investments at a rate that is high enough to ensure they can access the capital needed to finance those investments, but low enough to ensure that costs remain reasonable.

As shown in the formula in the figure below, to calculate a utility's revenue requirement of the total annual revenue a utility must collect to recover all of its costs and make a profit based on its allowed rate of return, the utility's capital assets, represented by the rate base, is multiplied by the utility's allowed rate of return. In contrast, the utility's operation and maintenance (O&M) costs, referred to as operating costs in the formula, do not generate a rate of return for the utility. Rather, these costs are simply passed through to the customer. The dissimilar treatment of capital and operating costs under the COSR framework creates a clear incentive for utilities to focus on capital investments, as this is what allows utilities to increase their profits and returns to shareholders.

$$\begin{aligned} &Revenue\ Requirement \\ &\qquad = (Rate\ Base * Allowed\ Rate\ of\ Return) + Operating\ Costs \\ &\qquad + Depreciation\ Expenses + Taxes\ and\ Fees \end{aligned}$$

In the past, bias towards capital expenditures was thought to be aligned with societal needs, as it supported the expansion of the gas (and electric) systems to meet growing demand and connect customers who might otherwise have been forced to use more expensive (and more polluting) heating fuels like heating oil. But today, it has created a starker tradeoff, or opportunity cost, to any allocation of utility resources. A financial incentive for capital investments may push a gas utility to focus on expanding its delivery system or fully replacing pipelines rather than pursuing lower-cost alternatives that would lower costs for customers, such as methane leak detection and management or pipeline repairs, which may be either operating costs or simply less costly capital expenditures.

Over the last few decades, and particularly in the last few years, it has become increasingly clear that a regulatory framework that incents gas system expansion is misaligned with market trends, customer interests, and public policies designed to support decarbonization.

All else equal, if the pace of gas utility capital investments continues to increase but gas demand does not, then within the COS regulatory framework under which utilities are entitled to recover their costs, customer bills must rise. Once an investment is deemed prudent after it is put into service, customers are typically expected to pay for that investment over its depreciable life—often 40 to 60 years. The risk for ratepayers of an ever-expanding gas delivery system is even more acute given the expected declines in demand for gas over the medium and long term due to building electrification and decarbonization goals.

Opportunities to Better Align Enbridge Gas's Financial Incentives with Customer Interests (Issue #2)

Differentiated ROE

To mitigate the rising risk of underutilized and stranded assets, the OEB should rebalance its regulatory framework incentive structure to discourage investment in system expansion and give financial preference to safety, reliability, and efficiency investments.

One approach for rebalancing gas utility incentives is through a differentiated return on equity (ROE), where capital expenditures in growth-related investments earn a lower return than capital expenditures in things like safety and mandatory relocations. Reducing the ROE for growth investments (i.e., investments related to connecting new customers and expanding existing gas system capacity) would better align Enbridge Gas's financial interests with the interests of customers to reduce stranded asset risk[12] and would:

- create a financial incentive to manage growth investments that avoids additional burdens on new and existing customers;
- enable a more symmetric ecosystem of gas utility incentives; and
- aligns incentives to invest in safety versus growth with the relative risk associated with each.

A regulatory framework that extends a uniform ROE for all capital expenditure categories is more likely to invite unduly risky expansion of the gas distribution system. As the average use of the system declines going forward,[13] continual expansion of the gas system will

[12] Ontario Energy Board. Enbridge Gas Application for 2024 Rate – Phase 1 Decision and Order. EB-2022-0200. P. 21-22.
[13] By proposing SFV pricing, Enbridge Gas has strongly signaled that it very much expects average customer use of the gas system to decline going forward. The implementation of SFV pricing would operate to shift virtually all of the risk associated with gas system expansion in the face of declining sales to customers.

equate to an ever-increasing rate base, placing significant upward pressure on customer bills. This upward pressure on customer bills may lead to material affordability and equity issues, where low- to moderate-income customers become saddled with the high cost of an underutilized gas distribution system. This customer inequity may be further compounded by the inability of this customer segment to afford upfront investments necessary to electrify their current gas end uses.[14]

Under the current uniform ROE paradigm, Enbridge Gas is financially indifferent to capital investments related to system growth versus capital investments focused on safety and mandatory relocations. Such an incentive structure would appear illogical when capital investments related to system expansion carry far greater risk to customers than do capital expenditures centered on safety that do not contribute to stranded asset risk in the same manner.

For Enbridge Gas, access to capital to fund investments is not infinite. Accordingly, investments dedicated toward gas system expansion displace other opportunities to invest in areas of the distribution system that do not present the same high-risk profile for customers. Indeed, absent ROE differentiation, Enbridge Gas has an inherent incentive to focus on growth investments when it nominally earns the same ROE between its capital investment expansion and other expenditure categories because any current investments in its gas system growth present future opportunities for investments in system maintenance, and may also present opportunities to upstream growth projects, leading to additional earnings opportunities for shareholders. The opportunity cost of these growth investments can be a significant burden for ratepayers, as reflected by Enbridge Gas's proposed total capital expenditure of $14 billion over the next ten years.[15] In Enbridge's capital estimate, a significant portion of its regulated capital is directed towards growth, (i.e. capacity expansion and new customer connections").[16]

By reducing the ROE for gas system expansion, the OEB would facilitate the following effects: better aligning the financial incentives extended to Enbridge Gas and more effectively deploying finite capital resources in a manner consistent with the public interest.

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[14] Low-income customer inequities and affordability issues would be only further amplified by implementation of a SFV pricing scheme, since these customers would have limited ability to control their bills by reducing their individual usage.
[15] Ontario Energy Board. Enbridge Gas Application for 2024 Rate – Phase 1 Decision and Order. EB-2022-0200. P. 21-22.
[16] Enbridge Gas. Utility System Plan. Exhibit I. 10.1-ED-60. EB-2024-0111. Filed 2024-07-08. P. 2.

1. **Create a financial incentive to manage growth investments and to avoid additional burdens on new and existing customers.**

A differentiated ROE creates a financial incentive for Enbridge to manage investments in gas system expansion and focus on higher return investments, such as safety and relocations, which would generally serve to lower the overall stranded asset risk of its capital investment portfolio. The differentiated ROE structure would extend lower earnings opportunities for system expansion investments, which should help to mitigate stranded asset risks by redirecting capital to other, less risky investment categories.

Enbridge has a significant degree of control over its growth spending. For example, it can expend more or less effort seeking out non-pipeline alternatives to projects aimed at increasing gas system capacity. Similarly, Enbridge works closely with potential new customers and developers and can impact their decisions through marketing, technical assistance, and otherwise. The purpose is to incentivize the gas utility to prioritize alternatives to capital expenditures that make long-term investments in the gas delivery system that are expensive, risky, and misaligned with the interests of ratepayers.

2. **Enable a more symmetric ecosystem of gas utility incentives.**

A differentiated ROE effectively pairs with existing regulatory tools that reward Enbridge Gas for progress in public policy outcomes like decarbonization, reliability, and affordability. By softening the upside earnings opportunities afforded to capital expenditures that facilitate continued system expansion, a more balanced incentive structure is possible, one that is a better fit for the unique and evolving needs of the energy transition in an era of flat to declining sales volumes. Indeed, incentives to support non-pipeline alternatives, such as those outlined in the section below, can become more attractive relative earnings opportunities on balance under a differentiated ROE approach.

As the example shows, Enbridge can earn additional income based on its performance, in addition to the near-guaranteed return they receive from operational investments. This dynamic incentivizes Enbridge to invest in operational investments to acquire the higher relative return on those investments, and to make those operations as efficient as possible so that their programmatic benefits – and the rewards from those benefits – are maximized.

3. **Avoid disincentives for investments in safety.**

Enbridge Gas would continue to earn the same ROE for all other categories of investments, including emergency repair, mandatory relocations, and reliability projects. Furthermore, Enbridge Gas would still earn a return for its capital investments toward new customer growth and system expansion, albeit at a slightly lower relative return. The idea is to incentivize the Company to deploy its investments to other projects with higher ROE while maintaining grid infrastructure safety and reliability. Under a differentiated ROE approach, Enbridge Gas would continue its mandated obligation to serve natural gas customers with a safe and reliable gas system without subsidizing unreasonable growth investments that impact a diminishing customer base over the coming decades.

Design details

To determine an appropriate ROE for growth investments, the OEB must ultimately examine several company, industry, and economy-wide factors (Enbridge Gas's capital structure, interest rates, gas utility industry risks, customer affordability, peer utility returns, etc.). However, Enbridge's cost of debt should be considered the floor for system expansion investment ROE because the cost of debt typically represents the lowest-cost financing option available to the company. Enbridge has an obligation to maintain a safe and reliable system and connect new customers who request connections. Therefore, Enbridge should be entitled to an ROE no less than the cost of debt. If the OEB desires a more gradual approach to ROE differentiation, then a system expansion investment ROE that is 1% to 3% lower than Enbridge Gas's overall ROE would be a motivating incentive to discourage further system growth and exacerbate stranded asset risk. If the OEB adopts a differentiated ROE in this case, a 1% decrease in the ROE for growth capital would be a reasonable start. Further decreases could be considered in future cases.

A differentiated ROE can be implemented in a way that maintains a fair return for the utility. One option, which would be ideal in this case, would be to compensate the utility for a lower return on growth capital by reducing the utility's risk, including by decoupling its revenue from customer connection forecasts. This is described more fully below.

Another option to maintain a fair return for the utility and achieve balance with a lower return on growth capital is to allow Enbridge Gas to capitalize certain operating and maintenance expenses related to pipeline repair. Such an approach would have the added benefit of incenting pipeline repair over replacement, which can help to stranded asset risk or the risk of underutilized assets in the future. A differentiated ROE would better reflect the risk profiles of different categories of capital expenditures. Given the uncertainty and risk such expansion presents for customers, the OEB has rightly interrogated the rationality of continued system expansion.[17] The OEB is cognizant that Enbridge Gas's system investments should account for the dynamic realities of an ongoing energy transition, including stranded asset risk. A differentiated ROE approach would enable Enbridge to recover reasonable and prudent costs while encouraging investment prioritization toward those capital categories that present relatively less long-term risk to customers.

Revenue Decoupling

Enbridge Gas's Y factors should sufficiently integrate partial revenue decoupling mechanism(s) that materially and equitably address the throughput incentive in a manner that is supportive of continued electrification and the ongoing energy transition. A partial revenue decoupling mechanism should be designed to ensure that Enbridge Gas is indifferent to whether new customers are added to its system while still exposing the company to revenue variations attributable to weather risks.

The primary objective of revenue decoupling is to weaken the link between utility earnings and sales volume. Revenue decoupling is designed to enable greater energy efficiency improvements by reducing the "throughput incentive" – the inherent financial incentive that utilities have to sell more therms of gas.

Revenue decoupling is a tool that addresses the throughput incentive. When variable rates are used to recover costs that are fixed in the short term, the utility can increase its revenues by selling more energy without a corresponding increase in its costs. This creates a powerful incentive to grow sales and oppose measures that reduce energy usage. However, revising the rate structure to collect a greater share of revenues via fixed rates is not an appropriate solution. A high fixed charge approach to addressing the throughput incentive would undermine customers' incentive to conserve energy and impose greater costs on low-usage (and often low-income) customers.

Removing the throughput incentive means that customers do not overpay for the use of the utility's existing assets when usage increases and that the utility does not fail to recover its prudently incurred costs for those assets when usage decreases. It also eliminates the profit opportunity that increased energy sales represent and thus reduces the utility's financial incentive to oppose energy-efficiency or DSM measures.

Under traditional regulation, utilities can retain any additional revenue they receive when their sales exceed the forecast that was used to set their revenue requirement, creating a

[17] Ontario Energy Board. Enbridge Gas Application for 2024 Rate – Phase 1 Decision and Order. EB-2022-0200. P. 22-23.

clear incentive for a gas utility to oppose energy efficiency and DSM initiatives that would result in reduced sales. Under revenue decoupling, most, if not all, variations between a utility's expected revenue and actual revenue are "trued up" annually. If the utility sells less gas than expected, rates will increase the following year to make up for the shortfall, and vice versa if it sells more gas than expected.

A Well-Designed Partial Revenue Decoupling Mechanism Should Leave the Utility Indifferent to Customer Additions or Reductions in the Near-Term

As the OEB has previously concluded, the energy transition is expected to result in declining sales from small-volume customers. In such a regulatory environment, it is important that Enbridge Gas's incentive structure does not present it with a financial preference for increasing average customer use within the MRP period. In addition, Enbridge Gas should not be exposed to the risk of under-collecting allowed revenues related to its fixed costs if the number of connected customers were to decline over the relevant time period.

In the Phase 1 Decision and Order, the OEB directed Enbridge Gas to utilize a harmonized average use variance account that requires it to continue to assume weather forecast risk as a part of the ratemaking process.[18] This is akin to "revenue per customer" decoupling, whereby it is thought that customer count is somewhat more closely correlated with growth in non-production costs, stronger than either growth in system peak or growth in energy sales. The revenue-per-customer method may not be appropriate in an era of energy transition, where new customers may have significantly different usage patterns than existing customers – e.g., partial electrification or enhanced energy efficiency measures – or where existing customers may begin departing the system – e.g., full electrification – over the course of an MRP period. An average use variance account is inherently tied to customer counts and, therefore, may still expose Enbridge Gas to under-collection of allowed revenues attributable to its fixed costs should the number of customers decline over the variance account period.

Given the concern that the energy transition is expected to result in declining sales from small-volume customers, an average use variance, or revenue per customer decoupling mechanism, may not adequately address the utility's financial exposure to a decline in the number of customers. In lieu of an average use variance account, the OEB should consider an alternative approach – revenue per customer class. Like revenue per customer, revenue per customer class determines the appropriate revenue to be collected regardless of the

[18] Decision and Order, December 21, 2023, at 123.

level of demand from customers. Revenue per customer class, on the other hand, is indifferent to the number of customers on the system or to average customer use.

To address the OEB's expectation of declining sales from small-volume customers, the OEB should explore a harmonized revenue balancing account that allows for truing up collected revenues against allowed revenues in a manner that is not tied to customer counts or customer average use. Such a total sales-based approach to decoupling could be designed in a manner that does not true up any weather-related revenue variances, thereby continuing to ensure that Enbridge Gas bears weather-related risks.[19]

Efficiency Carryover Mechanism

Adjustments that focus more on O&M spending can also help address energy transition risks and better align utility and customer interests, even if they do not directly blunt the incentive to invest in capital. For example, if O&M spending can be constrained more effectively, the regulator can bring down rate base via accelerated depreciation within the same revenue requirement envelope and the same rates. In other words, savings in other areas can make "room" to bring down rate base via depreciation adjustments. Reductions in rate base reduce the overall energy transition risks to customers.

Sustained O&M efficiencies can also soften the impact of rate increases arising from declining customer counts. An efficiency carryover mechanism is one tool that could be used for these purposes.

One benefit of price-cap regulation is the cost-containment incentive provided to the utility over the MRP control period. However, the strength of incentives to control costs is stronger at the start of the MRP period than at the end, and is different for capex and opex projects. In general terms, an efficiency carryover mechanism (ECM) is a tool designed to adjust the strength of the cost control incentive and allow cost containment to be sustained until the end of the MRP period. In the absence of an ECM some of the desirable incentive properties of an MRP can be lost towards the end of the period as the cost-based reset approaches. That is, savings from efficiency gains are limited to the years remaining in the regulatory period.

For example, a utility that puts in place more efficient processes by the beginning of year 1 of a 5-year term will reap 4 years of benefits and potential additional earnings. However, by

[19] It is important to note that a partial revenue mechanism that is not developed on a per-customer basis or tied to customer average use may decrease the utility's overall cost recovery risk. Accordingly, such a revenue decoupling design should be coupled with other alternative incentives to ensure that the structure remains balanced.

year 4 or 5, there is much less incentive to do so because the term is nearing its conclusion. It may even be in the utility's interest to hold off on efficiency improvements and wait to implement them at the beginning of the new rate term.

An ECM can be designed to address this by "carrying over" the results from one regulatory period into the next, providing an additional incentive to control costs even at the end of rate term. Also, since the ECM adjusts the strength of the incentive, the ECM can be used to adjust the strength of incentives for opex projects relative to capex projects, and hence address the risk of capex bias.

An ECM can also lessen the incentive for utilities to time spending to fall disproportionately in the test year.

Calibrated ECM Approach with Capex Efficiency Sharing

A special, calibrated kind of ECM can also help address capex efficiency in the context of an MRP. As noted above, the general purpose of an ECM is to maintain the strength of the utility's cost-efficiency incentive through the later years of the MRP. Although a standard ECM generally does not address capital expenditures, a special type of ECM that is applied separately to capex and opex and carefully calibrated to equalize the cost-containment incentive between them can help address capex bias across a multitude of utility expenditures.[20] Such an ECM design can include two parts: an Efficiency Benefit Sharing Scheme (EBSS) for opex; and a Capital Expenditure Sharing Scheme (CESS) for capex. These schemes would aim to provide a continuous financial incentive for utilities to pursue opex and capex improvements (at any point in the regulatory period) and share savings between the utility and customers. In order to better address a utility's capex bias, the ratio of sharing between the utility and customers can be different for opex and capex.

The capex sharing scheme could be based, in part, on the Australian model, the objective of which is to provide utilities with an incentive to undertake efficient capex during a regulatory control period and seeks to achieve this by rewarding utilities that outperform their capital allowance while also providing a mechanism to share efficiency gains and losses between utilities and customers.[21] A sharing ratio for capex savings could be

[20] For example, the Australian Energy Regulator (AER) employs a calibrated ECM. For details, see Australian Energy Regulator (2013, "Capital Expenditure Incentive Guideline for Electricity Network Service Providers, Explanatory Statement") and Australian Energy Regulator (2013, "Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, Explanatory Statement").
[21] Australian Energy Regulator (2023, "Capital Expenditure Incentive Guideline for Electricity Network Service Providers") at 2.

calibrated in a manner that helps to equalize regulatory treatment between opex and capex and stimulate more efficient investment decisions across the two expense categories.

Recommendation

An ECM is recommended both as a good tool for incentive regulation and as a mechanism that can help prepare for the energy transition. As with any individual mechanism, it must be evaluated and implemented in balance with the suite of other mechanisms comprising an incentive regulation framework. Implementation of a capex sharing scheme as part of an ECM framework could enable the OEB to ensure that (1) cost control incentives do not decline over a regulatory control period, and (2) Enbridge's preference for capital investment is mitigated by earnings opportunities through a shared savings mechanism.

Remove Bias Against CIACs

Enbridge currently has an incentive to include connection costs in rate base instead of having them covered by CIACs. Enbridge earns a profit on the former, but not the latter. This incentive is large because the magnitude of connection capital costs included in rate base is approximately $250 million annually.

This is contrary to the interests of existing gas customers, who benefit if connection costs are covered by CIACs as that means that the connecting customers cover the connection costs in lieu of existing customers. Also, connection costs are a significant component of rate base and thus contributor to energy transition risks. There is therefore a sound rationale to make Enbridge indifferent between those two connection cost recovery mechanisms.

Enbridge can impact the degree to which connection costs are included in rate base in at least two ways. First, Enbridge will presumably have a significant impact and role to play in the hearing to reconsider the appropriate revenue horizon that is expected to take place in Ontario.[22] Second, Enbridge will have an impact on the revenue calculations for specific large customers to the extent that it can apply a lower horizon to reflect customer-specific characteristics or risks (e.g., mines or other activities that may be shorter-lived).

This bias can be eliminated or reduced by allowing Enbridge to earn a margin on CIACs in certain circumstances. In particular, Enbridge should be eligible to earn a margin on CIACs only if the 40-year horizon is lowered or if Enbridge applies a lower horizon for a customer-specific reason. This would reduce the incentive for Enbridge to oppose a lowering the

[22] Ontario Government. Backgrounder: The Keeping Energy Costs Down Act. February 22, 2024. Available at: https://news.ontario.ca/en/backgrounder/1004216/the-keeping-energy-costs-down-act.

horizon by counterbalancing a reduction in rate-based connection costs with an additional return derived from the CIAC margin. This would also increase the incentive for Enbridge to be cautious when calculating the appropriate CIAC for certain risky connection requests. It would also address a potential argument that it is unfair to Enbridge to require it to undertake a large amount of work without any return if connections are increasingly funded through CIACs as opposed to rates.

Refinement to Y Factors

Enbridge Gas has proposed a Y factor cost recovery mechanism for incremental costs subject to Price Cap escalation (i.e., pass-through items or costs approved in other proceedings and implemented as part of the annual rate application). Enbridge Gas proposes to treat the following costs as Y factors:

a. Cost of gas and upstream transportation: The cost of gas supply, upstream transportation and gas supply balancing will continue to be passed through to customers through the Quarterly Rate Adjustment Mechanism (QRAM).
b. Demand Side Management (DSM) costs as determined in DSM proceedings. In accordance with the current treatment, changes to annual DSM Program costs approved as part of the DSM Program review process/proceedings will be updated in rates through the annual rate-setting application.
c. Lost Revenue Adjustment Mechanism (LRAM): Enbridge Gas DSM programs result in a reduction of volume consumption. The utility will continue adjusting the volumes used to calculate rates through the annual rate-setting application to capture DSM activities' impact on contract rate classes (i.e., LRAM volumes).
d. Normalized Average Use Adjustment: Phase 3 is expected to address rate design for all rate classes, including general service. Enbridge Gas proposes to replace the normalized average use adjustment with a Straight Fixed Variable (SFV) or Straight Fixed Variable with Demand (SFVD) rate design for the general rate classes, upon implementation of SFV or SFVD pricing, Enbridge Gas asserts that it would no longer require a Y factor for a normalized average use adjustment.

Ensuring that rates are affordable and fair to customers remains a central tenant when evaluating the appropriateness of the proposed elements within Enbridge Gas's Price Cap Incentive Rate-Setting Mechanism. This applies to the proposed Y Factors above, particularly where, as here, the mechanisms may present shortcomings when it comes to appropriately balancing risk between the utility and customers and ensuring that the financial incentives these mechanisms are extending to the utility are appropriately tailored to the needs of the energy transition, particularly in an environment of flat or declining sales.

As explained in the sections that follow, the OEB should: (1) examine opportunities to revise the QRAM to better share fuel price volatility risk between Enbridge Gas and its customers; and (2) preserve and enhance one or more mechanisms to address the throughput incentive in a manner that does not create barriers to energy efficiency and demand-side solutions or impede customer choice, including electrification decisions.

QRAM Could Better Share Gas Price Volatility between Enbridge Gas and Customers

Improvements to the management of gas supply can help to address affordability in an era when the upward pressure on rates is expected to increase with rate base growth and a declining user base.

Enbridge Gas's gas supply costs are handled through a gas supply pass-through mechanism as a part of the QRAM. Unlike most components of utility rates, a gas supply pass-through mechanism enables Enbridge Gas to recover its actual costs related to gas supply. So, if the company manages to reduce its gas supply costs, it retains none of the savings, and if it spends more than budgeted, its customers pick up the bill. This gives Enbridge Gas little incentive to manage its gas supply costs carefully, and it provides the OEB with limited visibility into whether Enbridge Gas spent more than was necessary.

Indeed, regulators often find it difficult to determine whether the utility's gas supply expenditures were, in fact, the best use of ratepayer funds. This is because regulators are unlikely to have good visibility into the effort the utility put into negotiating lower gas supply costs and what alternatives were available to the utility, such as conservation, demand-side management, or other physical and financial hedges.

The pass-through nature of the gas supply cost component of Enbridge Gas's QRAM often results in near-automatic cost recovery. Consequently, it provides little incentive for the utility to carefully manage its gas supply costs. This is problematic because Enbridge Gas is the party best positioned to manage gas supply-cost risk. Although gas supply costs are not entirely under Enbridge Gas's control, the company generally can negotiate more favorable gas supply contracts and take steps to reduce the amount of gas supply needed to meet demand (e.g., by working to conserve energy, shift demand, or facilitate electrification alternatives). In contrast, customers have little ability to manage gas supply cost risk – yet the current QRAM unfairly shifts this risk entirely onto their shoulders.

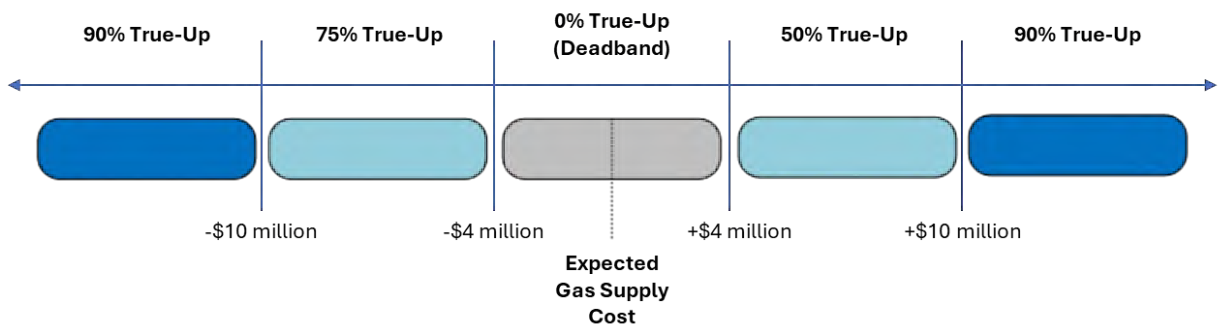
Given the energy transition and the prospect of flat or declining sales going forward, we are entering an era where the need for cost containment is even more critical for customers. Gas supply costs represent a significant aspect of a customer's bill, but Enbridge Gas currently has little to no incentive to reduce or control those costs today. A modification to QRAM that exposes Enbridge Gas to some amount of risk related to gas supply cost volatility may well be appropriate and induce the company to take more care in guarding against gas supply cost increases.

Straight-Sharing Approach to Gas Supply-Cost Sharing Mechanism

One approach to a cost-sharing mechanism design within a modified QRAM is a straight-sharing design. A straight-sharing mechanism employs gas supply forecasts to set the expected value that is built into rates, and the utility would true up some percentage (e.g., 90-98%) of the difference between expected and actual fuel costs in a symmetrical fashion. To ensure adequate guardrails for the utility's financial integrity, a utility's annual financial exposure could be capped at a fixed dollar amount.

Banded Design of Gas Supply-Cost Sharing Mechanism

As an alternative to the straight-sharing design illustrated above, the OEB could consider the use of an asymmetrical banded design. Such a design could feature a deadband on either side of the forecast within which no true-up is made. If actual costs exceed this deadband amount, there are two sharing bands: within the first tier, 50% of the difference is trued up; and within the second tier, 90% is trued up. If actual costs are less than expected, there are also two sharing bands: within the first tier, 75% of the difference is trued up; and within the second tier, 90% is trued up. This banded structure is illustrated in the figure below. Under such a mechanism, the difference for a single year could be recovered from customers over a two-year period to reduce rate shock.



Recommendation

The OEB should consider revising the QRAM to share gas supply-cost risk more fairly between Enbridge Gas and its customers. This could take the form of a straight-sharing approach for a cost-sharing mechanism or a banded design. Given the current stage of this proceeding and a lack of gas supply-cost-sharing experience to date, the OEB may consider implementing some form of straight-sharing mechanism initially.

Issue #7

IRPA Shared Savings Mechanism

Pursuant to the Integrated Resource Planning Framework for Enbridge Gas, Integrated Resource Plan Alternative (IRPA) project costs, similar to the costs for traditional infrastructure build, are eligible for inclusion in the rate base where Enbridge Gas owns and operates the IRPA. Where Enbridge Gas proposes to make an enabling payment to a competitive service provider and does not own or operate the asset, these IRPA project costs, if approved, are included in operating and maintenance costs and recovered as operating expenditures.

The OEB should examine opportunities to level the financial playing field for IRPA projects – both as against traditional infrastructure investments as well as between Enbridge Gas-owned projects and third-party owned projects. Although Enbridge Gas is permitted to rate base utility-owned IRPA projects, it still maintains a financial incentive to pursue traditional infrastructure investments when the traditional investments are larger than the IRPA project size. This inherent financial preference can manifest even in the absence of bad intent on the part of Enbridge Gas. Given finite resources and attention, opportunities for IRPA projects may simply not be investigated with the same rigor and creativity as would be applied to other higher-earning endeavors. Moreover, third-party-owned IRPA projects may receive even less resources and attention, given that such projects are not eligible for inclusion in the rate base.

One opportunity to address this misalignment of financial incentives with customer interests (given that IRPA projects should deliver cost savings to customers over traditional infrastructure) is to allow Enbridge Gas to share in savings attributable to the IRPA project compared to the traditional infrastructure investment it displaces. The shared savings ratio could be set initially at 30% - meaning that 30% of the cost savings would be retained by Enbridge Gas, with 70% of the cost savings flowing back to customers. Such a shared savings mechanism could be layered on top of Enbridge Gas's existing ability to rate base utility-owned IRPA project costs.

Furthermore, the OEB should examine opportunities to allow Enbridge Gas to earn a return on third-party owned IRPA project costs. Even if this return on third-party costs were set at a rate less than ROE, say 5%, it would still operate to better equalize treatment between IRPA project types, that is utility-owned versus third-party owned projects. Moreover, electricity IRPAs should be included in a shared savings framework as well - affording more equivalent opportunities for electricity-based energy solutions to address a system need or constraint as an alternative to IRPAs or facility projects undertaken by Enbridge Gas.

M2.EGI-10

Reference: Exhibit M2, pages 13 to 14

Preamble: CEG states: "Given the concern that the energy transition is expected to result in declining sales from small-volume customers, an average use variance, or revenue per customer decoupling mechanism, may not adequately address the utility's financial exposure to a decline in the number of customers. In lieu of an average use variance account, the OEB should consider an alternative approach – revenue per customer class."

Questions:

(a) Please provide further details of how the revenue per customer class would work under Enbridge Gas's proposed/historical IRM frameworks.
(b) Please confirm why CEG is proposing a revenue decoupling mechanism as part of Phase 2 rather than in Phase 1 or Phase 3.
(c) Please confirm, if Enbridge Gas forecasts net customer growth over the IRM period the Company will lose revenue under CEG's revenue decoupling proposal in this scenario.
(d) Please confirm, if customers leave Enbridge Gas's system during the IRM period the average customer's bill will increase to make up for the shortfall in revenue (all else being equal).
(e) Please confirm the revenue decoupling proposal suggested by CEG is specific to in-franchise low-volume rate classes (residential, general service).

Responses:

(a) CEG directs Enbridge to Exhibit M2, pages 13 to 14. Further details of the revenue decoupling mechanism design and a more detailed accounting of its interface with Enbridge Gas's proposed/historical IRM frameworks are beyond the scope of evidence that CEG has been asked to prepare and beyond what could be prepared within the proposed budget and time available for interrogatory responses.
(b) CEG was engaged to provide its expert opinion and prepare evidence for Phase 2 of this proceeding. CEG views revenue decoupling mechanism design as core to its evaluation of incentive-based regulatory structures and their respective alignment with the public interest in the context of a dynamic energy transition. CEG would be open to providing further evidence during Phase 3 of this proceeding if asked to do so but finds the design of a decoupling mechanism relevant to Issue #2 of Phase 2 and thus worth introducing at this juncture.
(c) CEG cannot confirm with specificity whether or not Enbridge would "lose revenue" under CEG's revenue decoupling proposal if Enbridge Gas forecasts net customer growth over the IRM period. In general, CEG's proposed revenue decoupling design is intended to provide an annual true-up of actual revenues collected to match target revenues over that same period on a per-customer class basis. The net effect of such an approach would be to lower the overall risk of revenue under collection rather than increase it.

(d) CEG can confirm that, generally speaking, revenue decoupling mechanisms operate to "true-up" a utility's actual revenues when forecasted sales exceed actual sales. The true-up component of a revenue decoupling mechanism would operate to place a small upward adjustment on customers' bills to close that gap. In this sense, it would operate like the current per-customer variance account, which could also operate to increase a customer's bill under certain circumstances.

(e) CEG's revenue decoupling proposal does not specify whether it should be limited to in-franchise low-volume rate classes (residential, general service). There should not be structural limitations to applying the approach across all customer classes. That said, CEG would need to conduct further analysis to determine whether it may be appropriate to limit the decoupling mechanism design proposed to in-franchise low-volume rate classes.

M2-SEC-2

Reference: Exhibit M2, pp. 2-3

Question:

(a) For each proposed recommendation, please provide CEG's view on, if implemented, would they increase or decrease Enbridge's business or financial risk?

Response:

Recommendation 2 (revenue decoupling) would decrease risk whereas recommendation 5 (share gas supply risk) would increase risk. For other recommendations, a properly nuanced answer would require additional analysis and, in some cases, Enbridge-specific data that we do not have access to. CEG observes that a regulator should view a utility's risk profile within its regulatory framework in a comprehensive manner, rather than viewing individual mechanisms in isolation.

M2-CCC-3

Ref: Ex. M2/pp.12-14

Questions:

a) Please advise whether CEG's proposed "revenue per customer class" decoupling approach results in a true-up of revenues for both changes in average use per customer and customer count (but not weather). As part of the response, please explain how variances in demand/throughput relative to forecast caused by changes in weather relative to forecast is addressed in the proposed methodology.

b) Please provide a numerical example that highlights the operation of the revenue per customer class decoupling approach. As part of the response, please highlight how the utility retains weather risk.

c) Please advise whether the recommended comprehensive revenue decoupling approach (i.e., full true up of revenues related to both volumes per customer and customer count) has been implemented in any other jurisdictions. If so, please provide references to the relevant policy documents, decisions, etc.

Response:

a/b) CEG confirms that the "revenue per customer class" decoupling approach discussed in the evidence is intended to true up actual revenues for changes in sales volume per customer class (but not weather) and customer count per class. The variances in sales volume would be 'normalized' to account for weather changes to ensure the utility still holds weather-related risk. This approach to weather normalization could operate akin to the approach directed by the OEB in the average usage per customer variance account. The difference is that rather than applying weather risk and weather normalization to the average use per customer, the CEG proposed revenue decoupling approach would seek to true up actual revenues collected to authorized revenues due to changes to total sales volume per customer class, which would include sales declines due to customer departures – not just changes to average use per customer.

Note that there are other mechanisms that could be used to achieve the same goal of ensuing that the utility is made largely indifferent to customer additions or reductions, as discussed below.

A hypothetical example is provided below to help illustrate the operation of a revenue per customer class decoupling approach.

Revenue Decoupling per Customer Class – Hypothetical Example	
Class	Residential
Allowed Revenues[5]	$2,000,000
Collected Revenues[6]	$1,500,000
Variance	$500,000
Weather Normalization Adjustment	($100,000)
Weather-Normalized Revenue Variance	$400,000

In the above hypothetical example, allowed revenues were $2,000,000 for the residential customer class. The utility under-collected revenues at a total of $1,500,000. Of the $500,000 variance, $100,000 of the loss in sales volume was attributable to weather. Accordingly, after a weather adjustment, the revenue variance to be trued up for the residential customer class is $400,000. This $400,000 would be collected via a minor increase in residential customer bills over a predetermined true-up period. This example would also work in the opposite direction to result in a negative variance if the collected revenues are higher than the allowed revenues. With a modest adjustment, the utility could be allowed to earn a percent of said revenue to account for incremental O&M costs of serving more customers.

The above hypothetical approach is comprehensive in its design, ensuring that the utility does not have an inherent structural preference for adding new customers over the plan period and would remain indifferent to customer departures as well. Moreover, the comprehensive per customer class revenue decoupling mechanism ensures that the utility is indifferent to reductions in customer usage. The Revenue Decoupling per Customer Class mechanism would be effectuated through a Revenue Balancing Account that would replace the existing Average Use per Customer Variance Account. Overall, it reflects a comprehensive approach to realigning structural financial incentives for the utility in an era of energy transition. In other words, the utility could not earn more revenue from increasing customer counts nor lose revenue from decreasing customer counts vis-à-vis the allowed revenues assumed in the test year.

[5] "Allowed Revenues" would be established during the test year on a per customer class basis. Allowed Revenues could be escalated year over year pursuant to the same I-X formula applied to the Price Cap mechanism.
[6] "Collected Revenues" would reflect actual revenues collected per customer class during the true-up interval, which could be monthly, quarterly, or annually.

In the alternative, should the OEB wish to preserve the existing Average Use per Customer Variance Account or prefer a different approach for other reasons, the core objectives of the Revenue Decoupling per Customer Class mechanism could be achieved through the creation of a Customer Count Variance Account. Under a Customer Count Variance Account approach, all or a portion of the revenue associated with net customer additions would be offset via the variance account. This customer count true up could be calculated against the customer counts for the test period. The variance account would record the revenue impact of the difference between the annual customer counts and those embedded in base rates for each of the general service rate classes.[7] The true-up likely should be offset by the incremental costs or savings from adding or subtracting customers of that class (i.e. the incremental O&M cost of serving an additional customer in the relevant rate class).[8] A hypothetical example is shown below.

Customer Count Variance Account – Hypothetical Example	
Class	Residential
Net customer additions vs. test year[9]	10,000
Average revenue per customer[10]	$600
Average incremental cost per customer[11]	$100
Variance	-$5,000,000

This example would also work in the opposite direction to result in a positive variance if there are net customer losses. This example calculates the variance based on average revenue per customer. However, it may be possible for the utility to calculate the variance with more specificity using the actual billing data for customers that are connected to the system and those that exit the system. We do not know whether that is possible with the utility's information systems. Either option would be an improvement on the current approach.

[7] For example, a simplified calculation would be: [variance in customer counts] x [average revenue per customer], with the assumption that each customer connecting to the system or leaving the system does so halfway through the year.
[8] The calculation would be [variance in customer counts] x [average incremental costs per customer].
[9] This example assumes that 20,000 customers were connected throughout the current year, with each customer being connected to the system for an average of 50% of the year. In year 2, all of the customer additions from year 1 would be included plus 50% of the customer additions in year 2.
[10] This would be a weather-normalized figure to ensure that the utility maintains the weather-related risk. However, a non-weather-normalized figure could be used without negatively impacting the efficacy of this approach.
[11] The incremental cost per customer per rate class would be based on the test year and adjusted by I – X for each future year. Although this is likely the simplest and best approach, the incremental cost per customer could alternatively be held static for each of the future years or set each year based on actuals.

This variance account could be designed in a number of different ways and the design would depend on how much of the revenue from incremental customers it would be appropriate for utility to retain. The above example reflects a decision that the utility should be allowed to retain enough incremental revenue from incremental customers to cover incremental costs associated with those customers (and vice versa with respect to customer defections). But if the regulator felt it was appropriate for the utility to retain all of the revenue from incremental customers this could be achieved by recording and truing up the revenue impact of the difference between the annual customer counts and forecast customer counts. One ancillary benefit of establishing a customer count forecast is that it would illuminate the utility's assumptions and projections related to customer growth or defections.

As this discussion shows, there are a number of ways to make the utility indifferent to customer additions and customer defections. Our main point is that this is a very important step to take in light of the energy transition for the reasons outlined in our report. Any of the above options would be acceptable because they would give the utility the appropriate incentives. The Revenue Decoupling Per Customer Class option is the most comprehensive whereas the Customer Count Variance Account would be the simplest to add on to the existing framework.

c) The CEG recommended comprehensive revenue decoupling mechanism shares similarities with the Hawaiian Electric Companies' revenue decoupling mechanism.

Reconciling Actual Revenue with Authorized Revenue

Revenue Balancing Accounts (RBAs) record the monthly differences between target revenues and the adjusted recorded electric sales revenues. The RBA applies monthly interest, equal to the annual rate for short-term debt from the cost of capital in each HECO Company's last base rate case, to the simple average of the beginning and ending balances each month in the RBA. In effect, the RBA applies one-twelfth of the rate each month. Finally, the RBA provides for collection or return of the calendar year-end balances in the RBA over the subsequent year period. The target revenue is the most recent Authorized Base Revenue or the re-determined Authorized Base Revenue calculated.

The Company must file with the Commission a statement of the previous year-end balance in each RBA sub-account and the Authorized Base Revenue level for the current calendar year with supporting calculations. An amortization of the year-end balance in the RBA sub-accounts are recovered through the per-kWh RBA rate adjustments.[12]

[12] *See* Hawaiian Electric Company, Inc., Revenue Balancing Account ("RBA") Provision, Revised Sheet No. 92, Effective October 1, 2023, *available at* https://www.hawaiianelectric.com/Documents/my_account/rates/hawaiian_electric_rates/heco_rates_rba.pdf.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

With respect to the attached document from the IRP TWG:

a) Does the document show the most up to date forecasts? If not, please provide the most up to date information.

b) Please confirm that the fall 2023 AMP. Addendum (filed in EB-2022-0091) is based on a previous customer addition forecast.

c) Please confirm that the AMP expected to be completed this fall, is based on the customer attachment numbers included in the attached document.

d) Please confirm that a new customer addition forecast is expected to be completed by Q1, 2025.

Response:

a) Yes, this is the most current information available.

b) Yes, the fall 2023 AMP Addendum was based on the customer addition forecast from Q1, 2023.

c) Yes, the AMP to be completed fall 2024 is based on the numbers in the attached, as those numbers represent the most current information available.

d) Yes, the update to the new customer addition forecast is expected to be completed in Q1, 2025.

IRP TWG Information Request from June 19, 2024 - Meeting 39

1. Enbridge to provide a table that shows housing starts, # of gas connections in the base forecast, and the # of gas connections in the adjusted forecast broken down between Ontario and Toronto forecasting out to 2034.
2. Enbridge to provide a table that shows its actual forecast of customers that will switch off gas each year until 2034.

Tables 1 and 2 provide the requested data for Request No. 1. Table 3 provides the requested data for Request No. 2.

For your reference, Enbridge Gas's (EGI's) forecasting process for Customer Additions and Existing Customers is provided in EB-2022-0200 Exhibit 3, Tab 2, Schedule 6.

As noted in EB-2022-0200 Exhibit 1, Tab 10, Schedule 4, EGI included energy transition adjustments into its forecasting and planning processes based on best available information at the time. As noted in the Reply Argument for EB-2022-0200, on an annual basis, EGI will review these adjustments and determine if any changes are warranted. The following information for Customer Additions for Ontario (Table 1) and Toronto (Table 2), and Existing Customers (Table 3) include the 2024 energy transition adjustment factors.

Table 1: Ontario Non-Apartment Housing Starts & EGI Customer Additions Forecasts - Base and Adjusted - Ontario (includes Toronto) 2025 to 2034

Year	2024 Ontario Housing Non-Apartment Starts [1,2]	Base Economic Forecast for Customer Additions [3]	Adjusted Customer Additions Forecast [3]
2025	39,132	42,711	40,533
2026	38,850	42,072	38,879
2027	38,153	41,100	37,000
2028	37,467	40,161	35,200
2029	36,823	39,304	33,382
2030	35,408	37,788	31,190
2031	34,020	36,367	29,209
2032	32,556	34,915	27,234
2033	31,113	33,502	25,330
2034	29,763	32,213	23,590
Total	353,285	380,134	321,547

Notes:

1. Non-Apartment Ontario Housing Starts are based on the Consensus Forecast. Additional details on the Consensus Forecast are provided in EB-2022-0200 Exhibit 3, Tab 2, Schedule 4.
2. Ontario Non-Apartment Housing Starts are based on the 2024 and 2025 Consensus Forecast with the Conference Board of Canada growth rate applied to the end of the forecast period.
3. Includes New Construction and Conversion Customers, and excludes community expansion.

Table 2: EGI Customer Additions Forecasts - Base and Adjusted – Toronto 2025 to 2034

Year	Base Economic Forecast for Customer Additions[1, 2]	Adjusted Customer Additions Forecast [2]
2025	1,803	1,752
2026	1,742	1,601
2027	1,676	1,456
2028	1,616	1,286
2029	1,559	968
2030	1,480	713
2031	1,411	539
2032	1,340	376
2033	1,274	231
2034	1,213	98
Total	15,114	9,020

Notes:

1. There is no Toronto specific Housing Starts. EGI relies upon the Ontario Non-Apartment Housing Starts and historical regional data to allocate a base forecast to Toronto.
2. Includes New Construction and Conversion Customers, and excludes community expansion.

Table 3: Customer Egress Forecast (Annual Rate)– Ontario (includes Toronto) & Toronto - 2025 to 2034

Year	Ontario (includes Toronto)	Toronto
2025	3,146	444
2026	3,172	448
2027	6,656	1504
2028	10,179	2573
2029	13,727	3646
2030	16,433	3865
2031	19,138	4079
2032	21,832	4288
2033	24,505	4496
2034	27,159	4696
Total	145,947	30,039

ENBRIDGE GAS INC.

Answer to Environmental Defence Motion Question #2

Reference:

Exhibit M2, CEG Evidence, pp.12-14
Exhibit N.M2.CCC-3

Question:

Comment on the decoupling mechanisms described by the Current Energy Group's response to CCC interrogatory 3.

Response:

The evidence from Current Energy Group (CEG) states that a partial revenue decoupling mechanism should be designed to ensure that Enbridge Gas is indifferent to whether new customers are added to its system while still exposing the company to revenue variations attributable to weather risks.[1] The headline statement in the CEG evidence is that "A Well-Designed Partial Revenue Decoupling Mechanism Should Leave the Utility Indifferent to Customer Additions or Reductions in the Near-Term".[2]

Before commenting on the two specific decoupling proposals that CEG advances in its response to M2.CCC Interrogatory #3 (a question that CEG previously refused to answer when it was asked by Enbridge Gas[3]), the Company has several preliminary comments about Environmental Defence's (ED) general proposal to implement a decoupling mechanism that would make Enbridge Gas indifferent to adding new customers.

(a) Enbridge Gas is not indifferent to adding new customers. Enbridge Gas supports customer choice. New customers are asking the Company for connections. Enbridge Gas aims to add feasible customers and support economic growth in Ontario. Enbridge Gas has a statutory obligation to connect new customers. And when the Company adds new customers, the fair return standard dictates that it should earn a comparable return on the invested capital costs.

(b) It is not clear whether other parties in this proceeding are indifferent to adding new customers. More customers result in economies of scale, which puts downward pressure on rates for all. Adding customers is not in contradiction to

[1] Exhibit M2, CEG Evidence, p. 12.
[2] Exhibit M2, CEG Evidence, p. 13.
[3] Exhibit M2.EGI.9 and 10.

goals of reduced carbon, and it is not in contradiction to an affordable energy transition at least cost to ratepayers (i.e. leveraging gas for peak days could be cheaper than the buildout of electric to meet peak demand). Additionally, new customers will keep the overall gas system infrastructure affordable for all customers that remain on the system.

(c) Ontario government policy is not indifferent to adding new customers. The Ontario government has made clear that it supports continued access to new gas connections. The Ontario government is strongly focused on encouraging and enabling housing development. Recent Ontario government policies confirm this. This context may be different from other jurisdictions where there are government policies or imperatives that underlie the impetus for revenue decoupling.

(d) ED's proposal is flawed by focusing solely on the "near-term". Even if Enbridge Gas could be "kept whole" in the current IRM term, the future impact of not adding customers and reducing the future rate base below the level that would reflect current customer forecasts needs to be taken into account. CEG's proposal does not address this. Said differently, even if Enbridge Gas is kept whole from 2024-2028, it will be in a worse position in future years if it has not added new customers in the near term because its rate base and customer base will be smaller starting from the next rebasing in 2029.

(e) ED's proposal is at odds with OEB policy under the Renewed Regulatory Framework (RRF). When performance based regulation was first established by the OEB, the regulator said that performance based regulation (PBR) is intended to move away from cost of service regulation and provide utilities with incentives for behaviour which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies. This key principle was confirmed in the RRF.[4] The proposal for partial revenue decoupling is designed to do the opposite – it posits that the Company's profit-maximizing and competitive motivations would lead to customer growth, so mechanisms need to be put in place to reverse that motivation.

(f) ED's proposal is for the revenue decoupling mechanism to be implemented alongside the Price Cap IRM that has been agreed by all parties (including Environmental Defence). This would be a fundamental change to the OEB's price cap methodology. Enbridge Gas would expect this to be affected in a broader manner than simply as a proposal from one intervenor's expert, with consideration of all implications and participation from impacted parties. In this regard, Enbridge Gas notes that the OEB is currently conducting a consultation

[4] Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach, pp.10-11.

"to advance its performance-based approach to rate regulation".[5] That process is the better place to consider changes to the OEB's approach to IRM. It should also be noted that the proposal to implement revenue decoupling for at least the low-volume customer classes by using a variance account effectively creates a cap on the Company's revenues. That is not the OEB's policy under the RRF.

(g) Any mechanism that claims to make Enbridge Gas "indifferent" to adding new customers, by taking away the benefits that the Company would achieve from adding new customers (incremental revenues, for example), will lead Enbridge Gas to minimize the number of new customers that it adds (at least for most of the IRM term). The Company will not commit capital to such activities without the opportunity for future return.

(h) Ultimately, it is telling that CEG is not able to point to any equivalent mechanism in place in any other jurisdiction, aimed at reducing incentives to add customers in order to address stranded asset concerns. This belies the fact that there is likely no simple answer.

The Company will have more comments and responses as ED and CEG further define their proposal in the oral hearing and written submissions on this unsettled issue.

Turning to the two decoupling mechanisms described by CEG in response to M2.CCC Interrogatory #3, Enbridge Gas has the following comments. Please note that these are based on the Company's current understanding of the proposals, and on having had a limited amount of time to consider and respond to this request. Enbridge Gas may have further comments as the process continues.

[5] Advancing Performance-based Rate Regulation | Engage with Us (oeb.ca).

Proposal #1 - Revenue by Customer Class Decoupling Approach

CEG's evidence states:

> Given the concern that the energy transition is expected to result in declining sales from small-volume customers, an average use variance, or revenue per customer decoupling mechanism, may not adequately address the utility's financial exposure to a decline in the number of customers. To address the OEB's expectation of declining sales from small-volume customers, the OEB should explore a harmonized revenue balancing account that allows for truing up collected revenues against allowed revenues in a manner that is not tied to customer counts or customer average use.

In general, Enbridge Gas questions the premise of this proposed mechanism. This proposal seems to be based on an expectation of net general service customer declines, but Enbridge Gas is forecasting net general service customer increases over the coming IRM term.

In the response to M2.CCC Interrogatory #3, CEG provided an example of a revenue balancing account. The example notes that allowed revenues per customer class would be established during the test year (Enbridge Gas interprets this to mean that they would be based on its 2024 approved revenue requirement), and then escalated each year by the Price Cap IRM formula. In future years, Enbridge Gas would compare the revenues actually received to the expected revenues and refund or collect the difference, on a weather normalized basis.

A key problem with this mechanism is that it does not support Enbridge Gas recovering the increased costs that will be incurred from adding new customers. Under the Price Cap IRM, rates are not updated for an updated forecast of customers (or their associated costs). Therefore, if the base expectation of revenues is inflated only by the price cap, that will result in Enbridge Gas (all things being equal) refunding all incremental revenues associated with new customers and not recovering the incremental costs associated with those new customers. Said differently, Enbridge Gas would have new costs associated with the additional customers but its revenues would only recover the costs associated with the base level of customers (inflated per the Price Cap).

The costs associated with new customers are only part of the relevant consideration from the Company's perspective. Enbridge Gas not only looks to recover its costs but also has the opportunity to earn a margin from new customers. Any such margin would also be foregone under the CEG proposal. As seen in response to ED Question #3, the Company expects to have modest net revenues (margin) from customer additions in some rate classes over the coming IRM term. Additionally, the return on equity component of the Company's costs is considered to be "earnings" from the Company's perspective. The CEG proposal would see Enbridge Gas have to return these "earnings" to ratepayers.

In the response to M2.CCC Interrogatory #3, CEG notes "*With a modest adjustment, the utility could be allowed to earn a percent of said revenue to account for incremental O&M costs of serving more customers*."

Enbridge Gas acknowledges that this proposed "adjustment" could address the cost recovery concern above (assuming that all the incremental costs, such as O&M and capital, including carrying costs and taxes, are addressed), but it does not address the lost opportunity to generate margin. Where Enbridge Gas loses benefits from adding new customers, it is not "indifferent", and it is effectively punished for complying with the obligation to connect, and for facilitating customer choice and access to new housing. This harms Enbridge Gas's ability to operate in an environment similar to competitive, cost-minimizing, profit-maximizing companies, where growth decisions are encouraged in appropriate circumstances.

Importantly, the "adjustment" noted by CEG would not be "modest". The Company's near-term costs of serving a new customer are very close to the incremental revenues from the new customer. In response to ED Question #3, Enbridge Gas sets out preliminary estimated revenues and costs from adding new customers. As seen there, the O&M costs are only a small portion of the Company's costs to add a customer. The costs for depreciation, taxes and return on capital investment are much higher. It should be noted that the determination of what are the appropriate costs and revenues associated with customer additions is a complicated determination. Some of the questions that would likely arise are detailed below in the comments on the second CEG proposal.

Enbridge Gas notes that the proposed revenue by customer class reconciliation approach may lead to unintended consequences (from the perspective of the party advocating for this mechanism), whereby the Company, faced with customer growth, may seek to delay that growth to the end of its five-year term in order to add those investments to rate base as quicky as possible, minimizing its short-term foregone benefits and maximizing its long-term benefits of adding capital.

As a more technical point, the Company notes that if the revenue class true-up is net of incremental costs, the incremental costs incurred for additions will be different than the incremental costs saved for departures. For additions, incremental costs would include O&M and capital, while for departures only the incremental O&M would be avoided. The incremental O&M associated with departures may be different from additions.

Enbridge Gas notes that the customer signals/impacts may not be as CEG intends. For example in the event of customer declines (if that was to happen), if there is a true-up of revenue shortfalls then costs will go up for all remaining customers. Assuming that more affluent customers are more likely to be able to choose electrification options, this outcome would impose greater costs on low-usage and low-income customers. On the other hand, where customer additions continue to occur and the additional revenues are immediately credited to ratepayers, then this could have the impact of diminishing incentives for customers to moderate or reduce their consumption.

There are things that are not clear from the briefly described CEG proposal.

It is not clear if the proposal relates only to general service (small volume) customer classes. If so, this may create a symmetry concern. For example, where net increases in the number of general service customers are forecast over the IRM term, then Enbridge Gas would lose all upside benefits, while being left with potential downside risk of larger volume customer declines, all while continuing to bear the risk of weather variability.

It is also not clear how the proposal would work with the ICM mechanism. Questions arising include the following. How is capital of customer additions paid for, if there is an expectation that additional revenue is returned via the revenue per customer class true-up mechanism? Is growth in the ICM threshold formula zero? How does one determine what is incremental capital that isn't covered in base rates (i.e. even with zero growth, the ICM threshold could potentially still cover some growth capital spending).

Proposal #2 – Customer Count Variance Account

CEG's response to CCC Interrogatory #3 states:

> In the alternative, should the OEB wish to preserve the existing Average Use per Customer Variance Account or prefer a different approach for other reasons, the core objectives of the Revenue Decoupling per Customer Class mechanism could be achieved through the creation of a Customer Count Variance Account. Under a Customer Count Variance Account approach, all or a portion of the revenue associated with net customer additions would be offset via the variance account. This customer count true up could be calculated against the customer counts for the test period. The variance account would record the revenue impact of the difference between the annual customer counts and those embedded in base rates for each of the general service rate classes. The true-up likely should be offset by the incremental costs or savings from adding or subtracting customers of that class (i.e. the incremental O&M cost of serving an additional customer in the relevant rate class).

In the response to M2.CCC Interrogatory #3, CEG provided an example of a Customer Count Variance Account. The example shows that for each year Enbridge Gas would either recover or refund the incremental net revenue associated with the number of customer additions or departures. Effectively, Enbridge Gas would record the margin associated with the new (or departed customers) in the account.

Enbridge Gas has a number of concerns with this proposal, in addition to concerns already raised above.

First, and fundamentally, Enbridge Gas objects to the principle that benefits associated with customer additions must be credited back to ratepayers immediately. The reasons for this concern are addressed above. It is very clear from the example given by CEG that all margin associated with customer growth will be returned to ratepayers. In that scenario, Enbridge Gas is not indifferent to adding new customers. Instead, the utility is disincented to do so. There are more attractive ways to invest capital.

Second, it is not clear that the approach proposed by CEG will always make Enbridge Gas indifferent to adding customers. In the early years of the IRM term, the Company will not wish to add customers. But at the end of the term, there may be reason to do so, knowing that the new capital will soon be added to rate base.

Third, the Company notes that it will be a complicated process to determine the inputs into this Customer Count Variance Account. The determination of what is the appropriate level of revenue and cost to take into account will be contentious. Enbridge Gas has set out its preliminary views about the appropriate approach and inputs to consider in determining revenues and costs for customer additions in the response to ED Question #3. However, this matter is sure to generate further debate and would likely require detailed evidence, discovery and hearing process. This will likely make the account contentious. This is underlined by the fact that CEG assumes a margin of $500 per customer[6], and ED assumes a margin of $525 per customer[7], whereas the Enbridge Gas response to ED Question #3 shows that the margin per new customer is very small, and is negative in the early years for some residential rate classes.

Examples of questions that will arise include:

- Do incremental costs of customer additions include both O&M and capital costs?

- The incremental cost per customer is not linear. There will be stepped increases/decreases with the magnitude of customer increases or decreases (i.e. reinforcements required with a certain # of customers, or lower internal administration costs with a certain # of customer departures) that result from economies of scale over time. How will this be addressed?

- What should be included in the incremental capital cost to add customers. Is it an average cost?

- Is there an impact on calculation, treatment or application of contributions in aid of construction under this approach?

[6] See Exhibit M2-CCC.3, p. 9.
[7] See ED Motion, November 4, 2024, p. 2.

- Does the approach assume that all capital costs get included in rate base at the next rebasing? If there is some assumption of reduced inclusion (since the goal of ED's proposal is to reduce customer additions), then the associated lost earnings need to be taken into account in order to keep the utility "indifferent".

- The incremental capital cost associated with a customer addition changes each year (i.e. the annual revenue requirement of a customer addition varies due to tax implications and the declining carrying cost as the asset is depreciated). How is this taken into account?

- The incremental costs may differ depending on whether one is truing up additional customers versus customer losses. For customer additions, there is incremental capital and O&M, whereas for customer losses the capital has already been spent and there is only incremental/variable O&M savings. How is this taken into account?

- Incremental costs and revenues will vary by customer – it may be that customers leaving the system have higher or lower consumption than the average customer, for example, so that recovery of an average amount of consumption would understate or overstate lost revenues. Additionally, revenue per customer may also be different (as compared to the average) for new customers (or vary between customers). It is not clear how the mechanism deals with these items.

- Where average cost and revenue per customer are used for this mechanism, then it may be the case that the Company will be more inclined to add smaller low-cost customers and delay the addition of larger customers. It's not clear that's a desired outcome. Is this taken into account?

- Additionally, there will be questions around what is the proper base level of customers against which to calculate a variance. Is it the 2024 base year total customer forecast, or is it based on actuals? How are customer numbers determined for future years (is it an average number or a year-end number?)

Finally, Enbridge Gas notes that a customer count variance account would need to be utilized with the existing average use variance account. The average use variance account would capture average use variances, for recovery or refund, in relation to the base forecast numbers of customers, while the customer count variance account would capture impacts of customer numbers that differ from the base forecast.

ENBRIDGE GAS INC.

Answer to Environmental Defence Motion Question

Reference:

EB-2022-0200, Hearing Transcript, Volume Two, July 14, 2023, p. 22, ln. 14.

EB-2023-0201, Exhibit I.ED-23, Page 4, Table 2.

Question:

In relation to the Customer Count Variance Account described by the Current Energy Group, provide the average revenue per customer and the average incremental cost per customer for the general service customer classes, and if those figures differ significantly from $600 in average revenue and $74.89 in incremental costs for residential customers, to explain why.

Response[1]:

The $600 in average revenue is for all general service customers, not solely residential rate classes.

Enbridge Gas notes that the average distribution revenue, excluding DSM costs, for a residential customer is approximately $500. The incremental O&M for a Rate 1 customer based on the Phase 3 2024 Cost Allocation Study[2] and the O&M costs as approved in the Phase 1 Decision is $94.12. The incremental cost of $74.89 referenced in the question was the incremental O&M cost for a residential Rate 1 customer presented as part of the Eganville Leave to Construct Application[3]. The increase in cost is a result of the harmonized cost study and the length of time and change in costs since the last approved cost studies. Please see Table 1 for a summary of the average revenue and incremental O&M cost per customer by rate class for general service customers.

[1] Enbridge Gas wishes to indicate that this answer has been prepared as fully as possible in the time available. Enbridge Gas may have further information based on better understanding of the question being asked, and on having more time to consider and respond.
[2] This cost allocation study will be filed in Phase 3 and maintains current rate zones.
[3] EB-2023-0201, Exhibit I.ED-23, p. 4, Table 2. This cost was based on the 2018 cost study escalated by PCI annually.

Table 1
Average Revenue per Customer and Incremental O&M per Customer

Line No.		Number of Customers	Average Revenue/ Customer ($)	Incremental O&M per Customer ($)
		(a)	(b)	(c)
1	Rate 1	2,163,088	485	94.12
2	Rate 6	172,974	2,167	228.92
3	Rate 01	369,871	616	118.80
4	Rate 10	2,205	11,641	1,235.38
5	Rate M1	1,205,199	493	95.36
6	Rate M2	8,077	10,182	928.47
7	Total General Service	3,921,414	600	
8	Total Residential	3,738,158	500	

The incremental costs Enbridge Gas incurs for adding a customer includes the O&M cost as shown in the table above, as well as the capital cost. The average incremental cost of adding a residential customer, determined by the revenue requirement calculation that includes both the incremental O&M and capital cost is between $491 and $610 in Enbridge Gas's rate zones. Please see line number 16, column (e) in Tables 2 to 4 which show the average revenue requirement of attaching a feasible customer. Note, the costs underpinning Tables 2 to 4 are based on the best available information today, which is the Phase 3 2024 Cost Allocation Study for current rate zones.[4] The Phase 3 2024 Cost Allocation Study is used as it is the only cost study that has been updated for the revenue requirement approved in Phase 1. The assumptions Enbridge Gas made in order to develop the cost estimates include:

a) The distribution rates used in determining the customer addition capital expenditure are based on the Phase 3 2024 Cost Allocation Study (consistent with Table 1).

b) The capital expenditure per customer attachment is calculated to be equal to Enbridge Gas earning a PI of 1.0 over 40 years (line 1 of Tables 2 to 4). This is a notional number and does not consider the actual cost to add a specific customer

[4] The Phase 3 2024 Cost Allocation Study includes the revenue requirement approved as part of the Phase 1 Interim Decision and Rate Order (EB-2022-0200), but does not include costs from the Phase 2 Settlement Proposal.

which could be higher or lower. Enbridge Gas believes this approach of estimating the incremental capital cost of adding a customer is appropriate as Enbridge Gas's portfolio must be equal to or greater than a PI of 1.0.

c) The revenue assumptions exclude projects with a SES and TCS surcharge.

d) The O&M amounts included reflect average variable O&M costs of each rate class, and do not include fixed O&M costs which can increase or decrease in a stepped fashion with material changes in the number of customers served, or due to other drivers. Please see Table 1 for the incremental O&M per customer (also see line 3 of Tables 2 to 4).

Table 2
Estimate of Incremental Revenue Requirement of Attaching Feasible Rate 1 Customers

Line No.	Particulars ($)	Year 1	Year 2	Year 3	Year 4	Year 5
		(a)	(b)	(c)	(d)	(e)
	Rate Base Investment					
1	Capital Expenditures	4,548	4,548	4,548	4,548	4,548
2	Average Investment	4,304	8,667	12,899	17,001	20,972
	Revenue Requirement Calculation:					
	Operating Expenses:					
3	Operating and Maintenance Expenses	94	188	282	376	471
4	Depreciation Expense	120	250	381	511	642
5	Property Taxes	14	27	41	55	68
6	Total Operating Expenses	227	466	704	942	1,181
	Required Return (1)					
7	Interest Expense	132	265	395	521	642
8	Return on Equity	151	303	451	595	734
9	Required Return	282	569	847	1,116	1,376
10	Total Operating Expense and Return	510	1,034	1,550	2,058	2,557
	Income Taxes					
11	Income Taxes - Equity Return (2)	54	109	163	215	265
12	Income Taxes - Utility Timing Differences(3)	(55)	(101)	(141)	(175)	(156)
13	Total Income Taxes	(1)	9	22	39	109
14	Total Revenue Requirement	509	1,043	1,573	2,097	2,666
15	Number of Customers	1	2	3	4	5
16	Average Revenue Requirement per Customer	509	522	524	524	533

Notes:

(1) The required return assumes a capital structure of 62% debt at 4.94% and 38% common equity at the 2024 Board Formula return of 9.21%. The annual required return is as follows: Average Investment (row 2) * 62% * 4.94% plus Average Investment (row 2) * 38% * 9.21%

(2) Taxes related to the equity component of the return at a tax rate of 26.5%.

(3) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

Table 3
Estimate of Incremental Revenue Requirement of Attaching Feasible Rate 01 Customers

Line No.	Particulars ($)	Year 1	Year 2	Year 3	Year 4	Year 5
		(a)	(b)	(c)	(d)	(e)
	Rate Base Investment					
1	Capital Expenditures	4,912	4,912	4,912	4,912	4,912
2	Average Investment	4,642	9,353	13,923	18,352	22,640
	Revenue Requirement Calculation:					
	Operating Expenses:					
3	Operating and Maintenance Expenses	119	238	356	475	594
4	Depreciation Expense	129	270	411	552	693
5	Property Taxes	32	64	96	128	160
6	Total Operating Expenses	280	572	863	1,155	1,447
	Required Return (1)					
7	Interest Expense	142	286	426	562	693
8	Return on Equity	162	327	487	642	792
9	Required Return	305	614	914	1,204	1,486
10	Total Operating Expense and Return	585	1,185	1,777	2,359	2,933
	Income Taxes					
11	Income Taxes - Equity Return (2)	59	118	176	232	286
12	Income Taxes - Utility Timing Differences(3)	(60)	(109)	(152)	(189)	(168)
13	Total Income Taxes	(1)	9	24	42	117
14	Total Revenue Requirement	584	1,195	1,801	2,402	3,050
15	Number of Customers	1	2	3	4	5
16	Average Revenue Requirement per Customer	584	597	600	600	610

Notes:
(1) The required return assumes a capital structure of 62% debt at 4.94% and 38% common equity at the 2024 Board Formula return of 9.21%. The annual required return is as follows:

Average Investment (row 2) * 62% * 4.94% plus Average Investment (row 2) * 38% * 9.21%

(2) Taxes related to the equity component of the return at a tax rate of 26.5%.
(3) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

Table 4
Estimate of Incremental Revenue Requirement of Attaching Feasible Rate M1 Customers

Line No.	Particulars ($)	Year 1	Year 2	Year 3	Year 4	Year 5
		(a)	(b)	(c)	(d)	(e)
	Rate Base Investment					
1	Capital Expenditures	3,955	3,955	3,955	3,955	3,955
2	Average Investment	3,738	7,531	11,210	14,777	18,229
	Revenue Requirement Calculation:					
	Operating Expenses:					
3	Operating and Maintenance Expenses	95	191	286	381	477
4	Depreciation Expense	104	218	331	445	558
5	Property Taxes	26	51	77	103	129
6	Total Operating Expenses	225	460	694	929	1,163
	Required Return (1)					
7	Interest Expense	114	231	343	453	558
8	Return on Equity	131	264	392	517	638
9	Required Return	245	494	736	970	1,196
10	Total Operating Expense and Return	470	954	1,430	1,899	2,360
	Income Taxes					
11	Income Taxes - Equity Return (2)	47	95	141	186	230
12	Income Taxes - Utility Timing Differences(3)	(48)	(88)	(122)	(152)	(135)
13	Total Income Taxes	(1)	7	19	34	95
14	Total Revenue Requirement	470	961	1,449	1,933	2,454
15	Number of Customers	1	2	3	4	5
16	Average Revenue Requirement per Customer	470	481	483	483	491

Notes:

(1) The required return assumes a capital structure of 62% debt at 4.94% and 38% common equity at the 2024 Board Formula return of 9.21%. The annual required return is as follows:

Average Investment (row 2) * 62% * 4.94% plus Average Investment (row 2) * 38% * 9.21%

(2) Taxes related to the equity component of the return at a tax rate of 26.5%.

(3) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

Updated Response: /u

By letter dated December 4, 2024, ED requested Enbridge Gas to update its response to motion question #3 to indicate “the cost of an additional customer incremental to the costs already covered by base rates.” The Company confirms that it believes its original response remains appropriate. The Company agrees that base rates can support a certain level of capital spending, in total. However, base rates and the annual escalation of those rates under a price cap rate setting mechanism during an incentive regulation (“IR”) term are not allocated to a specific type of capital expenditure recovered within rates. Generally, revenue growth through price cap escalation alone is insufficient to fully fund the cost associated with capital required to add customers and maintain safe and reliable service during the IR term. Growth and efficiencies are required to make up the difference and to earn allowed ROE under incentive regulation. What is clear is that there are incremental capital and operating costs associated with adding customers, that would not otherwise be incurred in the absence of doing so.

As part of the regulatory compact, the Company is obligated to serve new customers in return for the revenues generated from them. The obligation to serve is not compatible with the decoupling mechanisms proposed by ED, which are contrary to the OEB’s established rate setting mechanisms. The incremental revenues from customer growth are required to fund the necessary capital investments which enable the Company to add customers.

Further, when viewed in isolation, the cost of adding a customer typically outweighs the incremental revenues received from that customer in the first number of years. This is because the carrying costs of the associated capital costs are highest in the early years, but slowly decrease over time as the cost of assets are recovered through depreciation, whereas rates/revenues reflect an average carrying cost of assets (due to the varied mix of assets at all ages reflected in rate base). As a result, in the near term, where rates are set through a price cap mechanism, not cost of service, the addition of customers actually creates a drag on earnings, not a windfall.

Table 5 illustrates the forecast impact of customer additions over the IRM term. The forecast costs are shown at line 15 and reflect the cumulative revenue requirement of customer connection capital plus incremental operating costs per customer addition. Customer addition revenues, which are shown on line 18, reflect the revenue requirement associated with 2024 customer connection capital which is embedded in base rates and subject to annual PCI escalation, plus the cumulative gross margin associated with customer additions. Finally, line 19 provides the variance between customer addition costs and revenues, which shows the costs of customer connections outweigh the associated revenues. Of course, this issue would be amplified if the Company were not permitted to retain incremental revenues from new customer additions during the IRM term.

Table 5
Revenue Shortfall in IRM Term for Illustration

Line No.	Particulars	2024	2025	2026	2027	2028
		(a)	(b)	(c)	(d)	(e)
1	PCI (%)		3.3%	1.7%	1.7%	1.7%
2	Customer Adds ($) (1)		40,533	38,879	37,000	35,200
3	Revenue/ Customer($) (2)	600	620	631	641	652
4	O&M/ customer ($) (3)	94	97	99	100	102
5	Property Tax /Customer ($) (3)	14	14	15	15	15
6	Capital Expenditures ($Millions) (4)	224	286	256	230	208
	Revenue Requirement ($Millions)					
7	RR- 2024 Customer Adds	(5)	21	21	21	20
8	RR- 2025 Customer Adds	-	(5)	27	26	26
9	RR- 2026 Customer Adds	-	-	(2)	24	23
10	RR- 2027 Customer Adds	-	-	-	(1)	21
11	RR- 2028 Customer Adds	-	-	-	-	3
12	Total RR Capital Related (sum of lines 7 to 11)	(5)	17	45	70	94
13	O&M (line 2 x line 4)		4	8	11	15
14	Property Tax (line 2 x line 5)		1	1	2	2
15	Total Cost (sum of lines 12 to 14)		21	54	83	111
16	Base Revenue Escalated @ PCI	(5)	(5)	(5)	(5)	(6)
17	Customer Growth-Revenue (line 2 x line 3)		25	50	73	96
18	Total Revenue- Customer Adds		20	44	68	91
19	Revenue Shortfall (line 15 - line 18)		1	10	15	20

Notes:

(1) Customer additions based on AMP filed Nov 8, 2024.
(2) $600 per customer is the average for all general service customers, provided in Table 1, escalated for PCI in line 1.
(3) O&M and property tax based on Table 2, line 3, column (a).
(4) 2024 Customer Growth based on Phase 1 Rate order, and 2025-2028 based on AMP filed November 8, 2024.

The Company also notes that rate base growth and the associated carrying costs (i.e. cost of capital and depreciation expense and taxes), which has resulted from the level of capital expenditures required to maintain the safe operation of the system (i.e. through replacement of long lived assets, being replaced in current dollars) and meet growth requirements, has exceeded the revenue growth that is attributable to solely PCI escalation of base rates. Revenue growth due solely to PCI escalation is not sufficient to support the costs associated with capital requirements.

Revenues associated with PCI, growth, and cost efficiencies have been leveraged under the Price Cap rate setting mechanism to accommodate capital requirements. As rates are not tied to costs under a price cap mechanism, the ability to offset cost pressures in one area through efficiencies or revenue growth (i.e. scale economies) is a key attribute to the mechanism. The revenues achieved through the Price Cap mechanism should be treated as a whole (not segregated). This allows a utility to allocate funds across a variety of cost categories including O&M, capital and cost of capital. Isolating revenues by specific cost categories, such as growth capital contradicts the principles of Performance Based Regulation (PBR) and restricts the utility's operational flexibility.

The expectation that incremental revenues from the growth capital enables the funding of additional capital is reflected by the inclusion of the growth (g) factor in the ICM formula. The purpose of the g-factor is to account for the incremental capital funding that is notionally expected to be funded through existing rates resulting from revenues achieved from growth. By incorporating the g-factor, the ICM formula ensures that the incremental revenues generated from customer growth are recognized before incremental capital funding is awarded.

Finally, the imposition of either of the proposed decoupling mechanisms would impede the Company's ability to earn its allowed rate of return and a fair return, in any circumstance where more revenues are being returned to customers as compared to the cost offsets recognized. This impact is additive over an incentive regulation term.

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ENBRIDGE GAS INC.

Answer to Environmental Defence Motion Question

Question(s):

Provide Enbridge's latest estimates of customer connections and exits by rate class over the rate term as well as the revenue it forecasts generating over that term from net customer additions by rate class.

Response:

Table 1
Forecast Customer Additions

Line No.	Particulars	2025	2026	2027	2028	Cumulative Revenue (1) ($ millions)
		(a)	(b)	(c)	(d)	(e)
	EGD Rate Zone					
1	Residential	24,511	23,653	22,550	21,471	$ 108.4
2	Non-Residential	1,223	1,112	1,011	907	$ 27.1
	Union North					
3	Residential	3,014	2,840	2,661	2,496	$ 15.3
4	Non-Residential	181	162	140	120	$ 17.1
	Union South					
5	Residential	10,912	10,477	10,069	9,704	$ 46.2
6	Non-Residential	692	635	569	502	$ 66.2
7	Total	40,533	38,879	37,000	35,200	$ 280.2

Note:

(1) Cumulative revenue based on proposed 2025 Rates with high-level future year IRM adjustments for PCI and base rate adjustment for expensing capitalized indirect overhead. Residential additions are assumed to be Rate 1, Rate M1, or Rate 01 based on rate zone, and non-residential adds are assumed to be Rate 6, Rate M2, or Rate 10 based on rate zone. Billing units for customer additions based on rate class 2024 average use and assumed to be 50% effective in year of addition. Cumulative revenue calculation includes monthly customer charge, delivery commodity charge and Union South storage charge.

Table 2
Forecast Customer Exits

Line No.	Particulars	2025	2026	2027	2028	Cumulative Revenue (1) ($ millions)
		(a)	(b)	(c)	(d)	(e)
	EGD Rate Zone					
1	Rate 1	1,742	1,759	3,928	6,125	$ (11.2)
2	Rate 6	133	133	309	483	$ (4.6)
	Union North					
3	Rate 01	298	299	567	835	$ (5.5)
4	Rate 10	2	2	3	5	$ (0.7)
	Union South					
5	Rate M1	966	974	1,839	2,716	$ (2.0)
6	Rate M2	5	5	10	15	$ (0.2)
7	Total	3,146	3,172	6,656	10,179	$ (24.2)

Note:
(1) Cumulative revenue based on proposed 2025 Rates with high-level future year IRM adjustments for PCI and base rate adjustment for expensing capitalized indirect overhead. Billing units for customers based on rate class 2024 average use and assumed to be 50% effective in year of exit. Cumulative revenue calculation includes monthly customer charge, delivery commodity charge and Union South storage charge.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 69

To file the 2022 and 2023 scorecards.

Response:

The 2022 GDS Scorecard results are provided at Attachment 1. The 2023 GDS Scorecard is provided at Attachment 2.

▲ Above target (> 1.25 multiplier)
○ On target (1.00 - 1.25 multiplier)
▼ Below target (< 1.00 multiplier)

GDS 2022 year-end results

Key performance indicator	Weight	Year-end target: Doesn't meet	Year-end target: Meets	Year-end target: Exceeds	Year-end
Ensure safe, reliable operations	**35%**	**0x**	**1x**	**2x**	
People not getting hurt Total recordable injury frequency (TRIF) per 200,000 employee and contractor hours worked	15%	1.00	0.76	0.68	▲
Environmental incident frequency (EIF) Number of environmental incidents (non-compliances) per 200,000 employee and contractor exposure hours	5%	0.26	0.18	0.15	▲
Pipeline system safety (PSS) Leak and release frequency (LRF) defined as: (Tier 1 Count x 10 + Tier 2 Count) x 1,000 kms/kms of pipelines	5%	0.21	0.10	0.08	▲
Total damages per 1,000 locates First, second and third party line breaks per 1,000 locate requests	5%	2.28	2.07	1.86	▼
Cybersecurity: predictive susceptibility to a real phishing attack Percent clicked on compliance phishing test	5%	6.9%	4.9%	2.9%	▲
Maintain financial strength and flexibility	**35%**				
Adjusted earnings before interest, taxes, depreciation, and amortization (EBITDA)	35%	$1,784	$1,839	$1,894	▲
Progress toward our ESG goals	**10%**				
DE&I	5%				
Composite Net increase on overall diverse representation as a percentage of our workforce	3%	1.2%	1.5%	2.5%	▼
Composite Employee/leader training completion percentage of completion of Indigenous awareness training	2%	90%	95%	100%	▲
Emissions	5%				
GHG emissions reduction	5%	-8%	-4%	2%	▲
Execute and extend growth	**20%**				
EBITDA generated by growth capital (millions) Includes organic growth projects and M&A	20%	$17	$30	$58	○
Total	100%			2022 multiplier 1.40x	▲

ENBRIDGE
Life Takes Energy

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

[4-2-7, p.3]

Question(s):

Enbridge proposes a maximum impact of the LCVP on the average residential customer of $2 per month per target percentage of RNG as forecast the time procurement, to a maximum of $8 per target percentage of RNG procurement in 2029. Please provide similar customer impacts for other customer types, rate classes, and on an m3 basis.

Response:

Please see response at Exhibit I.4.2-ED-42, part a) for a correction to the sentence in evidence that is referenced in the question.

Please see Attachment 1 for the maximum bill impact to sales service customers in all applicable Enbridge Gas rate classes based on the maximum impact on the average residential customer of $2 per month for RNG purchases up to 1% of planned gas supply commodity purchases. Enbridge Gas used the maximum unit rate impact of 1.0000 cents/m^3 to calculate the maximum bill impact for non-residential general service and contract sales service customers. Please see response at Exhibit I.4.2-STAFF-33, Table 1, lines 1 to 4, column (a) for a calculation of the maximum unit rate impact of 1.0000 cents/m^3.

Please see Attachment 2 for the maximum bill impact to sales service customers in all applicable Enbridge Gas rate classes based on the maximum impact on the average residential customer of $8 per month for RNG purchases up to 4% of planned gas supply commodity purchases. Enbridge Gas used the maximum unit rate impact of 4.0000 cents/m^3 to calculate the maximum bill impact for non-residential general service and contract sales service customers. Please see response at Exhibit I.4.2-STAFF-33, Table 1, lines 1 to 4, column (d) for a calculation of the maximum unit rate impact of 4.0000 cents/m^3.

Updated Response: /u

Please see response at Exhibit I.4.2-ED-42, part a) for a correction to the sentence in evidence that is referenced in the question.

Please see Attachment 1 for the maximum bill impact to sales service customers in all applicable Enbridge Gas rate classes based on the maximum impact on the average residential customer of 50 cents per month for RNG purchases up to 0.25% of planned gas supply commodity purchases. Enbridge Gas used the maximum unit rate impact of 0.2500 cents/m^3 to calculate the maximum bill impact for non-residential general service and contract sales service customers. Please see response at Exhibit I.4.2-STAFF-33, Table 1, lines 1 to 4, column (a) for a calculation of the maximum unit rate impact of 0.2500 cents/m^3.

Please see Attachment 2 for the maximum bill impact to sales service customers in all applicable Enbridge Gas rate classes based on the maximum impact on the average residential customer of $4 per month for RNG purchases up to 2% of planned gas supply commodity purchases. Enbridge Gas used the maximum unit rate impact of 2.0000 cents/m^3 to calculate the maximum bill impact for non-residential general service and contract sales service customers. Please see response at Exhibit I.4.2-STAFF-33, Table 1, lines 1 to 4, column (d) for a calculation of the maximum unit rate impact of 2.0000 cents/m^3.

Low-Carbon Energy Program Maximum Sales Service Bill Impact
RNG Purchases of 0.25% of Planned Gas Supply Commodity Portfolio

Line No.		Annual Volume (1) (m^3)	Unit Rate (cents/m^3)	Maximum Bill Impact $	
		(a)	(b)	(c) = (a x b) / 100	
	EGD Rate Zone				
1	Small Rate 1	2,400	0.2500	6	/u
2	Large Rate 1	5,048	0.2500	13	/u
3	Small Rate 6	5,048	0.2500	13	/u
4	Average Rate 6	22,606	0.2500	57	/u
5	Large Rate 6	339,124	0.2500	848	/u
6	Small Rate 100	339,188	0.2500	848	/u
7	Average Rate 100	598,567	0.2500	1,496	/u
8	Large Rate 100	1,500,000	0.2500	3,750	/u
9	Small Rate 110	598,568	0.2500	1,496	/u
10	Average Rate 110	9,976,120	0.2500	24,940	/u
11	Large Rate 110	9,976,121	0.2500	24,940	/u
12	Small Rate 115	4,471,609	0.2500	11,179	/u
13	Large Rate 115	69,832,850	0.2500	174,582	/u
14	Average Rate 135	598,567	0.2500	1,496	/u
15	Small Rate 145	339,188	0.2500	848	/u
16	Large Rate 145	598,567	0.2500	1,496	/u
17	Small Rate 170	9,976,120	0.2500	24,940	/u
18	Average Rate 170	9,976,121	0.2500	24,940	/u
19	Large Rate 170	69,832,850	0.2500	174,582	/u
20	Average Rate 200	145,305,600	0.2500	363,264	/u
	Union North Rate Zone				
21	Small Rate 01	2,200	0.2500	6	/u
22	Large Rate 01	40,000	0.2500	100	/u
23	Small Rate 10	60,000	0.2500	150	/u
24	Average Rate 10	93,000	0.2500	233	/u
25	Large Rate 10	250,000	0.2500	625	/u
26	Small Rate 20	3,000,000	0.2500	7,500	/u
27	Large Rate 20	15,000,000	0.2500	37,500	/u
28	Average Rate 25	2,275,000	0.2500	5,688	/u
	Union South Rate Zone				
29	Small Rate M1	2,200	0.2500	6	/u
30	Large Rate M1	40,000	0.2500	100	/u
31	Small Rate M2	60,000	0.2500	150	/u
32	Average Rate M2	73,000	0.2500	183	/u
32	Large Rate M2	250,000	0.2500	625	/u
33	Small Rate M4	875,000	0.2500	2,188	/u
34	Large Rate M4	12,000,000	0.2500	30,000	/u
35	Small Rate M5 Interruptible	825,000	0.2500	2,063	/u
36	Large Rate M5 Interruptible	6,500,000	0.2500	16,250	/u
37	Small Rate M7	36,000,000	0.2500	90,000	/u
38	Large Rate M7	52,000,000	0.2500	130,000	/u
39	Small Rate M9	6,950,000	0.2500	17,375	/u
40	Large Rate M9	20,178,000	0.2500	50,445	/u

Notes:

(1) Typical customer annual consumption by rate class consistent with the bill impacts presented at EB-2022-0200, Exhibit 8, Tab 2, Schedule 8, Attachment 10, excluding rate classes that do not have a sales service supply option.

Low-Carbon Energy Program Maximum Sales Service Bill Impact
RNG Purchases of 2% of Planned Gas Supply Commodity Portfolio

Line No.		Annual Volume (1) (m^3)	Unit Rate ($cents/m^3$)	Maximum Bill Impact $	
		(a)	(b)	(c) = (a x b) / 100	
	EGD Rate Zone				
1	Small Rate 1	2,400	2.0000	48	/u
2	Large Rate 1	5,048	2.0000	101	/u
3	Small Rate 6	5,048	2.0000	101	/u
4	Average Rate 6	22,606	2.0000	452	/u
5	Large Rate 6	339,124	2.0000	6,782	/u
6	Small Rate 100	339,188	2.0000	6,784	/u
7	Average Rate 100	598,567	2.0000	11,971	/u
8	Large Rate 100	1,500,000	2.0000	30,000	/u
9	Small Rate 110	598,568	2.0000	11,971	/u
10	Average Rate 110	9,976,120	2.0000	199,522	/u
11	Large Rate 110	9,976,121	2.0000	199,522	/u
12	Small Rate 115	4,471,609	2.0000	89,432	/u
13	Large Rate 115	69,832,850	2.0000	1,396,657	/u
14	Average Rate 135	598,567	2.0000	11,971	/u
15	Small Rate 145	339,188	2.0000	6,784	/u
16	Large Rate 145	598,567	2.0000	11,971	/u
17	Small Rate 170	9,976,120	2.0000	199,522	/u
18	Average Rate 170	9,976,121	2.0000	199,522	/u
19	Large Rate 170	69,832,850	2.0000	1,396,657	/u
20	Average Rate 200	145,305,600	2.0000	2,906,112	/u
	Union North Rate Zone				
21	Small Rate 01	2,200	2.0000	44	/u
22	Large Rate 01	40,000	2.0000	800	/u
23	Small Rate 10	60,000	2.0000	1,200	/u
24	Average Rate 10	93,000	2.0000	1,860	/u
25	Large Rate 10	250,000	2.0000	5,000	/u
26	Small Rate 20	3,000,000	2.0000	60,000	/u
27	Large Rate 20	15,000,000	2.0000	300,000	/u
28	Average Rate 25	2,275,000	2.0000	45,500	/u
	Union South Rate Zone				
29	Small Rate M1	2,200	2.0000	44	/u
30	Large Rate M1	40,000	2.0000	800	/u
31	Small Rate M2	60,000	2.0000	1,200	/u
32	Average Rate M2	73,000	2.0000	1,460	/u
32	Large Rate M2	250,000	2.0000	5,000	/u
33	Small Rate M4	875,000	2.0000	17,500	/u
34	Large Rate M4	12,000,000	2.0000	240,000	/u
35	Small Rate M5 Interruptible	825,000	2.0000	16,500	/u
36	Large Rate M5 Interruptible	6,500,000	2.0000	130,000	/u
37	Small Rate M7	36,000,000	2.0000	720,000	/u
38	Large Rate M7	52,000,000	2.0000	1,040,000	/u
39	Small Rate M9	6,950,000	2.0000	139,000	/u
40	Large Rate M9	20,178,000	2.0000	403,560	/u

Notes:
(1) Typical customer annual consumption by rate class consistent with the bill impacts presented at EB-2022-0200, Exhibit 8, Tab 2, Schedule 8, Attachment 10, excluding rate classes that do not have a sales service supply option.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

[4-2-7, p.6]

Question(s):

Enbridge states: "Upon implementation of the LCVP, Enbridge Gas will first offer the low-carbon energy that has been procured to large volume sales service customers on a voluntary basis. Large volume sales service customers will have the ability to voluntarily assume an elected portion of the pass-through commodity costs associated with low-carbon energy as part of the proposed LCVP, up to 100 percent of their actual consumption." Please provide further details.

Response:

Enbridge Gas will procure renewable natural gas (RNG) within the thresholds of the maximum bill impact for the average residential customer[1] and the maximum target percentage of the gas supply commodity portfolio. Like conventional natural gas, the RNG price is a pass-through commodity cost.

Contracted RNG supply will be available to large volume customers through the Low-Carbon Voluntary Program (LCVP). Interested customers can voluntarily elect a percentage of their natural gas supply as RNG, up to 100%. Customers will be required to commit to the LCVP for a period of one year with automatic renewal in subsequent years until a time which the customer elects a change.

LCVP customers will be billed for their RNG supply monthly where their elected RNG supply percentage will be applied to actual consumption for the month subject to a monthly cap. The RNG consumption for the month will be charged at the unit rate for the LCVP, or Rider L of the Rate Handbook. Rider L will reflect the premium of the average RNG cost above the gas supply commodity charge for conventional natural

[1] The average annual consumption is 2,400 m^3 and 2,200 m^3 for residential customers in the EGD rate zone and Union rate zones, respectively. Using the highest average consumption in the calculation of bill impact ensures that the average residential customers in all rate zones are not impacted above the maximum bill impact proposed.

gas. The monthly RNG cap can be specified by the customer or will be auto populated if no cap is specifically identified by the customer.[2] The monthly cap helps customers with price certainty should their consumption be greater than forecasted. In addition, the monthly cap helps Enbridge Gas make sure enough RNG supply is available to meet LCVP demand.

If there are more elections through the LCVP than available RNG supply, Enbridge Gas will attempt to procure additional RNG on short-term contracts of up to one year. Contracts longer than one year would result in the risk that Enbridge Gas could exceed the maximum bill impact threshold should LCVP customers opt out of the program in future years. If Enbridge Gas cannot procure additional RNG to satisfy the LCVP elections, the Company will offer customers an election percentage proportionately reduced for all new LCVP election requests in the year.

If LCVP elections for the year are complete and RNG supply procured by Enbridge Gas is greater than the amount elected by LCVP participants, the remaining RNG supply volumes will be included in the gas supply commodity portfolio. All sales service customers will be allocated a percentage based on consumption and subject to the maximum bill impact for the average residential customer.

Under the Greenhouse Gas Pollution Pricing Act (GGPPA), biomethane, also known as RNG, is exempt from the Federal Carbon Charge (FCC). As such, customers receiving RNG will receive an FCC reduction on the percentage of their consumption that is supplied as RNG. LCVP customers will receive an FCC reduction on their RNG consumption from both the elected percentage and the portfolio percentage. All sales service customers will receive an FCC reduction based on the percentage of RNG included in the gas supply commodity portfolio.

[2] The auto-populated cap will be calculated as the average of the three highest months of consumption in the prior year.