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

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[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.

[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.

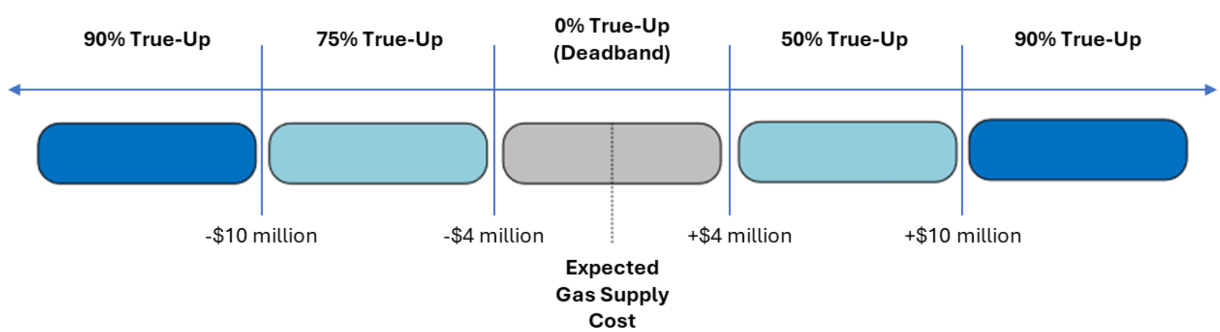
Given the energy transition and the prospect of flat or declining sales going forward, we are entering an era where the need for cost containment is even more critical for customers. Gas supply costs represent a significant aspect of a customer's bill, but Enbridge Gas currently has little to no incentive 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.