ONTARIO ENERGY BOARD

EB-2024-0111

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

AND IN THE MATTER OF Phase 2 of an application by Enbridge Gas Inc. to change its natural gas rates and other charges beginning January 1, 2024

Submissions of Environmental Defence and the Green Energy Coalition

Enbridge Rebasing Phase II – Incentive Ratemaking Mechanisms

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> *Ontario faces a fundamental conundrum with regard to the future of this resource. There are growing indications that it is unlikely that the natural gas grid can be decarbonized while continuing to deliver cost-effective building heat. There is growing doubt that it will be possible to replace the vast quantities of fossil fuel natural gas used today with clean alternatives, such as renewable natural gas (RNG) or hydrogen, in a cost-effective manner. ... This leads to a real risk of economically stranding the rate-regulated distribution assets used for home heating, with significant risk to customers, investors, and public finances.*
>
> Final Report of Ontario's Electrification and Energy Transition Panel[1]

Overview

The energy transition presents serious financial risks to gas customers and casts doubt on the future viability of Ontario's gas system. Ensuring that the transition is well managed is likely the OEB's most important and most challenging task in fulfilling its mandate to protect gas customers. Important progress was made in Phase 1 to make Enbridge's capital plan more consistent with the range of potential energy transition futures. Unfortunately, no concrete progress has been made with respect to aligning incentive ratemaking with energy transition risks.

Enbridge's incentive ratemaking proposals are business-as-usual and do not meaningfully reflect the risks arising from the energy transition. This is a serious problem because Enbridge does what it is incented to do. It is tempting to push the issue off until the next rebasing case because these issues are complex and there is considerable uncertainty. But that would be a mistake, because the infrastructure spending in the coming years will be a function of the incentives Enbridge faces, and customers will be paying for that spending for decades to come (until the 2080s at current depreciation rates). Changes to incentive structures are slow to take hold and impact behaviour. Those changes need to start happening today for the sake of customers tomorrow.

Consistent with the OEB's incremental approach to rate regulation, Environmental Defence and the Green Energy Coalition ("GEC") are only proposing one change for the current hearing – that Enbridge be made neutral with respect to customer connections/disconnections from a revenue perspective. This is an important early priority because it impacts Enbridge's approach to new connections, which are a particularly large and risky category of capital spending and can spur additional risky upstream investments.

As detailed below, Environmental Defence and GEC ask that the OEB decouple revenue from customer counts today, or in the alternative, require that it be implemented in Enbridge's next rate application. This is needed to remove Enbridge's incentive to convince as many developers as possible to connect to the gas system and to dissuade existing customers from leaving the gas system. That incentive is contrary to customer interests because it amounts to an incentive to:

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[1] *Ontario's Clean Energy Opportunity: Report Of The Electrification And Energy Transition Panel*, December 2023, p. 72 (link).

- Maximize the riskiest infrastructure spending;
- Minimize the number of new homebuyers and existing customers that secure energy savings from electrified homes; and
- Act contrary to the least-cost pathway to decarbonizing buildings.

These submissions describe the revenue incentive at issue, provide examples of how it impacts Enbridge's behaviour, describe the benefits of revenue decoupling, and discuss implementation options. Those options include returning all incremental revenue from net customer connections/ disconnections to ratepayers, allowing Enbridge to earn the incremental growth revenue it currently forecasts (no more or less), and a middle-ground between the two.

Revenue should be decoupled from customer numbers

Decoupling Enbridge's revenue from the number of customers that it serves would benefit customers in a number of ways, including by: reducing financial risk for the existing customer base, reducing energy bills, reducing the cost of decarbonization as a whole, enhancing customer choice, and supporting regulatory effectiveness and transparency. It would also be consistent with government and OEB policies.

Current incentives are strong and directly impact Enbridge behavior

Before addressing the benefits of decoupling revenue from customer numbers, it is necessary to explore what Enbridge's current incentives are and how they impact its behaviour and outcomes for consumers. Enbridge has a very strong incentive to convince as many developers as possible to connect to the gas system and to dissuade existing customers from disconnecting from the system via beneficial electrification. That incentive arises in part from the return that Enbridge earns on connection capital and from the incremental revenue that Enbridge is able to earn over the rate term from connecting customers.

Without decoupling, Enbridge is able to earn 100% of the revenue from new connections and it absorbs 100% of the lost revenues from disconnections. Enbridge expects to earn $256 million from net customer additions/exits over the rate term ($280 million from new connections minus $24 million from disconnections).[2] This is a significant sum.

There is strong evidence that the incentive directly impacts Enbridge's behaviour. As detailed below, many of Enbridge's actions over the past few years are consistent with a utility making strenuous efforts to (1) convince as many developers to connect to the gas system as possible and (2) dissuade customers from electrifying their buildings. In many instances, these actions do not appear to be aligned with customer interests.

[2] Response to ED Question #4 (link, PDF p. 73).

Convincing developers to connect

Enbridge actively works to convince developers to connect to its system. Enbridge's Director of Residential Market Development noted that Enbridge has connection targets and encourages developers to connect to the gas system in order to meet those targets.[3] Enbridge does more than simply connect customers when requests are received. They are actively trying to connect new developments, as noted in the following exchange:

> MR. ELSON: Okay. It would seem to me that Enbridge has a very significant incentive to convince as many developers as possible to install gas in their developments and to try to dissuade them from building electric developments seeing as this revenue from incremental customers is so essential to making sure that you can remain within your budget envelope. Is that fair to say?
> MS. BRUNNER: Yes, we are actively trying to connect new customers.

Enbridge's connection targets and active marketing efforts presumably have some impact. Many developers that put in gas would have done so regardless of Enbridge's efforts, but not all of them. There will be cases that are on the margin, such as developments that require longer service lines. In any event, Enbridge clearly believes it can impact the number of developments that connect to its system. Otherwise, it would not have connection targets for its staff and devote time and resources to convincing developers to connect.

Although convincing as many developers to connect to gas as possible has negative impacts on financial risks to ratepayers and energy affordability for new homebuyers as described below, Enbridge cannot be blamed for that. It is simply doing what it is incented to do.

Discouraging electrification

The business plan for Enbridge Sustain shows very clearly that Enbridge pays close attention to the revenue impacts of net customer connections/disconnections. It is also a clear example of Enbridge attempting to dissuade customers from disconnecting through electrification.

The below table is excerpted directly from the Enbridge Sustain Business Plan.[4] It shows the estimated gas distribution margin that will be retained by the regulated utility through Enbridge Sustain's hybrid heating offerings. Enbridge forecasts that it will retain additional distribution on the assumption that a portion of customers who adopt hybrid heating would have instead moved

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Cumulative
Gas Distribution Margin retained due to Hybrid Heating Program (Not included in financials above) **Based on % of customers assumed would move to 100% electrical heating & cooling**	10%	-	0.6	1.4	2.5	3.7	-	1.5	3.0	4.7	6.6	**8.2**
	20%	-	1.1	2.8	5.0	7.3	-	2.9	6.1	9.5	13.2	**16.4**
	30%	-	1.7	4.2	7.5	11.0	-	4.4	9.1	14.2	19.7	**24.7**
	40%	-	2.2	5.6	10.0	14.7	-	5.9	12.2	19.0	26.3	**32.9**
	50%	-	2.8	7.0	12.5	18.3	-	7.3	15.2	23.7	32.9	**41.1**
	60%	-	3.3	8.4	15.0	22.0	-	8.8	18.3	28.5	39.5	**49.3**
	70%	-	3.9	9.8	17.4	25.7	-	10.2	21.3	33.2	46.0	**57.6**
	80%	-	4.5	11.2	19.9	29.3	-	11.7	24.3	38.0	52.6	**65.8**
	90%	-	5.0	12.6	22.4	33.0	-	13.2	27.4	42.7	59.2	**74.0**
	100%	-	5.6	14.0	24.9	36.6	-	14.6	30.4	47.4	65.8	**82.2**

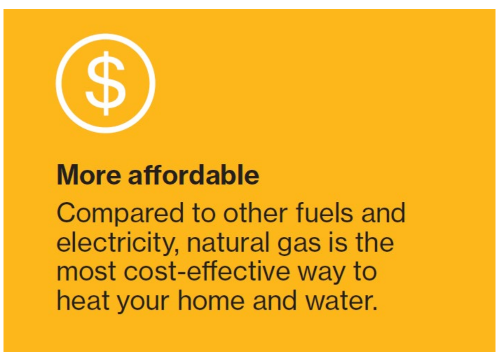
[3] Transcript Volume 2, December 18, 2024, p. 82, lns. 13-14 (link).
[4] Exhibit I.1.18-HRAI-5, Attachment 3, Page 23 (link, PDF p. 59).

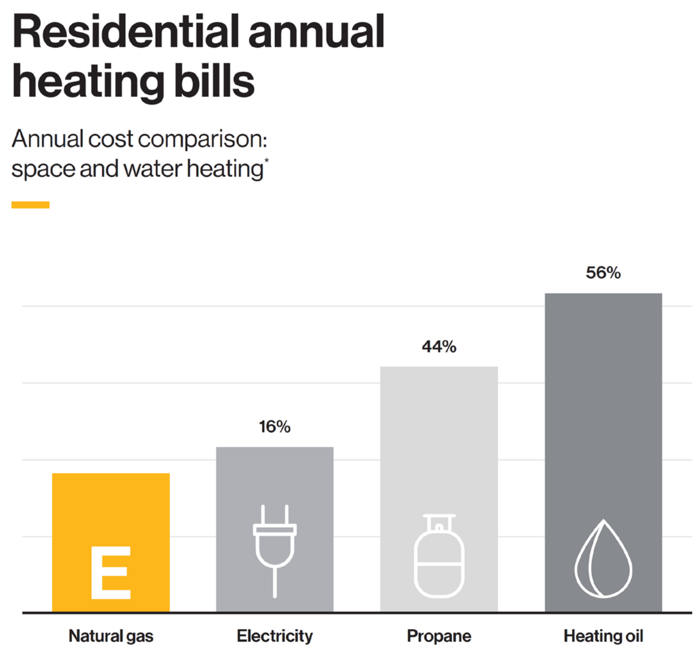
to 100% electrical heating and cooling. Columns for 2024 and 2029 are blank because those are the test years for which rates are based on a customer forecast. Distribution margin can be earned and retained in future years because, as noted above, Enbridge retains 100% of the revenue from net customer connections/disconnections in future years.

This aspect of Enbridge Sustain's business case is a clear example of the utility attempting to dissuade customers from electrifying their buildings. This table is explicitly stating that its regulated business can earn tens of millions of dollars by convincing customers to refrain from moving to 100% electrical heating and cooling.

Deceptive marketing

Enbridge has engaged in deceptive marketing that can most logically be explained by its incentive to connect and retain customers. Until very recently, Enbridge advertising said that gas is the most affordable way to heat homes and water. That is not true – heat pumps are.[5] Two examples of this advertising are shown below.





[6]

The Commissioner for Competition commenced an inquiry into the alleged deceptive marketing by Enbridge in December of 2023.[7] Despite this inquiry, Enbridge continued to publish materials saying that heating with gas is cheaper than heating with electricity at various times in 2024.[8] It

[5] EB-2022-0200, Evidence of the Energy Futures Group in Ontario Energy Board File, p. 22 (link).; Exhibit J3.6 (link, PDF p. 6).
[6] Exhibit K2.1 (link, PDF p. 44-45).
[7] Exhibit K2.1 (link, PDF p. 51); Transcript Volume 1, December 18, 2024, p. 62, lns. 14-17 (link)..
[8] Exhibit 1, Tab 16, Schedule 1, p. 2 (link, PDF p. 54).

also began using alternative wording that was unclear at best, such as saying that gas heating is "cost-effective" compared to electricity.[9]

Although Enbridge finally stopped publishing misleading advertising, it should not have taken this long. It took an investigation by the Commissioner of Competition, the Phase 1 decision, and insistence by intervenors as part of the Phase 2 settlement to finally secure a commitment to provide balanced information.

Anti-electrification / pro-gas DSM bias

Enbridge's 2023-2025 DSM plan exhibited a clear pro-gas and anti-electrification bias that is consistent with a strong incentive to minimize disconnections. For example, Enbridge's plan included a requirement that participants continue to be gas customers as a condition of participating in DSM programming. The OEB removed this requirement as it was contrary to customer choice, customer efforts to lower energy bills, and government policy.[10]

The original plan also included a focus on gas heat pumps despite that measure not being cost-effective. The OEB declined to approve that spending.[11] The OEB also declined to approve research and development funding on certain gas-fired measures.[12]

Despite the OEB's clear directions, Enbridge nevertheless proceeded with a gas heat pump incentive program using ratepayer funds and funded a variety of research and development projects for the gas-fired measures noted above.[13] Enbridge has attempted to justify this by saying it used the O&M budget not the DSM budget. If this spending is not contrary to the OEB's order, it is nevertheless so close to the line that it can only be explained by a strong incentive to promote gas in favour of electrification.

Anti-electrification / pro-gas energy transition planning

Enbridge's Phase 1 rebasing application also exhibited a clear pro-gas and anti-electrification bias that is consistent with a strong incentive to minimize electrification. For example, Enbridge submitted a study that Mr. Neme concluded was "highly biased in favor of gas and not credible."[14] The OEB ultimately concluded that Enbridge's application was "not responsive to the energy transition and increases the risk of stranded or underutilized assets."[15] It also concluded that Enbridge's "proposed capital expenditures for 2024 do not reflect the risk associated with the energy transition."[16]

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[9] Exhibit 1, Tab 16, Schedule 1, Attachment 1, p. 4 (link, PDF p. 55).
[10] EB-2021-0002, Decision and Order, November 15, 2022, p. 3 (link, PDF p. 32).
[11] EB-2021-0002, Decision and Order, November 15, 2022, p. 53 (link, PDF p. 33).
[12] EB-2021-0002, Decision and Order, November 15, 2022, p. 77 (link, PDF p. 34).
[13] Exhibit I.10.1-ED-63 (link, PDF p. 36); Exhibit I.1.10-PP-8.
[14] EB-2022-0200, Evidence of the Energy Futures Group in Ontario Energy Board File, p. 39 (link).
[15] EB-2022-0200, Decision and Order, December 21, 2023, p. 19 (link).
[16] EB-2022-0200, Decision and Order, December 21, 2023, p. 58 (link).

Enbridge's promotion of gas expansion and high-gas pathways is consistent with the following observation made by the Canadian Climate Institute, which Enbridge acknowledged provides credible, independent, expert-driven analysis on climate issues[17]:

> In a less regulated sector, market signals would reduce the incentive that companies would have to pursue a strategy of continued network expansion in the face of potential demand declines. But gas utilities are partially insulated from these kinds of signals. They therefore have a strong incentive to advocate for pathways that require ongoing system maintenance or expansion—such as hybrid heating or a shift towards low-emission gases.[18]

Anti-electrification / pro-gas connection lobbying

Enbridge has engaged in pro-gas connection lobbying that is consistent with its strong incentive to connect as many developers as possible. Enbridge's President even went so far as writing to the mayors of Ontario's municipalities, urging them to ask the provincial government to overturn the Phase 1 rebasing decision, which may have caused some developers to reconsider whether to connect to the gas system.[19] Enbridge's President wrote that the OEB's decision "sets a deliberate course to eliminate natural gas from Ontario's energy mix."[20] This is particularly bold because it is untrue – the OEB was explicitly seeking to reduce stranded asset risk, which is essential to maintain the viability of a gas system in a decarbonized future.

Any one of the above actions, in isolation, can be explained away. But when they are taken together, they paint a picture of a utility that is highly motivated to convince developers to connect to its system and to slow electrification, and a utility that is sometimes willing to take controversial steps to do so.

Decoupling would benefit customers

Decoupling revenue from customer counts would benefit customers with respect to financial risk, energy bills, energy transition readiness, and customer choice.

Reduce financial risk for existing customer base

Enbridge's incentive to convince as many developers as possible to connect to its system is problematic because it incents the company to maximize infrastructure spending in an area that is particularly risky and particularly large at a time when the viability of the gas system is already at risk due to the energy transition.

Infrastructure spending to connect new developments is risky because it largely serves home heating, which is the sector most vulnerable to energy transition risks since heat pumps are

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[17] EB-2022-0200, Hearing Transcript Vol. 12, p. 115, ln. 19 to p. 116, ln. 3 (link); Canadian Climate Institute, Who We Are (link, Ex. K12.3, PDF p. 113-115).
[18] Canadian Climate Institute, *Heat Exchange*, p. 58 (link).
[19] Exhibit K2.1 (link, PDF p. 56).
[20] Exhibit K2.1 (link, PDF p. 56).

highly competitive. As noted by Ontario's Electrification and Energy Transition Panel, there is a "real risk of economically stranding the rate-regulated distribution assets <u>used for home heating</u>, with significant risk to customers, investors, and public finances."[21] Although the gas system may serve hard-to-decarbonize industrial customers with low-carbon gas in a decarbonized future, those low-carbon gases are too scarce and too expensive to decarbonize home heating.[22]

Capital spending to connect new developments is also risky simply because these are new, long-lived assets. These assets will be depreciated over approximately 60 years under current policies, which is well into the 2080s.[23] The Canadian Climate Institute describes the issue as follows:

> This risk of stranded assets is most acute for new investments in infrastructure, such as pipeline replacements and expansions. Newer infrastructure has less accumulated depreciation. Its higher remaining asset values relative to older infrastructure represent higher liabilities for current and future customers to bear, should the assets become stranded due to disuse or underuse before the end of their expected lifetime.

Enbridge has also acknowledged that the risk of stranded assets is "most acute" on new assets because they have the longest life.[24]

Furthermore, customer connections are a major component of overall capital spending. Enbridge forecasts spending over $1.5 billion on customer connections over the rate term.[25] As with all capital spending, this would be added to rate base and paid off over approximately 60 years.[26] This constitutes an extremely large and risky bet, using ratepayer money.

<u>*Reduce energy bills for new and existing customers*</u>

Enbridge's incentive to convince as many developers as possible to connect to its system amounts to an incentive to saddle new homebuyers with higher energy bills. The owner of an electrified home will save approximately $10,000 (NPV) in lower energy bills compared to the cost of operating a home with gas equipment.[27] Although the savings from beneficial electrification will vary over time, those savings will generally increase as decarbonization proceeds because it costs *five times* as much to heat a home with RNG in comparison to an

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[21] *Ontario's Clean Energy Opportunity: Report Of The Electrification And Energy Transition Panel*, December 2023, p. 72 (link) (emphasis added).
[22] Canadian Climate Institute, *Heat Exchange*, p. III (link); EB-2022-0200, Evidence of the Energy Futures Group in Ontario Energy Board File, p. 39 (link); *Ontario's Clean Energy Opportunity: Report Of The Electrification And Energy Transition Panel*, December 2023, p. 72 (link) (emphasis added).
[23] EB-2022-0200, Exhibit I.4.5-ED-138 (The depreciation periods for new mains and services are between 55 and 60 years.) (link, PDF p. 1529).
[24] Transcript Volume 2, December 18, 2024, p. 47, lns. 12-15 (link).
[25] EB-2022-0200, Exhibit J13.7 (link, PDF p. 76); Transcript Volume 2, December 18, 2024, p. 7, lns. 7-18 (link); This figure includes all costs, such as meters and overheads. Without meters and overheads, the connection costs equal approximately $1.3 billion over the rate term. EB-2022-0200, Exhibit 2, Tab 5, Schedule 2, p. 2 (link, PDF p. 75).
[26] EB-2022-0200, Exhibit I.4.5-ED-138 (The depreciation periods for new mains and services are between 55 and 60 years.) (link, PDF p. 1529); Transcript Volume 2, December 18, 2024, p. 7, lns. 15-18 (link).
[27] Exhibit J3.6 (link, PDF p. 6).

electric heat pump using 100% clean electricity.[28] It is obviously counter to the interests of energy consumers to incent behaviour that will saddle new homebuyers with higher-than-necessary energy bills.

Enbridge's incentive to dissuade existing customers from electrifying their homes is particularly concerning and will also lead to excess customer bills. This can be done with biased marketing, such as the misleading bill inserts that Enbridge sent out when gas costs spiked at the beginning of the Ukraine war, which referred to gas as the most cost-effective way to heat homes.[29] Or it can be done by convincing customers to refrain from fully electrifying their homes, as discussed on page 5 above. It can also occur through the development of Enbridge's DSM plan and through the implementation of that plan via its staff and energy consultants. In all of these activities, Enbridge should not have an incentive to nudge customers away from options that could substantially lower their energy bills.

Reduce the cost of decarbonization as a whole

Enbridge's strong expansion incentive is inconsistent with the lowest-cost pathway to decarbonize our economy. The only cost-optimization study that has been published for Ontario concludes that "electrifying almost all building heat is the most cost-effective path to net zero."[30] That most cost-effective pathway would involve a 96% reduction in gas consumption in buildings in Ontario.[31] The cost-optimization model came to the same conclusions even when very optimistic assumptions around the availability and price of low carbon gases were used.[32] The results likely even underestimate the decline in gas because the model "does not account for how falling gas demand could raise costs for remaining customers."[33] As noted above, Enbridge acknowledged that the Canadian Climate Institute, which undertook this study, provides credible, independent, expert-driven analysis on climate issues,[34]

These results are consistent with the evidence of the Energy Futures Group in Phase 1 of this proceeding and with the conclusions of Ontario's Electrification and Energy Transition Panel.[35] Even the pathway study prepared for gas utilities in Massachusetts, which called for high levels of hybrid heating, also recommended full electrification of all new buildings as a safe bet.[36] For further evidence in support of the likelihood that decarbonization will involve the electrification of most buildings, see pages 4 to 22 of the Phase 1 submissions of Environmental Defence, which are attached as Appendix A for ease of reference. In this context of this extensive

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[28] Exhibit J3.6 (link, PDF p. 6).
[29] EB-2022-0200, Exhibit K2.1, p. 37; EB-2022-0200, Transcript Volume 4, July 18, 2023, p. 115, lns. 21-24.
[30] Canadian Climate Institute, *Heat Exchange*, p. 10 (link, PDF p. 12).
[31] Canadian Climate Institute, *Heat Exchange*, p. 17 (link, PDF p. 14).
[32] Canadian Climate Institute, *Heat Exchange*, p. 30 (link, PDF p. 20).
[33] Canadian Climate Institute, *Heat Exchange*, p. 20 (link, PDF p. 16).
[34] EB-2022-0200, Hearing Transcript Vol. 12, p. 115, ln. 19 to p. 116, ln. 3 (link); Canadian Climate Institute, Who We Are (link, Ex. K12.3, PDF p. 113-115).
[35] *Ontario's Clean Energy Opportunity: Report Of The Electrification And Energy Transition Panel*, December 2023, p. 72 (link); EB-2022-0200, Evidence of the Energy Futures Group in Ontario Energy Board File, (link).; Exhibit J3.6 (link, PDF p. 6).
[36] EFG Presentation, December 11, 2024, p. 5 (link).

evidence, Enbridge's incentive to convince as many developers as possible to connect to the gas system will only serve to increase the costs of decarbonization in the future.

Enhance customer choice

Decoupling revenue from customer counts would not remove gas as a choice for customers. Enbridge would continue to be subject to the obligation to serve and would continue to have an incentive to connect customers as connections capital would continue to be added to rate base.

Furthermore, the vast majority of gas connections are made at the request of developers, not by homeowners, and requests from developers are increasing while connection requests from homeowners are decreasing.[37] This divergence between connection requests from developers and homeowners suggests that new homebuyers are not actually getting what they would choose if given the option.

Decoupling would enhance customer choice by reducing the incentive to provide biased information to developers and to customers (see page 6 above). True customer choice is *informed* choice. Customers will be better able to make *informed* choices about their energy options if they are given balanced information by their utilities.

Decoupling would support regulatory effectiveness and transparency

Decoupling revenue from customer numbers would also support regulatory effectiveness by increasing the incentive to find efficiencies, making the stretch and productivity factors more meaningful, and enhancing transparency around the revenues from net customer additions/exits.

Enhance the incentive to find efficiencies

The opportunity to retain 100% of the revenue from new customers blunts Enbridge's incentive to find efficiencies. Under the current approach, rates are set on a single forward test-year cost of service basis and subsequently indexed by the price cap index formula.[38] This approach is meant to provide an incentive for Enbridge to find efficiencies in years 2 to 5 because it can retain the benefit of those efficiencies. However, Enbridge can also manage its costs using incremental growth revenue. [39] The ability to retain revenue from new customers gives Enbridge an alternative opportunity to manage its costs and earn incremental income that does not relate to efficiency whatsoever.

If revenue were decoupled from customer numbers, Enbridge's attention would be more directly focused on finding the efficiencies that benefit customers.

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[37] EB-2022-0200; Exhibit I.2.6-ED-94 (link, p. 6 for a chart of these figures).
[38] Price Cap = I – X +/- Y +/- Z + ICM.
[39] Transcript Volume 2, December 18, 2024, p. 14, lns. 18-22 ("And we manage those [costs] on an envelope basis, using essentially three things: The rate escalation that comes with the PCI, the revenue that comes with growth capital and also the cost efficiencies to the extent that we are able to find those.") (link).

Enhance the meaningfulness of the stretch factor and productivity factor

Decoupling revenue from customer counts would also make the stretch factor and the productivity factor more real and meaningful. The productivity factor is meant to represent an estimate of the long-run trend in productivity growth for the regulated industry whereas the stretch factor reflects the incremental productivity that a specific utility is expected to achieve based on its individual circumstances and plans.[40] However, this logic partially breaks down because utilities can retain 100% of the revenue from new customers. In year two, the utility should earn revenue based on their test-year cost of service, adjusted for inflation and productivity (and other PCI factors). But they earn significantly more than that because rates are based on test-year customer counts. There is no part of the price cap index formula that accounts for customer growth or decline. In other words, the rates increase based on the formula (I – X +/- Y +/- Z + ICM) without correcting for the fact that there are now more customers and therefore greater revenue.

Decoupling revenue from customer counts would also make the stretch factor and the productivity factor more real and meaningful. The productivity factor is meant to represent an estimate of the long-run trend in productivity growth for the regulated industry whereas the stretch factor reflects the incremental productivity that a specific utility is expected to achieve based on its individual circumstances and plans.[41] However, this logic partially breaks down because no part of the price cap index formula accounts for customer growth or decline. In other words, the rates increase based on the formula (I – X +/- Y +/- Z + ICM) without correcting for the fact that there are now more customers than the test year and therefore greater revenue.

Enbridge's stretch factor is 0.28%. However, under the current approach, that does *not* mean that it is expected to achieve productivity improvements worth 0.28% each year to cover its costs (adjusted for inflation, etc.). That is because Enbridge will earn an average of $64 million each year from net new customers and those amounts are not accounted for in the formula.[42] That incremental revenue gives Enbridge a cushion that allows it to cover costs without 0.28% in annual productivity improvements.

Enbridge was adamant during the hearing that it requires 100% of the incremental revenue from new customers to cover costs and earn a fair return. If that is indeed the case, that is because it negotiated an x-factor that it does not actually believe it can meet. That may well be the case. But that state of affairs is contrary to regulatory transparency and effectiveness because the stretch factor that is arrived at does not actually reflect the productivity gains that will be achieved.

Improve regulatory transparency

The hearing has shed light on how critically important the revenue from growth capital is to Enbridge and how it spends a great deal of time and effort maximizing that revenue. That is

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[40] Report of the Board, *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 17 (link).
[41] Report of the Board, *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 17 (link).
[42] Response to ED Question #4 (link, PDF p. 73) (Calculation: $256 million divided by 4 years. Note, the incremental income is highest in the latter years.).

concerning, because Enbridge's application had no details on this important incremental revenue source. The details did not even come out via interrogatories. It was not until responses to settlement conference questions that the parties first learned that Enbridge expected to earn $256 million over the rate term from net customer connections/disconnections. Such a large and important figure should be front and centre when intervenors and the OEB consider the whole rate approach. It was not.

Revenue decoupling would solve that. For instance, if the decoupling mechanism is based on a forecast of incremental revenue from new customers, that number will be tested, debated, and fully considered.

Decoupling and risk allocation

Some intervenors have expressed the idea that Enbridge should continue to bear the risk that less revenue is generated from new customers than anticipated. However, this is no reason to continue with the status quo. Allocating that risk to Enbridge has detrimental outcomes that far outweigh any potential risk-avoidance benefits, as set out above. It is unwise to allocate a risk to Enbridge when that provides it with incentives that are contrary to customer interests. Ratepayers benefit when Enbridge bears risks around items like cost control because that encourages the utility to be more efficient. Ratepayers do not benefit by giving Enbridge an incentive to convince as many developers to connect as possible and to dissuade customers from electrifying.

Eventually, customer counts will start declining. Enbridge expects that to occur in 2034.[43] At that point, Enbridge will almost certainly advocate to decouple revenue from customer counts as that would be necessary "to keep the company whole."[44] If we will have revenue decoupling at that point, we might as well adopt it now while there is an opportunity to return some of the incremental distribution margin back to customers.

Decoupling would support government policy

Decoupling revenue from customer counts would support government policy. The Ontario Government's vision is of an economy powered by "affordable, reliable, and clean energy."[45] Decoupling supports more affordable energy for the reasons outlined on page 9 above. It is neutral with respect to reliability. And it supports clean energy because electrified homes produce far less carbon emissions than those with gas.

Decoupling also supports other policy goals:

- **Viable gas system:** When gas demand and customer counts decline, the gas system could collapse under its own weight as a shrinking number of customers are unwilling to pay the cost of an expensive system. The gas system can only continue to be viable in a

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[43] Transcript Volume 2, December 18, 2024, p. 101, lns. 13-19 (link).
[44] Transcript Volume 2, December 18, 2024, p. 101, ln. 13 to p. 102, ln. 5 (link).
[45] Transcript Volume 2, December 18, 2024, p. 28, lns. 4-8 (link); *Ontario's Affordable Energy Future: The Pressing Case for More Power*, October 2024, p. 19 (link, PDF p. 96).

decarbonized future if it is rationalized. Removing the incentive to maximize growth of the system is consistent with the goal of a viable gas system.

- **Minimizing stranded asset risk:** Ontario's latest energy policy document notes the need to minimize stranded asset risk.[46] Decoupling is consistent with that goal, including for the reasons outlined on page 8 above.

- **Customer choice:** Decoupling is consistent with promoting customer choice, including for the reasons outlined on page 11 above.

- **Housing goals:** Decoupling revenue from customer counts is consistent with the goal of expanding the housing supply. The change would have no impact on the cost of housing. Also, without biased information from Enbridge, developers may find that they can use the recent and pending reductions in electricity system connection to make all-electric developments the cheapest option. But in any event, the decoupling proposal is entirely consistent with housing growth. If there are any impacts, they would be positive.

Decoupling would support OEB policy

Decoupling revenue from customer counts would support OEB policy. The OEB's regulatory structure attempts to provide "utilities with incentive for behaviour which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies."[47] The regulated business model provides too much protection from energy transition risks and encourages behaviour that is overly risky. The Canadian Climate Institute describes the issue as follows:

> Gas utilities' existing business models and current regulatory structures mean that their incentives can be at odds with maintaining future bill affordability for consumers in the context of the energy transition. …
>
> In the regulated segments of their business, gas utilities are largely insulated from most market signals—including the prospect of declining gas demand.
>
> [O]nce infrastructure is approved, utilities can be reasonably assured they will earn a return on it even if that usage case does not bear out. …
>
> In a less regulated sector, market signals would reduce the incentive that companies would have to pursue a strategy of continued network expansion in the face of potential demand declines. But gas utilities are partially insulated from these kinds of signals. They therefore have a strong incentive to advocate for pathways that require ongoing system maintenance or expansion—such as hybrid heating or a shift towards low-emission gases.[48]

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[46] *Ontario's Affordable Energy Future: The Pressing Case for More Power*, October 2024, p. 22 (link, PDF p. 99).
[47] Report of the Board, *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 10 (link).
[48] Canadian Climate Institute, *Heat Exchange*, p. 57-58 (link, PDF p. 24-25).

Decoupling would somewhat shift Enbridge's behaviour in the direction of what it would be if it were operating in a competitive market and thus fully exposed to energy transition risks. More changes are needed, but revenue decoupling is a move in the right direction.

Decoupling revenue from customer numbers in the gas sector would not require the equivalent change to occur in the electricity sector. There are important differences between those sectors on this topic:

- **Energy transition risk:** Electricity distributors do not face the same energy transition risk as Enbridge. The primary rationale to adjust Enbridge's incentives discussed on pages 3 and 8 above do not apply to electricity distributors.

- **Opportunity to increase customer counts:** Electricity distributors have very little, if any, opportunity to increase customer counts. They will be asked to connect all new developments that are built in their territory. Therefore, they do not have an incentive to market to developers at all, let alone use biased or misleading marketing. In contrast, gas is not needed in housing developments, and so Enbridge has an opportunity to increase its customer counts through marketing, lobbying, and otherwise.

- **Beneficial electrification:** Growth and expansion in the electricity sector is consistent with lowering customer energy bills because electrified homes are cheaper to operate than gas-fired homes.[49] An incentive to increase customer counts for a gas distributor is contrary to the interest of customers to secure lower energy bills. The opposite is true for electricity distributors.

Implementation options

Although Environmental Defence and GEC submit that revenue decoupling with respect to customer counts should occur as soon as possible, they is indifferent about the mechanics as long as Enbridge is made largely neutral to net customer connections/disconnections from an in-term revenue perspective. However, to assist the OEB in considering implementation options, we provide the following comments regarding implementation considerations.

Timing options

It is important that steps are made to align Enbridge's incentives with the energy transition as soon as possible. Those incentives take time to take effect. For example, the incentive structures will determine Enbridge's interactions with many customers and developers over the coming years. They will also impact how Enbridge designs its next rebasing application, how it designs its next DSM application, and the positions it puts forward in the upcoming generic hearing on the revenue horizon for gas connections. If Enbridge continues to have a strong revenue

[49] EB-2022-0200, Evidence of the Energy Futures Group in Ontario Energy Board File, p. 22 (link).; Exhibit J3.6 (link, PDF p. 6).

incentive to maximize net customer connections/disconnections, we will miss an opportunity to change course at a critical time.

It is also important that progress on incentives happens now because the energy transition is under way and will accelerate quickly. The IPCC recommends that countries reach net-zero carbon emissions by 2050 to limit climate change and the harm from climate change. Some say that net-zero must be achieved by 2040 in rich countries like Canada, while others seek to delay net-zero until 2060. All of these dates are extremely soon, ranging from 15 to 35 year from now, giving little time for incentives to have an impact on behaviour.

At a high level, there are three timing options:

- **Present concrete options for the next rebasing period:** Enbridge could be directed to study the issue and come back to the OEB with concrete revenue decoupling options at the next rebasing period that are sufficiently detailed to allow for implementation, akin to the settlement agreement term regarding differentiated ROE.[50]

- **Implement decoupling in the next rebasing application:** The OEB could direct Enbridge to implement revenue decoupling in its next rebasing application. This would be stronger than asking Enbridge to come back with options as it would ensure that the entire application is consistent with revenue decoupling from customer counts.

- **Implement during this rate term:** The OEB could direct Enbridge to implement a variance account in this proceeding to implement revenue decoupling with respect to customer counts. This could occur based on the directions provided by the OEB in this phase using one of the options outlined below or could be honed in phase 3.

Implementation during this rate term is essential. It is the only way to ensure that Enbridge has more neutral incentives when it communicates with customers and developers over the coming years; when it participates in the upcoming DSM proceeding and implements its DSM plan; when it participates in the upcoming gas expansion revenue horizon proceeding; and when it develops the details of its next asset management plan and rebasing application.

Mechanics for implementation

The decoupling mechanism could be implemented with a variance account that is similar in size and complexity to the average use variance account and operates alongside it, as described in the Customer Count Variance Account discussed by the Current Energy Group.[51] Environmental

[50] Exhibit N, Tab 1, Schedule 1, p 20 ("(a) Enbridge Gas shall study in its next rebasing application (i) a mechanism to implement differentiated ROEs on different asset types, and (ii) an Efficiency Carryover Mechanism (ECM) with a capital efficiency sharing mechanism. (b) Enbridge Gas shall file its analysis and materials outlining a number of options for implementing each item noted above. If Enbridge Gas does not propose implementing an item, it shall nevertheless present an option for the OEB's consideration for that item that is sufficiently detailed to allow it to be implemented in the next rebasing proceeding without further study.") (link).

[51] This is the second of the two options presented by the Current Energy Group. See Exhibit M2-CCC-3 (link).

Defence and GEC believe it should only be implemented with respect to general service customers for now.[52] Three options are outlined below.

By way of background, as noted above, rates are set based on a single forward test-year cost of service basis and subsequently indexed by the price cap index formula.[53] Rates are based on the customer counts forecast for the test-year, and there are no adjustments for actual or forecast customer connections/disconnections in years two to five. For the test year, rates are meant to be sufficient to cover capital and O&M costs when multiplied by the forecast customer numbers. In years two to five, Enbridge is allowed to retain the incremental revenue generated from new customers, and vice versa, because there is no mechanism that adjusts rates in years two to five based on forecast or actual customer counts in those years. The three options outlined below differ in whether they allocate that incremental revenue to the benefit of the utility or ratepayers.

To achieve decoupling with respect to customer counts, the OEB could adopt one of the following three mechanisms:

1. **True up revenue from actual customer counts against test-year customer counts:[54]** This is the second of the two options proposed by the Current Energy Group. It would return all incremental revenue from actual net customer additions/exits to ratepayers via a variance account. It would require that Enbridge estimate the difference in revenue from actual customer counts in a year against the number of customers in the test-year, and return and difference to ratepayers if customer growth occurs, or obtain additional revenue from customers if customer counts shrink. At a high level, the calculation for each rate class would be (test-year customers) X (average revenue per customer) minus (actual customers) X (average revenue per customer).

   This option is based on the assumption that the utility should be able to cover costs and earn a return based on the test-year envelope with the PCI adjustments. This option would return the full amount that Enbridge earns from net customer additions/exists to ratepayers, which Enbridge anticipates amounting to $256 million.

2. **True up revenue from actual customer counts against forecast customer counts:**[55] This option would allow Enbridge to retain only the incremental revenue it anticipated earning from net customer additions/exits. It would require that Enbridge calculate the difference in revenue from actual customers in a year against the revenue it would have earned based on forecast customer numbers. It would return the difference to ratepayers if customer growth was higher than forecast or obtain additional revenue from customers if growth was less than forecast. At a high level, the calculation by rate class would be (forecast customers) X (average revenue per customer) minus (forecast customers) X (average revenue per customer).

   This option is based on the assumption that the utility negotiated the PCI adjustments

[52] See Exhibit M2-CCC-3 (link).
[53] Price Cap = I – X +/- Y +/- Z + ICM.
[54] This is the second of the two options presented by the Current Energy Group. See Exhibit M2-CCC-3 (link).
[55] This is a variant of the above option and is discussed in Transcript Volume 1, December 17, 2024, p. 180, lns. 16-24.

such that it would not be able ably to cover costs and earn a return based on the test-year envelope with the PCI adjustments alone and that it requires 100% of the net revenue from incremental additions/exits. It would allow Enbridge to earn the full $256 million it anticipates earning from net customer additions/exits, but no more and no less.

3. **True up revenue from actual customer counts against forecast customer counts but only allow a percentage of forecast revenue from new customers to be retained:** This options would allow Enbridge to retain only a portion of the incremental revenue it anticipated it would earn from net customer additions/exits (e.g. 75%). It would require that Enbridge calculate the difference in revenue from actual customers in a year against the forecast number of customers, subject to the percentage reduction. It would return the difference to ratepayers if customer growth was higher than expected or obtain additional revenue from customers if growth was less than expected. At a high level, the calculation by rate class would be (forecast customers) X (average revenue per customer) X (0.75) minus (forecast customers) X (average revenue per customer) X (0.75).

   This is a middle ground option between the above two. It assumes that Enbridge needs some revenue from net customer additions/exits, but not all of the income. It would allow Enbridge to earn, say, 75% of the $256 million it anticipates earning from net customer additions/exits to ratepayers, but no more and no less.

Although Environmental Defence and GEC remain indifferent between the options, we note a number of benefits of option 3:

- Returning a portion of the incremental revenue to ratepayers would reflect the underlying logic of setting rates based on a test-year cost of service envelope and adjusting those annually by productivity and inflation factors. It would also reflect some benefit to Enbridge in somewhat reducing revenue risk.

- Refraining from returning *all* of the incremental revenue to customers would recognize that Enbridge may have negotiated the PCI factors expecting to receive at least some of the incremental revenue from customer growth. Also, is it unlikely that Enbridge was relying on earning 100% of its incremental revenue from new customers when it settled the PCI factors as it knew this issue was unresolved.

- Customers would be better off for two reasons.

  - First, Enbridge's revenue incentive to convince developers to connect to the gas system and to dissuade customers from disconnecting would be eliminated.

  - Second, customers would almost certainly be able to benefit from revenue returned to them via the variance account.

All of the above options are consistent with the settlement agreement, including the terms relating to a $3 million threshold on new DVAs. The settlement agreement explicitly notes that revenue decoupling can be implemented despite anything in the agreement. If there were a conflict with the $3 million threshold (which we do not believe there is), the below term would prevail:

> Nothing in the settlement of any issues precludes an OEB decision implementing an appropriate mechanism that would operate in conjunction with the IRM framework described in Issue 1, to decouple revenue from customer numbers. The Parties agree that 2025 rates would remain interim until this item is determined.
>
> The parties agree that the consideration of proposals arising from the evidence of the Current Energy Group in this proceeding and the next rebasing proceeding will not be restricted only to the specific parameters, designs, or implementation details as set out in the Current Energy Group report and that the OEB may consider other proposals put forward by any Party.[56]

Enbridge may argue that all of these options violate the fair return standard by not giving Enbridge incremental revenue to cover the costs associated with customer attachments, especially capital costs. These arguments are contrary to the incentive ratemaking approach. Enbridge's rates are based on test-year capital and O&M needs. Subject to ICM and the PCI adjustments, this is meant to decouple rates from costs. Connection costs are like any other capital costs. They are accounted for in rates and should be managed on an envelope basis like all capital needs. If Enbridge unexpectedly needs to repair a pipeline or replace a compressor, it does not secure incremental revenue. There is no reason Enbridge should require incremental revenue for each customer it connects. It should manage these costs through its capital envelope, which already includes over $1.5 billion in customer connections capital.[57]

As a practical matter, Enbridge's rates are based on $304 million for capital connections in its 2024 test-year budget. That amount is $50 million more than the average it forecast spending in each of the next four years ($252.2 million).[58] It is also $20 million more than it its actual spending for 2024 (11 months actual plus 1 forecast).[59] In this light, Enbridge is receiving much more in rates for customer connections than is necessary to meet those costs. But that is not how IRM works. Enbridge receives an envelope and is expected to work within it, which should be true for connections costs whether they are higher or lower than Enbridge expects them to be.

Conclusion

Environmental Defence and GEC ask the OEB to decouple Enbridge's revenue from the number of customers it serves in this proceeding via one of the three options set out above. In the alternative, they ask that the OEB direct Enbridge to implement revenue decoupling from customer numbers in its next rebasing application.

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[56] Exhibit N, Tab 1, Schedule 1, p. 20-21 (link).
[57] EB-2022-0200, Exhibit J13.7 (link, PDF p. 76); Transcript Volume 2, December 18, 2024, p. 7, lns. 7-18 (link); This figure includes all costs, such as meters and overheads. Without meters and overheads, the connection costs equal approximately $1.3 billion over the rate term. EB-2022-0200, Exhibit 2, Tab 5, Schedule 2, p. 2 (link, PDF p. 75).
[58] EB-2022-0200, Exhibit 2, Tab 5, Schedule 2, p. 2 (link, PDF p. 75)
[59] Exhibit J2.1 (link).

Enbridge's actions can be explained by its incentives. For the reasons outlined above, these incentives and the actions they cause are inconsistent with the goal of protecting gas customers in the face of the energy transition. It is not in the interests of ratepayers to oppose electrification of new developments and existing customers because all electric homes are much less expensive to run. It is not in the interests of customers to maximize gas expansion among new developments because this spending is risky and constitutes a very large proportion of overall rate base increases. These incentives are also inconsistent with a least-cost decarbonization pathway.

Decoupling revenue from customer numbers is just one of the changes that are needed. But taking this modest step forward would be an appropriate incremental approach to bring Enbridge's incentives more in line with the protection of ratepayer interests in the context of the energy transition.

The energy transition will cause gas demand declines

Enbridge's $7 billion capital plan and its depreciation proposal rely on unsupported implicit predictions about the role of gas pipelines in a decarbonized future. Its application is predicated on increasing demand, adding approximately 40,000 new customers each year for the next decade, and continuing forward with strong demand and revenue generation until the 2080s. Although Enbridge's formal forecasts only extend out 10 years, the economics underlying its capital projects are based on 40 years of strong forecast revenue (to the 2060s) and its proposed depreciation rates would not pay off those pipelines until the 2080s. Throughout its capital plan and depreciation proposals, Enbridge assigns a 0% chance that demand will decline and cause underutilized or completely stranded assets.

It is astonishing that Enbridge ignores the possibility of declining demand in its financial analyses despite the many reasons to believe that declining demand is a near certainty and massive declines are a significant possibility. As more fully detailed below, those reasons include the following:

1. **Fossil methane gas is a major source of carbon pollution** – one-third of Ontario's emissions are due to combustion alone and upstream leaks add at least an additional 40% to the harmful climate impact (likely more if the latest science and measurements are used);[3]

2. **Low carbon gases cannot replace more than a tiny portion of fossil gas** because of renewable natural gas ("RNG") potential is limited (~2.5% of throughput), blending of hydrogen into RNG is limited (~0.0035% of throughput), and 100% hydrogen is not feasible for the general service customers that generate 87% of Enbridge's revenue;[4]

3. **Electrification of building heat is extremely cost effective**, with households saving over $10,000 each compared to fossil gas, and even more when compared with heating with low carbon gases;[5]

4. **Government policy supports electrification**, including heat pump rebates, 0% interest loans for heat pumps, the price on carbon, federal climate legislation, official projections of a 41% decline in building emissions by 2030 from 2019 levels, provincial plans to build new electricity generation, and provincial directives to achieve lower energy bills regardless of the equipment used (which favours heat pumps as the cheapest option);

5. **Pathways studies forecast major declines**, with independent studies finding that high electrification pathways are cheapest and least risky, gas-sponsored studies promoting hybrid heating but still predicting demand declines, and the even the highly biased Guidehouse study finding electrification to be cheaper if one of many errors are fixed.

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[3] See page 5 below.
[4] See page 6 below.
[5] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 26 (link).

Fossil gas is a major source of carbon pollution

The fossil methane gas that flows through Enbridge's pipelines is a major source of carbon pollution. This puts the need and role of those pipelines into question as we reduce our carbon emissions to reach net zero over the next 30 years. Although this seems to be an obvious point, it is important to recognize how bad fossil methane gas is for the climate and how important it is to eliminate it to meet climate targets and avoid catastrophic climate change.

As a starting point, the *combustion* of fossil gas in Ontario generates approximately one-third of Ontario's carbon pollution.[6]

However, the impact is far greater if one accounts for upstream and downstream emissions, including leaks from extraction, transportation, storage, and end-use equipment, as well as emissions from the energy used in all those processes (e.g., compressors). Based on the default value for the Clean Fuel Standard, upstream emissions add over 40% on top of the combustion emissions for fossil methane gas.[7] The impact of upstream emissions is even greater if one focuses on the next twenty years, which many experts argue is critical when considering policies aimed at avoiding catastrophic climate change.[8] A tonne of methane is estimated to have 84 times the warming power of carbon dioxide over a 20-year period.[9]

Although upstream emissions occurring outside Ontario are not accounted for in Ontario's greenhouse gas emissions inventory, that does not make them irrelevant. Those emissions will need to be reduced regardless of their location, which will impact the price and availability of gas to Ontario consumers. At least some of those upstream emissions will be subject to a carbon pricing regime, which will also have impacts on prices in Ontario.

The picture is even worse because upstream emissions are considerably higher than those recorded in national inventories. [10] Canada has acknowledged this in its official National Inventory Report.[11] Studies cited in Canada's own National Inventory Report suggest that the actual upstream emissions are roughly twice those indicated in the National Inventory Report.[12] These discrepancies arise because the inventories are based on "industry self-reported bottom-up estimates" and there is "near scientific consensus that these self-reported bottom-up estimates are far below the actual emissions rates determined through top-down methodologies based on data collected from aircraft and satellites."[13]

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[6] See page 8 below.
[7] *Clean Fuel Regulations*, SOR/2022-140, Schedule 6, s. 8(d) (link, PDF p. 170); Exhibit L, p. 11 (link); EB-2020-0066, Exhibit JT1.7 (link, PDF p. 398); The default carbon intensity is 68 gCO2e/MJ for natural gas, this number can be broken out further to 48 gCO2e/GJ for emissions from end-use combustion, and 20 gCO2e/MJ related to upstream extraction, processing, transportation and distribution.
[8] Exhibit N.M10-EGI-107(a) (link, PDF p. 1).
[9] Environment and Climate Change Canada (link, Ex. K2.2, PDF p. 302).
[10] Canada's National Inventory Report (link, Ex. K2.2, PDF p. 6); Studies cited in the National Inventory Report suggesting that actual upstream emissions are roughly twice those reported in the National Inventory Report: KT9.5 (link); Exhibit KT9.6 (link). See also Exhibit N.M10.EGI.108, Attachment 2 (link, PDF p. 3).
[11] *Ibid*.
[12] *Ibid*.
[13] Exhibit M10 (link, PDF p. 5)

Studies of downstream methane leaks in cities across North America are also finding that actual top-down measurements find far higher emissions in comparison to bottom-up estimates used for official inventories.[14] Enbridge has acknowledged that they do not have an estimate for the *actual* upstream emissions nor measurements for behind-the-meter leaks in Ontario.[15]

There is no doubt that fossil methane gas is extremely harmful to the climate and must be eliminated over the next 30 years based on the combustion emissions alone. Depending on the true extent of the lifecycle emissions, fossil gas could be worse than coal, in which case these emissions need to be eliminated even faster.[16]

Low carbon gases cannot replace fossil gas

The only hope for the future of pipelines is low carbon gases – green hydrogen and RNG. However, these gases cannot replace more than a tiny portion of Ontario's current fossil gas consumption – particularly for the general service customers that provide 87% of Enbridge's distribution revenue.[17] Taken together, RNG plus hydrogen blending can replace at most 5.37% of the current fossil gas consumption even with highly optimistic assumptions about RNG potential and hydrogen blending feasibility, as detailed below.

RNG feedstocks are very limited

The potential for RNG to replace fossil gas is limited by the availability of feedstocks, such as agricultural by-products and municipal waste. A number of studies have been conducted to estimate the amount of RNG that would be feasible to produce from Ontario-based feedstocks. The estimates come to around 2.5% of Ontario's fossil gas consumption. The results are summarized in the table below:

Feasible RNG Potential – Percent of Current Fossil Gas Consumption	
Canadian Biogas Association Study	2.5%[18] (Ontario)
IESO, Pathways to Decarbonization Study (Interpreting Torchlight Bioresource Report)	2.5%[19] (Ontario)
Canada Energy Regulator, Canada's Energy Future 2023	3%[20] (Canada-wide)

[14] Exhibit N.M10.EGI.108, Attachment 2 (link, PDF p. 3); See also Exhibit K2.2, Tab 3 (link, PDF p. 12).
[15] Hearing Transcript Vol 2, p. 79, lns. 16-26 & p. 80, lns. 9-12 (link).
[16] Exhibit M10, p. 14 (link, PDF p. 14).
[17] Hearing Transcript Vol. 3, p. 12, lns. 15-25 (link).
[18] Hearing Transcript Vol. 2, p. 100, lns. 1-5 (link); Canadian Biogas Association study, p. 71 (link, Ex. K2.2, PDF p. 184); cited by Guidehouse in Exhibit I.1.10-ED-35 (link, Ex. K2.2, PDF p. 99).
[19] IESO Pathways to Decarbonization Study, Appendix B, p. 27 (link, Ex. K2.2, PDF p. 221); IESO Correspondence (link, Ex. K2.2, PDF p. 221); Hearing Transcript Vol. 2, p. 106, lns. 13-24 (link);
[20] Hearing Transcript Vol. 5, p. 176, ln. 3 to p. 177, ln. 8 (link).

Enbridge argues that Ontario will achieve far greater RNG volumes than any studies find feasible, even studies conducted by pro-biogas associations. They say this will occur through technological advancements and imports. Chris Neme and Dr. Hopkins both disagree that this is a reasonable assumption.[21] However, even if we assume that Ontario will achieve twice the amount found to be feasible in the two studies with Ontario-specific figures, that is still only 5% of Ontario's current fossil gas consumption.

Hydrogen blending is extremely limited

Enbridge's best current estimate is that hydrogen blending will be possible in the range of 5% to 20% by volume, which equates to 1.6% to 7.3% by energy content.[22] Although Enbridge seems to be optimistic about achieving the higher end of that range throughout its system, that appears to be inconsistent with the conclusions of a major study by the California Public Utilities Commission, which found as follows:

> This systemwide blending injection scenario becomes concerning as hydrogen blending approaches 5% by volume. As the percentage of hydrogen increases, end-use appliances may require modifications, vintage materials may experience increased susceptibility, and legacy components and procedures may be at increased risk of hydrogen effects.[23]

Even if we assume that hydrogen blending up to 7.3% of energy content is feasible, that is still extremely limited, and even more limited when it is considered as a percent of the RNG potential in a decarbonized gas system after fossil methane gas is phased out. If the RNG potential is very optimistically assumed to be 5% of current fossil gas consumption, and hydrogen is blended in at 7.3% by energy content, that means that hydrogen is only able to replace 0.37% of the current fossil gas consumption in a decarbonized gas system.[24] That is extremely low. Taken together, with high-end estimates for both RNG potential and hydrogen blending, a decarbonized gas system can replace a mere 5.37% of Ontario's current fossil gas consumption.[25] The low-end estimates come to 2.54% of Ontario's fossil gas consumption.[26] These are sobering numbers.

100% hydrogen blending is not feasible for general service customers

Green hydrogen may play a critical role in decarbonization for industrial uses, either through 100% hydrogen pipelines or on-site electrolysers. However, 100% hydrogen is not a reasonable solution to decarbonize the millions of buildings that constitute the vast majority of Enbridge customers and 87% of its distribution revenue. It is not reasonably possible to conduct the kind of simultaneous switchover that would be needed to convert these customers to 100% hydrogen.

[21] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 32 (link); Hearing Transcript Vol. 5, p. 13, lns. 9-28 (link).
[22] Exhibit J2.11 (link, PDF p. 30).
[23] CPUC Hydrogen Blending Study, p. 4 (link, Ex. K2.2, PDF p. 237).
[24] Calculation: 5% x 7.3% = 0.037%.
[25] Calculation: 5% + 0.037%
[26] Calculation: 2.5% x 1.6% = 0.04%; 2.5% + 0.04% = 2.54%

Chris Neme, Dr. Asa Hopkins, and other pathways studies agree on this point.[27] Further, the discussion of the logistics of a simultaneous switchover with Ms. Martin at the hearing make it abundantly clear that this simply will not happen.[28]

In addition, 100% hydrogen would require far larger (or more) pipes because a given diameter of pipe can only delivery about 30% as much hydrogen-based energy as methane-based energy.[29] Further still, it would be necessary to design and bring to market 100% hydrogen equipment to replace all of the current methane gas uses. Some face particular challenges, such as hydrogen stoves with invisible flames. Safety is also a major concern because hydrogen is a smaller molecule with very different combustion characteristics than methane.

These are just some of the technical barriers that make 100% hydrogen unfeasible for the vast majority of Enbridge customers.

Carbon capture and storage

It is unclear whether carbon capture and storage is feasible even for large industrial facilities in Ontario in light of geological and other factors, let alone whether it is cost-effective. But even if it could overcome the many technical and economic hurdles for large industrial customers, carbon capture and storage is clearly not feasible as a decarbonization solution for Ontario households.

Electrification of buildings is extremely cost-effective

Electrification of buildings is taking place now and will continue to accelerate because consumers are increasingly learning that it can save them a great deal on their energy bills while providing environmental and other benefits.

Homeowners that electrify their space and water heating will save approximately $17,000 over the lifetime of their equipment.[30] This is a net present value that has discounted future savings, and therefore the gross savings are even higher.[31] Customers often focus on simple values such as the savings on their energy bills. For 2023, the annual energy bill savings are $683. However, those savings will increase as the carbon price increases by 20 cents per m^3 between now and 2030.[32] By 2030, the annual energy bill savings arising from electrification of household fossil gas uses will be $1,134.[33] That is a very attractive benefit to a consumer that is replacing their air conditioner or furnace and deciding whether to install a heat pump.

[27] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 20-21 & 11 (link); Hearing Transcript Vol. 4, p. 172, lns. 19-25 (link).
[28] Hearing Transcript Vol. 2, p. 186, ln. 11 to p. 189, ln. 28 (link).
[29] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 21 (link);
[30] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 23 (link).
[31] *Ibid*.
[32] Enbridge, Federal Carbon Charge (link).
[33] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 23 (link).

This analysis of customer savings by Chris Neme of the Energy Futures Group is very robust. It has been tested by way of interrogatories and an oral hearing involving more than 30 intervenors. The full underlying modelling and all assumptions have been disclosed. In addition, Mr. Neme conducted a detailed sensitivity analysis that explored the following factors: lower gas commodity prices, worse heat pump efficiency, ineligibility for government rebates, higher heat pump cost, and the need for an electrical panel upgrade. He also did not account for a number of factors improving the cost-effectiveness of heat pumps, such as access to federal $40,000 interest-free loans. As detailed in his report, electrification remains cost-effective in all of the scenarios. As summed up by Mr. Neme: the "conclusion that electrification is cost-effective for customers today is very robust."[34]

The consumer savings from electrification will likely substantially increase in a future where the electricity system and gas system are both decarbonized.[35] Mr. Neme used conclusions from the IESO's Pathways to Decarbonization report and the cost of RNG to examine the impact on energy costs with decarbonized gas and electricity systems. He found that the energy cost savings from electrification in a future with fully decarbonized systems would be three times the savings today.[36]

As Mr. Neme explains, the savings from electrification increase because "[t]he incremental cost of RNG (relative to fossil gas plus a carbon tax) is simply much greater than the increase in the price of electricity that will be necessary to grow the electric grid so that it can serve electrified buildings."[37] Furthermore, Mr. Neme identifies three additional factors that will even further improve the economics of electrification: (a) the ability of electrifying customers to avoid fixed gas charges; (b) increasing gas distribution rates as customers exit the system; and (c) additional investments to make up for the fact that RNG is not always carbon neutral.[38]

Fully electrifying a home is also more cost-effective for Ontario households in comparison to using a hybrid heating system that relies on an electric heat pump coupled with a gas furnace for the coldest days.[39] That is primarily because backup heat is required only very infrequently and disconnecting from the gas system allows a customer to save $310 annually in fixed charges.[40] The savings from full electrification versus hybrid heating will increase with the proposed harmonized rates, which would bring the fixed customers charges to $398.25 annually[41] and increase the cost of gas at peak periods five-fold,[42] which presumably corresponds at least in part to the cold periods when backup gas would be used.

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[34] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 24 (link).
[35] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 25 (link).
[36] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 25 (link).
[37] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 25 (link).
[38] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 25-26 (link).
[39] Hearing Transcript Vol. 5, p. 172, ln. 17 to p. 174, ln. 7 (link).
[40] Enbridge Rate Zone (link); calculation: 22.88 x 12 x 1.13.

[41] Exhibit 8, Tab 2, Schedule 7, Attachment 2, Page 8 (link, PDF p. 759); calculation: $29.37 x 12 x 1.13.
[42] Exhibit 8, Tab 2, Schedule 7, Attachment 1, Page 9 (link, PDF p. 643); Exhibit 8, Tab 2, Schedule 7, Attachment 2, Page 8 (delivery increases from approximately 12 ¢/m³ to 68.3385 ¢/m³) (link, PDF p. 759) .

Furthermore, full electrification will likely become even more cost-effective versus hybrid heating in a future with fully decarbonized gas and electricity systems. As discussed above, the increase in cost for decarbonized gas outweighs the increase in cost for decarbonized electricity.[43]

In addition, fully electrifying a home results in considerably fewer carbon emissions in comparison to hybrid heating based on today's electricity generation mix.[44] The carbon reduction benefits from full electrification are likely to increase in light of the federal mandate for net-zero electricity generation by 2035.[45]

One might ask the following question: if heat pumps are so cost-effective, why are customers still installing gas furnaces? This is in part because it takes time for HVAC contractors to make the switch to heat pumps from furnaces and time for both contractors and consumers to learn that gas is no longer the cheapest way to heat a home. The cost-effectiveness of heat pumps is a relatively recent development driven by the following factors:

- **Improved cold climate performance:** In the past, heat pumps were inappropriate for our cold winters. Some contractors are not aware that this has changed. Cold climate heat pumps have high performance down to low temperatures (many down to -30°C). Even today, a standard cold climate heat pump can provide 100% of the heat in a Toronto home throughout a typical winter without supplemental heat.[46] But centrally-ducted heat pump units sold today also include a simple and cheap electric coil that fits into the air handler (i.e., blower fan unit) in the basement for supplemental heat for extremely cold days just in case. The technology continues to improve, and the best units have high heating capacities and efficiency levels in the range of 200% even at -30°C.[47]

- **Efficiency:** Heat pump efficiency has improved with advancements, such as variable speed compressors, which make them cheaper to operate both for heating and cooling.

- **Rebates:** Customers can now receive significant rebates and interest-free loans to purchase a heat pump (see below for details), which were not previously available.

- **Carbon price:** By 2030, the carbon price on gas will equal 32.40 cents/m^3.[48] By comparison, that amounts to over *three times* the price charged by Enbridge for methane gas in Toronto in January of 2020 (10.19 cents/m^3).[49]

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[43] See footnotes 35 to 38 above, and the text associated therewith.
[44] Exhibit J18.7, p. 4 (link).
[45] Canada 2030 Emissions Reduction Plan, p. 83 (link, Ex. K2.2, PDF p. 318).
[46] Guidehouse Heat Pump Study for Enbridge Gas, p. 10 (link, Ex. K2.2, PDF p. 285); This recent study prepared by Guidehouse for Enbridge shows that a cold climate heat pump can provide 100% of the heating for a Toronto home with a heating load of 2.5 tons. For Toronto homes that are larger or more leaky, supplementary electric resistance heating is forecast to only be required for 1 hour each year. The analysis is based on a standard cold climate heat pump as opposed to a top-of-the-line unit.
[47] Exhibit J18.7 (link).
[48] Enbridge, *Federal Carbon Charge* (link).
[49] Ontario Energy Board, *Historical Natural Gas Rates* (link).

We are beginning to see that awareness among customers that gas is no longer the cheapest option is steadily growing. For example, Enbridge is experiencing and forecasting steep declines in customers choosing to switch their homes from other fuels to gas (see page 31 below).

Government policy supports electrification

Government policy strongly supports electrification. This includes the following:

- The federal government is offering a $5,000 rebate for customers to switch to high-efficiency electric heat pumps as part of its Greener Homes Grant.[50] Enbridge customers are eligible for an additional $1,500.

- The federal government is offering an *additional* $5,000 rebate for customers to switch from oil to high-efficiency electric heat pumps if they earn a median income or lower (e.g., $122,000 after-tax income for a family of 4 in Ontario) through the Oil to Heat Pump Affordability Program.[51]

- The federal government is offering $40,000 in interest free loans, which can be put towards conversions to electric heat pumps, and not gas equipment, through the Greener Homes Loan.[52]

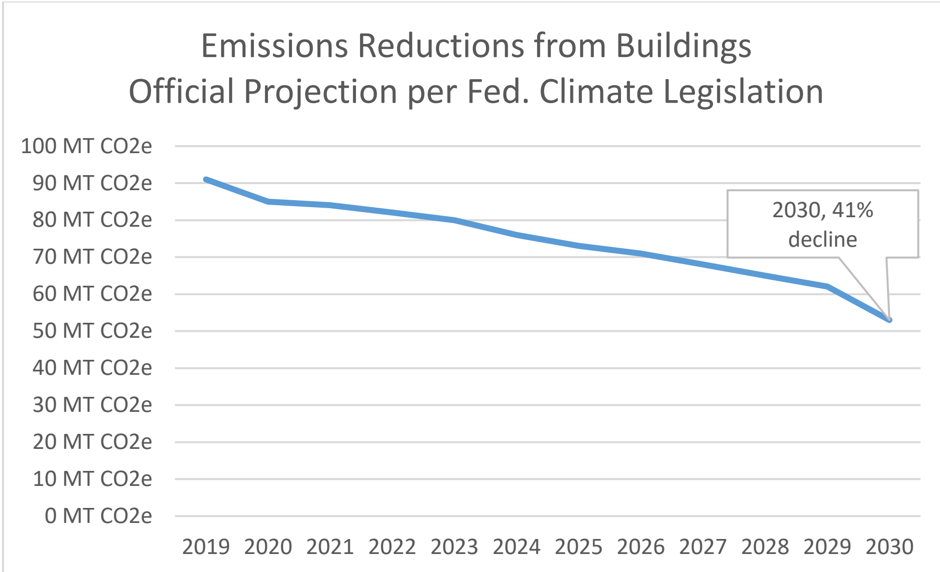
- The price on carbon will increase to 32 cents per m^3 by 2030.[53]

- Canada has passed the *Canadian Net-Zero Emissions Accountability Act*, which mandates official carbon emissions reduction targets, plans, and sector-by-sector projections;[54]

- Canada's official targets for overall emissions reductions pursuant to its climate legislation are net-zero by 2050 and 40 to 45 percent below 2005 levels by 2050; and[55]

- Canada's official projection for emissions reductions pursuant to its climate legislation is for emissions from buildings to decline by 41% by 2030 from 2019 levels, as illustrated in the chart below:[56]

[50] Government of Canada, *Canada Greener Homes* Grant (link).
[51] Government of Canada, *Oil to Heat Pump Affordability Program* (link).
[52] Government of Canada, *Canada Greener Homes Loan* (link).
[53] Enbridge, *Federal Carbon Charge* (link).
[54] *Canadian Net-Zero Emissions Accountability Act*, S.C. 2021, c. 22 (link).
[55] Canada, 2030, Emissions Reduction Plan Backgrounder (link, Ex. K2.2, PDF p. 306).
[56] Canada, 2030 Emissions Reduction Plan, p. 318 (link, Ex. K2.2, PDF p. 318); Canada, 2030, Emissions Reduction Plan Backgrounder (link, Ex. K2.2, PDF p. 313); Hearing Transcript Vol. 2, p. 134, ln 18 to p. 135, ln. 13 (link).



Enbridge refers to the "Powering Ontario's Growth" plan eight times in its submissions. But the plan *does not* call for continued gas expansion or anything close to the high-gas vision that Enbridge describes in its application. The plan merely says that gas will continue to play a critical role in Ontario.[57] That is obvious, as we cannot stop using fossil gas immediately and low-carbon gases could drive industrial decarbonization. Contrary to picture Enbridge attempts to paint, Ontario's plan focuses predominantly on the electricity sector. For instance, it describes how "electrification is playing a critical role in driving down emissions" in the building sector.[58] It also details major efforts to increase electricity generation and transmission.[59]

The core of Ontario's energy policy is to achieve lower energy bills. It is fuel agnostic. This policy is exemplified in a recent mandate letter from the Minister of Energy to the OEB. In the section on demand-side management (DSM), the Minister of Energy provided the following direction:

> It is also important that the DSM Framework be implemented in a way that enables customers to lower energy bills in the most cost-effective way possible, and help customers make the right choices regardless of whether that is through more efficient gas or electric equipment.[60]

A policy of lowering energy bills is equivalent to a pro-electrification policy when it comes to the vast majority of Enbridge customers – building owners – as that is the best and fastest way to lower their bills.[61]

Overall, federal policy is likely more relevant to anticipating future impacts of decarbonization on the gas system because the federal government has large and concrete programs in place that

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[57] Ontario, *Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future*, p. 30 (link).
[58] Ontario, *Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future*, p. 18 (link).
[59] Ontario, *Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future*, p. 41-75 (link).
[60] Mandate Letter to the OEB, November 15, 2021, p. 3 (link).
[61] See page 8 above.

are helping customers save money by electrifying their space and water heating.[62] The federal government has concurrent jurisdiction over environmental matters and also exercises considerable spending power. At present, climate policy in Ontario is dominated by the federal government. Although the OEB is a provincial agency, it is extremely important that it account for the impacts of federal policies and programs on the future of the gas system.

Finally, we could see a ban on gas in new construction in Ontario in the future. The International Energy Agency recommends that a ban on new gas heating be instituted by 2025.[63] A long list of municipalities with over 15 million residents across the United State have instituted these bans.[64] Most recently, the State of New York passed a ban on gas in new construction for heating and cooking.[65] Enbridge certainly cannot rule out the possibility that a similar ban could come to Ontario in the coming years. Nor can it rule out a future extension to equipment replacement in existing homes long before the end of the economic life of the pipelines it is constructing today.

Pathways studies forecast major declines

Most independently-conducted assessments of decarbonization pathways have concluded that high electrification pathways are the most likely and most cost-effective pathways, even in colder climates, and that this will result in major declines in peak and annual gas demand.[66] This includes work completed by the Canadian Climate Institute, which Enbridge acknowledges provides credible, independent, expert-driven analysis on climate issues.[67]

Although gas-sponsored studies often find a greater role for hybrid heating systems, even they nevertheless predict major declines in gas.[68] For example, the Massachusetts hybrid scenario still found that approximately 20 percent of customers would fully electrify.[69] The report also recommended a full electrification mandate for new construction as one of the no-regrets policies.[70]

The Guidehouse pathways study supports electrification

The report prepared by Guidehouse is an outlier in comparison even to other gas-sponsored pathways studies. For instance, it differs from many other jurisdictions due to the prevalence of hydrogen in all scenarios and the absence of a scenario where the large majority of buildings

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[62] See page 11 above for a list of those policies. For a discussion of the relevance of federal policy by Dr. Hopkins, see: Hearing Transcript Vol. 5, p. 30, ln. 22 to p. 32, ln. 19 (link).
[63] Exhibit I.1.3-SEC-7, Attachment 4, Page 28.
[64] Exhibit J8.3, Attachment 1.
[65] Exhibit J8.3.
[66] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 11 & 49 (link); Canadian Climate Institute, The Big Switch, May 2022, p. 5 (link, Ex. K12.3, PDF p. 69).
[67] Canadian Climate Institute, The Big Switch, May 2022, p. 5 (link, Ex. K12.3, PDF p. 69); Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 11 (link); Hearing Transcript Vol. 12, p. 115, ln. 19 to p. 116, ln. 3 (link).
[68] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 18 (link).
[69] Hearing Transcript Vol. 6, p. 68, ln 25 to p. 69, p. 22 (link).
[70] Hearing Transcript Vol. 6, p. 68, ln 25 to p. 69, p. 22 (link).

fully electrify.[71] It is also an outlier in considering 100% hydrogen delivery to residential and commercial customers as being a realistic option.[72]

The many flaws in the Guidehouse report are best described in Chris Neme's own words and via the summary table from his evidence:

> Overall, Guidehouse's assumptions are highly biased in favor of gas and not credible. There are numerous instances in which optimistic leaps of faith are made about equipment and systems necessary to make continued use of gaseous fuels look economically viable while much more conservative assumptions are made about electric alternatives. For example, Guidehouse assumes high penetrations of residential gas heat pumps and 100% hydrogen furnaces and appliances, despite the fact that these products are not even commercially available today. In contrast, Guidehouse assumes market penetration rates for electric heat pump water heaters in 2040 that are much lower than leading jurisdictions are achieving today through DSM programs. Similarly, Guidehouse assumes that the efficiency of electric heat pumps will degrade 2% per year after installation (based on an outdated study that doesn't apply to current electric heat pump technology) but that gas furnaces and gas heat pumps will experience no such degradation.
>
> To make it easier for the reader to begin to consider numerous concerns about the Guidehouse study in their totality, a summary is provided in Table 9 below. Note that the implications of correcting each Guidehouse error or bias are quantified and monetized where possible. However, that was not possible in many cases without the ability to run Guidehouse's model with changed assumptions. … Nevertheless, it is abundantly clear that correcting Guidehouse's errors and biases would result in the scenario that places greater emphasis on electrification being not just less costly, but substantially less costly than the scenario that relies more on gaseous fuels including 100% hydrogen. In fact, just correcting the first problematic assumption – the inappropriate use of a higher cost of carbon in the electrification scenario (with resulting higher emission cost even though the scenario produces fewer emissions!) – is enough to make the electrification scenario the lower cost option.

[71] N.M8.ED-3 (link, PDF p. 10)
[72] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 11 (link).

Table 9: Summary of Concerns with Guidehouse's P2NZ Study

Assumption	Concern	Implications
Cost of CO2e Emissions	Guidehouse improperly treats carbon taxes as a societal cost and assumes a much higher cost of emissions for electrification scenario.	Using same cost of emissions reduces electrification scenario costs by ~$67+ billion. That's more than enough (without any other changes) to make it the lower cost option.
Load Shapes for Electrified End Uses	Guidehouse assumes all building end uses - including water heating, cooking and drying - have the same seasonal and hourly load profiles as space heating.	Winter morning peak demand from electrified building loads likely to be about 40% lower than estimated by Guidehouse.
Heating Equipment Efficiency Degradation after Install	Guidehouse assumes electric heat pump efficiency degrades 2%/year after installation based on reference for very different older generations of heat pumps. No degradation of gas furnace or gas heat pump efficiency assumed, despite the same report suggesting gas furnace efficiency also degrades .	Guidehouse estimates of added electricity consumption for ASHP space heating overstated by 18%. The adverse effect is 0.7 TWh in 2030, 2.6 TWh in 2040 and 3.3 TWh in 2050 more in the Electrified scenario than in the Diversified scenario.
RNG Availability	Guidehouse assumes that the entire "technical potential" for RNG in Ontario would be available, even though the expert report it references suggests it would be feasible to access less than one-quarter of that amount.	Substantially more expensive gaseous resources would have had to be deployed under the "Diversified Scenario" if RNG supply constraints were reasonably set, possibly making the Diversified scenario inconsistent with a net zero emissions objective.
RNG Costs	Guidehouse RNG cost is for landfill gas, but most of the RNG potential it assumed to be available is from other much more expensive sources. The most expensive source of RNG would set the market clearing price for all RNG.	RNG costs likely to be at least 3 times greater than assumed, improving the relative cost of Electrification Scenario by at least $28 billion. The difference could be much higher because Guidehouse assumes RNG potential four times what its own reference study says is feasible, which would require accessing even more expensive RNG
GHG Emission Reductions from RNG	Guidehouse's analysis does not address the full lifecycle emissions of biomethane. Thus, it overstates the amount of emission reductions RNG provides.	If lifecycle emissions were fully addressed, additional emission reduction measures would have to be deployed to achieve net zero emissions, adding significant cost, especially for the Diversified Scenario, potentially making it inconsistent with net zero emissions objective.
GHG Emission Reductions from Blue H2	See evidence of Professors Howarth and Jacobson	If blue hydrogen emissions are greater than assumed, it would make the Diversified scenario more expensive and/or inconsistent with net zero emissions objective.
Electric Demand Response Resources	Guidehouse did not consider or model the potential for demand response to be applied to newly electrified space heating and water heating loads.	Electric system capacity costs from electrification are overstated, but difficult to quantify the magnitude of the overstatement.
Gas Heat Pump Costs	Guidehouse used an informal estimate from a gas heat pump manufacturer rather than a much higher recent Enbridge estimate. Worse, it failed to recognize that the estimate it used was expressed in U.S. rather than Canadian dollars.	Converting to Canadian dollars results in an increase cost of $3 billion for the Electrification Scenario and $16 billion for the Diversified Scenario - improving the relative cost of the Electrification Scenario by $13 billion.
Home Weatherization Savings Life	Guidehouse conservatively assumed that insulation and other building envelop efficiency improvements would last only 20 years. Enbridge assumes a more reasonable 30 years in its DSM planning.	Using a 30 year life reduces the cost of the Electrification Scenario by $11 billion and the Diversified Scenario by $5 billion - improving the relative cost of the Electrification Scenario by $6 billion.
Electric Water Heating Efficiency	Guidehouse assumes only ~10% of gas to electric water heating conversions by 2040 and ~25% by 2050 are to efficient heat pump water heaters. Leading jurisdictions are already achieving market penetration rates higher than that. Other studies assume much higher heat pump water heating rates.	If 75% of all such conversions were to heat pump water heaters, total forecast electric demand would be about 8.2 TWh (about 2%) lower under the Electrification Scenario (and about 3.5 TWh lower under the Diversified Scenario.
Customer Conversion Costs	Guidehouse did not address customer conversion costs - other than costs of heating equipment. Behind-the-meter pipe retrofits, ventilation requirements and utility inspection costs could be substantial.	Likely bias against electrification because costs likely to be higher for conversion to 100% hydrogen than for electrification for residential and commercial customers.
Utility Distribution System Costs	Guideholse excluded the cost of converting the distribuiton system to 100% hydrogen and all other incremental gas and electric distribution system costs.	Likely bias against electrification becuase the costs for 100% hydrogen delivery to residential and commercial customers likely to be much higher than for electrification of those customers. Also, electrification will enable reductions in gas utility costs from fewer customers (e.g., fewer connections, meters, customer service reps, etc.) as well capital and O&M cost savings from pruning parts of the gas distribution system .

Dr. Hopkins agrees with Mr. Neme's conclusion that the Guidehouse report is biased in favour of gas.[73] During the oral hearing we asked Dr. Hopkins to comment on each of the critiques of the Guidehouse report listed in Table 9 above. Dr. Hopkins' views were entirely aligned with Mr. Neme's.[74] With respect to the price of carbon, Dr. Hopkins described the approach taken by Guidehouse as a "methodological error."[75] Correcting only this one bias and error, while fully ignoring the remaining 12 critiques listed above, swings the results such that the so-called electrification scenario is $26 billion cheaper than the high-gas scenario.[76]

Additional flaws and biases have come to light subsequent to Mr. Neme's report. For instance, it is now clear that Guidehouse assumed a production price for green hydrogen that is less than half of Enbridge's best estimate and less than one-quarter of the current retail price of grey hydrogen.[77]

In addition, Guidehouse's reliance on massive quantities of blue hydrogen (generated from methane gas with carbon capture) is unreasonable.[78] Blue hydrogen is inconsistent with decarbonization because its lifecycle emissions are far too high (see 18 below). Guidehouse assumed emissions that are 10 times lower even than the studies that Enbridge cites on this question (see page 19 below). Guidehouse re-ran its model with green hydrogen replacing the blue hydrogen, which changed the results by $34 billion against the high-gas scenario.[79] But, the true impacts are even higher because Guidehouse underestimates the cost of green hydrogen by at least a factor of two.[80] More importantly, the model re-run is of little value because Guidehouse forced it to select green hydrogen as the alternative, rather than examine whether greater electrification would be the optimal result when accounting for the true emissions from blue hydrogen.[81]

Finally, it is critically important to recognize what the Guidehouse model *does not* do. The model does not determine the optimal amount of fuel-switching from gas furnace to cold-climate heat pumps.[82] Nor does it determine that the cheapest decarbonization pathway involves increasing investment in pipelines versus a pathway involving more electricity.[83]

Unfortunately, Enbridge includes misleading statements in this application and in lobbying materials to suggest that Ontario will save huge sums if it actively pursues a decarbonization pathway that emphasizes gases versus higher electrification.[84] That conclusion simply cannot be drawn from the Guidehouse report, even if we put aside the many errors referred to above. Nor

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[73] N.M8.ED-4 (link, PDF p. 10-13)
[74] Hearing Transcript Vol. 5, p. 8-24 (link).
[75] Hearing Transcript Vol. 5, p. 10, ln. 23 (see also the preceding discussion at p. 8, ln. 6 to p. 10, ln. 23) (link).
[76] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 27-28 (link).
[77] Exhibit J2.8, Page 2 (link, PDF p. 27); ED-131 (link, PDF p. 35).
[78] Exhibit JT1.24 (The Guidehouse report assumes an average of 5 billion m^3 of blue hydrogen each year on average from 2030 to 2050 in the diversified scenario) (link, PDF p. 47).
[79] Exhibit JT9.16, p. 1 (link, PDF p. 3160).
[80] Guidehouse assumed a production price for green hydrogen that is less than Enbridge's best estimate and less than one-quarter of the current retail price of grey hydrogen. Exhibit J2.8, Page 2 (link, PDF p. 27); ED-131 (link, PDF p. 35).
[81] Hearing Transcript Vol. 2, p. 171, ln. 9 to p. 172, ln. 18 (link); see also Hearing Transcript Vol. 2, p. 159, ln. 6-10 (link).
[82] Hearing Transcript Vol. 2, p. 159, lns. 6-10 (link).
[83] Hearing Transcript Vol. 2, p. 159, ln. 23 to p. 160, ln. 1 (link).
[84] E.g., see Hearing Transcript Vol. 2, p. 160, ln. 11, p. 163, ln. 11,p.165, ln. 13 (link).

can the report support the other ways that Enbridge relies on it in its application: (a) to argue against decreasing investments in the gas system (and conversely, in support of its proposed increases in gas system investments);[85] (b) to support Enbridge's proposed spending relating to hydrogen;[86] (c) to support Enbridge's proposed spending relating to RNG;[87] (d) to argue against reduced depreciation periods as a tool to address decarbonization-related risks;[88] (e) to argue against the need for a segregated site restoration fund as a tool to address decarbonization-related risks;[89] (f) as a consideration in Enbridge's Asset Management Plan;[90] and (g) to argue that net-zero cannot be achieved without gaseous pipelines delivering RNG, hydrogen, and natural gas with CCUS.[91]

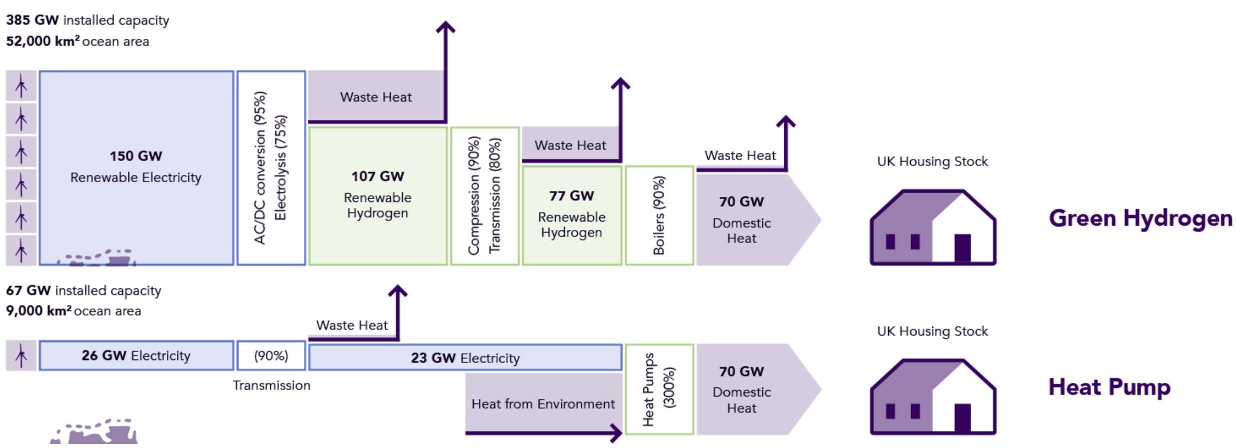
Neither the Guidehouse report, nor the conclusions Enbridge asks others to draw from it, are credible.

Hydrogen is ineffective for decarbonizing buildings

Hydrogen is ineffective for decarbonizing buildings, including both green hydrogen (generated from green electricity) and blue hydrogen (converted from methane with carbon capture).

Green hydrogen generally inferior to electrification

Green hydrogen, which is generated from renewable electricity via electrolysis, is generally not a viable decarbonization solution for uses that can be electrified cost-effectively, like heating for buildings. For instance, it is roughly six times more efficient to use renewable energy to power a heat pump directly versus converting it to green hydrogen and running that through a furnace, as illustrated in the following figure:[92]



[85] Exhibit 1, Tab 10, Schedule 5, Page 12-13, Para. 36 (link, PDF p. 1691).
[86] Exhibit 4, Tab 2, Schedule 6, Pages 5-17, Paras. 11, 17, 38, 42, & 46 (link, PDF p. 242, 244, 251-252, 253 & 254-255).
[87] Exhibit 4, Tab 2, Schedule 7, Page 10, Para. 22 (link, PDF p. 267).
[88] Exhibit 4, Tab 5, Schedule 1, Page 16, Para. 35 (link, PDF p. 845).
[89] Exhibit 4, Tab 5, Schedule 1, Page 19, Para. 43 (link, PDF p. 848-849).
[90] Exhibit 2, Tab 6, Schedule 2, Page 34 (link, PDF p. 440).
[91] Exhibit 1, Tab 10, Schedule 5, Page 14, Para. 41 (link, PDF p. 1692).
[92] Exhibit N.M2-ED-2/Appendix B, p. 3 (link); The precise difference in efficiency between using electricity directly in heat pumps versus converting it to hydrogen for use in furnaces will vary based on assumptions. We asked Enbridge to provide its best estimate and it declined to do so in Exhibit I.4.2-ED-129 (c) (link, PDF p. 89).

Blue hydrogen emissions are too high

The lifecycle carbon emissions associated with blue hydrogen are much too high for it to play a significant role in decarbonation. Drs. Howarth and Jacobson summarize the problem with blue hydrogen as follows:

> Greenhouse gas emissions are higher from blue hydrogen than from burning natural gas mainly because approximately 1.6 to 1.7 MJ of natural gas are required to make 1 MJ of hydrogen, which results in greater upstream unburned methane emissions from natural gas production, storage, and transportation. Emissions also arise as a result of less-than-perfect rates of carbon capture and in relation to the energy needed to run the stream reforming process and the carbon capture process.[93]

Drs. Howarth and Jacobson's work is based on: (a) actual top-down upstream emissions rates; (b) a broad meta-analysis of upstream emissions rates; and (c) real-world data from real-world steam methane reformation and carbon capture facilities.[94] In addition, Drs. Howarth and Jacobson conduct a sensitivity analysis using much lower upstream emissions rates and differing global warming potential (20 and 100 years), as well as considering the possibility of powering the steam methane reformation process with renewable electricity.[95] Based on this detailed and robust analysis, they nevertheless conclude that there is "no role for blue hydrogen in a carbon-free future."[96]

Although some other papers find lower emissions, they have one or more of the following flaws:

- Using outdated self-reported bottom-up estimates of upstream unburned methane emissions from gas production, storage, and transportation (despite the near scientific consensus that these self-reported bottom-up estimates are far below the actual emissions rates determined through top-down methodologies based on measured data);[97]

- Using high carbon capture rates based on *theoretical* facilities (real-world performance is much poorer);[98]

- Disregarding the combustion of gas used to power the conversion from methane to hydrogen (steam methane reformation) or other aspects of the lifecycle emissions that must be accounted for;[99]

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[93] Exhibit M10 (link, PDF p. 2 – see also the figure on page 14).
[94] Exhibit M10 (link).
[95] Exhibit N.M10-EGI-108 (link, PDF p. 15)
[96] Exhibit M10 (link, PDF p. 16).
[97] Exhibit M10 (link, PDF p. 5); Canada's National Inventory Report (link, Ex. K2.2, PDF p. 6); Studies cited in the National Inventory Report suggesting that actual upstream emissions are roughly twice those reported in the National Inventory Report: KT9.5 (link); Exhibit KT9.6 (link). See also Exhibit N.M10.EGI.108, Attachment 2 (link, PDF p. 3).
[98] Exhibit M10 (link, PDF p. 21).
[99] Exhibit M10 (link, PDF p. 4).

- Assuming that unburned methane leakage in gas production, storage, and transportation can and will be drastically reduced in the future (even though there are significant technical barriers and reduction targets are counted from national inventory levels that are known to greatly undercount emissions);[100] and

- Cherry-picking emissions measurements from too narrow a sample set (results from top-down measurements vary too widely to rely on measurements from one study, etc.).[101]

Although the three studies cited in Enbridge's reply evidence on blue hydrogen find somewhat lower emissions from blue hydrogen, they are far higher than the emissions assumed by Guidehouse and too high to be consistent with a carbon-free future. The following table compares the emissions from blue hydrogen generated by steam methane reformation in: (a) the Howarth and Jacobson study; (b) the three papers cited in Enbridge's reply evidence on blue hydrogen; and (c) the non-peer reviewed assumption used in the Guidehouse report:

GHG Emissions from Blue Hydrogen (SMR)	
Source	**GHG Emissions Intensity (gCO_2e/MJ H_2)**
Howarth and Jacobson	57 to 77
Romano et al (cited in Enbridge reply)	46
Bauer et al.	52 to 103
Oni et al.	57 to 70
Assumption Guidehouse, Pathways to Decarbonization	5.5

The papers cited by Enbridge also suggest that lower emissions can potentially be achieved with a different methane-hydrogen conversion process using an oxygen-blown autothermal reformer (ATR). However, even Guidehouse rules out ATR, reasoning as follows: "Unlike SMR, the ATR process requires an additional oxygen supply, which can lead to additional emissions and costs if the oxygen is not supplied as a by-product from a separate process."[102] Drs. Howarth and Jacobson also rule out ATR as a realistic option for those same reasons, and because (a) it has never been used commercially for this purpose and (b) it produces less hydrogen per unit of input methane, leading to greater upstream emissions.[103]

[100] Exhibit M10 (link, PDF p. 5).
[101] Exhibit N.M10-EGI-108 (link, PDF p. 3)
[102] Exhibit KT9.2 (link, PDF p. 26).
[103] Exhibit M10 (link, PDF p. 22).("Regarding Case no. 2, as far as we aware, blue hydrogen based on ATR has never been attempted in commercial operation. Romano et al. give no examples of actual commercial efforts to use ATR, and Kim et al. note in a 2021 paper that the required need for pure oxygen has been an impediment to ATR use by industry. The "overall carbon capture rate of around 93%" used by Romano et al., then, is hypothetical and dependent upon the 98% efficiency that they "assumed in the MDEA unit," which has not been tested in any actual plant. Further, it is important to note that ATR produces less hydrogen per input of methane from natural gas than

Enbridge touts hydrogen as a fuel that helps counteract the "life-shortening effect on Enbridge Gas's system" from decarbonization.[104] That may come true for the green hydrogen in large pipes that serve large industrial customers. But it does not apply to any hydrogen used in buildings nor for blue hydrogen for any decarbonization uses.

Electrification is feasible

Enbridge suggests that Ontario likely cannot manage to expand its electricity infrastructure fast enough to meet the needs from electrification. However, it provides no studies that state this, and instead puts forward misleading figures that overstate the problem. Mr. Neme responded to one of those misleading figures in his testimony as follows:

> MR. POCH: Okay. The Enbridge panel made several references to the challenges of Ontario switching from getting, as they put it, only 15 percent of its energy to 100 percent of its energy from electricity. Can you comment on that? Is it feasible?
>
> MR. NEME: Sure. Let me start by saying that the suggestion that we are going from 15 percent of the energy being supplied by electricity to 100 percent can be a little bit misleading for a couple of reasons. First, I believe we are actually starting at higher than 15 percent. I believe the number for Ontario is more like 21 or 22 percent.
>
> But, much more importantly, … even if we were to go to 100 percent does not mean a four- or five-fold increase in the amount of electricity that needs to be produced. That is because the electrification measures are a lot more efficient than the fossil fuel systems that they are replacing. Heat pumps are on the order of three times more efficient than a gas furnace. Heat pump water heaters are on the order of five or six times more efficient than a gas water heater, and electric vehicles are on the order of three to five times more efficient than internal-combustion gasoline-powered vehicles. So it is not as large a jump as one might think, just by looking at those two numbers, 15 and 100.
>
> In addition, I don't think any party, certainly not my position, believes that we actually have to go to 100 percent of energy being supplied by electricity. There is going to be a role, I believe and I believe most parties believe, for biofuels in the future.
>
> I think that is particularly true for important segments of the industrial sector and probably for important segments of the transportation sector, as well.

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does SMR, and so at least 38% more natural gas feedstock is required for ATR. This of course leads to greater methane emissions from the production, processing, storage, and transport of the needed natural gas, a fact apparently not included in the analysis of Romano et al.")

[104] Exhibit 1, Tab 10, Schedule 4, Page 17, para. 52 (link, PDF p. 1675).

> So, as to the feasibility of growing the electric grid – it is going to have to grow substantially. As to the feasibility of doing that, I think it is eminently feasible. Everybody has an electric meter today. We know what technologies – we have them today – that need to be installed in order to electrify. The electrification can proceed at a gradual pace, not only building by building but even appliance by appliance within the buildings. We know that those technologies are getter more efficient, too. In addition, we know how to add generating capacity on the grid. We know how to add storage. We know how to upgrade the [transmission and distribution] system. This can all be accomplished with technology and know-how that we have today. That is not to say it is going be easy or without cost, but it is eminently doable. I think that is underscored by every study that I have seen that suggests that a high-electrification pathway is possible, including the Ontario IESO's own high-electrification pathways study.

Dr. Hopkins also agreed that Enbridge's commentary "misrepresents the magnitude of the challenge" of electrification.[105] He also agreed that there is a possibility that expanding the electrical system could result in *lower* electrical costs on a unit basis if we are able to move from the hub-and-spoke model we currently use to a move efficient approach with the pursuit of new approaches or technological advances.[106] Expanding and decarbonizing the electricity system is already entirely feasible with existing technologies. Although prices may modestly increase, this will be offset by greater savings arising from the higher efficiency of electric equipment, lowering overall energy bills.[107] And this is comparing electrification to the status quo of continuing to burn fossil fuels – the energy bill savings will be even greater in comparison to expensive low-carbon gases and even greater still if technological advancements or new decentralized approaches to the electricity system mean that we can lower electricity prices at the same time.

Summary re likely gas declines

For the reasons set out above, the likely impact of decarbonization on the gas system is major declines in peak and annual demand as most or all of the general service customers that provide 87% of Enbridge's revenue leave the system. The best-case scenario for the gas system is that many adopt hybrid heating instead, but that scenario is constrained by the potential RNG available. In addition, the hybrid heat scenario still involves huge declines in annual demand, some decline in peak demand, and increasing pressure on customers to exit the system entirely.

Enbridge's pipelines could play a critical role in delivering RNG and 100% hydrogen to Ontario's industrial customers. However, this potential role is put in jeopardy if steps are not taken today to de-risk Enbridge's business and reduce rate base. More generally,

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[105] Hearing Transcript Vol. 4, p. 180, ln. 20 to p. 181, ln. 14. (link).

[106] Hearing Transcript Vol. 4, p. 179, lns. 15-19 and p. 180, lns. 3-10 (link).

[107] Canadian Climate Institute, p. 8 (link, Ex. K12.3, PDF p. 103); Enbridge acknowledged that the Canadian Climate Institute provides credible, independent, expert-driven analysis on climate issues at: Hearing Transcript Vol. 12, p. 115, ln. 19 to p. 116, ln. 3 (link); Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 25 & footnote 52 (link).

Enbridge must abandon the assumption underlying its capital and depreciation proposals that major declines in demand have a 0% chance of occurring and therefore can be completely ignored in economic analysis.

The OEB should require regular energy transition plans (issue 3)

In line with the recommendations of Dr. Asa Hopkins and Chris Neme, Enbridge needs to vastly improve its planning processes across its business with respect to energy transition plans, especially in relation to capital planning and depreciation. This is needed because there is now much more uncertainty regarding future demand and revenue levels over the 40-year economic horizons used for the capital planning economic tests (EBO 134 & 188) and over the 60-year depreciation periods of pipelines. These uncertainties create major risks for existing customers, which are discussed more fully below, especially with respect to capital planning.

In particular, Environmental Defence requests that the OEB direct Enbridge to develop an energy transition plan as soon as possible, to be updated on a regular basis. As set out below, the energy transition plan should involve: (a) a demand scenario analysis; and (b) business planning based on that demand scenario analysis.

Part 1: Demand forecast scenario development and analysis

The energy transition plan should set out at least three future scenarios with respect to gas demand. The utility cannot continue to rely on a single forecast because that amounts to predicting a single future, which is impossible in these uncertain times. As described by Dr. Hopkins:

> There is uncertainty about what is coming and what the exact shape of the energy transition will look like. And so good planning in the face of uncertainty takes a range of different potential futures into account and help[s] you evaluate what your … possible actions would be going into that range of futures.[108]

An analysis of multiple scenarios will still be required even after the provincial government releases its pathways study. The study is unlikely to predict a single future. Furthermore, it will simply be a study and may or may not become a policy, let alone be realized in concrete programs or directives. The same is true for the final report of the Electrification and Energy Transition Panel. Even if those do result in concrete policy that calls for the pursuit of a specific course of action, it is too risky to assume that there will be zero changes in policy and zero changes in government between now and 2050. Also, policy is only one factor. Customer economics and customer preferences are also critically important.

The plan would also unavoidably require an assessment of the probability of each scenario occurring. As Dr. Hopkins describes, this is a challenge, but it can be accomplished on a rough basis and is necessary in order to make decisions.[109] It is better to consider the weight that should

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[108] Hearing Transcript Vol. 5, p. 27, lns. 7-14 (link).
[109] Hearing Transcript Vol. 5, p. 54, ln. 15 to p. 56, ln. 3 (link).