Before the Ontario Energy Board

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Enbridge Gas 2024 Rebasing Phase 2

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I. Executive Summary

We have been asked to comment and provide recommendations on Enbridge's Energy Transition Technology Fund (ETTF), its proposal to procure low-carbon energy as part of the gas supply commodity portfolio appropriate through the Low-Carbon Energy Program (LCEP), its system pruning proposals, and its residential heating fuel cost comparison. An overview of our recommendations is set out below:

Energy Transition Technology Fund

1. **Focus on high-heat industrial processes:** The OEB should either reject the fund entirely or require that it be focused on one or a few projects that support the use of non-fossil-fuel-derived gases for high-heat processes. The current proposal focuses on long shots instead of safe bets, is so unconstrained it represents a blank check, is too spread out to achieve meaningful results, is inconsistent with previous OEB orders, and is heavily biased towards solutions that rely on gas pipelines and thus support Enbridge's business model even when they are risky, far less cost-effective than alternatives, and much less likely to bring about positive benefits for customers.

RNG procurement

2. **Redirect funds to more cost-effective uses:** The OEB should require that the Company reduce the LCEP portfolio targets by a factor of 4, cap the price at $25.58/GJ, and redirect the savings to expanded energy efficiency.
3. **Maximize ratepayer benefits:** The LCEP should exclusively procure new RNG supply (not recontract for existing supply) and heavily prioritize the development of Ontario-based RNG sources to increase overall supply and maximize long-term benefits.
4. **Achieve the most cost-effective GHG reductions:** The LCEP should procure RNG based on the cost per tonne of avoided lifecycle GHG emissions to reflect the major variance in carbon intensity of different RNG sources and to minimize the cost of carbon emissions reductions.

System pruning

5. **Achieve timely progress:** The OEB should require that Enbridge develop its approach to system pruning in consultation with the IRP Working Group within 6 months and begin implementation on a small pilot within 12 months. This is possible because Enbridge can leverage its existing IRP framework. Further, a pilot may be so small and inexpensive that an application for approval would not be necessary or reasonably justified. Without these specific directions, progress will be far too slow, and the next steps will be inconsistent with the Phase 1 decision.

Heating fuel cost comparison

6. **Enhance customer choice, knowledge, and benefits:** The OEB should require Enbridge to include heat pumps in its heating fuel cost comparison charts as this would clearly benefit customers by providing them with more and better information, which will in turn enhance customer choice and bill reductions. Enbridge's reasons for excluding heat pumps from the cost comparison are baseless.

II. Introduction

Enbridge Gas Inc. (Enbridge) originally filed its 2024 Rebasing application and evidence in 2022 under docket number EB-2022-0200. The application requested approval of rates for the sale, distribution, transmission and storage of gas, as well as approval of an incentive rate-making mechanism for 2025 through 2028. The proceeding on the application was split into three phases. Phase 1 of the proceeding was completed with a Board Decision and Order in December 2023. Enbridge filed evidence for Phase 2 on April 26, 2024 in Docket Number EB-2024-0111. On May 30, the Board finalized the Issues List for the proceeding, with 27 specific issues identified.

This report addresses four topics and five of the issues for this case:

- **Energy Transition Technology Fund (ETTF)** – are the proposed parameters appropriate (Issue #15)? and are Enbridge's proposed energy transition "safe bets" appropriate? (Issue #18);
- **Low Carbon Energy Program (RNG)** – are the specific proposals to amend the voluntary RNG program and procure low-carbon energy as part of the gas supply commodity portfolio appropriate? (Issue #17)
- **System Pruning and IRP** – has Enbridge appropriately responded to relevant OEB directions and commitments from previous proceedings, including issues related to the IRP Framework? (Issue #25)
- **Residential Heating Fuel Cost Comparison** – has Enbridge appropriately reviewed its energy cost comparisons and taken appropriate actions to revise them based on that review? (Issue #24)

The report is co-authored by Chris Neme, a Principal with Energy Futures Group (EFG), and Dr. David Hill, a Managing Consultant with EFG. Mr. Neme, Dr. Hill and their firm have extensive experience and expertise in both the development of policies and the assessment of options for, and implications of, decarbonization of fossil gas use in buildings and industry. That includes developing and conducting decarbonization pathways studies (e.g., in Massachusetts, Vermont and Delaware); helping clients review and provide input to similar studies led by other firms (e.g., the recent Massachusetts gas utilities study); reviewing and critiquing studies on renewable gas potential (e.g., a 2022 Michigan study); assessing the reasonableness of RNG pilot program proposals (Illinois); assessing the need for pipeline expansion in the context of local decarbonization policies (in testimony before the U.S. Federal Energy Regulatory Commission on behalf of the state of Washington); assessing the customer economics of electrification (e.g., in Illinois, Michigan, Nevada and British Columbia); supporting the design of electrification programs (e.g., in Michigan, Illinois and Massachusetts); and supporting the development of over-arching building decarbonization policies (e.g., Vermont's proposed Clean Heat Standard, Michigan's climate plan, and Illinois climate legislation).

Mr. Neme has prepared expert witness testimony in 26 other OEB dockets, mostly on gas DSM issues, but also on the energy transition and its implications for Enbridge capital investment in the Phase 1 rebasing proceeding (in 2023), on gas integrated resource planning (in 2020) as well as on Enbridge and Union's carbon cap and trade policies (in 2018). He has also filed testimony on energy efficiency, electrification, integrated resource planning and other distributed energy issues in nearly 50 DSM, IRP, and Rates cases before energy regulators in a dozen other different jurisdictions, including the neighboring provinces/states of Quebec, Manitoba, Michigan and Ohio. Mr. Neme was recently appointed to the OEB's DSM Stakeholder Advisory Group, currently serves on the OEB's Gas IRP Working Group, previously served on OEB's Evaluation Advisory Committee and was also previously elected by Ontario stakeholders to serve on the province's Gas Technical Advisory Committee and numerous Enbridge and Union Gas DSM Audit Committees over the past 20+ years. He also previously served as an outside reviewer of Ontario studies on achievable efficiency potential and carbon price forecasts.

Dr. Hill has filed expert witness testimony and appeared in regulatory hearings on more than two dozen occasions in twelve jurisdictions, including Ontario and Nova Scotia. These submissions and appearances include recent testimony on proposed gas infrastructure in Rhode Island, testimony in Illinois on Nicor Gas' proposed RNG pilot programs, and an expert report on the merits of a proposed interstate gas pipeline expansion on behalf of the Washington State Attorney General's office in filings with the U.S. Federal Energy Regulatory Commission. He is currently participating in Future of Gas workshop proceedings in Illinois, on behalf of the Natural Resources Defense Council. Dr. Hill's curriculum vitae is attached highlighting his work on energy efficiency, distributed renewable incentive programs, decarbonization pathways, electrification, integrated resource planning and other distributed energy issues.

III. Energy Transition Technology Fund (ETTF)

1. Overview

Enbridge has proposed the creation of a $5 million per year Energy Transition Technology Fund (ETTF) to "advance and accelerate research, development, demonstration, and commercialization of low-carbon technologies."[1] Enbridge states that it would use the fund to:

a. Accelerate technology development and deployment – through research and development (R&D) initiatives, field trials and technology demonstration projects;
b. Drive market adoption and transformation – through engagement with manufacturers, contractors, customers, policy-makers and others to improve availability, awareness and accessibility; and
c. Drive economies of scale – by collaborating with other utilities, manufacturers, industry associations and research organizations.

As detailed below, we recommend that the OEB either reject the fund entirely or require that it be focused on one or a few projects that support the use of non-fossil-fuel-derived gases for high-heat processes. The current proposal focuses on long shots instead of safe bets, is so unconstrained it represents a blank check, is too spread out to achieve meaningful results, is inconsistent with previous OEB orders, and is heavily biased towards solutions that rely on gas pipelines and thus support Enbridge's business model even where they are risky, far less cost-effective than alternatives, and much less likely to bring about positive benefits for customers.

2. Concerns with Enbridge's Proposal

A. The Company is Essentially Asking for a "Blank Check"

In its filing, Enbridge lists six criteria that a potential "technology innovation" project must meet in order for the Company to consider spending ETTF funds to support it. They can be summarized as follows:

a. Reduce greenhouse gas (GHG) emissions;
b. Provide safe, reliable and affordable low-carbon options for customers;
c. Be outside of those needs already funded through DSM;
d. Be compliant with industry codes and standards;
e. Range from pre-commercial to commercial activities; and
f. Cover residential, commercial, and industrial sectors, with appropriate pace of commercialization timeline.

Collectively, these criteria establish a very low bar. Essentially, as a long as a technology could contribute even a little bit to reducing future GHG emissions and is outside the scope of DSM, Enbridge can promote it. A project can be for any type of customer – residential, commercial or industrial. It can be at any stage of development – pre-commercial or commercial. Yes, it would have to also be compliant with industry codes and standards, but that is such a basic requirement that it shouldn't even need to be stated. The same is true of the being a "safe" and "reliable" option. Does that really screen anything out? Would Enbridge (or any other utility) ever really consider something that was determined to be unsafe or unreliable? The only proposed criterion with any potential value in helping to choose between "low carbon" technologies is the requirement that it would provide "affordable" options to

[1] Exhibit 1, Tab 10, Schedule 7, p. 2, paragraph 5.

customers. However, Enbridge has not provided any specificity regarding what that means to them.[2] Moreover, as discussed further below, several of the options that seem to figure most prominently in the Company's current thinking about the kinds of projects to pursue are quite expensive and highly unlikely to play significant roles in a least cost (i.e., most affordable) mix of strategies for decarbonization.

Selection criteria should help to differentiate the best options for focusing spending. Enbridge's do not. When Staff asked if Enbridge planned to develop a "scoring methodology to compare and rank potential initiatives", the Company responded by pointing to the six criteria discussed above, stated that it may add to or modify the list "as needs arise" and stated that a scoring methodology will be developed ("as appropriate"), *but only after the fund has been approved*. In the Technical Conference, the Company noted that it has been thinking about potential factors it might incorporate into a score matrix, including "level of uniqueness" (potential indicator of a competitive advantage) of a project, "technology readiness level", GHG reduction potential, whether other funding sources would be leveraged and probability of success.[3] However, these are just the Company's initial thoughts and no scoring matrix has been developed, let alone submitted for approval. In essence, the Board is being asked to approve $5 million/year without little clarity on how spending decisions will be made.

B. Enbridge Cannot Be Trusted to Spend on Greatest Needs or What Are Really "Best Bets"

Enbridge states that the technologies whose development it will fund through the ETTF will be consistent with the "safe bet actions identified in the Energy Transition Plan in EB-2022-0200 Exhibit 1, Tab 10, Schedule 6."[4] The problem is that Enbridge's conclusions regarding what is a "safe bet" are fundamentally flawed. They are also clearly biased towards solutions that maximize the potential future role (and therefore profits) of the Company.

For the purpose of determining whether a technology merits utility ratepayer funding, the definition of a "safe bet" should be a technology that is highly likely to play a significant role in the energy transition across a variety of plausible future scenarios. While the size of that role might be a little different depending on how technology and markets evolve, safe bets should be expected to have significant roles in the vast majority of independent (unbiased) assessments of likely decarbonization pathways. Key examples include:

- **Energy efficiency investments that reduce heating loads – e.g., weatherization of homes and businesses**. Weatherization will reduce annual gas use, reduce gas bills, reduce peak demand that drives gas infrastructure costs, and ultimately reduce impacts on the electric grid when buildings electrify their space heating. It will also reduce costs to the extent that some buildings are heated with very expensive RNG. This is a particularly safe bet because it provides benefits no matter what the heating source is.

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[2] In the Technical Conference, Enbridge stated that affordability means that a technology "would have a possible potential trajectory of getting to a reasonable price, price point for a customer to be able to adopt." (Technical Conference transcript, July 23, 2024, p. 57) However, the Company has not defined what it means by "reasonable". Nor has it specified the context – i.e., reasonable compared to what? For example, it has not set a prospective limit on cost per tonne of CO_2e reduction or a cost relative to other alternatives.

[3] Technical Conference Transcript, July 23, 2024, pp. 54-55.

[4] Exhibit 1, Tab 10, Schedule 7, p. 5, paragraph 14.

- **Residential and commercial electrification, particularly space heating but also other end uses**. There is no real debate about whether significant portions of current gas use will need to be electrified in order to decarbonize the fossil gas sector. The only questions are how much and how fast.
- **Low-carbon fuels for high-heat industrial applications**. While there are some potential electrification options for some lower-heat industrial process loads, electrification is currently less suitable for most higher-heat industrial processes so it seems likely that low-carbon fuels will play a significant role here.

As Mr. Neme's report in Phase 1 of the Rebasing proceeding made clear, the independent studies of decarbonization pathways with which we are familiar suggest significant increases in the adoption of those technologies will be necessary – across a range of potential futures – to affordably achieve decarbonization of the fossil gas sector. For example, Table 1 of that report – replicated below – shows that multiple studies in Canada and in northeastern U.S. states have concluded that massive reductions in gas throughput as a result of electrification will need to be part of any realistic transition to net zero emissions by 2050.[5]

Table 1: Decarbonization Study Conclusions on Reductions in Annual Gas Energy Throughput by 2050[6]

				Massachusetts	
	Canada	**Quebec**	**New York (scenarios 2-4)**	**Hybrid Electric Scenario**	**High Electric Scenario**
Throughput Reduction:	**68% to 100%**	**~75% to 80%**	**91% to 94%**	**73%**	**84%**
Sectors Applicable to:	Buildings	Buildings & Industry	Buildings & Industry	Buildings & Industry	Buildings & Industry
Relative to Base Year of:	2020	2016	2020	2020	2020

Since Mr. Neme's Rebasing Phase 1 report was filed, a new study just completed by the Canadian Climate Institute reached the same conclusion. Indeed, its very first "finding" is that "on a cost-optimal pathway to net zero, electricity will power most space heating in Canada."[7]

Conversely, there are many technologies about which there is at least great uncertainty – if not reason for tremendous skepticism – regarding the role they can and/or are likely to play in a decarbonized future. These technologies are the opposite of "safe bets". Many would be better labeled as "long shots". That includes key technologies that Enbridge has named as potential targets for its ETTF funds.

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[5] Note that only three of these studies were truly independent. The fourth – E3's study in Massachusetts – was funding and managed by the state's gas utilities. However, the study did involve an extended stakeholder engagement process which included soliciting input on study assumptions and feedback on study conclusions from a range of diverse parties.

[6] Canadian Institute for Climate Choices, p. 40 (electric heat can comprise up to 100% of residential heating) and p. 43 ("clean gases could potentially provide a total amount of energy equivalent to 32% of today's natural gas demand from Canada's buildings"); Dunsky, p. 13; E3, *Appendix G: Integration Analysis Technical Supplement New York State Climate Action Council Scoping Plan*, Tech Supplement Annex 2, "gas throughput" tab; E3 and Scottmaden, *Technical Analysis of Decarbonization Pathways*, p. 15.

[7] Canadian Climate Institute, Heat Exchange: How Today's Policies Will Drive or Delay Canada's Transition to Clean Reliable Heat for Buildings, June 2024, Executive Summary p. ii (https://climateinstitute.ca/reports/building-heat/).

For example, Enbridge specifically identifies carbon capture utilization and storage (CCUS) technologies for both commercial and industrial applications as a potential priority for funding through the ETTF.[8] CCUS is sometimes referenced as part of a potential mix of options for decarbonizing industrial use of fossil gas.[9] However, because electrification is a far better alternative, CCUS is not even mentioned by other studies – not even in the Massachusetts study funded by the state's gas utilities – as a viable option for commercial customers. That is the antithesis of a "safe bet".

Similarly, Enbridge has suggested that it has interest in potentially using ETTF funds to support development of end-use technology, such as residential furnaces and water heaters, that can burn methane-hydrogen blends that contain more than 20% (by volume) hydrogen.[10] The Company suggests that at least some current gas-burning equipment can burn hydrogen blends of up to 20%,[11] but that "a significant amount of work is needed to develop the end-use equipment for the residential, commercial and industrial application that would be compatible with higher (greater than 20%) blends of hydrogen."[12]

While that is undoubtedly true, it does not mean that supporting the development of such technology is a good idea. Indeed, we are unaware of any independent study that suggests it would ever be feasible, let alone economic, for an affordable energy transition to involve more than 20% hydrogen blending (by volume, which amounts to roughly 6% by energy content). There are a variety of reasons for this. For one thing, all equipment owned by all customers downstream of any injection of a hydrogen-methane blend would have to be capable of safely burning a greater hydrogen blend. As Mr. Neme explained in his critique of Enbridge's analysis of a 100% hydrogen delivery strategy in the Phase 1 proceeding (EB-2022-0200), even if models of all types of gas-burning appliances that are capable of burning greater hydrogen blends become available by 2035 and even if governments mandate the exclusive sale of such equipment by 2035 – two assumptions that would require significant leaps of faith – it is inevitable that a significant portion of gas-burning equipment still on Enbridge's distribution system in the 2030's, 2040's and even the 2050's will not be capable of burning greater than 20% blends. Gas furnaces, boilers and other equipment can last 20, 25, or even 30 years or more. Customers typically only replace them when they stop working or are at least very old. Thus, there will still be a lot of equipment in use even in 2050 that was purchased and installed before 2035.

Second, before injecting higher than 20% hydrogen blends, Enbridge would have to be 100% certain that all gas-burning equipment downstream of the injection had been replaced with newer models. That is, at best, impractical.

Third, it is important to remember that a 20% hydrogen blend by volume is only about 6% by energy content because hydrogen is much less dense than methane. Thus, even if 30% blends become possible, only about 9% of the delivered energy would be hydrogen. In a future in which gas throughput is

[8] Exhibit 1, Tab 10, Schedule 7, p. 7.

[9] For example, the 2020 Canadian Climate Institute study (p. 59) suggests that CCUS will likely compete on cost with biofuels for portions of the industrial sector's decarbonization mix while the E3 study for New York study included "a limited amount of CCS as a control strategy for some portion of the emissions in the industrial sector." (Appendix G, p. 24).

[10] For example, see Exhibit I.1.10-GEC-14 and Exhibit I.1.10-Staff-4(i).

[11] Though very little testing has been conducted at levels as high as 20% blends.

[12] Exhibit I.1.10-Staff-4(i).

expected to be only 10-30% of current levels under common 2050 decarbonization scenarios (see Table 1 above), a 30% hydrogen blend would be providing only about 1% to 3% of the total required GHG emission reduction.[13] In other words, not only are greater than 20% hydrogen blends more of a "long shot" than a safe bet to play *any* role in gas decarbonization, even if that long-shot comes through, the contribution to total required GHG emission reductions will be very, very small.

Finally, it is worth noting that because hydrogen is much less dense than methane – and therefore requires roughly three times as much pipeline capacity per unit of delivered energy – significant reliance on hydrogen blending could cause new or exacerbate any existing capacity constraints on Enbridge's system.

Importantly, CCUS for commercial buildings and residential/commercial appliances capable of burning greater than 20% hydrogen blends are not just long-shot technologies, but long-shots that would support greater use of Enbridge's distribution system. In other words, there is an obvious bias in Enbridge's focus. That bias also appears in several other parts of the Company's evidence on the ETTF. For example, while low-carbon hydrogen for industrial process heating could be characterized as a safe bet, the one source of industrial hydrogen that Enbridge mentions in its filing is – methane pyrolysis[14] – is predicated on continued production and distribution of fossil gas. When asked about other sources of low-carbon hydrogen that the Company might support through the ETTF, Enbridge says it is agnostic as to how hydrogen is produced and then mentions two other possible technologies (Steam Methane Reformation and Autothermal Reformation with carbon capture and storage) that also use fossil gas as a feedstock. To be fair, when asked whether the Company would consider supporting green hydrogen projects through the ETTF, Enbridge states that it would consider doing so.[15] Green hydrogen is the breaking down of water into hydrogen fuel and oxygen using renewable sources of electricity. It does not require continued reliance of fossil gas. However, the fact that the majority of Enbridge's discussion of hydrogen production is on technologies that use fossil gas as a feedstock raises questions as to how objectively Enbridge will consider the relative merits of options that require use of fossil gas versus those that do not. Indeed, the Company has also stated that it will not fund anything through the ETTF that doesn't involve continued reliance on gas – even if the alternatives (e.g., electric options) are more cost-effective at reducing emissions.[16]

It is worth noting that some leading gas utilities in other jurisdictions are funding pilot projects that focus on electrification. For example, the Massachusetts Department of Public Utilities, the state's energy regulator, recently issued an order that supported its state's gas utilities' proposal to invest in pilot projects to test the potential for cost-effective GHG emission reductions through networked geothermal systems.[17] Such systems use electricity to extract heat from the ground (or water sources) to distribute to multiple buildings in a geographic area, displacing heat otherwise provided by fossil gas and/or other fuels. Notably, in the same order in which the Massachusetts DPU approved networked

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[13] Less than one-tenth of the remaining 10-30% of energy supplied by gas.
[14] Exhibit 1, Tab 10, Schedule 7, p. 6.
[15] Exhibit I.1.10-ED-9(a).
[16] Exhibit I.1.10-ED-10(a) and Exhibit I.1.10-PP-11(c) and Technical Conference Transcript, p. 53.
[17] Commonwealth of Massachusetts Department of Public Utilities (DPU), Order on Regulatory Principles and Framework, Docket DPU 20-80-B (Investigation by the DPU on its own Motion into the role of gas local distribution companies as the Commonwealth achieves its 2050 climate goals), December 6, 2023 (https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18297602), pp. 84-86.

geothermal pilots, it rejected RNG and hydrogen blending pilots other than for "targeted end uses", such as high temperature industrial process heating needs, that are hard to decarbonize through other means (i.e., difficult to electrify). The DPU further ordered that any utility proposals for hydrogen or RNG pilots include cost-effectiveness screening, a thorough explanation of how the targeted application is "hard to decarbonize", a discussion of electrification alternatives and how the project aligns with the state's GHG emission reduction goals, and how it addresses "environmental justice populations" (ensuring that projects do not adversely affect indoor air quality).[18]

Similarly, Vermont Gas Systems is supporting a pilot project to produce and use green hydrogen by one of its largest industrial customers (a microchip manufacturing facility). Interestingly, the green hydrogen would displace grey hydrogen – hydrogen produced from natural gas or other fossil fuels – that had been used at the facility. The rationale for switching from grey to green hydrogen is that lifecycle GHG emissions would be reduced.[19]

C. Proposal is Inconsistent with Previous Board Ruling on Gas Heat Pumps

In its filing, Enbridge states that the ETTF "will include…end-use energy efficiency technologies not covered by DSM funding."[20] When asked what technologies that might include, the first item identified by the Company was gas heat pumps.[21]

The Company's proposal to potentially fund the development of gas heat pumps runs counter to a decision the Board made not even two years ago on the Company's DSM plan. In its DSM Plan filing, Enbridge had proposed a "Low-Carbon Transition Fund", with development of the market for gas heat pumps being a core element of that proposal. Numerous stakeholders objected to the proposal for a variety of reasons, including that gas heat pumps were not cost-effective, that they were less cost-effective than electric heat pumps, and that they had little chance of playing a significant role in a least cost approach to decarbonization. The Board ultimately agreed with stakeholders:

> "The OEB does not approve the Low Carbon Transition Program. The OEB finds that focusing efforts on gas heat pumps, a technology that is not currently commercially available nor as cost-effective as electric heat pumps is not prudent. Although gas-fired heat pumps may be more efficient that high efficiency gas furnaces, offering incentives for this measure would continue the use of natural gas and associated GHG emissions well into the future."[22]

Enbridge has not provided any information in this proceeding to suggest any of the reasons cited by the Board in rejecting funding of gas heat pumps through the Company's DSM plan has changed. The Company has instead stated that it views the Board's decision in its DSM proceeding "to be specific to the research and innovation funding requests in the DSM application" and that "it is appropriate to fund technology development initiatives for gas fired equipment outside of the DSM Plan/funding, including gas heat pumps, when the gas fired equipment can provide benefits beyond energy efficiency." The

[18] Ibid, p. 84.
[19] https://vgsvt.com/vermont-partnership-advances-use-of-green-hydrogen-as-clean-fuel-of-the-future/#
[20] Exhibit 1, Tab 10, Schedule 7, p. 6, paragraph 17.
[21] Exhibit I.1.10-ED-13(e).
[22] Ontario Energy Board, Decision and Order, EB-2021-0002, November 15, 2022.

Company goes on to suggest that such additional benefits include “maintaining customer choice”, “reducing GHG emissions” and “reducing gas peak load”.[23]

That is a specious argument. The only reason gas heat pumps reduce GHG emission is because they are an efficiency measure. Similarly, the only reason gas heat pumps reduce peak loads is because they are an efficiency measure. In other words, there is not any extra GHG reduction or peak load reduction benefit “beyond energy efficiency.” With respect to “maintaining customer choice”, the ETTF should only invest in technology that is likely to offer customers *better* choices. In its DSM order, the Board made clear it views gas heat pumps as unlikely to be a better choice. If gas heat pumps are not (and are unlikely to ever be) cost-effective relative to other efficiency technologies (including cold climate electric heat pumps), there is no “beyond efficiency” reason to support them. Put another way, if it is unreasonable to fund their development as part of energy efficiency program funding, it should also be unreasonable to fund their development through an energy technology transition fund.

D. Enbridge Likely to Spread Funding Across Too Many Projects to Make a Real Difference

While Enbridge has not yet identified the range of technologies whose development it intends to fund in 2025, let alone over the next several years, it appears prepared to potentially fund a wide range of technologies. That could result in spreading funds across too many projects to have a material impact on the development of any of them.

All of the technologies the Company is considering are already being explored across North America and/or across the globe. Thus, Enbridge is much more likely to be able to affect its customers’ interest in testing or adopting a new technology than it is to affect the evolution of the technology itself. Put another way, the marginal contribution that Enbridge could make to their market development is likely to be negligible if the Company’s funds are not concentrated on field tests, demonstration projects and/or pilot programs in Ontario. In our experience, such field tests or demonstration projects often cost millions of dollars when undertaken at a scale necessary to produce enough data to evaluate and inform other potential future investments in the province. That means the ETTF would be much more effective if it was concentrated on testing one or two technologies or perhaps several options for addressing one important market.

3. Recommendations

We recommend that the OEB reject Enbridge’s proposed Energy Transition Technology Fund (ETTF) because, as proposed, it is too open-ended in terms of what Enbridge can support with the funds, is likely to end up spending on projects that are energy transition long-shots rather than “safe bets”, and is therefore unlikely to be very helpful in supporting a cost-effective energy transition.

An alternative to completely rejecting the fund would be to require that it be targeted solely to one major energy transition need that is universally recognized by the industry – not just by Enbridge – as a safe bet. Since Enbridge is addressing energy efficiency and now some residential and commercial electrification through its DSM efforts, the logical choice for a targeted ETTF would be low-carbon fuel for high-heat industrial processes.

[23] Exhibit I.1.10.1-ED-63(d).

If such a targeted ETTF were to be approved, the Board should also require that Enbridge develop a scoring rubric for prioritizing different potential low-carbon alternatives for high-heat industrial process needs. At a minimum, scoring criteria should include:

- the lifecycle carbon intensity of the options (the lower the better);
- the potential for the cost per tonne of GHG emission reduction to be lower than other alternatives; and
- the likelihood that the project will accelerate adoption of the technology by Ontario customers.

Ideally, the funds would be spent on one or a small number of projects or pilots to increase the impact and avoid spreading the funds too thinly.

Finally, we recommend that the Board create a stakeholder advisory committee that would be expected to work with Enbridge on both the development of a scoring rubric, the actual scoring of different options and ultimately the selection of project funding priorities. Under its current proposal, the Company will ultimately make decisions on which technologies it will support with ETTF funds without any structured stakeholder input.[24] Given the concerns noted above, creating a structured process for stakeholder input is important to ensuring effective ETTF spending.

[24] When asked in GEC-16 about whether and how the Company would obtain input from other parties, Enbridge referenced its response to Exhibit I.1.10-Staff-4(i). That response essentially says that the Company regularly works with NRCan, industry organizations, industry stakeholders and research organizations like the Gas Technology Institute.

4. Low Carbon Energy Program (RNG)

1. Overview

The Phase 2 evidence includes the Company's proposal to amend its Voluntary RNG Program and to procure low-carbon energy as part of the gas supply commodity portfolio. The Company requests "*OEB approval to procure low-carbon energy, with a focus on renewable natural gas (RNG) as part of the gas supply commodity portfolio, beginning in 2026, and recover the incremental costs associated with this energy through the proposed cost recovery mechanism.*"[25] The evidence submitted by the Company includes a Low Carbon Energy Program (LCEP) proposal, an evaluation of low-carbon energy as part of the gas supply commodity portfolio, an overview of the RNG markets prepared by a third party consultant, and reporting on greenhouse gas (GHG) emissions reductions from RNG.

This section of our report discusses the risk that the proposed LCEP oversells the potential for RNG to economically reduce emissions. Specifically, the LCEP proposal risks overstating the available RNG supply, understating the costs of varying RNG supplies, and overstating potential GHG reductions. Even as proposed by the Company, putting aside the need for adjustments to assumptions, the cost for emission reductions from RNG does not compare well with the costs for other decarbonization strategies. We propose regulatory steps the Ontario Energy Board (OEB or Board) should consider in order to reduce the risks of the proposed LCEP to consumers.

As detailed below, we recommend the following:

1. **Redirect funds to more cost-effective uses:** The OEB should require that the Company reduce the LCEP portfolio targets by a factor of 4, cap the price at $25.58/GJ, and redirect the savings to expanded energy efficiency.

2. **Maximize ratepayer benefits:** The LCEP should exclusively procure new RNG supply (not recontract for existing supply) and heavily prioritize the development of Ontario-based RNG sources to increase overall supply and maximize long-term benefits.

3. **Achieve the most cost-effective GHG reductions:** The LCEP should procure RNG based on the cost per tonne of avoided lifetime GHG emissions to reflect the major variance in carbon intensity of different RNG sources and to minimize the cost of carbon emissions reductions.

2. Concerns with the LCEP/RNG Proposal

A. LCEP Likely Overstates Potential for RNG as a Decarbonization Strategy

The LCEP proposal states "*It is clear the energy transition is underway and RNG will play an important role*."[26] The proposal and application do not justify this declaration, and in several key aspects make assumptions and forecast results that likely overstate the potential value of RNG as a decarbonization pathway. These include:

- Since implementing the voluntary RNG pilot program in April 2021, the Company reports it has procured 5,600 GJ of RNG, at an average cost of $35.92/GJ.[27] As proposed, the LCEP would require the Company to procure more than **946 times more RNG in 2026 than it procured**

[25] Exhibit 4, Tab 2 Schedule 7, p. 1.
[26] Ibid. page 1.
[27] Exhibit I.1.10-PP-6, p.3.

during the 3-year pilot, increasing to **3,750 times more RNG by 2029 than it procured during the pilot**. These levels of increase are questionable, even recognizing that RNG project development is increasing in the region and throughout North America. The projected extremely rapid expansion also runs counter to the Company's reported experience of timing delays causing more than 60% lower capital expenditures for anticipated CNG and RNG projects.[28]

- It is important to recognize that the proposal to acquire 1% RNG by 2026 and 4% by 2029 **still leaves 99% to 96% of the gas commodity as fossil gas.** Moreover, because Enbridge does not plan to differentiate between different sources of RNG based on lifecycle GHG emissions, the actual emission reduction achieved through the proposed RNG purchases may be much less than the 1% to 4% volumes imply. As illustrated in some detail in Appendix A to this report, the carbon intensity of RNG varies significantly by feedstock source, conversion technologies and other project specifics. While agricultural anaerobic digestion that avoids direct methane emissions to the atmosphere (e.g., from manure) can have a negative carbon intensity (more than offsetting an equivalent combustion of fossil gas), other sources such as landfill or wastewater treatment may not even be able to off-set half of the GHG the emissions from an equivalent amount of fossil gas combustion. If approved, the Board should direct the Company's estimates of emissions reductions for RNG be differentiated to reflect the costs and varying carbon intensities by source.
- The Company's estimate of the net RNG price that is within the target bill impact and target percentages is $25.58/GJ.[29] This is 30% less than the average price for the Company's RNG procurement in the pilot program. The costs for procurement in the Company's pilot experience are more consistent with high range estimates from independent analysts. Even the low range forecast by the independent RNG analysts is 14% higher than the $25.58/GJ used in the Company's projections.[30] Thus, there is reason to be skeptical that the Company will be able to procure the levels of RNG that it has proposed within its proposed bill impact cap.
- The Company has built the LCEP based on their assessment of customer willingness to pay up to $2 per month to help decarbonize gas supply and reduce the environmental harm from the gas system. The Phase 2 application for RNG takes this threshold of consumer willingness to pay through rate impacts for enhanced environmental performance, and has assumed, without adequate comparison to alternatives and through favorable assumptions and inputs, that the increased RNG procurement proposed in the LCEP is a preferred option for maximizing the benefits from this additional spending. The Company's proposal indicates more than $630 million could be spent on RNG procurement just in calendar year 2029.[31] This annual level of spending is for a one-time reduction in emissions. The Company would need to continue to procure RNG at high costs, year over year, to just retain the level of emission reductions that it plans to achieve in 2029 (i.e. to avoid backsliding). Even if the Company was able to acquire 4% RNG by 2029 at $25.58/GJ, we estimate that increasing RNG levels to 4% by 2029 and then just maintaining that level of RNG through 2050 would likely result in more than $4.0 billion in increased gas bills for Enbridge's customers – even after accounting for reduced carbon tax

[28] Exhibit I.1.17-FRPO-43, p.3.
[29] Exhibit I.4.2-GEC-20.
[30] S&P Global estimate cited in Exhibit I.4.2-ED-50.
[31] Exhibit I.4.2-PP-46, p.2.

payments.[32] In contrast, once they are made, investments in energy efficiency, electrification and other measures typically provide emission reductions for decades. Our analysis and findings, and the Company's proposal do not support these levels of potential annual spending on RNG as a preferred option. We recommend lower targets for the LCEP, and redirecting of the resulting savings towards alternative decarbonization investments such as increased energy efficiency.

- The Company provides a range of estimates, demonstrating the costs of emissions reductions from RNG procurement are significantly higher than the realized costs for emissions reductions from their demand side management energy efficiency portfolio. The Company estimates that with an incremental cost of RNG of $25.58/GJ as assumed for the customer cost impact and reaching a 1% RNG procurement, the cost per tonne of CO2e reduction is $511.60.[33] **They also report emissions reductions from the 2023 DSM portfolio are significantly less expensive** ranging from $12.25/tCO2e for the large volume program to $94.52/tCO2e for the low-income program.[34] These DSM costs per tonne are estimated by dividing DSM spending into GHG emission reductions. They do not net out the significant energy cost savings DSM provides. Even when accounting for additional customer contributions to the cost of DSM measures and other portfolio level costs that Enbridge did not include in the DSM costs per tonne estimates, its DSM programs are very cost-effective. Thus, when all other benefits are netted out from costs, DSM actually provides GHG reductions at negative costs.
- By 2029 the LCEP's estimated annual cost for RNG supplies ranges from $337 million to $633 million.[35] In comparison, the Company's annual total DSM spending between 2019 and 2023 ranged between $119 million and $145 million.[36] **The potential scale and costs for LCEP RNG supplies and the much shorter-lived nature of their emission emissions, do not justify investments on the order of 3 to 5 times more than has historically been invested in efficiency.**
- Under the LCEP proposal, Enbridge could procure RNG supplies from anywhere across North America.[37] Rather than relying on a book and claim accounting method allowing an RNG supply injection to a pipeline that may be thousands of miles distant from Ontario and permitting an equivalent RNG supply to be credited to the LCEP, **the program, if approved, should prioritize or be restricted to support the development of regional RNG projects and infrastructure.** The availability of long-term RNG off-take contracts for regional projects can support municipalities, businesses and agriculture within the region, keeping the ratepayer supported funding for RNG procurement circulating within the regional economy. The LCEP program procurement should also restrict its procurement to newly developed RNG projects as opposed to contracting and re-purposing of pre-existing supplies. If the program does not require new sources of RNG the

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[32] This is an approximate estimate of the net present value (NPV) of increased costs from 2026 through 2050, relative to a baseline of not investing in any RNG. It assumes an RNG cost of $25.58/GJ; a comparable fossil gas cost of $3.59/GJ based on 2024 Enbridge commodity prices which, for simplification, are assumed to remain unchanged; a carbon tax of $110/tonne in 2026, increasing to $170/tonne in 2030 and then increasing by inflation; and a 4% real discount rate (the same rate Enbridge is using to assess cost-effectiveness of its DSM programs).
[33] Exhibit I.4.2-ED-48 p. 3.
[34] Ibid. p.3.
[35] Exhibit I.4.2-PP-46, p.2.
[36] Exhibit I.1.10-PP-6, p.2.
[37] Exhibit 4, Tab 2, Schedule 7, p. 6.

program may simply be shifting emissions reductions from a prior user of RNG to Enbridge's portfolio, with no net gain in RNG or reductions in total atmospheric emissions.

B. Avoid Overstating RNG Supply and Growth Projections

As proposed, the LCEP risks overstating the potential of RNG supply as a long-term decarbonization strategy. The Company's application includes as an appendix the September 2022 ANEW Study and cites other studies that have primarily been conducted on behalf of the biogas and gas industries. The methods applied in these studies include top-down feedstock resource driven estimates, and bottom-up potential site inventory estimates. In both cases, the assumptions and methods need to be viewed with healthy skepticism, and with a critical eye towards how the potential estimates directly relate to the proposed value and benefits for pipeline injected RNG in the Enbridge system.

Our comments are not a new independent estimate of RNG potential for North America, Canada or Ontario. Instead, we highlight issues with the cited studies and other references that support our recommendations for the LCEP to have lower RNG procurement targets, and a regional focus. These include:

- The ANEW study references the widely cited 2019 study conducted by ICF for the American Gas Foundation[38] and the Torchlight Bioresources 2020 study. These are both cited by ANEW as examples of top-down RNG resource assessments. Both the ICF study and Torchlight indicate that prior to 2030, contributions from thermal gasification and power to gas technologies are likely to remain pre-commercial and make limited contributions. The ANEW review calculates that reaching the low and high potential estimates in the ICF study would require decade-long compound annual growth (CAGR) rates of 30% to 40% respectively.[39]
- In comparison, the International Energy Agency, in their recent annual renewable energy assessment which included for the first time a special section on biogas and biomethane, estimates biogas and RNG supplies in the United States would grow by a factor of 2.1 in the coming five years.[40] This equates to a CAGR of 16%, roughly half the level and time horizon of the calculated required growth to meet the ICF resource-based estimates. The IEA's much lower implied growth rate is still seen as very accelerated, and the IEA characterizes the financial support and incentives from various Federal and state programs as providing "a very favorable framework for accelerated growth."[41]
- The ANEW study also cites a study it conducted for the RNG coalition indicating 47,000 waste facilities in North America that could be developed for RNG production.[42] ANEW states they "believe that a bottom-up approach that focuses on project counts and includes avoided emissions is more indicative of RNG supply growth."[43] The analysis continues to estimate the RNG potential based on development of all of the potential sites (therefore appearing to be a

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[38] Enbridge Gas Inc, North American Renewable Natural Gas Market Evaluation, September 2022, prepared by ANEW, p. 24.
[39] Ibid, p. 25, p. 26.
[40] International Energy Agency, Renewables 2023: Analysis and Forecasts to 2028, p. 139. (https://static1.squarespace.com/static/53a09c47e4b050b5ad5bf4f5/t/65a0575e6fd27e145d495322/1705006944797/Renewables_2023.pdf)
[41] Ibid, p. 139.
[42] ANEW, North American Gas Market Evaluation, p. 27.
[43] Ibid. p. 26.

technical rather than an achievable or economic potential), including landfills, large farm and other waste. Their resulting estimate, if 0 carbon intensity is applied, is that RNG could supply 18% by volume of the US and Canadian gas supply.[44]

- There are serious flaws with an estimate based on the assumption that all the inventoried sites will be developed. While we agree that project counts may be a more helpful method for estimating future potential, the assumed development of 47,000 sites is totally out of line with recent project counts, and with industry objectives for project development in the coming years. The 2023 Canadian Biogas and RNG market report indicates there were nearly 300 active projects operating in Canada, with estimated annual production of more than 20 PJ.[45] The RNG Coalition Sustainable Methane Abatement & Recycling Time (SMART) initiative, also cited in the ANEW study, has target of 500 operating projects by 2025, and a target of reaching 1,000 operating projects by 2030.[46] In light of these levels of existing projects and industry development targets for 2030, the ANEW studies estimate citing the potential RNG supply from 47,000 projects is misleading and contributes to the application's false sense of potential from RNG supplies.

To summarize our concerns with the LCEP's analyses of RNG supply, even if questionable approaches and assumptions on supply are put aside, and the Company's proposal for up to 4% of volume RNG be procured by 2029 is taken at face value, RNG can be expected to play a modest contributing role in decarbonizing the gas system, and should not be characterized as playing an important or major role in displacing future fossil gas commodity supplies.

Moreover, the issues with overstating potential RNG supplies should not be overlooked. Over-inflated estimates of RNG supply potential are likely to mislead and confuse consumers, regulators, and policy makers with respect to the long-term potential of RNG as decarbonization strategy.

Particularly in the near-term, during the proposed LCEP time horizon, RNG market development will not be limited by the amount of feedstock resources or by the potential number of sites that could be developed. Instead, the economics and comparative advantages of other competing renewable resources, utility and customer investment opportunities, and existing infrastructure and policy and planning factors are more likely to spur and or limit RNG growth. By citing and estimating high values for resource potential and the technical potential number of sites, the LCEP overstates the RNG role in an unhelpful manner.

C. Anticipate Higher RNG Procurement Costs

The LCEP program design proposes to procure an increasing annual percent of total commodity gas supply as RNG, starting in 2026 at 1% and increasing by 1% annually up to 4% in 2029. To contain the potential costs, the Company proposes the RNG procurement budget be limited to no more than $2/month/customer/ for each percent of RNG. Thus, in 2029 the proposed annual cost impact per customer could be up to $2*4%*12months = $96.[47]

[44] Ibid. p. 27 and 28.
[4545] https://biogasassociation.ca/resources/page/2023_canadian_biogas_and_rng_market_report/
[46] ANEW Study, p. 24, Table 5.1.2 RNG Project Counts
[47] Exhibit 4, Tab 2, Schedule 7, p. 7.

The Company estimates the percentage targets and the cost containment cap can be met with an RNG procurement price of \$25.58/GJ.[48] If this average price is exceeded, the Company would procure less RNG than the proposed percentages. The estimated price point is 30% lower than the Company's reported cost of procurement in the recent 3-year RNG pilot. It is also 14% to 30% lower than independent analyst projections cited in the application.[49] While higher volumes and market development may enable the LCEP to have lower procurement costs than the RNG pilot, it remains to be seen whether that is actually possible. To protect ratepayers, we recommend the Company not be allowed to procure RNG with a price higher than \$25.58/GJ, which already represents an extremely high cost per unit of emission reduction.

It is also important to note, that while the willingness of customers to support incremental costs of up to \$96 per year for decarbonization is admirable, it does not automatically lead to the conclusion that procurement of RNG is the most impactful or beneficial action that can be undertaken. The Company's should consider customers' likely responses if they were offered the choice of having this resource put towards measures that reduce emissions for multiple years (efficiency and electrification) versus RNG which has to be re-purchased every year in order to sustain a very modest level of emission reduction.

D. Prioritize Procurement Based on Carbon Intensities, Location and New Development

Lifecycle emissions accounting should be required. When burned in a furnace, GHG emissions from RNG are identical to GHG emissions from burning fossil gas. The only reason RNG can be considered emission reducing is because it provides some offsetting emission reductions elsewhere. Thus, the actual magnitude of such other emission reductions – and the net impact relative to emissions from displaced fossil gas consumption – is what really matters.

The proposal recognizes that carbon intensities of various feedstock and technology streams for RNG production vary significantly, and even vary by specific project. The application and analyses recognize that manure-based projects have the lowest, negative carbon intensities, due to their ability to capture and utilize otherwise direct atmospheric methane emissions, with attendant high global warming potentials. While manure-based projects can more than off-set an equal volume of fossil gas emissions, most of the RNG projects currently developed and a large portion of the potential RNG projects are not manure-based projects. Landfill gas, wastewater treatment, and food waste projects all typically have positive carbon intensities, which means that they only partially off-set the emissions from the avoided quantity of fossil gas (a carbon intensity of 0 means a resource exactly offsets the amount of emissions that result from burning fossil gas).[50] See Appendix A for details.

Further, to reduce emissions, RNG procurement needs to be sourced from the development of new capacity, and not merely be repurposed or re-contracted from pre-existing RNG uses. Jurisdictional resource assessments assume RNG can be acquired from large geographic "waste-sheds" via book and claim transfers. The LCEP proposes to acquire RNG from across North America. While regulatory and market conditions may support this practice, it contributes to overstating the benefits of RNG by ignoring the costs, leakage losses, and other physical constraints attendant with gas transportation and distribution. In Vermont, the Clean Heat Standard under final development specifically includes a

[48] Exhibit I.4.2-GEC-20.
[49] S&P Global estimate cited in Exhibit I.4.2-ED-50.
[50] ANEW Study p. 28-29.

requirement that Vermont Gas purchase the transmission pathway to its distribution system in Vermont before it can claim any GHG emission reduction from procured RNG. This position was supported by Vermont Gas Systems, as necessary to make RNG purchases comparable to any fossil gas purchases.

The LCEP does not propose to prioritize or require projects to have negative carbon intensities. The application states “The Company acknowledges the lifecycle emission benefits of using RNG: however, at this time, the CI (carbon intensity) score of RNG will not be the primary consideration when procuring RNG.”[51]

We disagree with this position. If it is approved at the lower recommended target levels, the LCEP should be required to account for different carbon intensities in their reported emission reductions and prioritize newly developed, in region, supplies with negative or zero CI values. If out of region supplies are permitted, then transmission pathways and costs must also be included in the procurement contracts.

E. Acknowledge RNG as a Complementary and Supporting Role

Independent decarbonization pathway studies consistently show that decarbonized gas can play a *supporting* role in meeting long-term emission reduction targets.

The LCEP application’s characterization of RNG as playing an important role in the energy transition, risks green-washing the impact and mis-directing resources from activities such as increased energy efficiency that the Company has demonstrated has a lower cost for avoided emissions.[52]

Even at existing and potential new RNG production sites, the on-site use of biogas for heat or power production may be a more economically attractive and valuable emission reduction resource than injection into the gas distribution system. Many landfill sites already have such alternative uses in place, based on requirements for management of methane emissions and favorable economics.

3. Recommendations for LCEP/RNG

The discussion above highlights issues and potential risks with the proposed LCEP. While there can be a constructive supporting role for RNG in the Company’s plans and decarbonization efforts, we recommend the Board direct the Company to make the following adjustments to the LCEP to reduce the attendant risks to consumers.

1. **Redirect funds to more cost-effective uses:** The OEB should require that the Company to reduce the LCEP portfolio targets by a factor of 4, cap the price at $25.58/GJ, and redirect the savings to expanded energy efficiency. The 2026 target would be reduced to 0.25%, increasing by 0.25% per year to a total of 1% in 2029.
2. **Maximize ratepayer benefits:** The LCEP should exclusively procure new RNG supply (not recontract for existing supply) and heavily prioritize the development of Ontario-based RNG sources to increase overall supply and maximize long-term benefits.
3. **Achieve the most cost-effective GHG reductions:** The LCEP should procure RNG based on the cost per tonne of avoided lifetime GHG emissions to reflect the major variance in carbon intensity of different RNG sources and to minimize the cost of carbon emissions reductions.

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[51] Exhibit 4, Tab 2, Schedule 7, p. 31.
[5252] Exhibit I.4.2-ED-48, p. 3.

5. System Pruning and IRP

1. Overview

In its Phase 1 Decision, the OEB found that the energy transition – the decarbonization of the gas system to address climate policy goals – "poses a risk that assets used to serve existing and new Enbridge Gas customers will become stranded." To help address that concern, the Board directed Enbridge to consider a range of measures – including "pruning" of the existing gas system to avoid potential asset replacement.[53] The Board also suggested that system pruning – which would require all existing customers served by a pipe or other gas distribution system asset to fully electrify – could be considered in the context of its IRP policy, whereby Enbridge provides financial incentives to customers to defray the cost of their conversion to electric heat and other electric end uses.[54]

In its Phase 2 filing, Enbridge addresses the Board's direction on system pruning by stating it plans to work with the current IRP Work Group to "consult on system pruning processes and what role the Company could play in a system pruning pilot."[55] The Company suggests that "system pruning will require further analysis to determine the conditions under which it could be an appropriate IRPA"[56] and that "the development of an IRP system pruning pilot will require time…to work through a comprehensive proposal, including of coordinated stakeholder engagement."[57]

As detailed below, we recommend that the OEB require that Enbridge develop its approach to system pruning in consultation with the IRP Working Group within 6 months and begin implementation on a small pilot within 12 months. This is possible because Enbridge can leverage its existing IRP framework. Further, if the pilot is relatively small and inexpensive, which may be likely, an application for formal approval would not be necessary or reasonably justified. Without these specific directions, progress will be far too slow, and the next steps will be inconsistent with the Phase 1 decision.

2. Concerns with Enbridge's Proposal

Conceptually, Enbridge's suggestion that there be discussions within the existing IRP Working Group process about how to proceed with consideration of system pruning as a form of an IRPA is reasonable. That said, we are concerned that IRP Working Group engagement on system pruning could be drawn out over an unnecessarily long period of time, potentially delaying for years the point at which a system pruning project is launched.

Part of that concern is the unreasonably long amount of time it has taken Enbridge to launch a standard (non-pruning) IRPA pilot project. As part of its order in the IRP proceeding (EB-2020-0091), the Board approved IRP pilot projects and stated that it "expects the IRP pilots projects will be selected and deployed by the end of 2022."[58] That was within about 18 months of the Board order. Unfortunately, we are now three years after that Order and no IRP pilot has been initiated yet. Though Enbridge has "selected" one and recently filed it for regulatory approval, it is unclear whether deployment will begin by the end of this year – or two years after the Board's initial deadline. While the Company might point

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[53] Ontario Energy Board, Decision and Order, EB-2022-0200, December 21, 2023, p. 2.
[54] Ibid., p. 51.
[55] Exhibit 1, Tab 17, Schedule 1, p. 18.
[56] Exhibit 1, Tab 17, Schedule 1, p. 22.
[57] Exhibit 1, Tab 17, Schedule 1, p. 23.
[58] Ontario Energy Board, Decision and Order, EB-2020-0091, July 22, 2021, p. 90.

to a variety of factors as causes of the delay, we have concluded that at least part of the issue is that the Company was slow in developing, presenting and refining project proposals. It may have also "let the perfect be the enemy of the good", wanting to analyze and re-analyze and discuss potential projects concepts before proposing them for approval. That is particularly problematic when the principal goal of pilots is to learn by doing. Put simply, we are concerned that an IRP Working Group process for consideration of system pruning could mean it is years before anything is actually tested in the field.

Another part of our concern stems from Enbridge's suggestion that there are a whole set of potentially new processes that would need to be discussed and agreed upon within the IRP Working Group before any pruning project can be advanced. In particular, Enbridge has identified the following "system pruning processes" which would have to be developed before even a pilot pruning project can be launched:

- "Binary screening, which would be used to rule out parts of the system where removal of the pipeline segment would cause an impact on safety and/or reliability;
- Technical evaluation to ensure a potential project is technically feasible;
- Stakeholder consultation with the Independent Electric System Operator (IESO), the local distribution companies (LDCs) and the local municipalities in areas where potential candidates for system pruning have been identified;
- Economic evaluation to determine if a potential pruning project is economically favourable; and
- Engaging with the customers attached to the potential candidate pipeline to determine their interest in switching from natural gas to electricity for all of their gas energy uses."

We do not see the need for entirely new processes for many of these issues for system pruning. Put simply, system pruning options can and should largely be considered in much the same way that other IRPA projects are considered. For example, there is no need for an entirely new "technical evaluation process". Conceptually, as long as customers can be severed from the system without causing safety or reliability issues for other gas customers, there should not be technical constraints to pruning. While it may be more challenging to pursue pruning in some cases (e.g., for distribution system segments with many, rather than a small number of customers that would need to electrify), that is not a technical issue. Moreover, the Company could simply start by identifying potential projects on its system that would require relatively few customers to electrify. Similarly, we do not see a need for the Company to have to consult the IESO or local municipalities about such projects. Electrifying a few customers should not affect electric grid loads at a level important to the IESO and local municipalities do not need to be I involved in individual customers' fuel choices. While consultation with the local distribution company could be important to ensuring any local electric distribution capacity constraints are identified, that is no different than the consultation Enbridge presumably undertook as part of its non-pruning IRPA pilot project proposal which included partial electrification of set of customers. It is also unclear why a new process – i.e., different from the current Board approved process for other types of IRPA project – is necessary for economic evaluation. We see no reason that the economic test for a system pruning IRPA should be any different from other forms if IRPA projects.

It should also be noted that though it is not yet commonplace, several jurisdictions have begun to invest in gas system pruning. For example, as noted in a white paper recently published by National Grid (a large gas utility serving customers in several northeastern states) and the Rocky Mountain Institute (a non-profit advocacy organization promoting clean energy), Pacific Gas and Electric has already completed 85 pruning projects in its California gas service territory.[59]

3. Recommendation

We recommend that the Board support Enbridge's suggestion that the IRP Working Group engage in discussions of approaches to system pruning, but that it give Enbridge and the Working Group no more than 6 months to discuss and resolve any issues, with direction to leverage and use existing IRPA processes to the maximum extent possible so that time is not wasted creating unnecessary new processes to starting system pruning projects. If necessary, the Working Group should meet more often – or have a subcommittee meet more often – in order to get any such work done in a timely manner.

We also recommend that the Board require Enbridge to identify, develop and implement an initial system pruning project within 12 months. While that may require some intensive focus from the Company, such direction is probably necessary for the Company to consider this a priority. A system pruning pilot could be very small and below the threshold at which it should be necessary or a good use of resources to require a formal regulatory approval application and process.

Finally, we recommend that Enbridge consider strategies for addressing situations where most customers are prepared to fully electrify but a very small number or portion are not. When that occurs in a situation in which getting all customers to disconnect from the gas distribution system would provide significant economic benefits to gas ratepayers as a whole, it may be appropriate to consider options other than just incentives. One option might be different gas rates for such "hold outs" that would fairly reflect the cost they are imposing on the system. However, consideration of this option should not hold up initiation of small pilot pruning projects for which there are no "hold outs".

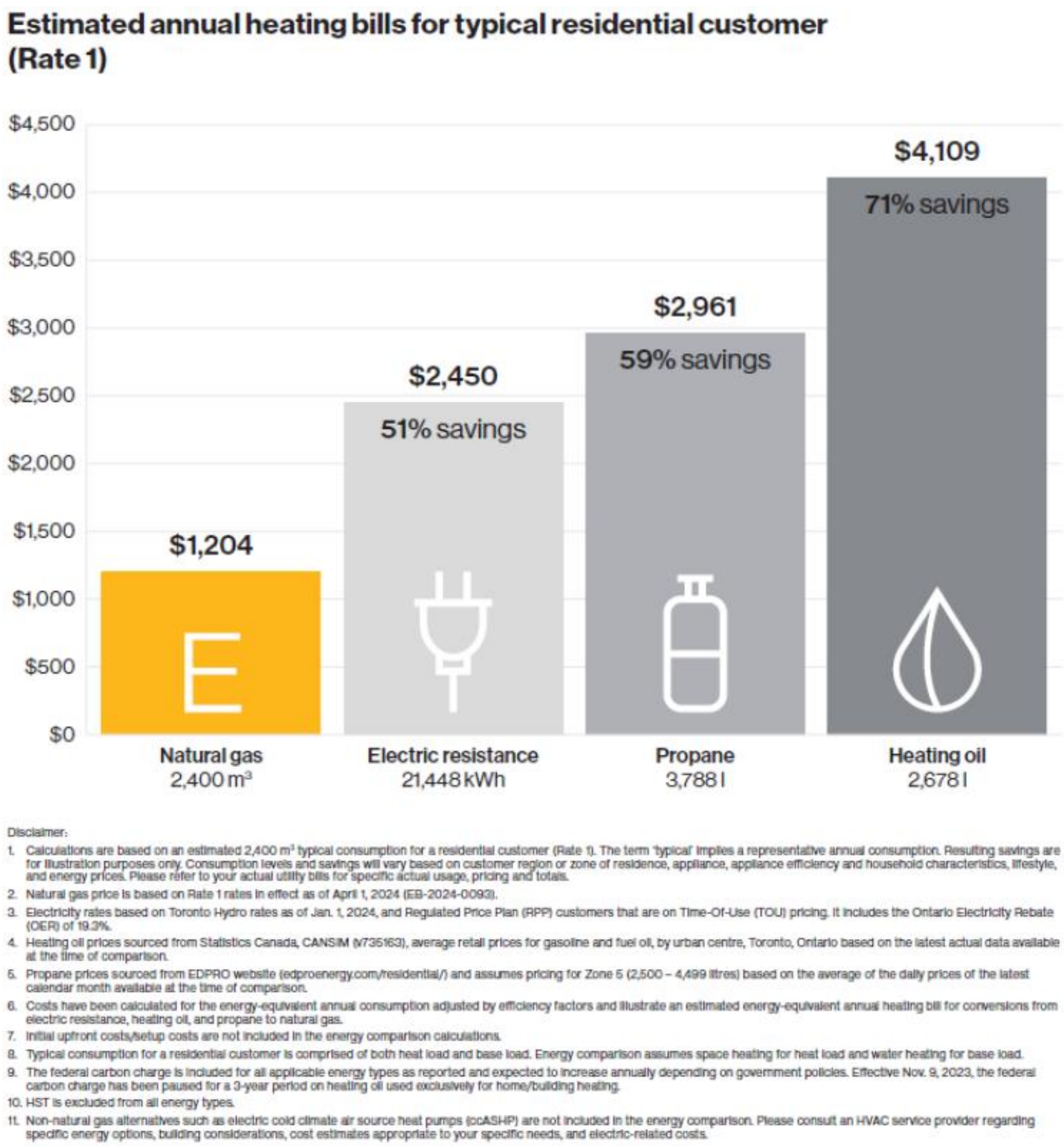
[59] A link to the white paper, as well as links to other gas system pruning references, is provided by Enbridge in Exhibit I.1.17-GEC-6.

6. Residential Heating Fuel Cost Comparison

1. Overview

Enbridge states in its filing that it has reviewed and updated its chart comparing the annual residential cost of heating with different fuels. The updates include more specifically labeling the electric heating option as "electric resistance" heating as well as modifications to language in footnotes addressing the fact that the graph does not address heating costs of electric cold climate air source heat pumps and that the federal carbon charge is expected to increase over time.[60] Enbridge chose not to add to the graph an estimated annual heating cost for customers who heat with cold climate heat pumps (ccASHPs). A copy of the updated graphic is provided for reference as Figure 1 below.

Figure 1: Enbridge's Updated 2024 Residential Annual Heating Cost Comparison



[60] Exhibit 1, Tab 16, Schedule 1, pp. 19-20.

As detailed below, we recommend that the OEB require Enbridge to include heat pumps in its heating fuel cost comparison charts as this would clearly benefit customers by providing them with more and better information, which will in turn enhance customer choice and bill reductions. Enbridge's reasons for excluding heat pumps from the cost comparison are baseless.

2. Exclusion of Electric Heat Pumps from Heating Cost Comparison is Misleading

Enbridge's decision to continue to exclude electric cold climate air source heat pumps (ccASHPs) from its annual heating cost comparisons is problematic for several reasons:

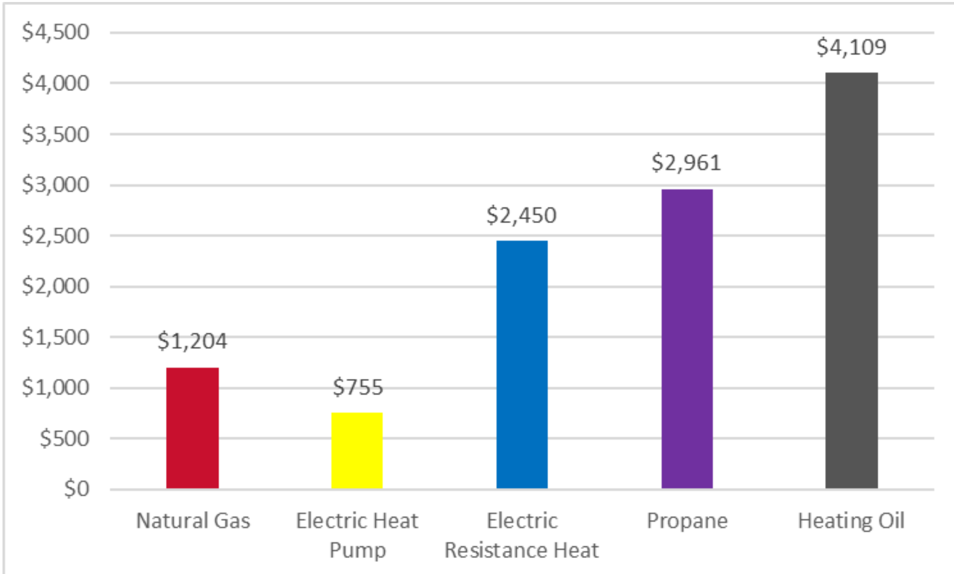
- **Electric ccASHPs have the lowest annual energy bills**. As Figure 2 shows, using all of the same assumptions that Enbridge is using, plus reasonable assumptions about the average seasonal efficiency of ccASHPs and heat pump water heaters,[61] we calculate that ccASHPs can be expected to have significantly lower average annual heating bills[62] than all the other heating fuel options that Enbridge is currently comparing. Indeed, converting from a ccASHP to gas would result in a 59% *increase* in average heating bills.[63] And that is without accounting for the cooling savings that cold climate heat pumps typically provide relative to central air conditioners. Leaving the lowest cost option – and the only option less expensive than gas – out of the comparison, is a disservice to the stated purpose of customer education.
- **Customers considering electric heat would consider heat pumps**. Any customer considering converting to electric heat would almost certainly consider a ccASHP instead of – or at least as well as – inefficient electric resistance heat.
- **Customers with electric resistance heat should consider heat pumps**. Any customer that already has electric resistance heat should consider a ccASHP as an option that could lower their annual energy bills.
- **Dramatic increases in heat pump penetrations are required to meet climate goals**. If Ontario is going to meet provincial and federal GHG emission reduction goals, large portions of the residential building stock is going to need to convert to electric heat provided by ccASHPs.
- **Small print footnotes explaining omissions are an inadequate solution**. Both Enbridge's relabeling its electric option as "electric resistance" and its inclusion of a footnote clarifying that the analysis does not include ccASHPs represent small improvements over previous comparisons, but are far from adequate for truly informing customers about their choices. For one thing, many customers will simply look at the graph and not read footnotes provided in very small print. Second, at least some customers will not really understand what "electric resistance" means and assume that just means heating with electricity. Third, many customers will not be fully aware of the option and benefits of heat pumps.

[61] We used the same average annual efficiency assumptions for ccASHPs (300% for Toronto) and heat pump water heaters (375%) that are being used by Guidehouse in the efficiency potential study it is conducting for the Board. The 300% efficiency value for ccASHPs in Toronto was originally developed by Guidehouse for an analysis it performed for Enbridge.

[62] Note that in its heating bill comparisons, Enbridge includes both space heating and water heating.

[63] Put another way, converting from gas to a ccASHP would reduce energy bills by 37%.

Figure 2: Effect of Adding Heat Pumps to Enbridge's 2024 Residential Annual Heating Cost Comparison[64]



Enbridge's states that the reasons that it has not included an annual heating cost for electric cold climate air source heat pumps is that (1) there is a wide range of potential upfront costs required to convert a home to an electric ccASHP; and (2) it is inappropriate to provide comparisons to ccASHPs without considering grid requirements for serving such equipment. Both of these arguments are fundamentally flawed.

First, Enbridge has made clear that its comparison is only of annual heating bills and not lifecycle costs that would include upfront capital costs.[65] In that context, the fact that there are upfront capital costs associated with conversions to ccASHPs is not relevant. If Enbridge is concerned that presenting comparisons without upfront capital costs may be misleading, then it should just present a comparison with lifecycle costs. Note that such a lifecycle cost comparison would need to account for not only capital costs but also for changes in variable costs, such as the increasing federal carbon charge.

Second, while it is true that there are upfront capital costs required to convert to a ccASHP system, that is also true of conversions from fuel oil, propane and/or electric resistance heat to gas as well. Enbridge has suggested that estimating the average capital cost of ccASHPs is "more complex" than estimating the capital cost of installing a gas furnace because of the potential electrical system upgrades required in some homes. While that may be true for some homes, it will not be true for others. Moreover, there are also unique upfront capital costs required for many conversions to gas, particularly for customers with electric resistance heat but also for some propane and fuel oil heated homes. Most notably, we would expect many of homes with electric resistance heat to require the installation of ducts in order to

[64] This comparison is for space heating and water heating costs. Cold climate air source heat pumps are typically more efficient than central (and/or window) air conditioners. The resulting cooling energy bill savings are not included in this graphic.
[65] Exhibit 1, Tab 16, Schedule 1, p. 4, paragraph 8.

enable the installation of a gas furnace.[66] In addition, some customers would incur upfront costs to connect to the gas system. Finally, in contrast with gas heating systems, ccASHPs provide cooling as well as heating. Thus, they enable customers to avoid the significant capital cost of purchasing air conditioners. Considering all these factors, there will likely be many customers for which the capital cost of converting to a ccASHP will be comparable to, if not lower than the capital cost of converting to a gas furnace.

Finally, Enbridge's suggestion that it should not include heat pumps in its comparison because of uncertainties regarding potential impacts on the electric grid is, at best, misguided. Again, Enbridge has billed its presentation as a comparison of customers annual heating bills, so concerns about potential for added capital costs incurred by electric utilities are not relevant. Moreover, for many potential conversions to heat pumps there will not be any added costs incurred on the grid. That is especially true for homes that were previously using inefficient electric resistance heat. Because they are more efficient, heat pumps will actually reduce grid costs of serving such homes. Also, it is important to recognize that Ontario's electric grid is currently summer peaking. Because cold climate heat pumps are typically more efficient at cooling than the air conditioning systems they would displace, they should provide significant near-term benefits to the grid – both in reducing generating capacity needs and in reducing capacity constraints for the portions of the distribution system that are also summer peaking. Finally, Enbridge's argument about electricity grid reinforcements ignores the fact that its comparison does not account for gas system reinforcements even though switching to gas heating (e.g. from oil or propane) could increase peak demands in areas of the gas distribution system that may require capacity upgrades in the future.

3. Recommendation

The bottom line is that Enbridge's comparison of the cost of different heating fuels intentionally omits the option with the lowest cost for reasons that are not reasonable or defensible. The Board should direct Enbridge to add ccASHPs to the annual heating fuel cost comparison graphs and tables that the Company develops and markets to customers. It would be reasonable to also add a footnote that explains that the capital cost of conversions can vary substantially – and to even list the key potential reasons for such variations. However, any such list of reasons for varying capital costs should be comprehensive and not just focus on reasons ccASHPs can have varying upfront costs. Such a list would include differing costs of different types of heating equipment, costs of installing ducts, costs of

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[66] In Exhibit I.1.16-GEC-8(a), Enbridge suggests that only about one-third of home with electric resistance heat have electric resistance baseboard heat; the Company suggests that most electric resistance heating in the province is supplied by electric resistance furnaces. Those conclusions are based on data reported by Statistics Canada. The data are derived from customer surveys. However, we consider customer reports suggesting that most electric heat is supplied by forced air furnaces to be highly suspect. In our experience, such heating systems are uncommon in North America, with electric resistance baseboard heating being much more common. The problem with reports of high penetrations of electric resistance furnaces is that customers can be confused about what that means. Some customers use the term "furnace" to mean any type of heating system. Some understand that their gas or propane furnace needs electricity to operate, so they may think of such fossil fuel-fired furnaces to be electric furnaces. That all said, even if only one-third of electrically heated customers have electric resistance baseboard heating, that is still a large fraction of customers who might consider switching to a different heating system for which there would still be a significant additional capital cost to convert to a gas furnace.

connecting to the gas distribution system, costs for upgrading electrical panels and/or other electrical systems and potential cost savings from not having to purchase new air conditioners.

7. Conclusions

There is one element that is present in all of the aspects of Enbridge's application discussed in our report, namely a very strong bias in favor of actions that support the continued use of and expansion of gas infrastructure. For instance:

- The ETTF includes long-shot investments in gas technologies while specifically excluding cost-effective electric-only safe bets.
- Enbridge proposes far more spending on RNG than is merited relative to other more cost-effective non-gas solutions.
- Enbridge has not proposed how it will prune its system to avoid asset replacements as the OEB directed and has not even presented a timeline for when it will do so.
- Enbridge excludes heat pumps from its cost comparison materials, even though providing this information would be an extremely inexpensive and effective way to enhance customer choice, knowledge, and benefits.

Our recommendations, summarized in the executive summary above, attempt to put customer interests first, as much as is possible in the context of the proposals that have been included, and not included, in the Company's application.

Appendix A: Varying Carbon Intensities of Different Sources of RNG

In this Appendix we provide three references, including information from the Company's application, indicating the critical importance of considering feedstock source and project specific conditions when estimating the emission reduction impacts and carbon intensity for various RNG sources.

All three of the sources cited in this Appendix recognize manure-based RNG as having potentially negative carbon intensities, meaning it can more than offset GHG emissions from the fossil gas that it displaces. However, only a small fraction of RNG potential – on the order of 12% in the U.S. by 2040 under optimistic RNG assumptions[67] – is from manure. They also recognize that landfill gas has a positive carbon intensity and may not be able to even off-set half of the GHG emissions from the fossil gas that it displaces. This is important because landfill gas is often the least expensive and most readily available source of RNG – accounting for 23% of U.S. potential.[68]

The Company's assumption in the LCEP application that the carbon intensity of RNG can be assumed to be zero is not supported by these tables. Thus, we recommend any RNG procurement be based on more specific estimation using the GREET model or similar life-cycle basis methodology.

1. For their study on the potential for renewable natural gas conducted for the American Gas Association in 2019[69], ICF International recognized the wide range of carbon intensity variability, citing the results in Table 2 below based on modeling using the Environmental Protection Agency's GREET model for California. As the table shows, landfill gas has a lifecycle emissions intensity of 15-34 gCO2e/MJ while agricultural residues, forestry residues, energy crops and municipal solid waste had emission intensities of 25-55 gCO2e/MJ. An emissions intensity of zero means that the fuel would exactly offset emissions from fossil gas, an intensity above zero means the fuel would not fully offset emissions from fossil gas and an intensity below zero means the fuel would more than fully offset emissions from fossil gas. For context, the Canadian government's January 2023 estimate of the lifecycle emissions of fossil gas was 67.78 gCO2e/MJ. In other words, using the midpoints of the ranges provided, most sources of RNG would offset only 40-65% of GHG emissions that would have been emitted from the fossil gas that they displace.

Table 2: Lifecycle Carbon Intensity by RNG Feedstock and Region of the U.S. (g/MJ)

RNG Feedstock	New England	Mid-Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Landfill gas	18 - 26	15 - 21	28 - 34	28 - 32	22 - 26	26 - 28	26 - 31	21 - 32	13 - 29
Animal manure									
Dairy	-304 - -294	-308 - -300	-292 - -285	-292 - -286	-299 - -294	-294 - -292	-294 - -288	-300 - -286	-310 - -290
Swine	-404 - -394	-408 - -400	-392 - -385	-392 - -386	-399 - -394	-394 - -392	-394 - -388	-400 - -386	-410 - -390
Beef / Poultry	36 - 36	31 - 31	46 - 46	44 - 44	36 - 36	38 - 38	42 - 42	44 - 44	41 - 41
Water resource recovery facilities	18 - 26	15 - 21	28 - 34	28 - 32	22 - 26	26 - 28	26 - 31	21 - 32	13 - 29
Food waste	-97 - -82	-104 - -91	-79 - -68	-79 - -70	-90 - -82	-83 - -79	-83 - -73	-91 - -70	-108 - -76
Agricultural residue	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55
Forestry and forest product residue	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55
Energy crops	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55
Municipal solid waste	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55	25 - 55
P2G / Methanation	0	0	0	0	0	0	0	0	0

[67] Renewable Sources of Natural Gas, ICF International, for the American Gas Foundation, December 2019, pp. 66-67.
[68] Ibid.
[69] Ibid., p. 72.

2. In response to GEC-22[70], Enbridge provides the following table, similarly illustrating the wide variability of carbon intensity depending on feedstock. Enbridge's estimates are a little different from ICF's. However, it too found that landfill and waste water treatment sources of RNG would have lifecycle emissions rates that would not come close to offsetting fossil gas emissions – producing only about a 25% reduction in the case of landfill gas and about a 45% reduction in the case of waste water treatment facilities (both relative to the Canadian government's 67.78 carbon intensity factor for fossil gas).

Table 3: Enbridge Estimates of Carbon Intensities of Different Sources of RNG

Carbon Intensities and Production Costs of RNG

Line No.	Feedstock Type	Average Carbon Intensity (gCO_2e/MJ)	Notes	Average Carbon Intensity (gCO_2e/m^3) (6)	Production Cost ($/GJ)	Notes
		(a)		(b)	(c)	
1	Manure	(372)	(1)	(14,148)	19 to 69	(4) (5)
2	Food Waste	(36)	(1)	(1,380)	20 to 37	(4) (5)
3	Landfill Gas	51	(1)	1,927	4 to 20	(4) (5)
4	Waste Water Treatment	38	(1)	1,434	8 to 53	(4) (5)
5	Wood Waste (7)	13 to 16.8	(2) (3)	494 to 638	14 to 31	(2) (3) (4) (5)

Notes:
(1) California Air Resources Board. 2024. Certified Fuel Pathway Table. https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/current-pathways_all.xlsx
(2) Verdant Associates. August 2023. Renewable Natural Gas in California. https://www.energy.ca.gov/sites/default/files/2023-08/CEC-200-2023-010.pdf
(3) Gas Technology Institute. February 2019. Low-Carbon Renewable Natural Gas (RNG) from Wood Waste. https://www.gti.energy/wp-content/uploads/2019/02/Low-Carbon-Renewable-Natural-Gas-RNG-from-Wood-Wastes-Final-Report-Feb2019.pdf
(4) ICF. December 2019. Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf
(5) World Resources Institute. December 17, 2020. Renewable Natural Gas as a Climate Stratety:Guidance for State Policymakers. https://www.wri.org/research/renewable-natural-gas-climate-strategy-guidance-state-policymakers
(6) Converted from gCO_2e/MJ to gCO_{2e}/m^3 using the Clean Fuel Regulations specified energy density for RNG of 38 MJ/m^3.
(7) Derived via gasification.

3. A recent study by McKinsey[71] reinforces the variability of carbon intensity by source:

[70] Exhibit I.4.2-GEC-22.
[71] Renewable Natural Gas: A Swiss Army Knife for US Decarbonization, McKinsey and Company, November 2023, p. 4.

Table 4: McKinsey Estimates of Carbon Intensities of Difference Sources of RNG

Renewable natural gas (RNG) production pathways

	Fossil natural gas	Landfill	Agricultural manure[1]	Food waste	Wastewater
Current US supply potential, million MMBTU[2]/year	603,600	890	1,200	70	95
Actual US supply, 2022, million MMBTU[2]/year	~37,500	~70	~20	~5	~5
Penetration,[3] %	N/A	~8	~2	~7	~6
Carbon intensity range, gCO_2e/MJ[4]	80–90	50–60	<–150	–30 to –80	30–40
Supply cost range, $/MMBTU[2]	3–5	10–15	25–30	20–25	15–20

[1]Includes chicken and swine.
[2]Million British thermal units.
[3]Calculated as supply divided by potential.
[4]Grams of carbon dioxide equivalent per megajoule of energy.
Source: CARB; EIA; McKinsey analysis