OEB Staff Compendium

Panel 3 – Green Energy Coalition / Environmental Defence Panel on Energy Transition (Energy Futures Group)

Enbridge Gas Inc. EB-2022-0200

July 20, 2023

OEB Staff Compendium for EB-2022-0200 Oral Hearing

Index

TAB 1

IV. Protecting Consumers in the Context of Future Decarbonization

While there is always uncertainty about how the future will unfold, it is very likely that decarbonization of the economy (i.e., achieving net zero GHG emissions by 2050) will ultimately mean very high levels of electrification of buildings and, to a somewhat lesser extent, electrification of industrial operations.[106] The uncertainty is when the gas system will begin to shrink, how fast the shrinking will accelerate, and exactly how much smaller the gas system will ultimately become. This reality has major implications for gas distribution system investments that regulatory policy and decisions should address and reflect in order to protect consumers. What follows are discussions of several ways in which the Board should consider addressing and reflecting the likely implications of decarbonization.

1. Modify Policy on New Connections to Reduce Risk of Stranded Assets

Regulatory policy on new connections should be reconsidered in light of the likelihood of extensive electrification and the significant savings customers can achieve by switching from gas to electric heating. The costs of new connections are largely socialized in rates, to be repaid over long periods (40 years) through forecast distribution rate revenue from the newly connected customers. This creates a major risk for existing customers. If new customers convert to all-electric buildings 10 or 15 years from now, the capital cost of having connected them to the Enbridge system will not have been fully recovered under current connection rules, creating a stranded asset that customers still on the gas system will have to pay. The same is true of existing homes or businesses that consider connecting to the gas system today.

In addition, modifying policy on new connections could cause an immediate reduction in rates by reducing gas connection infrastructure costs and/or reducing the portion of those costs borne by existing ratepayers.

The cost of new connections in the context of decarbonization also creates the risk of unfair cost allocation. Even if a new customer remains on the system long enough to pay for the costs to connect them to the system, they would still not have contributed at all to the cost of the remaining system. It is unclear how long they would need to remain with the system in order to pay a fair share of the costs of the gas system, but merely remaining long enough to pay their own connection costs is clearly insufficient.

Also, if most new homes and businesses are ultimately going to have to become all-electric – and/or going to want to become all-electric because of significant cost advantages relative to very expensive biomethane and/or hydrogen – it is much easier and less costly to design and build those homes and businesses as all-electric buildings from the get-go. If they are instead built to burn methane, the task of decarbonizing Enbridge's system will get harder and more expensive because of the additional emission reductions required – with all gas customers collectively absorbing that added cost.

Thus, the Board should consider several policies for both mitigating the risk of stranded or underutilized assets from new connections and leveling the playing field between gas and electricity.

[106] Moreover, even if Enbridge's much less likely vision of the future were to become reality, there would still be considerable electrification, reductions in annual gas throughput and reductions in gas peak demands.

A. Shorten New Construction Connection Cost Recovery Periods

The Board direct Enbridge to shorten new construction connection cost recovery periods. Enbridge is proposing to maintain most of its existing policies with respect to recovering costs associated with connection of new small volume customer buildings – e.g., new residential subdivisions and new small commercial developments. In particular, it is not proposing any changes to the following existing policies:

- **Customer connection horizon of 10 years**. This is the period of time within which a new building must be connected to the gas system in order to be subject to an agreement on any terms regarding costs of connections, including contributions in aid of construction, system expansion surcharges or temporary connection surcharges.
- **Customer revenue horizon of 40 years**. This is the period of time over which additional revenue collected from new connections must be sufficient to cover connection costs minus any initial contributions or surcharges. Note that the comparable horizon for electric connections in Ontario is 25 years.[107]

These policies have been in place since the Board's decision in 1998 in the EBO 188 case. However, our understanding about the future use of the gas distribution system is very different today than it was 25 years ago. As discussed in this report, it is highly likely that many if not the vast majority of existing residential and commercial gas customers will have to electrify in the next couple of decades for the Ontario economy to fully decarbonize. Even in Enbridge's preferred "diversified scenario" from the Guidehouse P2NZ study, 36.5% of existing residential gas customers are assumed to have converted to electric heat pumps by 2040.[108]

In that context, the case for greater certainty about revenue recovery from any new connections – to guard against the risk of stranded assets – is very compelling. Since the typical life of a new gas furnace is estimated to be 18 years, and it is most likely that a customer will electrify at the time that they need to replace their heating system, a maximum customer revenue horizon of 15 years would be much more appropriate. That said, some customers will electrify sooner, such as when they replace a central air conditioner and/or in an effort to save energy costs or to decarbonize.

Given the uncertainty about the pace of decarbonization and its impact on the gas system, it would also make sense to tighten up the maximum customer connection horizon. A reduction from 10 years to the 5 years used on the electricity system is reasonable.

It is worth noting that Enbridge has estimated that reducing the maximum customer revenue horizon to 15 years would reduce system access spending by about $600 million over the 2024-2028 period.[109]

B. Reduce Infill Connection Costs Funded by Rates

A similar change is warranted for infill connections. The portion of the infill connection costs covered by rates should be limited to those costs that would be recouped over 15 years. In contrast, Enbridge's proposed harmonized connection policy would fund the majority of infill connection costs from rates (e.g. the meter and up to 20 meters of service line) even though this cost would not be recovered from

[107] www.oeb.ca/oeb/_Documents/Regulatory/Distribution_System_Code_AppB.pdf
[108] JT1.28, Attachment 3, "DivScen_Assumptions" tab, rows 23-24.
[109] JT5.21, p. 3.

TAB 2

Environmental Defence Opening Statement Outline

1. Declines in demand are certain; massive declines are possible

(a) Fossil gas: a major source of GHG emissions

- Combustion of fossil gas = ~33% of Ontario's emissions
- Upstream and BTM leaks are undercounted; may make gas as bad as burning coal
- Huge fossil gas reductions required to meet climate targets

(b) Low carbon gases cannot replace fossil gas

- Potential RNG volumes are far too low due to limited feedstocks (~2.5% throughput)
- Hydrogen blending potential is extremely limited (between 0.6% and 6% at best)
- 100% hydrogen is not feasible for most customers (b/c it needs new/larger pipelines and massive coordinated simultaneous changeovers)
- Hydrogen for industry may use on-site electrolysers, not provincial pipelines

(c) Markets and price signals are likely to drive electrification

- All-electric heat pumps are now far cheaper than traditional gas heating (lifetime and annual costs) – over $10k in lifetime savings
  - All-electric is even cheaper when compared to use of low-carbon gases (RNG/H2)
  - All-electric is also cheaper than hybrid gas-electric heating
- Gas heat pumps are not cost-effective nor market available

(d) Government policy supports electrification

- *Canadian Net-Zero Emissions Accountability Act* mandates targets and plans
- Federal gov't projects 41% decline in building emissions by 2030 (from 2019)
- Net-zero electricity generation by 2035
- New York State: Fossil gas ban for new construction

(e) Pathways studies find significant gas declines

- Independent studies: high electrification pathway is cheapest and least risky
- Gas-sponsored studies: promote hybrid heating, but still predict demand declines
- Guidehouse study: fundamentally flawed, but its "electrification" scenario is still cheapest even if a few errors are corrected

2. Actions needed now to protect customers

(a) Priority #1: reduce capital costs

- Rate base slated to grow by $2 billion over 2024 to 2028
- Capital invested today is not paid off until the 2080s
- Risks: rising rates, underutilized/stranded assets, and possible death spiral

(b) Customer connections: moratorium on subsidized new connections

- Existing ratepayers to pay $1.3 billion for new customers' connections over 2024-28
- Existing ratepayers should pay $0 in new connection costs
  - Mitigate stranded asset risk
  - Consistent with "beneficiary pays" principle
  - Improved fairness
  - Necessary to slow rate base growth
- Alternatively, reduce subsidy from 40 to 10 years of revenue

(c) Capital planning: account for risk of underutilized/stranded assets

- Project economics must account for the risk of declining demand
  - E.g. Calculate PI based on weighted average of three demand scenarios
- Current practices assign 0% risk of decline in PI calculations
- May mean that: (a) a growth project is not cost-effective, (b) a growth project requires greater CIACs, or (c) repair is chosen over replacing a pipeline

(d) Depreciation: account for risk of demand declines

- Current approach:
  - Assumes 0% chance of underutilized/stranded assets
  - Allows for continued rate base growth
  - Risk of future rate increases, unaffordability, death spiral, and inequities
- Need interim increases and a new approach that:
  - Accounts for future demand scenarios (e.g. economic life is based on weighted average of three demand scenarios)
  - Ensures costs are paid off before demand drops and customers exit
- Need to act asap to mitigate risks and avoid rate spikes

(e) Site restoration costs: need a segregated fund

- Ratepayer dollars held by Enbridge for SRC: $1.6 billion
- Estimated cost to decommission all assets today: $6.9 billion
- A segregated SRC fund is needed to:
  - Mitigate risk of non-payment in death spiral situation
  - Increase ability to allocate stranded asset risk to Enbridge
- CER provides a good precedent

(f) Take actions consistent with all futures

- Integrated resource planning: allow electric non-pipe alternatives, where cost-effective
- DSM programs: expand access with instant rebates and upstream incentives
- Diversify into geothermal and district heating
- Strategic pruning: where costly replacements are required, help ratepayers and participating customers save via neighbourhood electrification, where cost-effective

TAB 3

those customers' distribution charges until after 2050.[110] If the new customer converts to all-electric buildings 10 or 15 years from now, the capital cost of having connected them to the Enbridge system will not have been fully recovered under current connection rules, creating a stranded asset that customers still on the gas system will have to pay. Even if they stay just long enough to pay off their individual connection costs, they would have had a "free ride" by not contributing any costs to the overall system beyond their own service line and meter.

C. Require All New Connections to Be Net-Zero GHG

From a public policy perspective, there are compelling arguments for a moratorium on new gas connections. Indeed, the state of New York just enacted legislation that would ban the use of fossil gas and other fossil fuels in most new buildings.[111] An alternative to a new connections moratorium would be to require that (1) all new gas connections be heated with hybrid systems comprised of cold climate electric heat pumps with gas furnaces used only for back-up heat on the coldest hours and days of the year; and (2) all of the gas supplied on those coldest hours and days of the year will be net-zero GHG-emitting with the new customers bearing the full cost of that more expensive gas (i.e., without cross-subsidies from existing gas customers).

Energir, the Quebec gas utility, recently announced that it will seek approval in its next rate case for a similar, though less restrictive policy. It would give potential new customers the option of either a 70% electric / 30% RNG option or a 100% RNG option.[112] Given the significant limitations on RNG availability, it would be more prudent to limit this offer, at least for residential and commercial buildings, to cold climate electric heat pump-gas furnace systems in which the electric heat pump delivers much more than 70% of heating needs – probably 90% or more – in most of Ontario.

2. Align Depreciation and Rate Design with Expectation of Declining Gas Throughput

The proposed approach to depreciation is highly problematic because it does not address decarbonization risks at all and implicitly assumes a 0% risk of underutilized or stranded assets even long past 2050. Given the almost certain inter-generational inequities that will arise from decarbonization of the gas system in Ontario under the Company's current or proposed approach to asset depreciation, the Board should consider and implement alternative approaches. Specifically, the Board should require Enbridge to assess near-term and longer-term rates, costs of capital and inter-generational equity impacts of (1) maintaining its currently proposed Equal Life Group (ELG) depreciation method, (2) adopting an Economic Planning Horizon (EPH) for new assets, (3) adopting an EPH for all assets, and (4) switching to a Units of Production (UOP) method of asset depreciation. That analysis should be performed using load forecasts consistent with the most likely decarbonization pathway or pathways.

The Board should require that Enbridge file this analysis in 2024. It is important that this happen as soon as it reasonably can. The longer we wait, the closer we get to the point when gas sales are likely to decline, reducing the ability to mitigate against inter-generational inequities. Also, the longer we wait, the greater the short-term adverse effect on customers still on the system. For example, Enbridge estimates that adopting a 2050 EPH in 2024 would increase the amount of revenue required to be collected from ratepayers in that year by $257 million, but waiting to adopt a 2050 EPH until 2028 will

[110] JT3.11.
[111] https://www.washingtonpost.com/climate-environment/2023/05/03/newyork-gas-ban-climate-change/.
[112] https://www.energir.com/en/about/media/news/vers-la-carboneutralite-des-batiments/

result in an increase of $342 million and waiting until 2030 will result in an increase of $405.[113] In other words, there is an opportunity cost to waiting to make changes to depreciation approaches.

As the earlier sections of this report make clear, much of the existing Enbridge Gas distribution system – particularly the parts of the system predominantly serving residential and commercial buildings – will be used much less in a decarbonized future than they are today. For example, as shown in Table 1 (section II((2)(F) above), decarbonization studies generally suggest annual gas sales to residential, commercial, and industrial customers will decline by 70-90% or more by 2050. Even the fundamentally flawed and biased study conducted by Guidehouse for Enbridge suggests that gas sales to residential and commercial customers will decline dramatically by 2050.[114]

Put simply, decarbonization is likely going to result in far fewer gas customers paying for undepreciated gas asset costs than are paying for them today, with the cost of those assets being recovered over a much smaller volume of gas sales than is the case today. At best, this raises a serious concern about inter-generational equity. It could lead to what is sometimes called a "death spiral" in which increasing electrification leading to higher gas rates drives even more customers to electrify with only those customers least able to afford to leave the system left paying for it. That kind of feedback loop and its effects on levels of electrification is typically not accounted for in decarbonization studies.

In its filing, Enbridge has proposed a shift from an "Average Life Group" (ALG) approach for depreciating gas assets to an "Equal Life Group" (ELG) approach. Enbridge's consultant, Concentric Energy Advisors, explains that the new ELG approach will create greater inter-generational equity than the current Enbridge ALG approach by better aligning the timing of asset cost recovery with the mix of different expected lives of the different assets within an asset group.[115] That is a good thing. However, it is important to recognize that the ELG approach only addresses one form of inter-generational inequity – accounting for the fact that some types of equipment have shorter lives than the average life of all equipment with which they are grouped. It does not address inter-generational inequities associated with the likely decline in the level of use of assets in the future relative to today.[116]

Enbridge states that it considered the potential for introduction of an "Economic Planning Horizon" (EPH) which would require that recovery of all past and new capital investments be achieved by a fixed date – e.g., 2050 – in order to account for the impact that the energy transition would have on the economic life of Enbridge's assets. The Company concluded that an EPH "is not appropriate at this time" because of the possibility that low carbon fuels such as biomethane and hydrogen would be "viable sustainable alternatives" to fossil gas. Enbridge pointed to the Guidehouse P2NZ study as evidence that its gas system "will be a key contributor to achieving net-zero in the province."[117] Those statements

[113] JT4.17.
[114] Under its Electrification Scenario, Guidehouse estimates total annual gas sales to residential and commercial customers to be nearly 90% less than in 2020; even under its Diversified Scenario, total annual gas sales to residential and commercial buildings are estimated by be about half as large as in 2020. (E1/T10/S5/Attachment 2, p. 29 of 86) Moreover, much of the remaining gas throughput will be hydrogen, most if not all of which will have to be delivered through new dedicated hydrogen distribution pipes rather than existing methane distribution pipes.
[115] E4/T5/S1 Attachment 1, p. 15 of 451.
[116] In response to a question from GEC attorney David Poch, Larry Kennedy of Concentric Energy Advisors confirmed that their current study did not adjust ELG for the impacts of future declines in gas throughput. Transcript of Technical Conference, March 27, 2023, p. 127, lines 7-19.
[117] E1/T10/S4 p. 18 or 20.

ignore the reality that even the gas utility's most optimistic view of the future will involve significant loss of customers and gas energy sales. They also do not account for the fundamental flaws in the Guidehouse report, discussed above.

Enbridge's consultant, Concentric Energy Advisors, also addressed the potential application of an EPH. Concentric observed that "while there is strong evidence that the future of natural gas in Ontario may be impacted by climate change legislation, it is still unknown to what extent this change will impact EGI's system." Concentric concluded that additional study of the changes that climate policy will have on Enbridge should be undertaken before adopting an EPH.[118] This response is less than satisfying. While it is certainly true that there is some uncertainty about the future impacts of the energy transition on the gas utility, the uncertainty is more about the magnitude and precise timing of the decline in use of the system, not whether there will be a decline. Furthermore, an EPH can be adjusted over time.

Concentric acknowledges that "intergenerational equity would require that the original cost of investment of an asset is recovered by the customers who gain the benefit of the assets." However, it suggests that an EPH is not the appropriate mechanism to address intergenerational inequities resulting from a substantial reduction in customer load because some customers will still be using the assets after the EPH cut-off date.[119] Concentric is suggesting that if gas assets will not be retired, there would be an inter-generational inequity associated with the fact that the much smaller number of customers still using the gas system after 2050 would benefit – at the expense of current customers and those still on the system through 2050 – if an 2050 EPH were adopted. However, Concentric never addresses why that inequity should rule out adoption of an EPH while the inequity associated with future customers paying much more for an asset per unit of gas energy consumption does not rule out use of a ELG approach to depreciation that does not account for such reductions in energy throughput. Surely it is possible that the inequity of post-2050 customers getting a "free ride" would be outweighed by the increase in equity resulting from assigning a larger portion of the costs of gas assets to the 2020s and even the 2030s when many more customers are using the system. Note that New York regulators recently required gas utilities in that state to file depreciation studies that examine several scenarios, including one in which all new gas assets are fully depreciated by 2050 and another in which all gas assets are fully depreciated by 2050. These studies are intended to "inform future discussions of how best to recover costs of assets and reduce potential stranded costs in the LDC's respective rate proceedings."[120]

Concentric did suggest a potential alternative to EPH as a way to address inter-generational inequities caused by gas customers exiting the system and gas sales declining over time: a "units of production" (UOP) depreciation method.[121] Under a UOP, annual depreciation expense is proportional to expected usage in a given year relative to total expected lifetime usage. As explained during the Technical Conference, this method may offer greater flexibility to periodically adjust for evolving expectations

[118] E4/T5/S1, Attachment 1, p. 19 of 451.
[119] Response to GEC-66c.
[120] State of New York Public Service Commission, Order Adopting Gas System Planning Process, Case 20-G-0131 and Case 20-G-0297, May 12, 2022, pp. 61-62.
[121] Response to GEC-66d.

about changes in use of the gas system.[122] The challenge would be in reaching agreement on estimates of expected long-term changes in gas consumption.

UOP depreciation is beginning to be considered in some other jurisdictions. For example, Pacific Gas and Electric (PG&E), a very large dual-fuel utility in California, proposed in its 2023 general rate case application that its regulators approve a proposal "to use the units of production method of cost recovery for depreciation of PG&E's gas distribution facilities due to the anticipated reduction in throughput as the state reduces its reliance on natural gas as a fuel."[123] Similarly, the Massachusetts gas utilities recently provided the following recommendation to their regulators:

> *The Department should investigate the role of accelerated depreciation to align cost recovery of gas distribution costs with the utilization of the distribution system rather than the useful life of the assets that make up the distribution system. The Consultants offered an example, known as Units of Production ("UOP") depreciation method. The UOP method is recognized by the National Association of Regulatory Utility Commissioners. The LDCs encourage the Department to investigate this cost recovery option in order to mitigate customer affordability and equity concerns to the extent that gas customers decrease over time as the LDCs pursue decarbonization and electrification strategies.*[124]

Regardless of the specific approach taken, it is important that steps be taken as soon as possible to align depreciation approaches with the likely declines in gas throughput to ensure equity and ongoing affordability.

3. Require Assessment of Repair vs. Replace Trade-offs for Aging Pipe

One important way to reduce the risk of stranded or under-utilized gas system assets, and related long-term adverse gas rate impacts, is to reduce the magnitude of new investment in such assets – whenever that can be done safely, without significant risk of system reliability problems and at reasonable cost. Put simply, there is an economic value to "buying time" by deferring capital investments in gas distribution system infrastructure when there is a known and substantial risk that those assets could become stranded or under-utilized. That value should be reflected in regulatory decisions on such investments.

To that end, the Board should require Enbridge to explicitly assess the potential for repairing (whenever that is feasible) rather than replacing aging pipes – and to conduct that assessment in a way that accounts for the possibility that a new pipe will be underutilized or stranded before the end of its life. Such assessments should include estimates of any potential near-term cost savings and related differences in rate impacts, any potential differences in long-term costs and rate impacts, the magnitude of any differences in methane leaks, the nature of any differences in safety risks, differences between how long repairs would last relative to life of a new pipe, the long-term potential to prune the gas system so that the pipe is no longer needed in the context of future decarbonization pathways, and other relevant factors. That kind of analysis would enable the utility, stakeholders and the Board to

---

122 Technical Conference, March 27, 2023, p. 128 line 26 through p. 129 line 6.

123 PG&E, 2023 General Rate Case Application, June 30, 2021, p. 10.

124 Massachusetts Gas LDCs, Common Regulatory Framework and Overview of Net Zero Enablement Plans, regulatory proceeding D.P.U. 20-80, p. 21 (https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14633273).

TAB 4

routinely assess cost, stranded/under-utilized asset risk, and other trade-offs of a repair vs. replace decision. For example, it may be reasonable to accept a shorter-term fix with lower cost for 10-15 years (and perhaps even again in another 10-15 years) if there is any chance of eliminating the need for the pipe replacement by pruning the gas system over the next couple of decades.[125]

4. Improve IRP to Reduce Risk of Stranded/Under-Utilized Assets

A second important category of capital investments is upgrading the capacity of pipes to ensure reliability can be maintained for growing methane peak demands. Two years ago, the Board issued an order on Gas Integrated Resource Planning (IRP). However, our collective understanding of the potential implications of the energy transition has evolved significantly since evidence was presented in that case. Thus, at least two modifications to the policy the Board put forward in that case should be considered in this proceeding.

A. Removing Prohibition on Electrification Measures as IRPAs

The Board should remove the current restriction on considering electrification measures as potential IRPAs. IRPAs are the term used in the OEB policy for non-pipeline alternatives to distribution needs. Gas utilities in other jurisdictions have begun to assess and even propose IRPAs that include electrification in order to cost-effectively avoid expensive gas distribution system upgrades. Concern about the risk of stranded gas assets, given the likely shrinking of the gas system as economies decarbonize, has been an important part of the context for those developments. For example, last year Pacific Gas and Electric Company (PG&E) proposed a pilot project in which it would retire a natural gas pipeline by electrifying 1200 housing units on the California State University Monterey Bay campus. As the Sustainability Director for the University stated "As California shifts to electrification, any new investments in natural gas infrastructure risks becoming a stranded asset. It is like buying a fax machine in 1999."[126] "PG&E estimates that the cost to gas customers to complete this alternative zonal electrification work will be less than the cost to replace the gas system."[127] Further, "the net present value of cash costs of electrification for…the Project have a value of $14.4 million, and the value of the benefits of the Project (i.e. avoided costs of conventional gas pipe replacement) are approximately $15.4 million, resulting in a net benefit of approximately $1.0 million to customers."[128] A regulatory decision on the case is still pending.

B. Require Analysis of IRPAs Under Multiple Possible Future Load Forecasts

Load forecasts drive determinations of needs to upgrade gas transmission and/or distribution system capacities, the timing of those needs, the extent to which deployment of IRPAs could defer such needs, and therefore the relative cost-effectiveness of traditional supply and IRPA solutions to addressing the need. To date, the load forecasts that Enbridge has used to assess needs have not reflected the potential for peak demands to begin to decline in the future as climate policy and related market trends accelerate electrification. To be fair, Enbridge needs to ensure that its customers' peak hour energy needs are met, so it cannot rely on uncertain estimates of when gas demand will begin to decline in

---

[125] Note that the pruning of the methane delivery system could be enabled either by electrification of a neighborhood or community and/or by bringing new 100% hydrogen pipe to the area.

[126] https://csumb.edu/news/news-listing/east-campus-may-become-californias-largest-electrification-project/

[127] Ward, A. & Pendelton, J. (August 10, 2022). Application of Pacific Gas and Electric Company (U 39 G) for Approval of Zonal Electrification Pilot Project and Request for Expedited Schedule. Filed before the Public Utilities Commission of the State of California. P. 1.

[128] Ibid. P. 4.

identifying potential capacity needs that must be addressed. However, it can and should consider those uncertain futures when assessing the relative merits of different approaches – both traditional supply investments and IRPAs – to meeting those potential needs. The Board should require them to begin to do so. More specifically, the Board should require that Enbridge examine the need for capacity upgrades and assess the relative cost-effectiveness of IRPAs – both rate impacts akin to Phase 1 of the recently approved IRPA cost-effectiveness framework and customer and societal impacts akin to Phases 2 and 3 of the framework[129] – under both Enbridge's traditional load forecast and under a forecast (or two) of accelerating electrification consistent with decarbonization pathways studies. A conceptual illustration of how such scenario analyses could framed is presented in Appendix B to this report.

5. Segregated Fund for Site Restoration

There are compelling arguments for site restoration funds to be moved to a protected and segregated fund as the need for a future gas pipeline system is increasingly in question. The obvious rationale is to protect future customers and taxpayers from this future liability, including in a "death spiral" scenario (discussed above). The risk is material and the potential magnitude of the risk is in the billions of dollars. However, I have not attempted to determine the net financial impact on customers. I recommend that the issue be addressed in the next phase of this proceeding based on a deeper analysis by a third party that would provide a full and balanced examination of the cost impacts and recommendations on the design and implementation of a segregated fund that would maximize returns on funds held for site restoration costs, minimize administration costs, and minimize liability for customers.

6. Reduce Capital Spending Where Possible

The risk of underutilized and stranded assets calls for additional efforts to reduce capital spending, wherever that is possible, especially on long-lived infrastructure. A number of my recommendations will achieve that end, but could be others. Utilities and regulators always should seek to avoid unnecessary capital spending, but even greater scrutiny is required in the current context.

V. Conclusion

Major declines in peak and annual gas demand are very likely in the future as efforts to decarbonize the Ontario economy accelerate. This is the conclusion of most independent decarbonization pathways studies. It is also consistent with an analysis of the availability and feasibility of the electric and gas technologies required for net zero greenhouse gas (GHG) emissions and the current cost effectiveness of electrification. It is even consistent with results of Enbridge's own decarbonization study if just one of the most glaring of the many flaws in the study is corrected.

The potential implications of declining gas peak demand and gas sales are significant and important. In a nutshell, there is a growing risk that current and any new gas capital assets will become underutilized, if not stranded. This creates significant risks for the ratepayers who would be saddled with paying for those assets in the future. It will likely also create significant inequities between customers today and those left on the system in the future.

To mitigate these risks, we recommend that Enbridge and/or the OEB take the steps in section IV of this report above.

[129] Including changes to Phases 1, 2 and 3 of cost-effectiveness framework proposed by Gas IRP Working Group.

Appendix B: Hypothetical Example of IRP Scenario Analysis

In many respects, the most important aspect of risk for gas infrastructure investments today is the potential for climate policy to (1) render such investments unnecessary, at least in the medium to long run, if gas demands are going to decline because of either increased electrification and/or much higher gas prices associated with renewable gas; and (2) add value to efficiency resources and electrification because of both avoided future carbon emission compliance costs (beyond those currently reflected in carbon taxes) and/or higher avoided costs of gas associated with low-GHG gases. Conceptually, one can conceive of three potential futures related to climate policy:

1. Canada does not follow through on its commitment to achieve net zero greenhouse gas emissions, or at least lowers its ambition and imposes no new requirements on fossil gas;
2. Canada follows through on its net zero emission commitments, adopts additional policies requiring increasingly stringent reductions in the consumption of fossil gas, and those requirements are met with a combination of electrification and low-GHG gases; and
3. Canada follows through on its net zero emission commitments, adopts additional policies requiring increasingly stringent reductions in the consumption of fossil gas, and those requirements are met largely with electrification of gas end uses.

Enbridge could be required to estimate how the need for an infrastructure capacity upgrade would be affected under each of these scenarios, how gas prices would likely change under each of them, and how the resulting net present value of net benefits from investing in non-pipe solutions would change under each. Of course, there could be hybrids of the three scenarios as well. And there could be variations on the second and third scenarios in terms of the timing of requirements. Such hybrids and variations could also be considered.

A hypothetical example can help to conceptually illustrate the importance of multiple scenario analyses. Consider the three scenario assumptions in Table 12, along with the related graphic depictions of demand growth without non-pipe solutions in Figure 6, and with non-pipe solutions in Figure 7. As Figure 6 shows, under the electrification scenario the duration and the magnitude of the need for additional capacity is very different than under the other two scenarios. As Figure 7 shows, because the maximum load without a non-pipe solution never gets to be more than 4% higher than the existing capacity, it is possible to completely eliminate the need with five years of a non-pipe solution.

Table 12: Hypothetical Characterization of Three Scenarios for Gas Infrastructure Need

Scenario		2024 Peak Demand	Max Capacity w/o Upgrade	Annual Demand Growth				Max Annual EE IRPA Savings	Year Upgrade Needed w/o IRPA	Upgrade Deferral Year w/Max EE
				2025 to 2029	2030 to 2034	2035 to 2039	2040 to 2044			
1	Business as Usual	94	100	2.0	2.0	2.0	1.0	1.0	2027	2030
2	GHG Regs - Electric/RNG/H2	94	100	2.0	1.5	-1.0	-2.5	1.0	2027	2031
3	GHG Regs - Electrification	94	100	2.0	0.0	-6.0	-6.0	1.0	2027	indefinitely

Figure 6: Peak Loads Relative to Maximum Capacity without Non-Pipe Solution

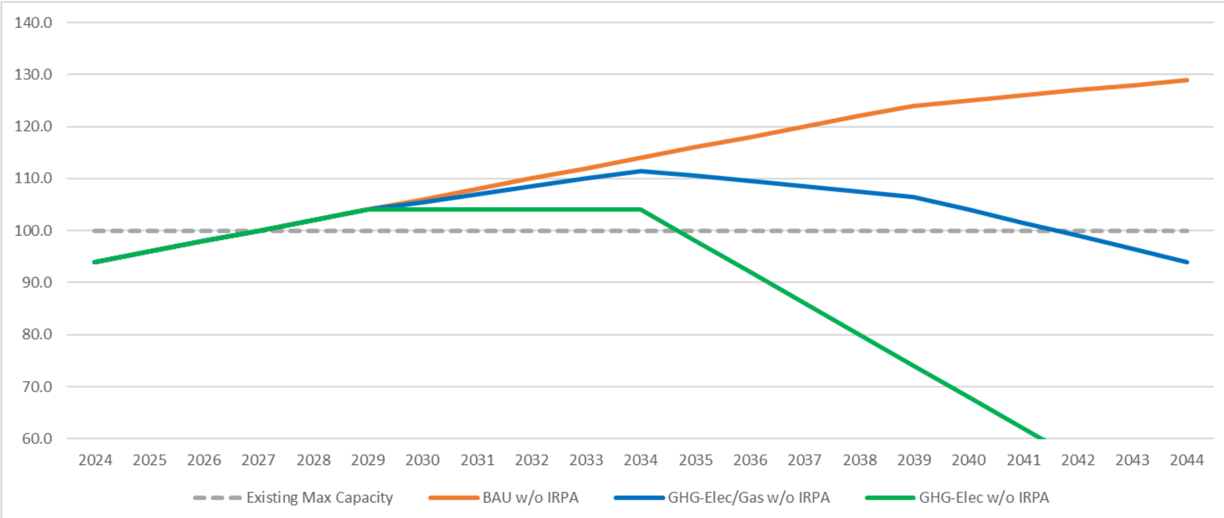
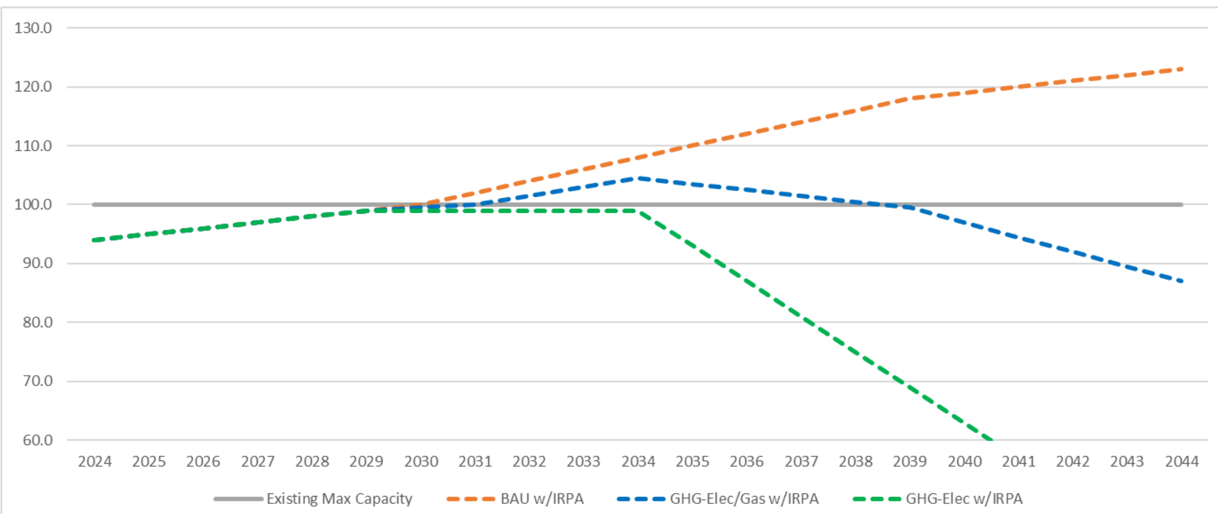


Figure 7: Peak Loads Relative to Maximum Capacity with Non-Pipe Solution[130]



Importantly, different scenarios could not only affect the viability a non-pipe solution for addressing reliability needs; they could also affect the economics of non-pipe solutions. Consider the hypothetical societal economics of the non-pipe solution scenarios example presented in Table 13. In this simplified example, the cost of the infrastructure upgrade is $100 in 2024 dollars (column a), which translates to a net present value (NPV) of $89 (column g) if installed in 2027 – assuming a 4% real discount rate. The cost of the energy efficiency IRPA is $20. However, energy efficiency has non-T&D deferral benefits such as avoided energy costs. The hypothetical value of those additional benefits is $16 in the Business as Usual (BAU) scenario. Put another way, the value of the T&D deferral benefit would need to be greater

[130] Non-pipe solutions are assumed to run only for as many years as they can defer the infrastructure investment or – for the electrification scenario – for as long as needed before naturally-occurring (including policy driven) demand reductions without non-pipe solutions are enough to eliminate the need for continued IRPA investment.

than $4 per year of non-pipe solution deployment in order for the non-pipe solution to be cost effective to Enbridge customers as a whole and/or society.

Under the BAU scenario, six years of the non-pipe solution – from 2024 to 2030 – would be required to defer the T&D upgrade by three years from 2027 to 2030. If the upgrade is deferred to 2030, the NPV of the project cost would decline to $79 (column h), or a $10 savings (column i). That T&D deferral benefit is not enough to cover the $21 NPV difference (column f) between six years of the non-pipe solution cost and the other non-T&D benefits provided by the efficiency programs, so the non-pipe solution would not be cost-effective. However, the non-pipe solution would be cost-effective under either of the Greenhouse Gas (GHG) regulation scenarios. In the electrification/low-GHG gases scenario, the reason is that the value of avoided energy costs (column c) is assumed to be 50% greater (because of assumed very high cost of low-GHG gases) as under the Business-as-Usual scenario, making the efficiency investments cost-effective even without any T&D deferral benefit ($12 in savings per year). In the electrification scenario, though avoided energy costs are the same as in the BAU scenario, the fact that electrification lowers peak demand relative to the BAU scenario means that the non-pipe solution completely eliminates the need for the infrastructure project. That has much greater value (column i) than just deferring it (as in the other two scenarios).

Table 13: Hypothetical Scenarios of Non-Pipe Solution Cost-Effectiveness [131]

	Scenario	Cost of Infra-Structure Upgrade (2024 $) (a)	EE IRPA Annual Cost (b)	Cost Savings (Excl T&D) from 1 Year of IRPA (c)	Net Cost (Excl T&D) from 1 Year of IRPA (d)	Years of EE IRPA Required (e)	Net Cost (Excl T&D) from Multiple Years of IRPA (f)	NPV of 2027 T&D Upgrade w/o IRPA (g)	NPV of Deferred T&D Upgrade w/IRPA (h)	NPV of IRPA Deferral Benefit (i)	NPV of Total Net Benefits of IRPA (j)
1	Business as Usual	$100	$20	$16	$4	6	$21	$89	$79	$10	($11)
2	GHG Regs - Electric/RNG/H2	$100	$20	$24	($4)	7	($24)	$89	$76	$13	$37
3	GHG Regs - Electrification	$100	$20	$16	$4	5	$18	$89	$0	$89	$71

Again, this is just a set of hypothetical scenarios presented for illustrative purposes. It is also presented only from an all customers or societal cost-effectiveness perspective. A similar comparison of the net present value of rate impacts would also be appropriate for informing decisions. Nevertheless, this example clearly illustrates how cost-effectiveness could be very sensitive to assumptions about the future, particularly with respect to climate policy. In fact, even if one assumed that there was an 80% likelihood that the BAU scenario would become reality, and that there was only a 10% chance of each of

[131] Note that the net benefits shown in the last column of this table is only illustrative of the cost-effectiveness of a non-pipe alternative in the context the hypothetical futures characterized. It does not suggest that a renewable gas approach to addressing climate policy goals would be lower cost than an electrification approach. Economic trade-offs between renewable gas and electrification would need to be assessed under an IRP analysis applied to the entire energy system, including gas commodity costs and the costs of electric alternatives, rather than to just non-wires alternatives to traditional T&D investments. In fact, it is possible, if not likely, that non-pipe solutions would look better under a renewable gas scenario than under an electrification scenario precisely because a switch to renewable gas would be more expensive (leading the avoided costs of gas, a potentially key benefit in deploying non-wires solutions, to be dramatically higher) than electrification.

the other two scenarios becoming reality, the probability weighted average result would be that the non-pipe solution was cost-effective (i.e., a different conclusion than if one only looked at a BAU scenario).

The Board, Enbridge and other stakeholders should have the opportunity to see how these different future scenarios affect the cost-effectiveness of IRPAs. While it will always be impossible to empirically assign probabilities to each scenario analyzed, it is important that all parties understand how sensitive the cost-effectiveness of different solutions are to assumptions about the future. In the hypothetical case presented here, the business-as-usual load forecast would have to have a nearly 90% probability of being the most accurate forecast for a traditional supply-side investment to be the most cost-effective solution. Given what we know about current government policy and related market trends, that should raise concern about approving such an investment. On the other hand, if an IRPA was cost-effective only if one assigned a 90% probability to a fully electrified future with dramatic annual reductions in peak demand beginning within the next 5-10 years, the decision might be very different.

TAB 5

with electric utilities on, today?

MS. WADE: I would say in the context of IRP, where we are going into a specific geographic region and geotargeting programs for significant take-up, we have not gone into a specific geographic area and targeted significant uptake of electrification measures.

I would note within the DSM plan that there is the opportunity to incent electrification measures with the new framework, but that is from a broad-base perspective. So the implications in a very small geotargeted area on a specific electric grid are not the same as if we were to go and launch a program, say, where we are going to be doing our pilot say in Parry Sound, without doing that in very close partnership with the local LDC.

MS. GIRVAN: Thank you. With respect to B, which is "Require analysis of IRPAs under multiple possible future load forecasts that include the effects of decarbonization on the economy"?

MS. WADE: So I would say with regards to this, I would first maybe take a step back and note that as part of our demand forecast process, I think we have mentioned a few times there is going to be an evolution of the way that we are monitoring and including energy transition assumptions to ensure that we have the most accurate demand forecasts that we are using in our integrated resource planning alternative analysis. I think what Mr. Neme here is speaking about, if I can interpret his suggestion or proposal here, is that it would almost be like a pathways study within a specific geotargeted area, to understand what the costs and benefits would be to customers in that area should an electrification pathway come to fruition and/or a low-carbon fuels.

And so I just note that this would be a very time-intensive process. It would require significant level of effort to be able to do that scenario analysis, and I think we are still evaluating.

At this point, it feels like I am not sure the value that would be provided to the Board in the decision of the IRP alternative as opposed to the best available information that we have at the time with the commitment to continually iterate the analysis and come back and re-evaluate any scenario or, sorry, any assessments that we have done with any new information that we have.

MS. GIRVAN: Okay. All right. Thank you. Number 7, I just wondered what Enbridge's position is on the creation of a segregated fund for site restoration.

MS. GIRIDHAR: Again, I think this may be better addressed to the depreciation panel, but I can at a high level tell you Enbridge isn't currently supporting the idea of a segregated fund for site restoration.

MS. GIRVAN: Okay. With respect to the last one, number 8, I actually don't need your input on that. It is "reduce capital spending on gas assets wherever possible." So I think there are going to be lots of arguments for that, and I guess we will see what your position is.

MS. GIRIDHAR: I would just reiterate that we know we