EB-2020-0200

ENBRIDGE GAS INC.

COMPENDIUM OF MATERIALS IN AID OF CROSS-EXAMINATION OF DR. ASA HOPKINS (IGUA)

July 17, 2023

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I. Executive Summary

This report discusses the risk that infrastructure built pursuant to Enbridge's current application may ultimately be underutilized or stranded due to market forces and/or climate policy, and proposes steps that Enbridge and the Ontario Energy Board (OEB or Board) can take to mitigate those risks to consumers. The report is authored by Chris Neme, a Principal with Energy Futures Group (EFG). Mr. Neme and his firm are leading experts on the implications of decarbonization for gas customers and best practices to address those implications. Mr. Neme has decades of experience with Enbridge Gas and the Ontario regulatory context from approximately 30 years of work on gas and (to a lesser extent) electric DSM in the province, and participation in various OEB advisory committees on DSM, Gas IRP, and carbon prices. What follows are the key conclusions and recommendations of the report.

1. Key Conclusions

I conclude in this report that 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. I discuss each of these points in some detail in Section III of this report.

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 who end up paying for an inappropriate and disproportionately large share of the cost of gas system assets – including assets that were intended primarily or exclusively to meet the needs of other customers who will have left the gas system. This will be particularly problematic for lower-income households who could face the biggest hurdles to exiting the system.

There are a variety of ways in which the Board should mitigate those risks. In particular, I recommend the following:

1. **Shorten new construction connection cost recovery periods.** There are two components to this recommendation:
   a. **Reduce the customer revenue horizon from 40 years to 15 years.** This will reduce the risk that new customers do not end up covering the full cost of their connection to the system through rates, let alone contributing to other system costs, if they electrify at the time that their new heating system needs to be replaced. Enbridge estimates this change would reduce system access spending by about $600 million over the 2024-2028 period.
   b. **Reduce the maximum customer connection horizon from the current 10 years to 5 years.** Given the likelihood that gas sales will begin to decline, it is prudent to put tighter limits on the sunsetting of connection offers to builders and developers.
2. **Reduce infill connection costs funded by rates to the amount that will be recouped from resulting gas bills over 15 years.** Analogous to the above recommendation, this will reduce the

risk that new customers do not end up covering the full cost of their connection to the system through rates, let alone contribute to other system costs.

3. **Require all new connections to be net-zero greenhouse gas emitting.** This would include requiring that all new connections install hybrid heating systems with a cold climate air source heat pump meeting the vast majority of heating needs (and a back-up gas furnace functioning only during the coldest hours of winter). Also, all gas provided to new connections would have to be biomethane (often called renewable natural gas or RNG). This recommendation is similar to a proposal that Energir, the Quebec gas utility, recently proposed for its upcoming rate case.
4. **Require Enbridge to immediately assess and report back to the Board by 2024 on the near-term and longer-term rates, costs of capital, affordability, and inter-generational equity impacts of alternative asset depreciation approaches.** The current 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. The Company should assess, among other things, a Units of Production approach, which could account for declining annual sales, and thus promote better inter-generational equity and help to ensure affordability as demand declines. Depreciation approaches that account for decarbonization should be studied now because delaying a shift in approaches will cause increasingly large rate shocks as time goes on.
5. **Require Enbridge to routinely assess trade-offs between repairing and replacing aging pipe.** The assessments should account for the possibility that a new pipe will be underutilized or stranded before the end of its life as a result of decarbonization policies or market forces significantly driving down gas demand in the future. They should include estimates of 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, and the long-term potential to save money by cost-effectively pruning the gas system.
6. **Improve IRP to reduce the risk of under-utilized or stranded assets.** There are two components to this recommendation:
   a. **End the interim prohibition on considering electrification measures as IRP Alternatives (IRPAs).** Things have changed since the Board put this prohibition in place in the gas IRP proceeding several years ago. Our understanding of decarbonization includes both recognition of the likelihood that significant electrification will occur and new direction from the Minister. Indeed, the Board recently required Enbridge to provide rebates for electric heat pumps through its DSM programs. It would be prudent to enable Enbridge to target electrification to areas that could simultaneously reduce other gas infrastructure investment costs.
   b. **Require analysis of IRPAs under multiple possible future load forecasts that include the effects of decarbonization of the economy.** To date, Enbridge has based its assessment of system needs and the role that IRPAs could play in cost-effectively deferring such needs on forecasts that do not reflect the likely impacts of decarbonization on demand. At a minimum, assessments of cost-effectiveness should consider demand declines as a material possibility.
7. **Consider the creation of a segregated fund for site restoration.** Enbridge currently retains billions of ratepayer dollars for future site restoration costs. This creates a material risk for

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

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[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/

The OEB also asks that Enbridge Gas begin their case with a witness panel to provide a summary of the current version of the Guidehouse report. Parties and OEB staff will then have an opportunity for cross-examination on Guidehouse report issues.

The OEB also asks that Enbridge ensure that energy transition witnesses are available on subsequent witness panels so that energy transition matters arising from the evidence provided by those panels can be addressed as they arise.

The approved issues list continues to define the scope of the proceeding. To assist the parties with their preparation for the oral hearing, and without seeking to limit relevant questioning in other areas, the OEB has identified the following as matters of particular interest:

- The risks that have been identified in relation to the energy transition, including the risk that assets may be stranded, and the regulatory options to mitigate those risks in relation to system access and system renewal investments
- Whether Enbridge Gas's application of the revenue horizon parameter established in E.B.O. 188 continues to be appropriate in light of energy transition
- Regulatory options for managing revenue related to site restoration costs

The OEB expects parties to work directly with OEB staff to develop an effective hearing schedule that aligns with the OEB's directions above. Due to the large number of parties and the amount of evidence already on the record, the OEB also expects parties to coordinate efforts and be mindful of the amount of hearing time available. OEB staff will contact the parties directly to begin the process of preparing a hearing schedule.

The OEB notes that masks are not mandatory at the OEB's offices, however it is a mask-friendly environment. Please stay home if you are sick or have symptoms of illness, even if they are mild. If you are not well, please join the hearing virtually.

Undertaking Responses

The OEB requests that Enbridge Gas respond to any undertakings as early as possible while the hearing is ongoing. All responses to undertakings from the oral hearing shall be filed with the OEB and sent to all other parties no later than **August 14, 2023**.

Submissions

The OEB is also scheduling final written submissions at this time, including submissions on those issues that will be heard in writing only (i.e., Issues 10, 34, 37 and 40). Enbridge Gas's argument-in-chief shall be filed no later than **August 17, 2023**. The depreciation, apparently for reasons conventional to the formulation of the utility depreciation policy, but with judgments justified at least in part by reference to the impending energy transition changes.

Enbridge has also broad forward some tentative proposals on exploring how its business could be diversified to better position it for the future. We will discuss those particular initiatives in Phase 2. They are the small expansion of hydrogen blending, some RNG procurement, and a bit of money to spend on exploring innovation in support of its continued utility future.

What Enbridge Gas has not done, at least not to public knowledge, is take a serious look at how its gas delivery business will actually change; which customers are more likely to leave the system sooner rather than later; when, where, and in what numbers; which of its assets are more like to be underutilized sooner rather than later and the costs of retiring those assets, or avoiding new investments in them in the first place in order to avoid stranding associated costs; where it makes sense to deploy capital and operating resources to meet demand for gas delivery services into future; what regulatory mitigation tools may be most useful to address shareholder and customer risks; yet it is asking the Board for a lot more money from customers to cover business risks and recover the cost of all of its assets sooner rather than later. IGUA has focused its resources in this matter on these topics.

IGUA has sponsored evidence from Dr. Asa Hopkins of

Synapse Energy Economics. Dr. Hopkins canvasses actions that prudent gas utilities and their regulators are taking now to address these hard questions about changes in gas delivery -- not just business expansion, but also business retreats -- that they may have to take, and the wisdom of preparing for such sooner rather than later in order to protect both shareholders and customers from unnecessary cost. He presents conceptually a practical way to model potential gas utility futures in order to quantify risks and identify mitigating actions that, in the end, could avoid billions of dollars of unnecessary costs.

Pending consideration of the evidence that we will hear in the coming days, it is IGUA's preliminary view that, until that work is done by Enbridge, the extent to which Enbridge's unmitigable business risk has changed cannot be properly evaluated and it would be unjust and unreasonable for customers to be required to pay now to compensate Enbridge Gas on the premise of greater unmitigated risk and to pay again later when that unmitigated risk crystallized at greater cost than need be the case.

IGUA has also sponsored the evidence of Dr. Sean Cleary to address the more conventional aspects of the fair return standard and assess the extent to which Enbridge Gas has demonstrated that its capital structure is in need of thickening. Dr. Cleary concludes that market indicators do not support that position.

The third expert that IGUA has sponsored is Dustin

Ontario Energy Board

EB-2009-0084

Report of the Board

on the Cost of Capital for Ontario's Regulated Utilities

December 11, 2009

The FRS was further articulated by the National Energy Board in its RH-2-2004 Phase II Decision as:

> A fair or reasonable return on capital should:
>
> - be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);
> - enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
> - permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).[9]

In its letter of July 30, 2009, the Board noted that the National Energy Board's articulation of the FRS is consistent with the principled approach described on page 2 of the Compendium to the Board's March 1997 *Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities* (the "1997 Draft Guidelines") and the policies set out in the Board's December 20, 2006 Report.

The Board is of the view that the FRS frames the discretion of a regulator, by setting out three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. As set out by Enbridge in their final comments, the Supreme Court of Canada has "described this requirement that approved rates must produce a fair return as an 'absolute' obligation."[10] Notwithstanding this mandatory obligation, the Board notes that the FRS is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.

Informed by the comments made by stakeholders in the context of this consultation and the relevant jurisprudence, the Board offers the following observations about the application of the FRS.

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[9] National Energy Board. RH-2-2004, Phase II Reasons for Decision, TransCanada PipeLines Limited Cost of Capital. April 2005. p. 17

[10] *British Columbia Electric Railway Co. Ltd. v. Public Utilities Commission of British Columbia et al [1960] S.C.R. 837*, at p. 848.

First, the Board notes that the FRS expressly refers to an opportunity cost of capital concept, one that is prospective rather than retrospective.

Second, the Board agrees with the National Energy Board which stated that "[i]t does not mean that in determining the cost of capital that investor and consumer interests are balanced."[11] Further, the Board notes that the Federal Court of Appeal was clear that the overall ROE must be determined solely on the basis of a company's cost of equity capital and that "the impact of any resulting toll increase is an irrelevant consideration in that determination. This does not mean however, that any resulting increase in tolls cannot be considered by a tribunal in determining the way in which a utility should recover its costs."[12] The Federal Court of Appeal also stated that:

> It may be that an increase is so significant that it would lead to "rate shock" if implemented all at once and therefore should be phased in over time. It is quite proper for the Board to take such considerations into account, provided that there is, over a reasonable period of time, no economic loss to the utility in the process. In other words, the phased in tolls would have to compensate the utility for deterring the recovery of its cost of capital.[13]

Third, all three standards or requirements (comparable investment, financial integrity and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate consideration to comparability test is not sufficient to meet the FRS.

Fourth, a cost of capital determination made by a regulator that meets the FRS does not result in economic rent being earned by a utility; that is, it does not represent a reward or payment in excess of the opportunity cost required to attract capital for the purpose of

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[11] National Energy Board. Reasons for Decision. Trans Quebec & Maritimes Pipelines Inc. RH-1-2008. March 19, 2009. p. 6.
[12] *TransCanada PipeLines Ltd. v. National Energy Board, 2004 FCA 149*, para. 35-36.
[13] *TransCanada PipeLines Ltd. v. National Energy Board, 2004 FCA 149*, para. 43.

investing in utility works for the public interest. Further, the Board reiterates that an allowed ROE is a cost and is not the same concept as a profit, which is an accounting term for what is left from earnings after all expenses have been provided for. The Board notes that while cost of capital and profit are often used interchangeably from a managerial or operational perspective, the concepts are not interchangeable from a regulatory perspective.

Fifth, there was considerable discussion in the consultation about utility bond ratings. The ability of a utility to issue debt capital and maintain a credit rating were generally put forth by stakeholders in the consultation as a sufficient basis upon which to demonstrate that a particular equity cost of capital and deemed utility capital structure meet the capital attraction and financial integrity requirements of the FRS. The Board is of the view that utility bond metrics do not speak to the issue of whether a ROE determination meets the requirements of the FRS. The Board acknowledges that equity investors have, as the residual, net claimants of an enterprise, different requirements, and that bond ratings and bond credit metrics serve the explicit needs of bond investors and not necessarily those of equity investors.

Finally, the Board questions whether the FRS has been met, and in particular, the capital attraction standard, by the mere fact that a utility invests sufficient capital to meet service quality and reliability obligations. Rather, the Board is of the view that the capital attraction standard, indeed the FRS in totality, will be met if the cost of capital determined by the Board is sufficient to attract capital on a long-term sustainable basis given the opportunity costs of capital. As the Coalition of Large Distributors commented:

> [t]he fact that a utility continues to meet its regulatory obligations and is not driven to bankruptcy is not evidence that the capital attraction standard has been met. To the contrary, maintaining rates at a level that continues operation but is inadequate to attract new capital investment can be considered confiscatory. The capital attraction standard is universally held to be higher than a rate that is merely non-confiscatory. As the United States Supreme Court put it, 'The mere fact that a rate is non-confiscatory does not indicate that it must be deemed just and reasonable'.[14]

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[14] Final Comments of the Coalition of Large Distributors. October 26, 2009. pp. 5-6.

Enbridge Gas Inc.

Application to change its natural gas rates and other charges beginning January 1, 2024

Evidence
of
DUSTIN MADSEN, CPA, CA, CPA
(IL, USA), CDP, CRRA

PRESIDENT

EMRYDIA CONSULTING CORPORATION
(U.S. AND CANADA)

Sponsored by Industrial Gas Users Association

EMRYDIA

April 21, 2023

ELG procedure will increase depreciation expense for EGI, and eventually result in lower depreciation accruals in the future than the ALG.[18]

Q: Please provide your recommendation in respect of the proper depreciation procedure for Enbridge.

A: I recommend that the OEB direct Enbridge to utilize the ALG procedure for both the EGD and Union assets. I am also supportive of using either the remaining life or whole life technique as appropriate. I note that Concentric confirms that the ALG procedure combined with the remaining life technique remains the most widely used approach in the United States.[19] Both the ALG procedure with the remaining life approach and the ALG procedure with the whole life approach are common in Canada.

Maintaining the ALG procedure for the EGD assets and applying the ALG procedure to the Union assets provides for a continuation of the ALG procedure for a large portion of Enbridge's depreciable asset base. Further, while Enbridge has raised concerns regarding the need to assess a truncation and potential economic life for some of its assets in the future, those concerns are presently speculative. Maintaining the ALG procedure permits a continuation of the status quo for a portion of the asset base, reduces potential intergenerational inequities that may be caused by changing the depreciation procedure, and provides an opportunity for future study of any changes that may be required. Particularly, if there is ultimately a need to implement an economic life for certain asset accounts that effort may be better performed on a case-by-case basis, rather than attempting to partially transition to such a result prematurely and perhaps unnecessarily for all impacted accounts as suggested by Concentric and Enbridge.

As a final point regarding approval of the ALG procedure in the test period, I note in response to IGUA-45, Enbridge calculated the impact of the change from current rates,

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[18] EGI IRR Exhibit I4 2024 Rebasing 2023-03-08, PDF page 1921, Exhibit I.4.5-IGUA-12e).
[19] EGI IRR Exhibit I4 2024 Rebasing 2023-03-08, PDF page 1256, Exhibit I.4.5-STAFF-173d).

A: I have reviewed all the service life and survivor curve recommendations provided by Concentric and am generally supportive of most of the recommendations. In most cases, Concentric's recommendations appear to align with the underlying retirement data, peer analysis and management discussions. However, in certain accounts where Concentric appears to have exercised significant judgment, I disagree with Concentric's recommendations and outline the reasons for such disagreement below.

Before addressing each individual account, I note that I do have some concern that Concentric's recommendations in this matter tend to err towards shortening lives for high dollar investment accounts. While this is not uniform, I am concerned by an apparent trend. This concern is emphasized by the statements from Concentric supporting its transition to the ELG procedure, including a perceived need to move closer to an economic life for the assets and the results achieved by the economic planning horizon calculated by Concentric. As noted earlier, the useful lives of assets, as well as the selected depreciation procedure, should be based first on the underlying data supporting those recommendations. If an economic life is warranted for consideration due to external factors, that adjustment should be made separately rather than indirectly through life reductions that are not supported by the underlying data, peer analysis or discussions with management.

3.1.2.1 Account 466 – Transmission – Compressor Equipment

Q: Please provide your recommended average service life and survivor curve for account 466.

A: Concentric recommends using a 30-R4 curve for this asset class. For the reasons detailed below, I recommend using a 37-R4 curve for this asset class, which relative to Concentric's recommendation, reduces depreciation expense by $9.7 million assuming use of the ALG procedure as I recommend, or by $12.8 million if the ELG procedure is adopted.

Enbridge Gas Inc.

Application to change its natural gas rates and other charges beginning January 1, 2024

Evidence of Dr. Asa S. Hopkins

On the Topic of Business Risk and Capital Structure

Sponsored by Industrial Gas Users Association

their costs will differ from expected values, not that they will differ from past values.

Q31 Does EGI use these kinds of tools to mitigate short-term/volatility risk?

A31 Yes. EGI has a wide range of deferral and variance accounts. Rationalizing these accounts in light of the Enbridge Gas Distribution (EGD)/Union Gas merger is the subject of Exhibit 9 in EGI's filing. These accounts protect EGI investors from risks related to variance in gas supply costs, overall gas demand, pension costs, incremental capital costs, carbon charges, and taxes, as well as costs related to integrated resource planning and demand-side management (among others).

Q32 How has EGI's use of these tools changed since 2012?

A32 EGD and Union Gas had a number of accounts in 2012. These helped protect the companies from similar risks in 2012 to the risks mitigated by today's accounts. Some new sources of variance are covered by accounts today that were not relevant in 2012 (such as carbon charges and renewable natural gas). Overall, it appears that the OEB understands the changing circumstances that EGI faces over time and has approved accounts that mitigate new sources of volatility as they arise. This is consistent with the low regulatory risk that both Concentric and credit rating agencies identify for EGI, and with the stability seen in EGI's returns to its investors.

Q33 Have you compared EGI's allowed and achieved returns?

A33 Yes, Figure 1 and Figure 2 show the allowed return and achieved return for EGI and its predecessor companies for the years 2007–2022. These figures show that EGI and its predecessor companies have consistently achieved stable returns that are higher than the allowed returns. (The data are from Exhibit I.5.3-IGUA-30, Attachment 1.)

Figure 1. Achieved and allowed return on equity for Enbridge Gas Distribution (2007–2018) and Enbridge Gas Inc. (2019–2022)

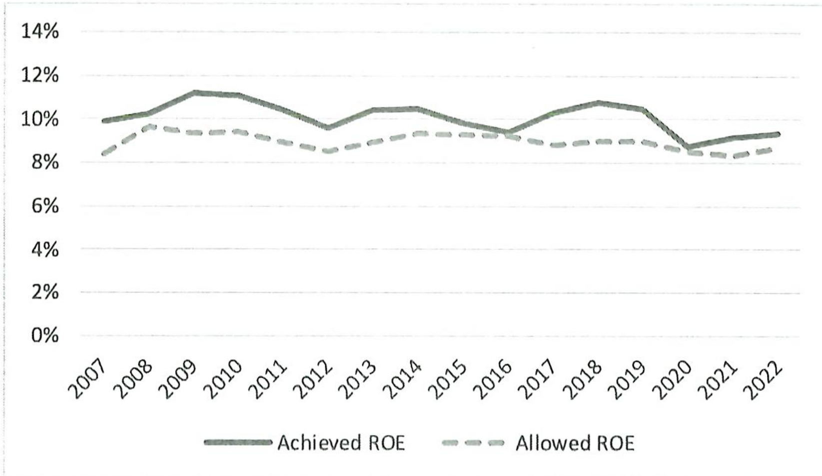
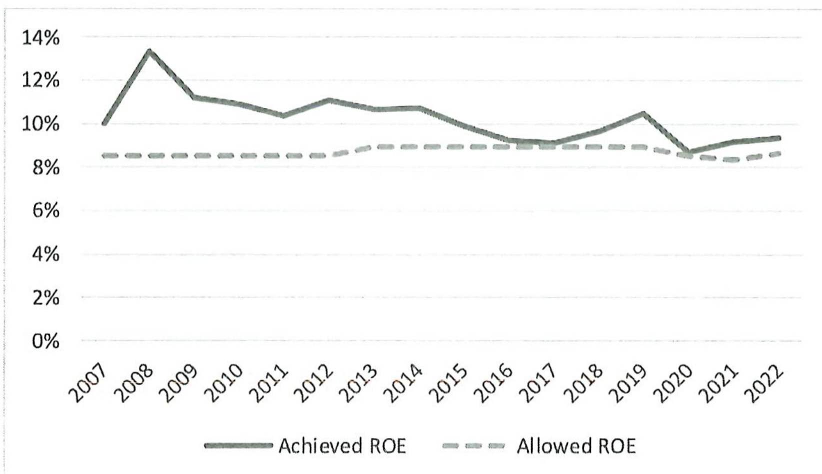


Figure 2. Achieved and allowed return on equity for Union Gas (2007–2018) and Enbridge Gas Inc. (2019–2022)



Q34 What conclusions can you draw from analyzing EGI's achieved and allowed returns?

A34 EGI's volatility of returns is not higher than the volatility of returns exhibited by EGD and Union Gas and is within the middle of the range.

The evidence provided consists of examples of proceedings in the United States that examine the future of gas utilities. Concentric claims that these:

> "illustrate the degree to which the Energy Transition affects gas utilities' business risk today, as investors must consider that the long-term prospects of the industry have changed. Even if these impacts take years to unfold, investors take these factors into account today."[30]

I have prepared a survey of "future of gas" regulatory context and studies for eight U.S. jurisdictions, which I include as Attachment 3 to this evidence. This survey shows that leading states are taking a proactive look at the potential risks associated with energy transition. Those states are laying the groundwork for the types of analysis and actions that would be required to mitigate capital risks for gas utilities, if they arise.

To take Massachusetts as an example, Concentric quotes the petition from the state's attorney general asking for the creation of a docket to assess the future of gas utility operations and planning in light of the state's binding net zero commitment for 2050. Concentric fails to follow up and report on what followed that petition: the regulator opened a proceeding focused on the utilities' role in the state's achievement of its targets, in a cost-effective way and with a focus on safe and reliable service, while "potentially recasting" the role of the gas utilities in the state. The resulting study went further than almost all other comparable analysis that I am aware of in laying out both the challenges for gas utility regulation and the ability of straightforward regulatory and financial tools to mitigate risks. As a result, Massachusetts gas utilities and their regulators have a better sense of their future and path through the energy transition than other gas utilities. In short, and contrary to Concentric's claims, regulatory attention to energy transition issues reduces uncertainty and lowers risk. OEB consideration of EGI's plans in the context of the Ontario Ministry of Energy's Cost-Effective Energy Pathways

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[30] Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 31 of 164.

"strategically downsize" the gas system. First, each utility is required to produce a long-term plan every three years. Second, the regulator required each utility to produce a depreciation study to quantify the impacts of different depreciation approaches on ratepayers and capital at risk. The study requires depreciation analysis in three scenarios: (a) full depreciation of all new gas plant by 2050, (b) full deprecation of all gas plant by 2050, and (c) 50 percent of gas customers exit the gas system by 2040 and 10 percent of gas customers remain after 2050. The consultants who conducted these studies examined both straight-line and units-of-production-based depreciation approaches.

3. Maryland: The state's consumer advocate commissioned a study of the impact of energy transition on the finances of the state's gas utilities. The study presents the results of models projecting gas sales, customers, rate base, fuel costs, and rates in a case corresponding to the state's identified pathway for building decarbonization. The modeling shows that business-as-usual approaches to utility investment and depreciation would result in more risk for the utilities than would approaches that adapt to the changing circumstances.

4. Washington, DC: As part of a commitment resulting from its purchase by AltaGas, Washington Gas Light produced a "climate business plan" to examine how the company could adapt to be consistent with the District's greenhouse gas reduction commitments. The resulting study examines multiple scenarios, quantifies the unrecovered cost of service in different scenarios, and estimates stranded costs absent mitigating actions. The utility also suggested numerous regulatory changes to mitigate these risks, including decoupling between sales volumes and revenue and having electric ratepayers contribute to gas revenue requirements.

5. California: State policymakers commissioned a study on the challenge of retail gas in a low-carbon future. This study quantifies some of the challenges facing gas utilities resulting from sales reductions and resulting revenue

depending on the gas system to deliver low-carbon fuels so they can achieve their net zero goals.

Q74 What lessons do you draw from this modeling that are applicable to this rebasing case?

A74 The most important lesson is that modeling of this sort is straightforward. With the additional data and insight that EGI has regarding its system, capital needs and plans, and operations and maintenance cost structures, the utility should be able to straightforwardly adapt the pathways and policy directions adopted by the province into a set of scenarios and model its own future.

The case I have used as a simple illustration here is highly unlikely to align with the province's selected pathway at any level of detail. However, it is broadly similar to some cases considered (like the high electrification case in Guidehouse's analysis), and the modeling supports further insights related to its results in this case:

- Proactive planning regarding asset retirements, with depreciation approaches tailored to assets retiring in any given year, can reduce and potentially eliminate stranded cost risks—even in a case that has a more extreme version of building sector departure from the gas system than modeled by Guidehouse in its electrification case.

- In this scenario, gas rates rise throughout the study period, but only rise sharply at the end. This will eventually shift the competitive balance between gas and electricity, although mostly during the final stages of the transition.

- However, the amount of capital at risk of stranding at the end can be quite small compared with total utility capital. A simplistic approach to mitigating such a risk could be to create a fund during the time when all

F. Financial Risks

Q78 Concentric discusses financial risks as a separate item from capital risks. Do you agree with this separate treatment?

A78 No, I do not. A utility's financial situation is intimately tied to its investment strategy and asset recovery strategy. Therefore, financial risk parameters are closely linked with capital risks.

Q79 How would planning for and mitigating capital risks impact a prudent gas utility's financial situation?

A79 The prudent gas utility manager has an obligation to shareholders to align the utility's financial approach to the reality of the market and policy context in which it operates, and to consider all of the implications of potential actions. Accelerating depreciation, for example, would increase a utility's funds from operations (FFO), and thereby increase the creditworthiness of the utility's debt on standard measures.

In Attachment 4 I illustrate this through the simplified illustrative example of the strategically downsizing utility. In this case, the company's financial parameters shift substantially in the direction of lower financial risk, such as greater FFO relative to debt. Figure 3, reproduced from Attachment 4, shows the trajectories for three financial parameters of interest to rating agencies such as S&P, in this illustrative case.

Survey of Analysis of Gas Utility Futures

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1. INTRODUCTION

Decarbonization of buildings and industrial sectors will transform gas utilities and require changes in regulation and business models. This transition is in its infancy, and there are numerous competing visions for how to resolve the resulting challenges. Responses to these challenges will vary among states and utilities and will be driven by history, climate, the state of the gas system, and public policy choices. In a growing number of states, policymakers, regulators, and utilities are analyzing building and industrial decarbonization and the resulting impact on gas utilities and their customers. This white paper surveys the status of analysis of this energy transition across U.S. states. It draws insights, identifies gaps, and highlights emerging best practices from those processes.

In this paper, we survey selected states, moving from northeast to southwest across the United States. For each state, we review the underlying public policy and describe the processes conducted to date. Where analysis has been conducted, we describe the analysis and summarize its results.

2. MASSACHUSETTS

Massachusetts has adopted a statutory net zero greenhouse gas emissions requirement for 2050, as well as sectoral emissions limits for 2025 and 2030. The state conducted a 2050 Roadmap study to lay out pathways to achieve its net zero objective. This Roadmap study identified an "All Options" pathway as the most promising path forward. This pathway used electrification as the primary mechanism for decarbonization of both the transportation and buildings sectors. Subsequent analysis to support the 2025 and 2030 sectoral sublimits was similarly based on electrification, although the buildings analysis anticipates a phased approach in which hybrid or dual-fuel systems (using a heat pump alongside existing combustion-based heating systems) play a transitional role for one or two decades before full electrification is achieved.

The Massachusetts Department of Public Utilities (MA DPU) created Docket 20-80 following a request by the Attorney General's Office to investigate "the impact on the continuing business operations of local gas distribution companies as the Commonwealth achieves its target 2050 climate goals." The MA DPU recast this request and opened the docket "to examine the role of Massachusetts gas local distribution companies (LDCs) in helping the Commonwealth to achieve its 2050 climate goals." The DPU set out to explore strategies to meet emissions objectives while safeguarding ratepayers, safety, and reliable gas service, and "potentially recasting the role of LDCs in the Commonwealth" as part of a project to develop "a regulatory and policy roadmap to guide the evolution of the gas distribution industry."

KEY REGULATORY PROCEEDINGS

- **Docket No. 20-80:** Investigation by the Massachusetts Department of Public Utilities on its own Motion into the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals

EXISTING ANALYSIS

Docket 20-80 Analysis

The MA DPU directed the state's gas utilities to contract with consultants who would analyze strategies to achieve net zero emissions, adding greater detail and alternative approaches to those captured in the state's Roadmap study. In their Request for Proposals to hire the required consultant(s), the LDCs added to the scope of the study by including a commitment to "developing recommendations for new business models and associated regulatory frameworks or other initiatives and actions that can be implemented in the near term to contribute to the Commonwealth's achievement of the net zero target by 2050, with sufficient flexibility to adjust over time as technologies evolve and more is known." This addition to the scope, led by the utilities, ensured that the consultants would do more than simply analyze the societal energy transition; they would also examine the utility financial and regulatory implications of the pathway results.

The consultants' analysis built upon the state's 2050 Roadmap and added detail not captured by the Roadmap. For example, the Roadmap did not differentiate between hybrid/dual-fuel heat pump adoption and whole-building adoption, whereas the consultants' study made this distinction.

The consultants' *pathways* analysis[1] included:

- Rate base and revenue requirements over time;
- Customer costs and qualitative discussion of impacts on choices; and
- Quantification of the impacts of targeted electrification to allow asset retirement.

The consultants' follow-on *regulatory* analysis[2] elaborated on options and approaches available to address the issues raised in the pathways analysis:

- Minimize or avoid gas infrastructure projects to reduce costs that need to be recovered from gas system customers—methods include geographically targeted electrification,

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[1] E3 and Scott Madden. *The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals Independent Consultant Report: Technical Analysis of Decarbonization Pathways.* March 18, 2022. Available at: https://thefutureofgas.com/content/downloads/2022-03-21/3.18.22%20-%20Independent%20Consultant%20Report%20-%20Decarbonization%20Pathways.pdf.

[2] E3 and Scott Madden. *The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals Independent Consultant Report: Considerations and Alternatives for Regulatory Designs to Support Transition Plans.* March 18, 2022. Chapters 4 and 5. Available at: https://thefutureofgas.com/content/downloads/2022-03-21/3.18.22%20-%20Independent%20Consultant%20Report%20-%20Regulatory%20Designs.pdf.

non-pipeline alternatives to pipeline replacement, and networked geothermal systems. The consultants also suggest formal review and pre-approval for capital investments.

- Coordinate electric and gas system planning to support reliability and resilience on the electric grid during the transition.
- Review line extension policies and practices to reduce the risk of ratepayer support for uneconomic pipeline expansions.
- Align infrastructure cost recovery with utilization. The consultants modeled a "units of production"-based depreciation approach that mitigates some of the per-therm depreciation and financing costs for utility assets when throughput falls and delays unsustainable increases in gas rates as 2050 approaches. The consultants explicitly quantified the unrecovered rate base in 2050 in each of several scenarios and showed how units-of-production depreciation limits the associated risk.
- Identify and quantify transition costs and evaluate impacts on customers of baseline and alternative approaches to cost recovery (such as accelerated depreciation, exit charges, or transferring costs to electric customers). The consultants identify that equity impacts can vary markedly between different approaches and that customer economic choice regarding their buildings has system-level effects that should be accounted for by utility planners and regulators.
- Tailor regulatory changes to the timeframes relevant in the pathway being pursued.

3. New York

Six New York gas utilities are regulated by the New York Department of Public Service (NY DPS), which is led by the Public Service Commission (NY PSC). The NY DPS created docket 20-G-0131 covering all of the activities related to a modernized gas planning process. Under this docket, the commission instructed Staff and the LDCs to conduct analysis and develop reports described below. This action was triggered by the state greenhouse gas (GHG) emission reduction targets and the gas moratorium declared by certain New York gas utilities.

KEY REGULATORY DEVELOPMENTS

- **20-G-0131** The New York Department of Public Service created docket 20-G-0131: Proceeding on the Motion of the Commission in Regard to the Gas Planning Procedures
    - **Order Adopting Gas System Planning Process** - May 12, 2022

EXISTING ANALYSIS

Depreciation Studies

The NY PSC required the LDCs to complete a depreciation study to examine both the structure of accelerated depreciation and its potential impacts on ratepayers. The PSC required the LDCs to calculate the revenue requirement and bill impacts, under the following scenarios: (a) full depreciation of all new gas plant by 2050, (b) full depreciation of all gas plant by 2050, and (c) 50 percent of gas customers exit the gas system by 2040 and that 10 percent of gas customers remain after 2050.

National Fuel Gas (NFG) Rate Base. NFG presented rate base as of 2050, given different scenarios. With the High Electrification scenario, straight-line depreciation (with current assumed asset life) would result in a rate base that is almost 4 times larger, compared to the rate base assuming accelerated depreciation. In this scenario, rate base in 2050 is over $1,800 million, while with a units of production depreciation methodology, it would be over $400 million. The difference in 2050 rate base is less stark under a medium electrification scenario. With straight line depreciation, it is estimated to be over $1,600 million; using units of production-based depreciation, it is over $1,200 million.

Long-Term Plans (LTP)

The commission required the LDCs to complete long-term plans every three years. NFG was the first utility to complete its LTP. NFG created three scenarios in the report: a Reference case, a Supply Constrained Economy, and an Aggressive scenario. While the report presented the GHG emission reduction results and the cost for each scenario, it did not elaborate on issues such as potential stranded assets or policy recommendations. The remaining LTPs are expected in 2023.

4. MARYLAND

The Maryland Public Service Commission regulates three investor-owned gas utilities. In response to the establishment of state climate goals, the PSC has issued a notice seeking comments on the PSC's statutory obligation to consider the achievement of the state's climate goals in its duties. In response to this, the Office of People's Counsel (OPC) has submitted a petition for the Commission to establish a docket for near-term priority actions and comprehensive long-term planning for Maryland's Gas Companies.

While there have been no PSC orders for any long-term studies, the OPC and Baltimore Gas and Electric (BGE) have released reports with forward-looking analysis.

KEY CLIMATE LEGISLATION OR REGULATION

1. **MD PSC Notice of Consideration of New Statutory Factors**, Oct 6, 2021 - seeking comment regarding the Commission's newly established statutory obligation to expressly consider the

"protection of the global climate...[and] the achievement of the State's climate commitments for reducing statewide greenhouse gas emissions" in the exercise of its duties.

COMPLETED REPORTS

Maryland's regulators have not required any studies; however, two reports were released in October 2022.

Climate Policy for Maryland's Gas Utilities: Financial Implications (OPC)

The Maryland Office of People's Counsel (OPC) sponsored a study titled *Climate Policy for Maryland's Gas Utilities: Financial Implications* (Nov 2022), conducted by Synapse Energy Economics. This study quantifies the impacts of policy-consistent electrification on gas rates for the state's three large gas utilities, incorporating the utilities' current plans for capital spending on leak-prone pipe replacement and assuming no change in depreciation rates. The analysis shows that gas rates increase by a factor of five to ten, driven by the combination of reduction in sales and the cost of alternative gaseous fuels. The modeling shows that the utilities' rate base in 2050 is comparable to today's rate base in inflation-adjusted dollars. The report points out that changes in capital investment and depreciation can reduce the pace of rate increases and mitigate stranded cost risks, while also improving equity outcomes.

Integrated Decarbonization Strategy (Baltimore Gas and Electric)

Policy Recommendations. BGE provided regulatory and policy recommendations. These include:

- Rate Design: For gas customers, BGE recommends exploring subscription or other fixed-price methodologies that would allow the collection of gas infrastructure costs from hybrid customers with much lower volumes.
- Renewable Gas Procurement: Measures to allow for the procurement of these fuels, such as allowing utilities to offer voluntary RNG products, a renewable portfolio standard for gas, and inclusion of a social cost of carbon in gas supply planning or in a clean heat standard.
- Accelerated depreciation: The report notes that this may become a necessity as gas system utilization drops, resulting in a lower useful life for certain gas infrastructure. This report does not propose a methodology but points to proposals put forth by National Grid in Massachusetts and PG&E in California.
- Redirection of incremental gas investment: Involving changes to utility planning practices, such as more intensive coordination between electric and gas distribution planning.
- Electric to gas benefit payments: Establishment of transfer payments from the electric to the gas business to ensure the costs of the gas system are borne by those who benefit from the capacity and other benefits provided.

Alternatives.

- **Networked Geothermal**. Proposal to pilot a networked geothermal program. The report argues that this would require detailed engineering studies of networked geothermal potential in the state, demonstration projects, and development of rate design structures to support this effort.

Consultants for the Attorney General of Rhode Island, in recommending that the State of Rhode Island Division of Public Utilities and Carriers condition the sale of Narragansett Electric (the largest electric and gas LDC in Rhode Island) on the limitation of capital expenditures, summarized the "going concern" issue as follows:

> *[L]egal and societal pressures are building to substantially reduce fossil fuel consumption. Moreover, policymakers are becoming increasingly concerned about methane emission in both gas production and distribution activities. In addition, the costs associated with replacing obsolescent natural gas distribution systems have increased substantially over the past decade, as many distribution utilities have accelerated their system replacement efforts. Finally, electric alternatives to natural gas heating (e.g., "mini-splits") are becoming more efficient and cost competitive. The economic risks to gas distribution service are both environmental and economic. Having a monopoly on natural gas distribution service does not insulate the utility from competition with alternative energy sources.* ***In that context, it is not clear that natural gas distribution systems serving residential and smaller commercial customers have a long-term future****.*[123]

The future for the gas distribution business is far from certain, and the Company is taking a variety of steps to position itself in response to the Energy Transition. As noted above, the Energy Transition creates both risks and opportunities for gas utilities such Enbridge Gas. For example, the Company's previously-discussed IRP may provide rate base IRPAs. However, there remains substantial risk from an investor's perspective. For example, Wells Fargo stated:

> *We had many conversations with investors this year regarding gas utilities place (or lack thereof) in a decarbonizing world and, from a similar but different angle, how the LDCs fit into the ESG picture. This conversation started in 2019, which saw the advent of the local ban on new gas hookups. The discussion heated up in the throes of the pandemic as (1) the LDC underperformance itself led investors to seek out explanations as to why with terminal value concerns coming up as one potential reason and (2) the green theme gained momentum with clean energy plays, such as NEE and ORSTED, topping the performance charts.*[124]

Wells Fargo's position has been echoed by a variety of equity and debt investors and industry participants. For example, Moody's noted that "[l]ong-term challenges to natural gas infrastructure

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[123] Direct Testimony and Exhibits of Mark Ewen and Robert Knecht, Docket No. 21-09, November 8, 2021, at 23. ***Emphasis added***.

[124] Wells Fargo Securities, "Gas Utility 2021 Outlook," January 6, 2021, at 3.