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

Table of Contents

I. INTRODUCTION AND QUALIFICATIONS

Q1 Please state your name, business address, and position.

A1 My name is Asa S. Hopkins. My business address is 485 Massachusetts Ave., Suite 3, Cambridge, Massachusetts 02139. I am a Vice President at Synapse Energy Economics, Inc. Among other work, I lead Synapse's consulting regarding the future of gas utilities, and I also work extensively in the related area of building decarbonization technology and policy.

Q2 Please describe Synapse Energy Economics.

A2 Synapse Energy Economics is a research and consulting firm specializing in energy industry regulation, planning, and analysis. Synapse works for a variety of clients, with an emphasis on consumer advocates, regulatory commissions, and environmental advocates.

Q3 Please describe your professional experience before beginning your current position at Synapse Energy Economics.

A3 Before joining Synapse Energy Economics in 2017, I was the Director of Energy Policy and Planning at the Vermont Public Service Department from 2011 to 2016. In that role, I was the director of regulated utility planning for the state's public advocate office, and the director of the state energy office. I served on the Board of Directors of the National Association of State Energy Officials. Prior to my work in Vermont, I was an AAAS Science and Technology Policy Fellow at the U.S. Department of Energy ("DOE"), where I worked in the Office of the Undersecretary for Science to develop the first DOE Quadrennial Technology Review. Prior to my time at the U.S. DOE, I was a postdoctoral fellow at Lawrence Berkeley National Laboratory, working on appliance energy efficiency standards. I earned my PhD and Master's degrees in physics from the California

Institute of Technology and my Bachelor of Science degree in physics from Haverford College. My resume is included as Attachment 1.

Q4 Have you previously provided evidence before the Ontario Energy Board?

A4 No.

Q5 Please describe your experience specifically related to gas utility business risk.

A5 I lead Synapse's work in the area of the future of gas utilities. My team and I are assisting a number of clients to understand the future of gas utilities in the context of deep building decarbonization objectives. This work includes assisting Conservation Law Foundation in Massachusetts Department of Public Utilities Docket 20-80 (an investigation into "the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals"); Natural Resources Defense Council in New York and Nevada's regulatory proceedings regarding the future of gas and in Consolidated Edison's recent rate case; the Colorado Energy Office regarding approaches to decision-making in the face of uncertainty, in the context of Colorado's regulatory proceedings regarding gas utility Clean Heat plans and building decarbonization; the County of San Diego (with the University of California San Diego) in developing the buildings and utilities portion of its Regional Decarbonization Framework; the Maryland Office of People's Counsel in modeling the impact of the state's decarbonization objectives on utility sales and finances; and the District of Columbia Department of Energy and Environment in assessing Washington Gas Light's Climate Business Plan. In Washington, DC, I provided testimony on behalf of the District of Columbia Government in the proceeding in which Altagas purchased Washington Gas Light regarding the implications of the District's decarbonization plans on the future of the utility's regulated gas business. In 2022, I testified on behalf of the Industrial Gas Users Association regarding gas utility business risk and return on equity before the Régie de l'Energie in Quebec and was recognized as an expert in "energy transition in the gas industry, and business risk."

Q6 On whose behalf are you providing evidence in this case?

A6 My evidence was sponsored by Industrial Gas Users Association. Attachment 2 to this evidence is my executed Acknowledgement of Expert's Duty form.

Q7 What is the purpose of your testimony?

A7 The purpose of my testimony is to analyze the business risk facing Enbridge Gas, Inc. ("Enbridge", "EGI", "the Company", or "the Utility") as presented by EGI and Concentric in Exhibit 5 of EGI's filing. Business risk is one component of the overall risk facing EGI. This business risk informs the choice of the appropriate capital structure, specifically the equity share of the utility's capital.

Q8 How is your testimony organized?

A8 My testimony begins with a summary of my conclusions and recommendations. I then proceed to an introduction to utility business risk and define the two primary classes of business risk relevant to this proceeding: operational or volatility-related risk and capital risk. I then discuss how to evaluate changes in business risk, before addressing the evidence on changes in the two types of business risk for EGI. I first address operational or volatility-related risk, then capital risk. The testimony ends with a summary of conclusions.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q9 Please summarize your primary conclusions.

A9 I summarize my primary conclusions as follows:

- EGI's volatility-related or operational business risk is low and has not changed appreciably between 2012 and the present. It would be decreased by the adoption of proposals in this case, namely EGI's rate design and Volume Variance Account proposals.

- The energy transition to a decarbonized future for buildings, industry, and electric generation is happening, and it will result in changes to EGI's business.

- EGI and Concentric have not adequately analyzed the energy transition impacts on EGI's business, and therefore have not shown that it materially increases EGI's capital-related risks.

- Scenario modeling of different futures for EGI is both possible and essential in order to understand its business risk. The utility is the only entity that has the sufficient expertise in its own system, finances, and operations to conduct such modeling at the level of detail required to develop plans and guide business decisions. It would be prudent for the utility to do such analysis and to share both the methods and results in detail with the Ontario Energy Board ("OEB") and stakeholders.

- High-level modeling, based only on publicly available information in this case, indicates that it could be possible for EGI to manage a high-electrification transition for the building sector while recovering all of its invested capital along with a fair return.

Q10 Please summarize your primary recommendations.

A10 I recommend that the OEB:

- Determine that EGI's volatility/operational business risk has stayed the same or decreased since 2012 (depending in part of how the OEB decides regarding EGI's rate design and weather variance proposals).

- Determine that EGI has not demonstrated that its capital-related business risk has increased.

- Weigh the more certain and near-term volatility/operational business risk more heavily than more uncertain and longer-term capital-related business risk when making an overall determination on business risk, and thereby conclude that EGI has not shown that its business risk is higher than it was in 2012.

- Require EGI to conduct a detailed business analysis, along the lines of the illustrative examples I provide in my testimony, following the publication of Ontario's ongoing pathways study and the conclusions of the Electrification and Energy Transition Panel, to inform its capital and operational plans.

- Require EGI to bring that analysis and associated plans to bear in developing its net rebasing application.

III. INTRODUCTION TO UTILITY RISK

Q11 How do you categorize the potential business risks a utility faces?

A11 I classify business risks into two categories, which I refer to as (1) operational or volatility risks and (2) capital or capital-recovery risks. I define the risks I consider in each category, below.

Q12 What are the operational or volatility business risks to utilities?

A12 These are the risks that the utility may receive less revenue than expected and/or it may be forced to pay unexpected costs. Due to the nature of cost-of-service regulation, there can be a regulatory lag between the establishment of the cost of service and the collection of revenues. If circumstances change in the meantime, the investors' returns may be higher or lower than expected. These business risks are manifested in volatility in the rate of return earned by utility shareholders. A gas utility without any weather adjustment in its regulatory regime, for example, might over-earn during cold winters and under-earn during warm ones; this would be a business risk for utility shareholders. (EGI's delivery rates currently have a sales variation adjustment but not a weather adjustment, though EGI is requesting incorporating a weather adjustment in this proceeding.) Emergencies such as the Covid-19 pandemic, natural or man-made disasters, or the addition or departure of large customers can also change utility costs or revenues. Because these risks are the result of year-to-year variation in circumstances, and periodic rate cases reset the utility's revenues to align with cost of service, these risks are inherently short-term in nature.

Q13 What are capital or capital-recovery risks?

A13 These are risks that the utility will be unable to both recover its invested capital and earn a reasonable return on that capital over the lifetime of an investment. This capital risk is sometimes referred to as "stranded cost" or "stranded asset" risk, although I want to make a clear distinction between a stranded cost and an actual loss to utility investors. A stranded cost is the undepreciated value of an asset that is no longer used and useful in the provision of utility service. In the regulatory paradigm adopted in both Canada and the United States, assets that are no longer used and useful should be removed from a utility's rate base.[1]

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[1] The *Stores Block* (*ATCO Gas & Pipelines Ltd. v Alberta (Energy and Utilities Board)*, 2006 SCC 4) decision by the Supreme Court of Canada affirmed this principle. For the United States, see, for example:

Interpreted directly, this would result in the loss of invested capital as well as the loss of the potential to earn any further return on that capital. In practice, however, when a utility asset that was installed prudently becomes no longer used and useful, regulators commonly allow the continued recovery of some or all of the value of that asset. So, the mere existence of stranded assets does not immediately or necessarily create losses to investors.

Q14 On what timeframe does capital risk manifest itself?

A14 In theory, a utility could face a capital recovery risk on different timeframes, both near-term and longer-term. For example, during electricity market restructuring, many electric utilities that owned power plants and were required to divest them found that the market value of their assets was less than the net plant balance on their books, so they faced a near-term capital risk that they might not be able to recover these investments. In this case, regulators generally mitigated the utility's capital risk with a transition charge to recover the revenue the utility needed to be made whole. In the case of EGI and other gas utilities concerned about energy transition, capital risks would manifest over long timeframes, due to eventual customer departures from the gas system. EGI does not face any near-term risk that its undepreciated investments will no longer be used and useful or become stranded.[2]

Q15 What about when a customer departs the gas system today? Doesn't that create a stranded cost for the utility?

A15 Occasional customer departures are not enough to create stranded costs, because utility depreciation is conducted on an averaged basis across an asset class. The

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U.S. District of Columbia Circuit Court of Appeals. 606 F. 2d 1094. Tennessee Gas Pipeline Company v. FERC. The Court states "…the precept endures that an item may be included in a rate base only when it is "used and useful" in providing service."

[2] As EGI states in Exhibit I.1.10-OGVG-1, "Enbridge Gas does not have actual stranded asset costs for the 2013 to 2022 period and is not forecasting any stranded asset costs from 2023 to 2028 related to its distribution, storage or transmission assets."

depreciation rate is set to recover the appropriate amount of capital over the average lifetime of an asset class (such as service lines or meters), knowing that some individual installations of that class will have shorter lives and others will have longer lives. Capital recovery risk is only manifest when there is a systematic change in the lifetime of an entire asset class.

Q16 Can you give examples of continued recovery of the investment in a class of assets no longer performing their past service?

A16 Yes. One example is the replacement of traditional meters with "smart" meters, where it makes sense to replace all meters at the same time even though many meters have a remaining undepreciated value. To give another example, when an aging electric power plant is retired it usually has some components that have been more recently installed, so that even if the original plant is fully depreciated there are some components that are stranded. In each of these cases, the regulator commonly either explicitly or implicitly approves the continued recovery of the prudently invested funds through some kind of regulatory asset structure. In some jurisdictions, regulators and legislatures have created securitization structures in which shareholders are paid for their investment in a set of assets no longer in service. The cost of this payment is then transferred to a bond-funded structure (with explicit or implicit ratepayer and/or taxpayer support) and the costs are paid back to bondholders over some period. Securitization can lower ratepayer costs by paying only the cost of the new debt, rather than the higher weighted average cost of capital, and potentially spreading costs over a longer period than the asset life.

Q17 What is the risk to investors in the case of stranded assets?

A17 There are two potential sources of investor risk associated with stranded assets. The first is that the regulator might not allow recovery of the investment once the assets are not used and useful. The second is that the competitive position of the utility might not allow it to raise rates to the level required to recover the investment from the utility's customers. That is, regulators might allow recovery, but the utility could find that its revenues fall (rather than rise) if it increases rates because customers choose to reduce their consumption in response to the rate increase. (As I discuss below, EGI is not in this situation today, and there is no analysis showing it is likely to occur.)

Q18 Could the competition-based risk occur without stranded assets?

A18 In theory, a change in the competitive environment (for example if a competing fuel became much less expensive) could result in customer demand falling enough to trigger spiraling rate increases and losses to investors not instigated by the recovery of costs of stranded assets. However, the falling demand associated with competition would likely result in stranded assets, so I do not consider this to be an entirely separate kind of risk.

Q19 How should different types and timescales for business risk inform the establishment of the regulated utility's capital structure?

A19 The equity share of the capital structure should most directly reflect the risks regarding return on invested capital in the period until the next time the capital structure is evaluated, with less weight given to risks that extend further out in time. Thus, short-term risks should be the primary driver for considering changes to the capital structure. If utility investors faced stranded cost risks in the short term, then these risks would be weighted more heavily because of their greater impact within the period of the rate setting. I discuss the considerations of short-term versus longer-term risks further below.

Q20 Are there independent third-party entities which evaluate EGI's business risk?

A20 Yes, the credit rating agencies evaluate business risk, alongside financial risk, as part of the evaluation of what credit rating to assign to EGI.

Q21 How do the credit rating agencies describe EGI's business risk?

A21 S&P gives EGI a rating of Excellent, its top rating. In its February 1, 2022, rating report (which is relied upon by Concentric and EGI), S&P states:[3]

> Our assessment of EGI's business risk reflects our view of OEB's regulatory framework, which underpins the utility's predictable and steady cash flow. In our view, the regulatory process is transparent, consistent, and predictable. These factors collectively support EGI's timely recovery of prudently spent capital and operating expenses. In addition, the federal carbon levy is a flow-through cost to customers, and gas commodity costs are recovered through a quarterly adjustment mechanism from ratepayers, limiting EGI's exposure to commodity risk.
>
> Further supporting our view is EGI's large customer base. EGI serves almost all of Ontario's gas distribution network with about 3.8 million customers, most of whom are residential and small business customers. As such, we expect EGI's cash flows to remain stable. However, demand for natural gas in the residential customer class can vary due to weather-driven fluctuations that can result in some cash flow volatility. Our favorable view of EGI's business risk is slightly offset by the company's limited geographic footprint and exposure to a single regulatory regime.

Q22 What insights do you draw from S&P's statement regarding how S&P evaluates business risk, and its conclusions regarding EGI?

A22 Overall, S&P's text is consistent with its rating of Excellent, and S&P states that it has a favorable view of EGI's business risk. S&P does express minor concern regarding fluctuations in cash flow (what I refer to as volatility or operational risk), but S&P does not discuss capital recovery risk or cite it as a factor relevant to its analysis of EGI's business risk. The only aspect related to energy transition that S&P addresses is the federal carbon levy, which is treated as a pass-through (a process which limits a potential risk). Viewed as a whole, this business risk summary does not appear to be consistent with EGI's and Concentric's claims that business risk is increasing, primarily driven by capital risk associated with

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[3] Exhibit I.5.3-STAFF-227, Attachment 2, Page 5 of 13.

energy transition. As far as risks that EGI does face, S&P appears to be primarily concerned with risk that can manifest in changes in cash flow and business performance within the relatively near term (e.g., weather fluctuations).

Q23 Can prudent utility management mitigate some of the business risks that utilities face?

A23 Yes. I will elaborate approaches appropriate for different kinds of risks later in my testimony.

Q24 How should utility management of business risk inform the capital structure?

A24 The capital structure should reflect the amount of business risk that a prudently managed utility, faced with the same circumstances as the utility in question, would experience. Prudent utility managers evaluate risks and analyze the costs that those risks might impose along with the costs of efforts to mitigate them. They then take the actions that are warranted to mitigate risks. (For example, if a risk is small—accounting for both its likelihood and impact—and would cost a great deal to mitigate, then it would be prudent to leave the risk unmitigated.) If utility management does not take prudent actions to mitigate risks, and therefore the company faces higher risks than warranted, that does not justify a higher return to shareholders.

I recognize that regulators have an important role to play in risk mitigation, because many of the actions that utility management would take to prudently manage risk require regulatory approval. Therefore, there is some risk that regulators will prevent the utility from taking a mitigating action. However, if the utility has conducted clear and comprehensive risk and mitigation analysis, it is sensible to assume that regulators will take the appropriate actions to advance the long-term public interest by allowing the utility to take justified mitigating actions. Ontario's "transparent, consistent, and predictable" regulatory regime (as described by S&P[4]) is the foundation of EGI's low business risk.

IV. CHANGE IN BUSINESS RISK

Q25 What is the key question regarding business risk in this proceeding?

A25 Business risk and equity thickness is considered in a two-part process in this proceeding. The first question is whether it can be conclusively shown that EGI's business risk has changed from what it was in 2012, the last time that the company's equity thickness was set. If it has changed, then the next question is what equity thickness would best reflect EGI's business risk.

Q26 Which aspects of this question does your testimony address?

A26 My testimony is focused on the first question: has EGI's business risk conclusively changed since 2012?

Q27 How do you evaluate whether business risk has changed?

A27 Business risk has two main components, as I discussed above: operational/short-term risk and capital/long-term risk. Regulators have a challenge in evaluating two very different types of risk and boiling them down to a single evaluation of "business" risk to inform the capital structure. If both types of risk have gone up, or gone down, then the direction is clear (although the magnitude can still be uncertain). Whereas if some risks are increasing and some are decreasing, or some are clearly changing in one direction while others are uncertain, developing a single assessment is difficult.

[4] Exhibit I.5.3-STAFF-227, Attachment 2, Page 5 of 13.

Q28 What about the matter of the timing of risks? That is, should near-term risks be weighed differently than risks that would manifest further in the future?

A28 The most important feature is not necessarily the timing of the risks, so much as their certainty. It happens that near-term risks tend to be better understood and characterized, and the range and likelihood of possible outcomes is more certain. If there were known risks coming in the further future, and their impacts were well characterized and quantified, they could potentially be considered to be as certain and impactful as near-term risks. But given the potential for change and the ability to adapt, it is generally the case that risks should be given less weight the further they would manifest in the future. In 2013, the OEB came to a similar conclusion:

> Regarding the risk of future events, the Board agrees with CCC that the relevant future risks are those that are likely to affect Enbridge in the near term. Any risks that may materialize over the longer term can be taken into account in subsequent proceedings. In considering the risk of future events, the Board will take into account the fact that, generally, the more distant the potential event, the more speculative is any conclusion on the likelihood that the risk will materialize.[5]

Q29 What principles should regulators use when weighing different changes in risk to come to a single final assessment of increase or decrease in business risk?

A29 Risks which can be better quantified and evaluated should be given greater weight, all else equal. In general, this means near-term, well-understood risks should be given greater weight, while uncertain, less established risks should be given less weight.

[5] EB-2011-0354, Decision on Equity Ratio and Order, February 7, 2013, at 7.

V. OPERATIONAL OR VOLATILITY RISK

Q30 What tools do gas distribution utilities have to reduce the annual volatility in their returns?

A30 Gas utilities can, with regulatory approval, establish a wide range of deferral accounts and other mechanisms to protect against fluctuations outside of their control. For example, gas utilities commonly pass through the cost of gas supply directly to customers. This way, if the wholesale cost of gas changes, customers bear that risk directly and the gas distribution business is not affected. In addition, it is common for gas utilities to have a weather adjustment process so that warmer or colder winters do not affect their ability to collect the allowed revenues to cover the cost of the installed gas system. Some utilities have accounts that allow them to recover the cost of lost or unaccounted for gas (that is, gas which the utility procures but which does not show up, in aggregate, on customer meters because it leaks or is otherwise unaccounted for). This reduces the utility's risk that unexpected amounts of lost gas will result in under-collection of overall revenues. Some utilities have decoupling regimes which completely or partially separate the amount of revenue collected from the amount of gas sold for any reason. Revenue per customer decoupling, for example, allows the utility to adjust its rates to collect a fixed overall revenue per customer for distribution service. This mitigates some of the disincentive the utility might have to encourage energy efficiency, while simultaneously protecting against weather fluctuations. While the examples I have listed here are common, each utility and jurisdiction tend to take their own approach to these kinds of tools based in their own situation and regulatory and legal context.

Utilities can also mitigate short-term risk by having regular or frequent rate cases (e.g., every two or three years) to mitigate the risk that utility costs will shift away from the costs used to establish rates. Multi-year rate plans can establish expected changes in utility costs between rate cases, so that utilities only take the risk that 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)

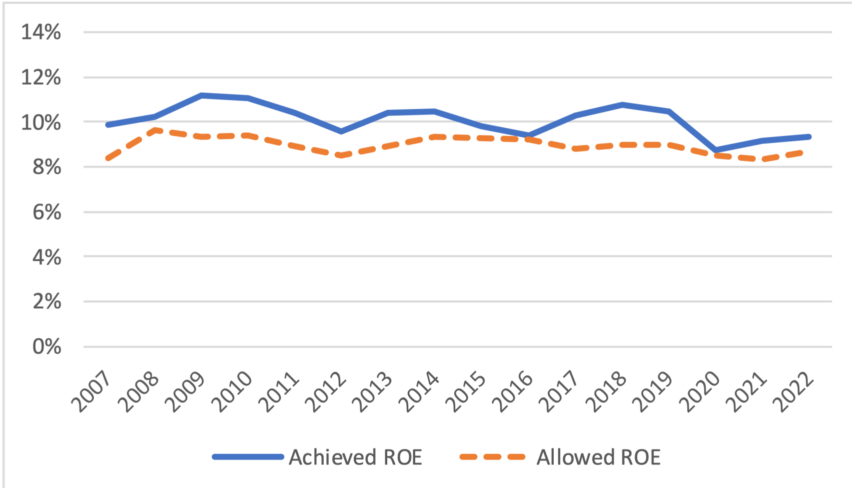
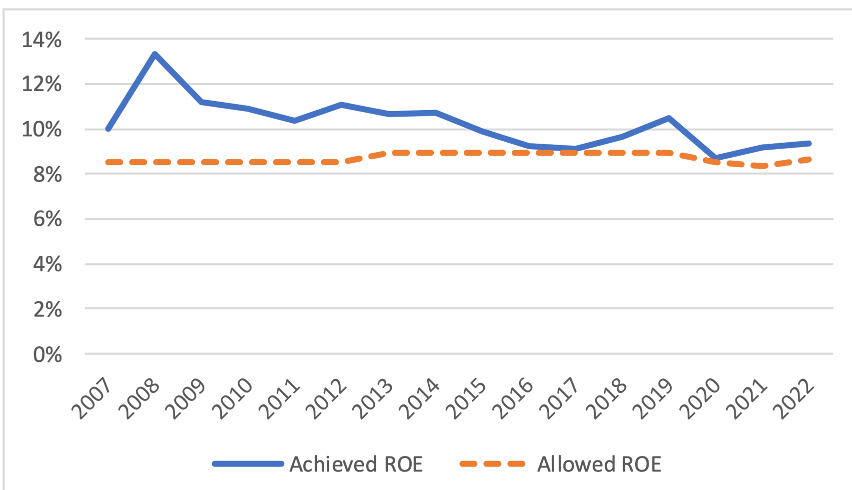


Figure 2. Achieved and allowed return on equity for Union Gas (2007–2018) and Enbridge Gas Inc. (2019–2022)



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.

To compare volatility, I used the calculated 0.64 percent standard deviation of EGI's achieved returns over its four-year existence as a combined company. Then I looked back at the standard deviation of EGD and Union Gas over four-year periods from 2007 to 2018. For EGD, the standard deviation ranges from 0.37 percent to 0.86 percent for different periods, and for Union Gas, the range is 0.25 percent to 1.23 percent.

Q35 What conclusions can you draw from analyzing the volatility of EGI's achieved returns?

A35 I conclude that EGI shows no indication of a change in operational or volatility-related business risk over the period from 2007 to the present. This is consistent with the addition of new variance and deferral accounts to manage new sources of volatility that have arisen over this period. The fact that EGI and both of its precedent parts exceeded their allowed returns every year since at least 2007 indicates that investors considering the near-term risk facing EGI should not expect their returns to fall below the allowed level, and that return will generally fall in a relatively narrow band above the allowed level.

Q36 Looking forward, is EGI proposing any changes in this proceeding that would have an impact on short-term or operational risk?

A36 Yes. I would highlight two proposed changes, related to rate design and to variance accounts.

Rate design: EGI is proposing a change to a straight fixed variable (SFV) rate design without a volumetric component, for delivery charges. Specifically, the proposed rate design (after harmonization) collects almost all delivery revenue from a customer charge and a demand charge. This rate design would make EGI's revenue more stable regarding year-to-year fluctuations, reducing its operational business risks. As Concentric states, "If approved, this proposal would further decrease the Company's exposure to volumetric risk."[6]

Variance accounts: EGI currently has an Average Use True-up Variance Account for EGD and a Normalized Average Consumption Account for Union Gas. These accounts stabilize EGI's revenue with respect to volumetric fluctuations away from the expected level due to causes other than the weather. Because revenue still changes with the weather, S&P identifies "weather-driven fluctuations that can result in some cash flow volatility" as a negative consideration with respect to business risk.[7] EGI is proposing to replace the Average Use True-up Variance Account and the Normalized Average Consumption Account with a single Volume Variance Account for the combined company. EGI states that "[i]ncluding this revenue variance [due to weather] in the proposed Volume Variance Account reduces volumetric risk in a symmetric and revenue-neutral manner for both customers and Enbridge Gas."[8]

I agree with Concentric and EGI that adopting one or both of the utility's proposals for a straight fixed/variable rate design and the volume variance account would lower the company's operational/volatility-related business risk.

Q37 What do you conclude regarding the implications of changes in short-term or operational risks for EGI's capital structure?

A37 I conclude that these business risks are the same or lower than they were in 2012. If the company's proposals are adopted for the Volume Variance Account or straight fixed/variable rate design, this aspect of business risk would be clearly lower than in 2012. Together, these results imply that, if this were the only business-risk-related issue in this proceeding, the OEB should either not reopen

[6] Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 57 of 164.
[7] Exhibit I.5.3-STAFF-227, Attachment 2, Page 5 of 13.
[8] Exhibit 9, Tab 1, Schedule 2, Page 27 of 30.

the question of the equity share (if risk is unchanged) or should open it only for the purposes of potentially reducing the equity share (if risk is lower).

VI. CAPITAL RISK

Q38 What are the types of capital risks that EGI faces?

A38 As I discussed earlier in my testimony, there are two types of capital risk that a utility might face over the longer term. The first is the risk that the regulator will not allow recovery of prudently incurred investments that become stranded, and the second is a competitive risk—namely that rates cannot be sustained at a high enough level to recover the investment. The drivers for such risks in Ontario are associated with policies and actions to reduce the province's greenhouse gas emissions, combined with the competitive position of gas compared with electricity.

Q39 How concerned are you that the OEB would allow EGI's capital risk to significantly increase?

A39 The OEB's "transparent, consistent, and predictable" regulation of EGI (to quote S&P) gives me confidence that the OEB will ensure that EGI plans appropriately to adapt to the policy and market contexts in which it finds itself over the course of the energy transition in the coming decades. The provincial government is thinking carefully about how to cost-effectively reach net zero greenhouse gas emissions. For example, the Ministry of Energy is conducting a Cost-Effective Energy Pathways Study that will identify cost-effective pathways to support the province's energy transition, which will inform the conclusions of the Electrification and Energy Transition Panel.[9] The OEB surely recognizes the

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[9] "Ontario Finalizes Electrification and Energy Transition Panel." November 17, 2022. King's Printer for Ontario. Accessed at https://news.ontario.ca/en/release/1002487/ontario-finalizes-electrification-and-energy-transition-panel. "Ontario Retains ESMIA and Dunsky to Conduct Cost-Effective Energy Pathways

importance of its role in managing the energy transition in a way that preserves gas system safety, which would require a functioning gas utility to operate and maintain its system. The OEB is well aware of the risk of additional unnecessary costs that would be associated with sudden shifts in the province's regulatory environment.

Q40 If EGI does not work within the policy and regulatory structures established by the province and OEB, could it experience increased capital risk?

A40 Yes. To the extent that EGI acts imprudently by failing to appropriately plan for the energy transition or by poorly managing the transition, it may experience lower returns and/or fail to recover its capital. However, this unlikely case is not the regulator's responsibility when considering the business risk facing a prudently run utility (such as for the purpose of setting the equity thickness).

A. Evaluation of EGI's Evidence Regarding Capital Risk

Q41 Is the energy transition a new issue for Enbridge?

A41 No. Ontario's climate plan has called for a dramatic reduction in emissions (including a reduction in emissions from natural gas) since at least 2016, and Enbridge Gas has been aware of this context and planning for it. In its June 2016 "GD Strategic Plan," Enbridge shows that 2050 emissions would need to be noticeably lower than the combined current emissions from heating and industry (of which natural gas is the dominant source).[10] The presentation discusses the competitive position of gas and electricity,[11] with a particular focus on the impact of electrification on winter peak demand,[12] and the need to "rebrand" existing gas

Study to Support the Province's Energy Transition." February 3, 2023. Dunsky Energy and Climate Advisors. Accessed at https://www.dunsky.com/ontario-retains-esmia-and-dunsky-to-conduct-cost-effective-energy-pathways-study-to-support-the-provinces-energy-transition/.
[10] Exhibit JT7.23, Attachment 1, Page 49 of 95.
[11] Id., p. 50.
[12] Id., p. 51.

infrastructure as a way to reduce emissions.[13] The presentation also identifies power to gas (i.e. hydrogen) and renewable energy (with a photo of cows, implying waste-based renewable natural gas) as parts of Enbridge's "long term future."[14] The presentation identifies "top issues for [gas distribution]" to be "navigating a challenging carbon policy environment" and "accelerated development of low-carbon business platforms."[15] All of these issues, highlighted for Enbridge's leadership seven years ago, are at the core of the energy transition discussion in Concentric's report and in this proceeding.

Q42 What does Concentric say regarding changes in capital risk?

A42 Concentric states that "[t]he Energy Transition places gas distribution utilities' long-term ability to earn a return of invested capital at risk as increasing costs must be collected from declining volumes."[16]

Q43 Do you agree with Concentric's analysis of capital risk?

A43 No, I do not. Concentric argues that four elements contribute to the significant increase in Energy Transition risk: government actions, investor concerns, utility commitment, and regulatory response. For each of these four elements, however, Concentric did not convincingly link energy transition to increased capital risk. That is, Concentric did not causally link any of these aspects of energy transition to an increased risk that EGI shareholders would fail to recover all of their invested capital with a fair return, if the utility manages the transition prudently.

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[13] Id., p. 52.
[14] Id., p. 57.
[15] Id., p. 59.
[16] Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 91 of 164.

Q44 Concentric argues that capital risks must be considered in the immediate term (and therefore in the establishment of today's capital structure) because today's investors take a long-term perspective, even though the risks would not manifest in shareholder returns for many years. Do you agree?

A44 I agree that investors look to the long term, while they also look to the near term. Investors look at risks across all timeframes and consider the picture as a whole, and they consider the likelihood of different outcomes over time. Standard financial evaluation includes discounting future returns, relative to near-term returns, when considering the value of an investment. Uncertain future capital risks are part of the overall picture and should be given weight reflecting their timeframe and chance of occurrence. I do not agree that investor sentiment about the long-term risks facing the natural gas industry, when not grounded in analysis of the actual risks facing EGI, is an appropriate metric for establishing whether and to what extent EGI's business risks have changed.

Q45 Concentric says that government actions have contributed to a "significant increase" in EGI's capital risk associated with the energy transition.[17] Do you agree?

A45 No. Concentric fails to concretely link government actions on energy transition to an increase in EGI's capital risk.

First, Concentric lists the greenhouse gas emission reduction targets of the federal government and the Ontario provincial government. However, Concentric did not identify specific proposed policies that would put at risk the ability of EGI's shareholders to earn on and recover capital. Ontario has not yet set a clear pathway for how it will decarbonize its building and industrial sectors. As Guidehouse's analysis shows, there are plausible pathways in which the province relies more on EGI than it does today, as well as pathways where EGI's role is noticeably reduced. While each pathway presents different challenges for EGI, it is premature to conclude that EGI faces material capital recovery risks associated

[17] Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 6 of 164.

with any specific pathway. EGI itself advocates for the continuing role of gas and potential future uses of its delivery infrastructure in achieving decarbonization goals reliably and cost effectively.

Second, Concentric claims that the implementation of a carbon tax would increase delivered gas cost to customers. The report shows that the carbon tax is expected to reach $170 per metric ton in 2030.[18] However, Concentric did not provide estimates of the impact of carbon pricing on the competitive position of EGI relative to electricity, nor has Concentric shown that such competition would result in failure to recover any capital along with a fair return.

Third, Concentric argues that restrictions on gas use in buildings "threaten natural gas customer growth because they generally apply to new buildings."[19] Concentric has not shown how growth in the number of customers is required in order to recover invested capital or return, or even how customer growth (with associated additional capital investment) would impact the ease with which capital is recovered. A gas ban (depending on how it is implemented) could prevent EGI from establishing new connections but would likely have no impact on existing customers or the utility's ability to recover the cost of service, with a fair return, from those customers. Furthermore, even if growth were somehow required to recover already invested capital, the Concentric report presents no tangible evidence that gas bans are a risk in Ontario, recognizing that "it is not aware of any building gas bans" in Ontario.[20] In fact, Ontario law requires Enbridge and its ratepayers to support expansion of gas service to additional communities[21].

[18] Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 21 of 164.
[19] Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 22 of 164.
[20] Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 24 of 164.
[21] Ontario Regulation 24/19.

Q46 Concentric says that investor environmental, social, and governance (ESG) concerns indicate or contribute to an increase in EGI's capital risk. Do you agree?

A46 No. Concentric cites industry reports on cost of new debt issuances but does not provide proof that EGI's cost of debt is any higher than other utilities, or higher than it was in 2012, due to ESG concerns. In fact, Concentric cites Enbridge's 2021 Sustainability Linked Bond (SLB) issuances as an example of the impact of investors' ESG concerns, and this shows a small *reduction* in the cost of debt for Enbridge.[22] S&P states that "ESG factors have no material influence on our credit rating analysis of EGI."[23]

Concentric cites an S&P report analyzing debt issued by North American energy companies from 2019–2021 wherein S&P estimates that the debt yield of the highest carbon intensive companies is 150 basis points higher than for the lowest carbon intensity issuers.[24] However, there is no evidence that EGI was included in this analysis, nor any evidence that EGI has a higher or lower carbon intensity than its nominal peers. Concentric and EGI are unable to confirm if EGI is included in the highly carbon intensive grouping, or the lowest.[25] Without more analysis, it is unclear where EGI would land or even whether it would qualify to be included in the analysis, since S&P's grouping of energy companies is defined as including "investment-grade companies from the integrated oil and gas and midstream energy sectors."[26] In short, this S&P analysis covers risk in a sector that does not correspond to the regulated utility business in which EGI operates, and Concentric and EGI provide no information that would allow the OEB to conclude that the market reflects any conceptions of EGI's business risk associated with its carbon intensity.

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[22] Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 32 of 164.
[23] Exhibit I.5.3-STAFF-227, Attachment 2, Page 8 of 13.
[24] Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 26 of 164.
[25] Exhibit I.5.3-IGUA-31, Page 1-2.
[26] Exhibit I.5.3-STAFF-202, Attachment 1, Page 4 of 19.

Concentric claims that "an increasing number of investors… are prioritizing environmental, social, and governance ("ESG") considerations when making investment decisions.[27] In a succeeding section of Concentric's report, the impact of this is illustrated under "Enbridge developments." On June 2021 and September 2021, Enbridge issued SLBs that received an estimated 5 and 10 basis point "greenium," which is the "discount relative to the estimated interest rate of a debt issuance from Enbridge."[28] Further "(b)ond analysts have noted that such premiums are increasingly common among green bond issuances as investor demand far outpaces supply."[29] This is an actual, quantitative data point that illustrates how investors' ESG concerns affect the company. Since the result is a small *decrease* in the cost of new debt, this example does not support the assertion that investor concerns about the energy transition leads to an *increase* in EGI's capital risk.

Q47 Concentric says that emissions reduction targets announced by North American utilities are indicative of a "significant increase" in EGI's capital risk. Do you agree?

A47 No. Concentric lists numerous examples of utilities' climate commitments. These utility commitments are indicative of the fact that a decarbonization-focused energy transition is happening. However, Concentric again provides no tangible evidence that these utility commitments cause or indicate any specific course of action that would result in EGI not earning its return on and of capital.

Q48 Concentric says that regulatory responses have contributed to an increase in EGI's capital risk. Do you agree?

A48 No. Concentric's arguments do not sufficiently link "future of gas" proceedings to an increase in capital risk.

[27] Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 25 of 164.
[28] Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 32 of 164.
[29] Ibid.

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.

Study will similarly reflect the transparent, consistent, and predictable regulatory process in Ontario, which is a key component of S&P's evaluation of EGI's business risk as "Excellent."

Q49 Why do you not separate volumetric risk out as a distinct type of risk from operational/volatility risk and capital risk?

A49 Volumetric risk is not a distinct risk to be accounted for separately. EGI's return to investors is not a direct function of its sales volumes. Changes in sales volumes resulting from year-to-year fluctuations (such as from weather or economic cycles) would manifest as operational/volatility risk (to the extent not mitigated by the tools discussed previously). Long-term trends in sales, such as could result from energy transition, would impact rates, competitive position, and eventually a business's or individual's choice to remain EGI's customer; i.e. capital risk.

Q50 Concentric says that volumetric risk has increased modestly, contributing to an increase in EGI's capital risk. Do you agree?

A50 No, I do not agree. Concentric argues that volumetric risk has increased relative to the previous equity thickness proceedings, due to "a weaker economic outlook, introduction of competition from alternative gas suppliers and increased competition from electricity (i.e., the Energy Transition)."[31] Concentric lays out the mechanisms that drive short-term and long-term volatility of volumes, but then presents the risk mitigation strategies that are available to EGI. Concentric concedes that EGI faces "limited short-term volumetric risk" because of ratemaking mechanisms such as the proposed SFV rate design and deferral and variance accounts.[32] Concentric also raises the issue of a death spiral, but acknowledges that it does "not expect a death spiral scenario to be likely for Enbridge Gas because it is reasonable to anticipate both the Company and its

[31] Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 80 of 164.
[32] Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 57 of 164.

regulators would work proactively to avoid such a scenario."[33] Volumetric risk impacts from a "death spiral" situation are not expected in the near term in any case. As EGI stated in Exhibit I.1.10-OGVG-1, "Enbridge Gas does not have actual stranded asset costs for the 2013 to 2022 period and is not forecasting any stranded asset costs from 2023 to 2028 related to its distribution, storage or transmission assets." Between short-term actions, such as ratemaking mechanisms, and long-term actions with the countenance of the OEB, Concentric has not shown there is unmitigated volumetric risk that is distinct from capital risk related to energy transition.

Q51 Concentric says that EGI's financial risk has increased modestly and that this supports its conclusion that EGI's business risk has materially increased. Do you agree?

A51 No. Concentric utilized credit metrics from the S&P reports to argue that financial risk has increased modestly and this forms part of its argument that the business risk of EGI has increased since 2012.[34] However, business risk and credit risk need not necessarily align.

Concentric provided the credit ratios but did not provide analysis that pinpointed the factors leading to the change. There are indications that the changes in the credit ratios are driven by increased need for debt financing to fund the Company's capital plan (and also that the credit ratios improve as a result of this rebasing case, even without the change in equity thickness). For the period 2022–2023, the Company's capital expenditure program is twice its depreciation cost, which implies negative discretionary cash flow and a need for external funding requirements.[35]

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[33] Ibid.
[34] Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 80 of 164.
[35] Exhibit I.1.8-STAFF-14, Attachment 6, Page 51 of 57.

There has been no change in S&P's perceived business risk of EGI. As shown in Table 1, S&P has rated the business risk of EGI (and its preceding companies) as "Excellent" at every opportunity from 2012 to the present.

Table 1. Standard & Poor's credit rating report summary

Pub Date	Company	Credit Rating		Business Risk	Financial Risk	Liquidity
24-Dec-12	EGD	A-	Stable	Excellent	Significant	Adequate
27-Jun-13	EGD	A-	Stable	Excellent	Significant	Adequate
16-May-14	EGD	A-	Stable	Excellent	Significant	Adequate
27-Nov-15	EGD	A-	Stable	Excellent	Significant	Adequate
27-Nov-15	EGD	BBB+	Stable	Excellent	Intermediate	Adequate
27-Nov-15	EGD	BBB+	Stable	Excellent	Intermediate	Adequate
29-Nov-16	EGD	BBB+	Stable	Excellent	Intermediate	Adequate
20-Nov-17	EGD	A-	Stable	Excellent	Significant	Adequate
21-Dec-12	UGI	BBB+	Stable	Excellent	Significant	Adequate
17-Jun-13	UGI	BBB+	Watch Negative			
4-Nov-13	UGI	BBB+	Stable	Excellent	Significant	Adequate
12-May-14	UGI	BBB+	Stable	Excellent	Intermediate	Adequate
24-Sep-15	UGI	BBB+	Stable	Excellent	Significant	Adequate
6-Sep-16	UGI	BBB+	Watch Positive	Excellent	Significant	Adequate
2/28/2017	UGI	A-	Stable			
12/1/2017	UGI	A-	Stable	Excellent	Significant	Adequate
1/2/2019	EGI	A-	Stable	Excellent	Significant	Adequate
4/3/2020	EGI	A-	Stable	Excellent	Significant	Adequate
1/19/2021	EGI	A-	Stable	Excellent	Significant	Adequate
1/1/2022	EGI	A-	Stable	Excellent	Significant	Adequate

Sources: Exhibit I.1.8-STAFF-14, Attachment 13, Exhibit I.1.8-STAFF-14, Attachment 14, and Exhibit I.1.8-STAFF-14, Attachment 6.

Q52 Did Concentric or EGI conduct quantitative analysis of any of their arguments to demonstrate that EGI's capital risk has materially increased?

A52 No. Industrial Gas Users Association asked Concentric and EGI to identify and provide quantitative analysis supporting numerous contentions in the Concentric report, but both firms stated that no such analyses had been completed. They provided no analysis of any of the following:

- the impact of demand-side solutions on meeting net zero targets and risk (Exhibit I.5.3-IGUA-34)

- the impact of accelerated depreciation rates or equity thickness on competition (Exhibit I.5.3-IGUA-35)

- the finances of EGI as a company in any scenario in which EGI's investors are unable to earn a full "return of" their invested capital (Exhibit I.5.3-IGUA-36(a)) or EGI is no longer able to engage in the distribution of natural gas (Exhibit I.5.3-IGUA-37)

- any specific assets that are at risk of becoming stranded due to the energy transition or other cause (Exhibit I.5.3-IGUA-36(c))

- changes in gas system operations and maintenance costs along different decarbonization pathways or energy transition scenarios (Exhibit I.5.3-IGUA-36(d))

- infrastructure investment or retirements on EGI's system along different decarbonization pathways or energy transition scenarios (Exhibit I.5.3-IGUA-36(e) and (f))

- the competitive position of gas and electricity for sectors other than the residential sector (Exhibit I.5.3-IGUA-38(a)), or EGI's market share in new construction (Exhibit I.5.3-IGUA-38(c))

- actions the company could take to work proactively to avoid a "death spiral" outcome (Exhibit I.5.3-IGUA-40(b))

- the amount of customer-switching to electricity that might be required to potentially cause a "death spiral" for EGI (Exhibit I.5.3-IGUA-41)

- the impact of declines in per-customer gas use, declines in the rate of new customer additions, the economic growth outlook, or the OEB's encouragement of competition for EGI on the likelihood of a "death spiral" or the conditions or timeframe under which such an event occurs (Exhibit I.5.3-IGUA-42(b), (d), (f) , and (h))

- impacts on EGI's Debt/EBITDA, FFO/Debt, FFO/Interest Coverage, EBIT/Interest Coverage, or Debt/Capitalization of changes in depreciation rates, infrastructure investment or retirement, or any decarbonization pathway (Exhibit I.5.3-IGUA-44(b))

- the potential relative risk of EGI (compared with other Canadian utilities) associated with the portion of residences in Ontario that use natural gas for space heating (Exhibit I.5.3-IGUA-49)

Q53 What are your conclusions regarding Concentric's analysis of EGI's capital risk?

A53 Concentric has not shown that EGI's capital risk has actually increased since 2012. Concentric has pointed to various indicators but not connected those indicators to any concrete scenarios or circumstances in which EGI's shareholders or bondholders would actually fail to recover all of their invested capital, with a fair return. Neither Concentric, EGI, nor any other firm working for EGI has conducted empirical analysis of any of the wide variety of claimed factors that Concentric cites in its report as evidence that EGI faces increased capital risk, or what the impacts on EGI, its investors, or customers would be if the identified risks became manifest.

B. Competition between Gas and Electricity

Q54 What is the competitive position of gas compared with other energy sources in Ontario today?

A54 It is important to consider this question on a sectoral basis because the relevant fuels for competition vary. In the residential sector, for example, EGI reports that in 2022 natural gas provided 33 percent savings relative to electricity for space and water heating.[36] That savings ratio is the smallest it has been since 2015, reflecting the recent spike in commodity gas prices associated with the war in Ukraine. Absent that recent spike, gas bills are generally close to half of electric bills for similar service. (It appears that these calculations assume electric resistance heat; using heat pump technology would likely make electricity more competitive, depending on the details of the technology and how it is installed.) Looking at the practical impact of energy prices on consumer choices in the market, we see that EGI has steadily added customers, indicating that it retains a favorable market position in the residential space.

In the industrial sector, gas retains a favorable position against oil, propane, and coal, resulting in shifts from those fuels to gas. For example, ArcelorMittal Dofasco is transitioning its steel plant in Hamilton from coal to gas and electric arc furnace, with support from a new Enbridge pipeline.[37] This project will reduce the greenhouse gas footprint of the steel produced by 25 percent by 2030, showing a key competitive advantage of gas over coal.

Q55 How has the competitive position of gas changed versus electricity since 2012?

A55 EGI was only able to provide comparisons for residential customers back to 2015. While gas had a greater advantage over electricity in 2015, the overall effect of change in electricity and natural gas bills from 2015 to 2022 is to leave natural gas with a noticeable continuing advantage.

[36] Exhibit I.5.3-IGUA-38, Attachment 1, Page 2 of 4.

[37] "ArcelorMittal Dofasco hosts groundbreaking ceremony for its transformational low-carbon emissions steelmaking project." October 13, 2022. ArcelorMittal. Accessed at https://dofasco.arcelormittal.com/media/news-articles/arcelormittal-dofasco-hosts-groundbreaking-ceremony-for-its-transformational-low-carbon-emissions-steelmaking-project, and "Hamilton Reinforcement Project." Enbridge. Accessed at https://www.enbridgegas.com/about-enbridge-gas/projects/hamilton-reinforcement-project.

Looking at the raw commodity price through the indicator of the Henry Hub price, which is a greater factor for large-volume commercial and industrial customers, gas commodity prices remained low or fell between 2012 and 2021, before the recent war-related spike (which recent data indicates may be dissipating). Retail electricity rates are generally slightly higher (although perhaps lower in real terms) today than they were in 2012.[38]

On net, I would conclude that the competitive position of gas versus electricity is comparable today to what it was in 2012.

Q56 What is the role of public policy and provincial plans in consideration of the competition between gas and electricity?

A56 If gas retains a price advantage, unmanageably rapid departures from the gas system are unlikely. Instead, policy is going to drive adoption rates and the path forward. At this time, Ontario does not have an established path forward to decarbonize the building and industrial sectors. That pathway is being developed through the Ministry of Energy's Cost-Effective Energy Pathways Study process.[39] Once that path is clear and policies and programs are developed to accomplish it, those will become among the primary drivers for customer heating system choice. Even if the province were to choose a high-electrification path, the resulting customer departure rate would likely be manageable because it would be restrained by customer equipment lifetimes and gas's competitive price. For example, customers would be unlikely to jump at the need to change to a heating source that is more expensive, absent a programmatic incentive; the incentive could be targeted and scaled to meet policy objectives. This means that approaches such as neighborhood-level conversions to electric heat are available

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[38] "Historical electricity rates." Ontario Energy Board. Accessed at https://www.oeb.ca/consumer-information-and-protection/electricity-rates/historical-electriciity-rates.
[39] "Ontario Finalizes Electrification and Energy Transition Panel." November 17, 2022. King's Printer for Ontario. Accessed at https://news.ontario.ca/en/release/1002487/ontario-finalizes-electrification-and-energy-transition-panel.

and EGI could manage its asset investments and depreciation to mitigate stranded costs. Forward-going customer and utility decisions regarding adding gas service to new construction could similarly account for the new policy context.

Q57 How does the competitive position of natural gas and electricity inform your consideration of changes in EGI's capital risk?

A57 Capital risk is linked to competitive position by the concern that costs will be stranded if the utility is unable to raise rates further without reducing revenue (that is, by driving more sales away than it gains from raising rates). Because EGI begins with its service and fuel having a cost advantage over electricity rates for comparable services, I believe that EGI could sustain a substantial increase in delivery rates and stay below the level where stranded costs would become an issue.

Q58 Have Concentric or EGI conducted analysis of EGI's competitive position and how it relates to capital risk?

A58 No, neither the utility nor its contracted business risk expert have conducted such analysis.

C. Setting a Standard for Utility Energy Transition Risk Analysis

Q59 In the previous two sections, you stated that Concentric's analysis is not sufficient to justify a conclusion that EGI's capital risks have increased. What would an analysis need to include for you to find it convincing?

A59 Risk is composed of the combination of likelihood and consequence. A capital risk analysis should include identification and analysis of the circumstances under which a utility would fail to recover its invested capital along with a fair return, the extent of the shortfall, and the likelihood of such circumstances. The most obvious way to conduct such an analysis would be through scenario analysis.

Q60 What would the structure of such a scenario analysis look like?

A60 A scenario analysis would develop a number of plausible future scenarios, assign those scenarios weights based on transparent assumptions about the futures they represent, and model the conduct of a prudently run utility adapting and managing itself in that scenario. It is important to capture not just the external changes in the equipment and buildings that use the utility's product, but also the state of the utility business itself (such as its plant in service, depreciation, operations and maintenance costs, return to investors, etc.). Scenarios should be realistic and internally consistent. For example, they cannot depend on both high and low prices for a given input, or expect unreasonable responses from building owners.

Q61 What is the purpose of this scenario modeling, beyond risk analysis?

A61 Scenario modeling can help answer a wide range of questions to inform utility management (and regulators). For example, scenario analysis of this sort can be used to identify no- or low-regrets actions, such as actions which occur along the prudent path forward in multiple scenarios. It can identify essential choices or points where it is no longer reasonable to maintain optionality. It could identify brittleness to the availability of particular inputs (or availability at a given price point).

Sensitivity analysis is aimed at testing what happens if things go differently than expected. For example, a sensitivity analysis can capture what happens if a utility begins along one path based on assumptions about customer demand and fuel availability but discovers the world is different from its assumptions. Some approaches to managing a given scenario may be more flexible to managing such changes than others.

With respect to capital risk analysis, scenario modeling could identify which pipes or other assets are used and useful for what times, in each scenario. This modeling can also identify any barriers that may exist to fully depreciating those assets before they retire. The scenarios would also identify which assets would be able to serve their full engineering life, such as high-pressure pipe serving industrial and power generation customers that plan to retain pipeline gas service as part of their net zero plans. Where scenario modeling identifies assets at risk of stranding, the analysis could identify, and quantify the potential cost of, mitigating actions to avoid stranding.

At the foundational level, scenario analysis of capital risk aims to answer: under what circumstances is a prudent utility manager forced to strand costs; how likely are those circumstances and what is the extent of the stranding; and are some approaches in the near term more or less likely to create unavoidably risky situations later?

Q62 What are other important considerations for this analysis?

A62 There are a handful of additional items to look for in scenario analysis of the gas utility's future:

- The analysis should be geographical in nature and grounded in the topology and configuration of the utility's system. What opportunities are there for neighborhood-level approaches that work well with the age and configuration of existing assets, such as for non-pipeline alternatives?

- The analysis should include the value of optionality—once a utility invests in a long-lived asset it cannot un-invest, so incremental approaches that limit investments in irreversible decisions are more valuable than approaches which depend on large commitments.

- The analysis should respect the ability for customers to make decisions, and account for their behavior when presented with different electric and gas rate designs and incentives. For example, the analysis would examine the impacts of a straight fixed-variable rate design on customer decision-making and expenditures, and it would identify if there are likely tipping points for the competitive position of electricity and gas, from the standpoint of different types of customers.

Q63 In what ways does the Concentric report fall short of the type of analysis you have described here?

A63 The Concentric report describes general conditions for EGI and for its industry at large. It does not identify or conduct any analysis that even attempts to examine the future of EGI and its specific business or financial parameters under different approaches to energy transition, either approaches internal to the utility, or external approaches in terms of Ontario's pathway. To rigorously argue that energy transition creates capital risk for EGI, some kind of analysis of actual risk facing EGI itself is necessary.

Q64 In what ways do the Posterity Group[40] and Guidehouse[41] reports fall short?

A64 The Posterity Group and Guidehouse analyses are scenario analyses, but they look only at the external characteristics of Ontario's energy system and ignore the state of EGI as a company within this context. They do not include analysis of the totality of EGI's capital investments or retirements, rate base, depreciated assets, system operations, operations and maintenance costs, rates, or returns to investors in their scenarios. As such, neither analysis is capable of answering the business-specific questions that are necessary for quantifying and understanding business risk for EGI and its mitigation by EGI.

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[40] Exhibit 1, Tab 10, Schedule 5, Attachment 1.
[41] Exhibit 1, Tab 10, Schedule 5, Attachment 2.

Q65 When is the right time to conduct a scenario-based or stochastic business risk analysis?

A65 EGI could have conducted such an analysis for this rate proceeding, if it had taken the next step beyond the Guidehouse report; but it chose not to do so. That analysis would have considered the Guidehouse scenarios and sensitivities, as well as other, business-specific parameters. At this point, however, I do not think it would be worthwhile for EGI to build an analysis of this sort from the Guidehouse report's foundation. This is because of the Ontario pathways study currently underway, and the necessary policy choices that study will set up for the provincial government. At this point, the right path forward would be for EGI to wait until that study and policy-setting process is complete, then develop business-specific analysis of its future in the context established by that framework. This will prevent the utility from wasting effort analyzing scenarios that are far from the province's selected path and allow it to use its resources to go deeper on understanding and planning for its path forward. In its letter to the OEB of April 4, 2023, regarding the Guidehouse study, EGI states that it is aware of and anticipating the provincial study and policy-setting process:

> "Enbridge Gas never expected that its own pathways report would be determinative of any OEB decisions in this case. In this regard, it is important to note that the work of the Electrification and Energy Transition Panel is now underway, and that the Panel's work will be complemented and supported by a Ministry of Energy sponsored independent Cost-Effective Energy Pathways Study."[42]

[42] Letter from David Stephens to OEB, April 4, 2023. Regarding "Update re Guidehouse Pathways to Net Zero Emissions for Ontario report."

D. Survey of Analyses Conducted Elsewhere

Q66 Are you aware of utilities or others that have conducted analyses of the sort you have just described?

A66 I am not aware of any one study that has met the full set of best practices that I laid out. However, some utilities, regulators, and policymakers are making good progress. I have included as Attachment 3 to this evidence a white paper that I co-wrote with my colleague Sol Deleon regarding the status of relevant processes and analyses in eight different jurisdictions across the United States: Massachusetts, New York, Maryland, Washington, DC, Minnesota, Colorado, Oregon, and California.

Q67 Are there particular exemplars or lessons from this analysis that are relevant for EGI and the OEB?

A67 Yes. I would highlight aspects of the analysis conducted in five states as particularly relevant here:

1. Massachusetts: In Case 20-80, the state's gas utilities expanded the scope for a study required by the regulator to include explicit analysis of potential regulatory actions and their impacts for the utilities. The study consultants quantified the impact of changing depreciation to a "units of production"-based approach on both near-term rates and the undepreciated plant balance remaining in 2050. They also quantified the potential impacts of geographically targeted electrification and neighborhood-level approaches to asset retirement. The consultants proposed an extensive suite or menu of potential regulatory changes to help the utility manage the energy transition while mitigating both equity and investor concerns.

2. New York: New York's utility regulator has established study and planning requirements that are informing that state's approach to gas utility transformation in line with that state's Climate Scoping Plan's directive to

"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

shortfalls. It then presents the results of analysis of different options to mitigate those challenges, including: limiting gas infrastructure investment; reducing costs by geographically targeting electrification and asset retirement; changes to depreciation rates and cost allocation; looking for revenue outside of the gas system; and shutting down uneconomic gas infrastructure.

Q68 You were involved in writing the Maryland study you just referenced, is that correct?

A68 Yes, I was on the Synapse team that produced that report.

Q69 In the Maryland study, Synapse quantified potential stranded costs for the Maryland gas utilities resulting from electrification, is that right?

A69 Yes. We quantified the rate base remaining in 2050, when sales had fallen by about an order of magnitude and rates were higher by about a factor of 5 to 10 (depending on fuel cost assumptions). We showed that if the state's utilities did not change their approach to managing their capital (e.g., they kept their depreciation rates unchanged) customer departures could result in stranded costs for meters, services, and (potentially) mains.

Q70 Have you conducted subsequent analysis that better captures the options for utility management to mitigate stranded cost risks?

A70 Yes, we have. We have developed a different modeling approach, described in Attachment 4, which captures a wider range of options for asset depreciation and utility investment and retirement approaches. This model is illustrative rather than dispositive, and it includes numerous simplifying assumptions. These simplifying assumptions are necessary because of limits in the information available to an independent consultant regarding a particular utility's gas system. However, I believe that modeling of this sort is reasonable and appropriate for EGI to conduct in order to understand its actual stranded cost risk.

E. Illustrative Modeling of Gas Utility Capital Risk

Q71 Could you describe the illustrative model in more detail?

A71 Attachment 4 describes a simplified illustrative model of a gas distribution utility undergoing a strategic downsizing over the course of the time between now and 2050. The purpose of this modeling is to show what the rate implications of such a transformation would be for customers of the retiring or retained gas systems, and the financial implications for the utility. The model is designed to avoid stranded assets and identify the extent to which avoiding stranded assets creates unsustainable rate implications. If rates in the model become unsustainable, that implies that some stranded costs may be forced by competitive factors, unless these costs are mitigated through regulatory means. A model of this sort (especially if tailored to the specific knowledge that a utility has about its own systems and finances) can be used to examine different scenarios and identify whether and when any assets become stranded. The model can also evaluate what the value of those assets at risk might be, and thereby assesses whether each scenario includes any capital risk for the utility, along with the size of that risk.

Q72 Does this model you are presenting here capture EGI in detail?

A72 No, it does not. While I have scaled the modeled utility to roughly align with EGI's parameters, this model is just a simplified illustration compared with the analysis that would be possible with access to the utility's information about its system and customers.

Q73 Could you summarize the modeled decarbonization scenario and key results from Attachment 4?

A73 The case examined to illustrate the model in Attachment 4 is of a world in which gas sales to non-industrial customers (which use the low-pressure gas distribution system) decline linearly to zero in 2050, while sales to industrial customers (which use the high-pressure gas distribution and transmission systems) remain flat. This is broadly similar to the Electrification Scenario examined by Guidehouse in Exhibit 1, Tab 10, Schedule 5, Attachment 2, except the decline in gas use in the non-industrial sector is somewhat faster (reaching zero by 2050, while Guidehouse's analysis has some remaining building-sector sales in 2050[43]). In this case, we assumed that services and meters are retired as customers depart the system. We also assumed that distribution mains will be retired, but with a lag (reflecting the fact that a given segment of main cannot be retired until all customers have departed). All distribution mains are retired by 2050 when the last non-industrial customers leave the system.

In this illustrative case, the utility's rate base falls by about a factor of two (in nominal dollars) by around 2040, before rising again as the continued investment in the high-pressure and transmission systems to serve industrial customers dominates over the reductions resulting from retiring the low-pressure system. In nominal dollars, it rises to today's level by 2060. Delivery rates for building-sector customers rise sharply at the start of the modeled scenario, reflecting the change in depreciation rates. Delivery rates then stay roughly level in inflation-adjusted terms until around 2040, when they first rise above their 2024 level. Starting in about 2043, real building-sector rates rise to about 150 percent of today's rates. I've used that as an illustrative threshold for the level at which delivery rates might not remain competitive with electricity, and stranded asset risk increases. Because of the extensive depreciation that has already occurred by this point, however, the actual amount of assets at risk is quite small.

Industrial rates rise steadily throughout the study period, as the costs of high-pressure and transmission assets are allocated more and more to them (because building-sector sales are falling). There is no risk of stranded assets serving the industrial sector in this simple scenario, because the industrial customers are

[43] See Exhibit 1, Tab 10, Schedule 5, Attachment 2, Page 29 of 86, Figure 8.

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 customers remain on the system, so that everyone contributes to this final asset cost, or potentially look for taxpayer (rather than ratepayer) support. If the costs were recovered through a transition charge, and the process starts soon, the cost could be very low (roughly 1 percent of rates) to cap all-in rates at a level that is low enough to maintain rough cost parity with electricity and avoid poor equity outcomes.

- There is some near-term rate shock from accelerating depreciation, as soon as that change is made. Some kind of ramp-in is likely both appropriate and easily manageable.

- Waiting makes things worse. The longer the utility waits to change its approach (in a world where building-sector customers and sales are falling toward zero), the larger the rate shock and the larger the potential amount of stranded costs to mitigate.

- Having a clear long-term plan sooner rather than later is key for successfully managing a scenario like the one we modeled, and likely for other scenarios as well. Thankfully, Ontario is developing a provincial plan. It will be important for EGI to adapt its business to that plan quickly after it is adopted.

Q75 How does the capital risk in the scenario you modeled inform your thinking about the reasonableness of EGI's request to change its equity thickness in this case?

A75 Our modeling takes on an ambitious electrification case, which should (if Concentric's report were taken at face value) present one of the highest risks for stranded costs. In this case, using relatively simple levers around depreciation and retirement, the actual dollars at risk of stranding are quite small. In this case, the present value of potential capital losses is less than 1 percent of today's plant in service. It is also likely to be less than the net increase in ratepayer costs resulting from EGI's proposed change in equity ratio just between 2024 and 2028. It is not reasonable to compensate EGI's investors more in the next five years than the losses a prudently run utility could, hypothetically, face two to three decades from now. This is especially true because this near-term compensation would not absolve ratepayers of the need to later also pay as part of the utility's efforts to minimize its stranded costs if an unmitigable risk does come to pass.

Q76 Has EGI grounded its request for increased equity thickness in analysis of the cost of business risk related to energy transition?

A76 No. EGI is arguing that its consultants know better than S&P and that its business risk has increased despite S&P not identifying that risk in rating reports for the company. My analysis shows that EGI faces small, if any, capital risk from an ambitious electrification scenario; this aligns with S&P's silence regarding this risk. EGI has the information at hand to do a more complete analysis than the one that I have presented, yet it has not done so. EGI's analysis could overcome the information deficiencies that I have as an external consultant operating on the limited budget of an intervening party.

Q77 Based on your analysis of the capital risk facing EGI, what do you recommend the OEB order regarding EGI's capital risk analysis?

A77 The OEB should reject EGI's argument that it requires a greater equity thickness because of energy-transition-related capital risk until such time as EGI presents quantitative analysis of the risk it faces (and which it cannot mitigate while acting prudently), in the context of Ontario's pathway to net zero emissions. When such analysis is presented and withstands intervenor and OEB scrutiny, it can be the basis for just and reasonable decisions regarding equity thickness.

F. Financial Risks

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

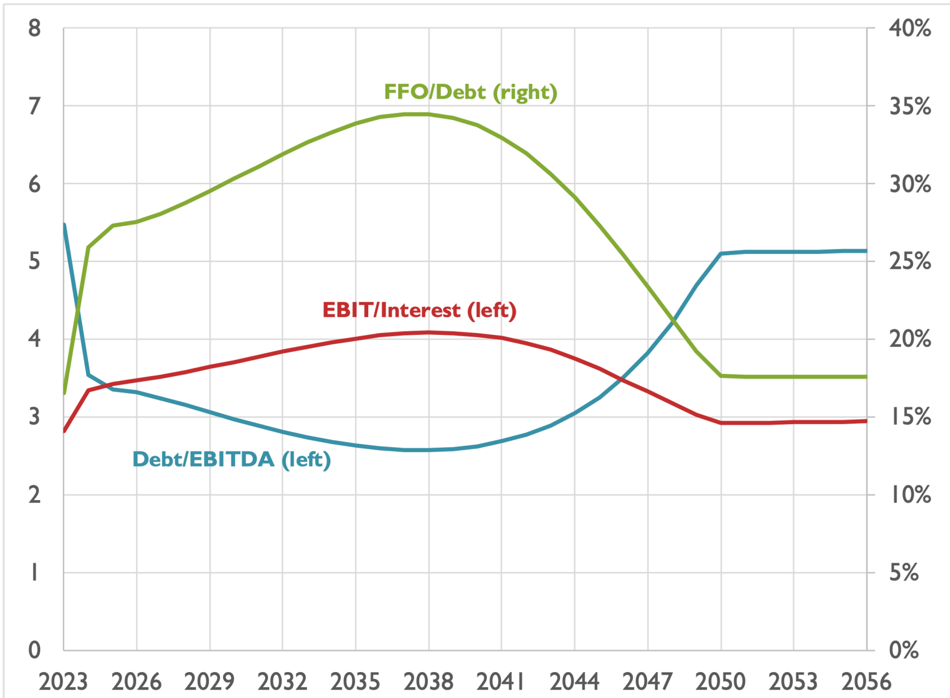
A78 No, I do not. A utility's financial situation is intimately tied to its investment strategy and asset recovery strategy. Therefore, financial risk parameters are closely linked with capital risks.

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.

Figure 3. Financial parameters for a hypothetical strategically downsizing utility, showing EBIT/Interest and Debt/EBITDA on the left-hand scale and FFO/Debt on the right.



Q80 How should EGI and Concentric have accounted for these effects in their assessment of EGI's energy-transition-related business risk?

A80 If Concentric and EGI had evaluated the specific situations facing EGI, such as through a scenario analysis approach like the illustrative one that I detailed above, they would have been able to quantify the financial implications of different approaches to managing the energy transition—similar to what I showed in my illustrative example. They might, for example, have seen that a reduction in equity thickness is appropriate in the case of accelerated depreciation. (By reducing the equity thickness, the financial parameters would come back closer to today's levels. Overall, the company could have the same credit rating with less equity.) This would have the effect of counteracting some of the ratepayer cost of higher depreciation rates, thereby lowering competition-related customer departure risk and allowing for a more orderly path through the energy transition.

G. Rate Design

Q81 What impact does rate design have on capital risk?

A81 An SFV rate design, of the sort proposed by EGI in this case using almost exclusively a fixed customer charge and a nearly fixed demand charge, could make it more difficult to mitigate capital risks. This is because the kind of rate design can encourage customers to depart from the gas system by fully electrifying, rather than reducing gas use and remaining on the system. For example, consider the case of a customer installing a heat pump for space heating. If the customer chooses to use a hybrid configuration (that is, they will use gas when it is very cold and the heat pump the rest of the time) they would see no reduction in their gas delivery bill under EGI's proposed rate design. This could make it more attractive for the customer to instead switch all heat to electricity. At that point, a large customer charge makes it less attractive to remain a gas customer using gas for only non-heating end uses, and departure becomes more attractive.

Q82 Has Concentric addressed this risk associated with EGI's proposed rate design?

A82 Concentric did not address this risk in its business risk report in this case. However, in Exhibit I.5.3-IGUA-42, Concentric states that "in a straight-fixed-variable rate design, declines in average use per customer increases the ratio of fixed to variable costs, which may also contribute to customer decision-making with regard to fuel switching." When asked directly whether an SFV rate design increases the risk of a "death spiral" in Exhibit I.5.3-IGUA-39, Concentric states that an SFV rate design "cannot reduce long-term risk if fewer and fewer customers remain on the system."

Q83 Are you suggesting that EGI not adopt the SFV rate design because of its impact on capital risk?

A83 No, I am not. As I have detailed above, I believe that, prudently managed, EGI faces very little capital risk, so it is not necessary to design rates with this risk in mind. However, it is important to understand that if EGI adopts such a rate design it will need to account for customer response when making its capital and financial plans. In promoting the SFV rate design and highlighting its impact on volatility and near-term volumetric risk, while dismissing its impact on capital risk, EGI is essentially undertaking the same kind of balance that the OEB must account for when considering whether EGI's business risk has changed: near-term risk decreases balanced against small and hypothetical negative long-term consequences. EGI management came out in the same place with respect to rate design as I do with respect to EGI's business risk: to place more weight on more certain near-term risks, and not be swayed by hypothetical, long-term, and mitigable risks.

H. Summary Capital Risk Implications for EGI

Q84 What are the implications of the risks and opportunities for a generic prudently managed gas utility facing the long-term situation that EGI faces?

A84 The general long-term business risks that have been the focus of my work in this area and that I identified in my testimony (namely those related to climate change policy and competition with electricity) have potential solutions that a prudent utility in EGI's situation could pursue. A prudently managed utility in this situation would develop a detailed and comprehensive plan for the coming energy transition, quantify its risks, and take action to mitigate those risks for which the benefits of relevant actions outweigh the costs, while remaining flexible to adapt to changing circumstances. The utility would be examining opportunities to develop new lines of business or solidify existing lines of business by engaging with how it can help building and industrial customers reduce and eventually eliminate their net emissions. The quantification of risks and opportunities, alongside the impact of mitigating actions, presented in the plan would allow greater investor confidence associated with reduced uncertainty.

Q85 Does EGI face any unique unmitigable risks or opportunities that are different from the generic prudently managed utility that should be accounted for in the establishment of its return on equity?

A85 Not that have been presented in this case. EGI has taken some initial steps towards understanding the provincial scenarios ahead of it and is taking some mitigating actions. It is possible that EGI's lack of comprehensive planning and associated actions to date could have closed or restricted its abilities to taking mitigating actions in the future, although I do not know of any particular example. If this turns out to be the case, EGI's unmitigable risks may be higher than they would have otherwise been. Without a comprehensive understanding of the risks and the utility's plan to mitigate them, it would be inappropriate to reward the company's shareholders with a greater equity share and thereby charge ratepayers a higher rate to compensate the utility for risks that may not occur, and that prudent utility management could mitigate. Paying more now, without taking prudent actions to reduce the need to pay more later, is neither just nor reasonable.

Q86 What are your conclusions regarding the capital risk that EGI faces, and Concentric's argument that it has increased?

A86 Concentric has failed to provide convincing evidence that EGI faces a capital recovery risk that is higher than it faced in 2012. Based on the indicative analysis I conducted, which is the only quantitative assessment of capital recovery risk presented in this case, EGI faces little to no capital recovery risk. It is possible that a more complete and information-rich analysis of future scenarios for EGI could identify future cases in which, despite prudent utility management, the utility faces material reductions in its return on or of capital. EGI has the information required to conduct such an analysis but has failed to conduct it. Once the province identifies its preferred pathway for decarbonization, EGI should conduct a detailed analysis of its options along that pathway and come back to the

OEB with a plan, accompanied by a quantitative assessment of capital recovery risk.

Q87 Could you elaborate on what this plan should contain?

A87 The first essential step is for the utility to develop a business plan for managing the firm in the changing public policy and competitive context in which it operates. That plan should identify and quantify risks and opportunities, including when they would manifest in impacts on the company as well as what their impacts would be. This plan should include a comprehensive assessment of electricity and gas utility roles in decarbonization, gas load forecasts, infrastructure needs, gas price forecasts, analysis of customer counts and consumption patterns by customer type, and the availability and costs of alternative fuels. Developing such a plan would reduce uncertainty regarding the company's future business, and thereby lower investor risk. Such a plan should also inform analysis of, and selection of, additional mitigating actions. These actions could include:

- Detailed and careful examination of any choice to invest in new gas system infrastructure, including a clear-eyed view of the useful life of that infrastructure (which informs the appropriate depreciation rate and cost/benefit analysis) and the options for economic non-pipeline alternatives to reduce or eliminate the need for rate-based utility infrastructure investment.

- Reevaluation of depreciation approaches for each type of utility asset, including differentiation among assets that serve different types of customers that may have different long-term usage patterns. This could include utilization-based depreciation approaches that move beyond straight-line depreciation to assign depreciation costs based on the projected units of fuel expected to pass through a given asset in each year of its remaining useful life. It could also include identifying which assets may have alternate future use (such as supporting district heating solutions or carrying different fluids such as captured carbon dioxide) so that their costs and lifetimes can be appropriately modeled.

- Developing partnerships with electric utilities to cost effectively meet winter peak needs through the gas system, subject to regulatory approval and where consistent with provincial plans.

- Evaluation of low-carbon fuels such as green hydrogen[44] or biomethane, including costs and availability as well as impact on pipeline performance and leakage. This should include consultation with experts in different end-use markets, including industrial customers, to identify where these fuels will deliver the greatest overall benefit (such as in meeting needs that cannot be electrified).

Q88 Has EGI started to take risk-mitigating actions of the sort you identified?

A88 The most important actions that EGI has taken to date are to commission the studies from Posterity Group and Guidehouse submitted in this proceeding. These could provide the foundation on which to build a risk analysis that would evaluate scenarios for the likelihood and consequence of capital risk events. However, given the provincial pathways study now underway, the outcome of that process should form the foundation for EGI's decision-making and modeling. The utility could nonetheless use the already characterized scenarios to develop and test its modeling tools.

In terms of concrete actions to test pathways and understand performance risks (and business opportunities), EGI's preliminary work on renewable natural gas and hydrogen could provide some important information to reduce uncertainty and thereby lower risk. It is important that these pilots and other research and

[44] Green hydrogen is hydrogen generated from water through electrolysis using zero-carbon electricity.

development actions be grounded in the eventual roles for different fuels. For example, the value of testing hydrogen blending for residential heating applications (where blending limits will constrain its potential impact, and competitive technologies are available) is very different from the value of piloting hydrogen and other low-carbon gases for industrial applications.

Q89 Does this conclude your testimony?

A89 Yes, it does.

Dr. Asa S. Hopkins CV

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Vice President*, April 2019 – present, *Principal Associate*, January 2017 – March 2019.

Conducts research and writes expert testimony and reports related to state energy policy and planning, energy efficiency, strategic electrification, deep decarbonization, and the present and future of electric and gas utility regulatory and business models.

Vermont Public Service Department, Montpelier, VT. *Director of Energy Policy and Planning,* October 2011 – December 2016

State energy planning and utility regulation

• Directed the year-long development of the 2016 Vermont Comprehensive Energy Plan, including stakeholder meetings, public forums, and coordination of contributions from other departments and the Governor's office. Primary author of the executive summary and five chapters.

• Led the Department's approach to establishing budgets and performance targets for energy efficiency utilities. Oversaw staff conducting program evaluation and savings verification.

• Submitted testimony and conducted analysis in support of public advocacy and negotiation in prominent litigated regulatory proceedings.

Policy development, analysis, and advocacy

• Developed the structure of Vermont's 2015 Renewable Energy Standard, including its novel "energy transformation" requirement. Worked with stakeholders to develop support for the policy and with the legislature to shepherd it to passage. This policy will result in more reduction of Vermont's GHG emissions than any others passed in the last 15 years.

• Led execution of Vermont's Total Energy Study, which examined technology and policy pathways for Vermont to meet GHG emission and renewable energy goals.

• Led cost-benefit analysis of Vermont's existing net metering structure and led the development of departmental proposals for a new structure.

• Prepared and delivered public, stakeholder, and interagency presentations, including to agency and business leaders, legislative committees, and the governor.

• Oversaw programs providing financing, technical, and process assistance to clean energy projects.

During tenure, Vermont rose in the rankings on national clean energy state scorecards: ACEEE State Energy Efficiency Scorecard from 5th to 3rd and U.S. Clean Tech Leadership Index from 10th to 3rd.

U.S. Department of Energy, Washington, DC. *Special Advisor to the Under Secretary for Science / AAAS Science and Technology Policy Fellow,* September 2010 – August 2011

Dr. Hopkins served as the assistant project director for the Department of Energy's first Quadrennial Technology Review. In this role, he coordinated a team that solicited input from Department of Energy and National Laboratory staff and scientists, ran a series of public workshops, facilitated coordination with the White House, developed a set of technology assessments, and ultimately drafted the Report on the First QTR, published Sept. 27, 2011.

Lawrence Berkeley National Laboratory, Berkeley, CA. *Environmental Energy Policy Postdoctoral Fellow*, January 2009 – August 2010

Conducted technical and economic analysis to support the Department of Energy in setting the energy efficiency standards that appliances must meet in order to be sold in the United States.

California Institute of Technology, Pasadena, CA. *Graduate Research Fellow,* 2002 – 2008

Los Alamos National Laboratory, Los Alamos, NM. *Post-Baccalaureate Researcher, Theoretical Division,* June 2001 – June 2002

EDUCATION

California Institute of Technology, Pasadena, CA
Doctor of Philosophy in Physics, 2008
Master of Science in Physics, 2007

Haverford College, Haverford, PA
Bachelor of Science *summa cum laude*, in Physics with minors in Computer Science and Growth and Structure of Cities, 2001

SELECTED PROJECTS

The Future of Gas Utilities – Dr. Hopkins leads Synapse's work in the area of the future of gas utilities. He and his team are assisting a number of clients to understand the future of gas utilities in the context of deep building decarbonization objectives. This work includes assisting Conservation Law Foundation in Massachusetts Department of Public Utilities Docket 20-80 (an investigation into "the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals"); Natural Resources Defense Council in New York and Nevada's regulatory proceedings regarding the future of gas; the Colorado Energy Office regarding approaches to decision-making in the face of uncertainty, in the context of Colorado's regulatory proceedings regarding gas utility Clean Heat plans and building decarbonization; the County of San Diego (with the University of California San Diego) in developing the buildings and utilities portion of its Regional Decarbonization Framework; the Maryland Office of People's Counsel in modeling the impact of the state's decarbonization objectives on utility sales and finances; and the District of Columbia Department of Energy and Environment in assessing Washington Gas Light's Climate Business Plan.

Puerto Rico Energy Bureau – Synapse has provided extensive support to Puerto Rico's electricity regulator since 2015. Dr. Hopkins has coordinated the engagement since 2018. Dr. Hopkins has led or substantially contributed to the development of Puerto Rico's first energy efficiency and demand response regulations; emergency microgrid regulations; and the review of the island's second Integrated Resource Plan and subsequent processes to optimize resilience using both transmission and distributed generation resources.

Massachusetts Comprehensive Energy Plan – On behalf of the Massachusetts Department of Energy Resources (the state energy office), Synapse and Sustainable Energy Advantage assisted DOER and its sister agencies in the development of Massachusetts's first Comprehensive Energy Plan. Dr. Hopkins assisted DOER leadership in defining the scope and approach for the CEP, to distinguish it from other state planning processes. He worked with Pat Knight to develop an approach to modeling energy transformations toward low-carbon alternatives in electricity, buildings, and transportation that are consistent with state policy and approaches while being grounded in stock turnover rates and feasible policies and programs.

Northeastern Regional Assessment of Strategic Electrification – On behalf of the Northeast Energy Efficiency Partnerships, Synapse and Meister Consultants Group identified the opportunity, costs, and benefits available if strategic electrification is adopted as a key strategy for decarbonization in New York and New England. Dr. Hopkins, Kenji Takahashi, and Pat Knight are primary authors of the resulting report, published in July 2017, which characterizes the current markets for efficiency electrification technologies (such as heat pumps and electric vehicles), identifies policies to overcome market barriers, assesses the state of electrification technologies, and models the extent of electrification both possible given market dynamics and required to meet regional greenhouse gas emission goals.

2016 Vermont Comprehensive Energy Plan – Directed the year-long development of the 2016 plan, including setting its strategic approach to current Vermont energy planning challenges and grounding it in quantitative analysis. Developed the public engagement process, then hosted expert stakeholder meetings and public forums. Adapted the results of the 2014 Total Energy Study to produce scenarios that illustrate the proposed pathways identified in the plan. Coordinated contributions from staff and leaders in other departments, and from the Governor's office. Wrote the executive summary and 5 of the 14 chapters.

Total Energy Study – Scoped and led a legislatively-mandated report on policy and technology pathways to meet Vermont's renewable energy and greenhouse gas emission goals. Designed and facilitated a focus-group-based stakeholder engagement process to identify technology and policy visions for analysis. Retained outside modeling consultant, then worked closely with them to build credible business-as-usual and policy case models of Vermont's energy economy to the year 2050 using the TIMES/FACETS integrated assessment model. Translated those model results to make REMI PI+

calculations of impact on Vermont GDP and jobs. Synthesized qualitative and quantitative results into intermediate and final reports identifying key outcomes for policy design.

Demand Resources Plan Proceedings – In each of three, three-year cycles, led the development of the Department of Public Service's positions regarding appropriate budgets, rate and bill impacts, and performance targets for Vermont's energy efficiency utilities. Analyzed current efficiency utility performance to calibrate expected future performance. Negotiated performance metrics that reflect policy priorities. Developed new regulatory and budget treatment of research and development for behavioral energy efficiency programs.

Quadrennial Technology Review – As Assistant Project Director, managed the project activities of the eight-person core team for the U.S. Department of Energy's first Quadrennial Technology Review. This review of DOE's energy technology activities established a robust framework and codified principles used to build DOE's energy technology portfolio (including identifying the appropriate and highest-leverage activities for DOE relative to the private sector and other government actors). Extensive collaboration and discussions within DOE, as well the public through a series of workshops with industry, government, national laboratory, and academic participation, culminated in the publication of the first DOE-QTR report in September 2011. Coordinated successful stakeholder workshops; facilitated focus groups. Drafted discussion papers that served as the basis for extensive intra- and inter-agency and White House coordination and negotiation. Primary author of the final report's section on building and industrial energy efficiency. Project was completed on schedule and on budget, and met its critical milestones.

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TESTIMONY

Washington DC Public Service Commission (FC 1169): Provided direct and rebuttal expert testimony regarding Washington Gas's application for an increase in rates, from the standpoint of the District of Columbia's climate and clean energy policies. On behalf of the District of Columbia Government, November 2022 and January 2023.

New York Public Utilities Commission (Case No. 22-E-0064 and 22-G-0065): Direct and Rebuttal Testimony of Alice Napoleon and Asa Hopkins regarding Con Edison's proposed gas-side investments as greenhouse gas mitigation strategies and gas extension allowance rule changes and the need for long-term planning for the gas system and adequacy of the company's non-pipe alternatives framework. On behalf of Natural Resources Defense Council, May 2022.

Régie de l'énergie du Québec (R-4156-2021): Testified as an expert on the business risk facing Quebec's natural gas utilities related to the energy transition, as part of a proceeding to set the utilities' cost of capital and capital structure. On behalf of the Industrial Gas Users Association.

Vermont Public Utility Commission (Case No. 21-1107-PET and 21-1109-PET): Addressed the impact of GlobalFoundries proposed "self-managed utility" on the general good of the state and Vermont's energy policy, with particular focus on the impact on environmental soundness and greenhouse gas emissions mitigation. On behalf of Conservation Law Foundation, June 2021.

Public Service Commission of Wisconsin (Docket No. 5-CG-106): Addressed the need for a pair of liquified natural gas facilities in light of the fossil fuel use reductions required to meet state and federal goals for mitigating climate change and the potential for cost-effective demand-side alternatives. On behalf of the Sierra Club, June 2021.

Vermont Senate Finance Committee: Provided expert testimony in the form of a presentation entitled "Updating Vermont's Renewable Energy Standard" to the Vermont Senate Finance Committee in January of 2020. Dr. Hopkins presented on the history of the standard, what has changed since 2015, and future potential.

Vermont Public Utility Commission (Case No. 17-1247-NMP): Addressed the consistency of a proposed solar generation facility with the Vermont Comprehensive Energy Plan. On behalf of Derby GLC Solar LLC, January 2018.

Washington DC Public Service Commission (FC 1142): Provided expert testimony regarding the merits of the proposed merger of Washington Gas and AltaGas, Ltd. with respect to the impact on environmental quality, with particular emphasis on the impact of utility management and its approach to climate change on the ability of the District to achieve its climate change mitigation goals. On behalf of the District of Columbia Government.

Régie de l'énergie du Québec (R-3986-2016): Provided an expert report and testimony regarding best practices in utility demand response programs, in the context of Hydro Québec Distribution's ten-year

Supply Plan. On behalf of the Regroupment national des conseils régionaux de l'environment du Québec (RNCREQ).

Vermont Public Service Board (Dockets No. 8586 and 8685): Addressed the need for a proposed solar PV generator and its associated contract under PURPA rates, its economic impact on the state, and its consistency with the Vermont Electric Plan. On behalf of the Vermont Department of Public Service, July 2016.

Vermont Public Service Board (Docket No. 8684): Proposed avoided energy and capacity cost rates for use in Rule 4.100, Vermont's implementation of PURPA. On behalf of the Vermont Department of Public Service, October 2015 and May 2016.

Vermont Public Service Board (Docket No. 8600): Addressed the need for a proposed solar PV generator, its economic impact on the state, and its consistency with the Vermont Electric Plan. On behalf of the Vermont Department of Public Service, March 2016.

Vermont Public Service Board (Docket No. 8525): Introduced a memorandum of understanding between the DPS and Green Mountain Power regarding a proposed rate design, with particular focus on new critical peak price rates to be available and marketed. On behalf of the Vermont Department of Public Service, November 2015.

Vermont Public Service Board (Docket No. 7970): Addressed whether increases in the expected cost of a gas pipeline expansion project were sufficient to warrant reopening the underlying proceeding, particularly with respect to the need for the project, the economic impact on the state, and consistency with the general good of the state and the Vermont Comprehensive Energy Plan. On behalf of the Vermont Department of Public Service, May 2015.

Vermont Public Service Board (Docket No. 8311): Addressed how statutory criteria for the use of electric energy efficiency funds for electrification measures (such as heat pumps) might be met. On behalf of the Vermont Department of Public Service, January 2015.

Vermont Public Service Board (Docket No. 7862): Presented the Department's positions regarding whether Entergy Vermont Yankee should be granted a continued certificate of public good, with particular focus on the need for the plant, the economic benefit of continued operation, consistency with the Vermont Electric Plan, and whether continued operation by Entergy was in the general good of the state. On behalf of the Vermont Department of Public Service, October 2012 and April 2013.

Vermont Public Service Board (Docket No. 7833): Addressed the need for a proposed biomass electric generator and its consistency with the Vermont Electric Plan. On behalf of the Vermont Department of Public Service, October and November 2012; February and September 2013.

Vermont Public Service Board (Docket No. 7770): Addressed a number of topics related to the merger of Green Mountain Power and Central Vermont Public Service, most particularly the disposition of a windfall repayment due to ratepayers. On behalf of the Vermont Department of Public Service, January and March 2012.

Vermont Public Service Board (Docket No. 7815): Addressed consistency of a proposed long-term PPA with the Vermont Electric Plan and the utility's integrated resource plan. On behalf of the Vermont Department of Public Service, January 2012.

SELECTED PRESENTATIONS

Hopkins, A. S. "IIJA, IRA, and the Growing Federal Role in Transmission—and Why States Should Care," presented at the National Association of State Energy Officials Annual Meeting, October 2022.

Hopkins, A. S., J. Litynski, A. Takasugi. "Policy approaches to increasing electricity affordability in California," presented to various California stakeholders on behalf of Natural Resources Defense Council, February 2022.

Shipley, J., Hopkins, A. S., Takahashi, K., & Farnsworth, D. "Renovating regulation to electrify buildings: A guide for the handy regulator," presented with Regulatory Assistance Project, January 2021.

Hopkins, A. S. 2019. "Efficiency, Electrification, and Renewables in New England and Puerto Rico" at 2019 ACEEE Energy Efficiency as a Resource Conference, October 2019.

Hopkins, A. S. 2019. "Strategic electrification and winter cold snaps: A resource and a challenge" at 2019 ACEEE Energy Efficiency as a Resource Conference, October 2019.

Panelist on "Deep Dive Session on State and Local Electrification Roadmaps" at Electric Power Research Institute (EPRI)/Northeast Energy Efficiency Partnerships (NEEP) Electrification Summit, August 2019.

Hopkins. A. S., K. Takahashi, D. Lis. 2018. "Decarbonization through Strategic Electrification Meets Utilities and Regulation in the Northeast" at the 2018 ACEEE Summer Study on Energy Efficiency in Buildings, August 2018.

Hopkins, A. S. 2019. "Strategic Electrification: Impacts and approaches to meeting decarbonization goals in the northeastern states (and elsewhere)" at Lawrence Berkeley National Laboratory, Energy Technologies Area, August 2018.

Hopkins, A. S. 2017. "Utility Performance Regulation" at the Western States Regional Meeting of the National Association of State Energy Officials, April 2017.

Panelist on "A Regulatory Perspective of Grid Transformation" at the IEEE Innovative Smart Grid Technologies Conference, September 2016.

Panelist on the "Comprehensive Energy Plan Update" at the Renewable Energy Vermont Conference, October 2015.

Hopkins, A. S. 2015. "Vermont's Total Energy Study." Presentation at the National Association of State Energy Officials Energy Policy Outlook Conference, February 2015.

Panelist on "The Role of Energy Efficiency in Mitigating Winter Peak Issues" at the Association of Energy Services Professionals (Northeast Chapter) & Northeast Energy Efficiency Council, November 2014.

Hopkins, A. S. 2014. "Total Energy Study." Presentation at the Renewable Energy Vermont Conference, October 2014.

Panelist on "State Energy & Economic Policy Impacts on Industry Transformation" at the Power Industry Transformation Summit, April 2014.

Hopkins, A. S. 2008. "Mobilizing Pasadena Democrats: Measuring the Effects of Partisan Campaign Contacts." Presentation at the American Political Science Association Annual Meeting, August 2008.

HONORS, AWARDS, AND FELLOWSHIPS

Certified Public Manager, 2014

AAAS Science and Technology Policy Fellowship, 2010 – 2011

Dean's Award for Community Service, 2009

Delegate to the 2004 Democratic National Convention

NSF Graduate Research Fellow, 2002 – 2005

Los Alamos National Laboratory Student Distinguished Performance Award, 2002

Two-time first-team Academic All American, 2000 and 2001

Barry M. Goldwater Scholar, 1999 – 2001

OTHER ACTIVITIES

NASEO - Electricity Committee: Affiliate Co-Chair, 2020-present

Newton, MA Citizens Commission on Energy, Member 2017-present

Guest on Synapse Energy Economics, Inc.'s *Energy Nerd Show,* Aug 6, 2020

Board Member, National Association of State Energy Officials, 2015-16

Industrial Advisory Board for ARPA-E-funded project "Packetized Energy Management," 2016

Burlington, VT Public Works Commission: Member 2012 –2014, Chair 2015

Resume updated May 2023

Form A: Acknowledgement of Expert's Duty

Dr. Asa S. Hopkins

EB-2022-0200

Ontario Energy Board

FORM A

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

ACKNOWLEDGEMENT OF EXPERT'S DUTY

1. My name is _Asa S. Hopkins_ I live at __West Newton______, in the _____State_ of____Massachusetts____.

2. I have been engaged by or on behalf of the Industrial Gas Users Association to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date __May 8, 2023____________

Asa S. Hopkins

Signature

Survey of "Future of Gas" Regulatory Context and Studies White Paper

Survey of Analysis of Gas Utility Futures

May 1, 2023

AUTHORS

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CONTENTS

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,

[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.

- **Regulatory process to identify opportunities for non-pipeline alternatives (NPAs)**. This would include the assessment of technical feasibility, customer acceptance, and net-benefits and costs of NPAs.

UPCOMING

OPC Petition

On February 9, 2023, the Office of People's Counsel in Maryland filed a petition in front of the MD PSC for near-term priority actions and comprehensive long-term planning for Maryland's Gas Companies. OPC notes there is a misalignment between the state's GHG emission reduction goals and the utilities' spending on infrastructure. OPC notes that, if this is not addressed, MD's residential customers may be financially responsible for utility assets that are stranded because market forces have caused their early retirement.

OPC has not provided a list of studies or analysis it recommends, but the list of questions it provided in the petition indicate areas that could be investigated. These include questions related to data collection, long-term planning, potential substitutes for fossil gas, gas infrastructure, rate design and cost allocation, workforce issues, and legislation.

5. WASHINGTON, D.C.

*Utilities in Washington, D.C. are regulated by the DC Public Service Commission (DCPSC). It regulates one natural gas utility, Washington Gas. The DCPSC created FC1167, a climate policy proceeding to consider if the utilities are meeting and advancin*g *DC's climate goals and then to take action, where necessary, to guide the companies in the right direction.*

KEY REGULATORY PROCEEDINGS

- **GD2019-04-M**
- **FC1167**

EXISTING ANALYSIS

Climate Business Plan (CBP)[3]

The DCPSC required the CBP by as part of approval of AltaGas's purchase of Washington Gas. The CBP is a long-term business plan outlining how Washington Gas can evolve its business model to support and

[3] Washington Gas and AltaGas. March 2020. *Natural Gas and its Contribution to a Low Carbon Future: Climate Business Plan for Washington, D.C.* Available at: https://washingtongasdcclimatebusinessplan.com/wp-content/uploads/2020/04/Climate-Business-Plan-March-16-2020-FOR-WEB.pdf.

serve the District's 2050 climate goals. It was delivered on March 2020. Supplementary materials were also made available, including the ICF Technical Report and Supplemental Technical Information.[4]

Scenarios. The analysis included the creation of four scenarios—Business As Usual, Partial Decarbonization, Policy Driven Electrification, and Fuel Neutral Decarbonization—to assess the effectiveness, costs, potential trade-offs, and equity implications associated with these scenarios. AltaGas proposed the Fuel Neutral Scenario as the preferred option that would meet the District's climate goals at 59 percent of the cost of full electrification while maintaining energy reliability and customer choice.

Unrecovered Cost of Service. The CBP also estimated the unrecovered cost of service on the gas system that would not be covered based on existing rates. This was estimated at $4.6 billion for the Policy Driven Electrification case and $3.6 billion for the preferred Fuel Neutral Decarbonization case. This assumed that sales volume decreases to 8 percent of 2018 levels by 2050.

Stranded Cost Estimates. The Policy Driven Electrification Case assumed that gas service in the District would be almost or completely terminated. In this case, the report estimates stranded rate base in 2050 to be $1.5 billion to $2.1 billion. This assumes current depreciation policies along with incremental capex for maintenance and reliability. The study did not provide backup for these estimates.

Table 1. Comparison of additional cumulative 2020–2050 cost elements beyond those evaluated in scenarios ($2018 millions)

Impact	Policy Driven Electrification Case	Fuel Neutral Decarbonization Case	Additional Costs in Policy Driven Electrification Case
Cumulative Incremental Costs in Study Results (Million$)	6,532	3,843	+2,690
High Level Estimation of Transmission and Distribution Costs to Accommodate Peak Demand Growth – Using SEU Approach	$2,800 +/-	0	+$2,800 +/-
Unrecovered Cost of Service 2020-2050 (at Current Rates)	$4,600 +/-	$3,600 +/-	+$1,100 +/-
Stranded Rate Base in 2050	1,500 to $2,100 or more	0	+$1,500 to $2,100 or more
Final Customer Transition Costs	$800 +/-	0	+ $800 +/-
System Decommissioning Costs	+ Unknown	0	+ Unknown
Reliability and Resiliency Costs	+ Unknown	0	+ Unknown
BAU Costs of 100% RPS – Not Included in incremental Power Generation Production Costs	+ Unknown	+ Unknown	Negligible

Source: ICF International. April 2020. Opportunities for Evolving the Natural Gas Distribution Business to Support the District of Columbia's Climate Goals. Prepared for Washington Gas and AltaGas. Page 62. Available at:

[4] Available for download at https://washingtongasdcclimatebusinessplan.com/.

https://washingtongasdcclimatebusinessplan.com/wp-content/uploads/2020/04/Technical-Study-Report-Opportunities-for-Evolving-the-Natural-Gas-Distribution-Business-to-Support-DCs-Climate-Goals-April-2.pdf

Policy Recommendations. The CBP notes that policy changes are required to ensure recovery of the full cost of service and to address stranded assets and system transition costs associated with certain scenarios. Two regulatory proposals were highlighted:

- Decoupling rates from volumetric throughput: Decoupling of throughput from cost recovery or restructuring of rates to reduce cost recovery related to throughput.
- Cost sharing: A recovery mechanism to socialize cost and benefits of gas use to all energy users. The intent is to equitably distribute fixed costs of the natural gas system and maintain reasonable rates for customers.

6. MINNESOTA

The Natural Gas Innovation Act (NGIA) was signed into law on June 26, 2021, directing the commission to initiate a proceeding to evaluate changes to natural gas utility regulatory and policy structures to meet Minnesota's state GHG emission reduction goals. In response, the Commission created docket G999-CI-21-565.

KEY REGULATORY ACTIONS

- G-999/CI-21-566 – Framework for future NGIA plans to be filed by gas utilities
- G-999/CI-21-565 – In the Matter of a Commission Evaluation of Changes to Natural Gas Utility Regulatory and Policy Structures to Meet State Greenhouse Gas Reduction Goals

EXISTING ANALYSIS

In July 2021, Great Plains Institute (GPI) and Center for Energy and Environment (CEE) released a report entitled *Decarbonizing Minnesota's Natural Gas End Uses: Stakeholder Process Summary And Consensus Recommendations.*[5] This report summarizes the recommendations of a stakeholder group regarding the decarbonization of Minnesota's natural gas end uses. The stakeholder group includes members from utilities, regulators, state agencies, consumer and environmental advocates, and others. The results were presented to the Minnesota PUC in August 2021. The report notes specifically that NGIA "establishes a regulatory framework for natural gas and dual-fuel utilities to implement and recover their costs for programs that reduce or avoid greenhouse gas emissions from customers' use of natural gas."

[5] Great Plains Institute and Center for Energy and Environment. July 2021. *Decarbonizing Minnesota's Natural Gas End Uses: Stakeholder Process Summary and Consensus Recommendations*. Available at: https://e21initiative.org/wp-content/uploads/2021/07/Decarbonizing-NG-End-Uses-Stakeholder-Process-Summary.pdf.

Scenarios. The stakeholders hired Energy and Environmental Economics Inc. (E3) to model high-level scenarios for decarbonizing natural gas end uses by 2050. The results are intended to support further discussions. The four scenarios were: (a) a reference case, (b) high electrification in which almost all buildings switch to all-electric and industry is electrified where possible, (c) high electrification with gas backup where buildings keep their gas connection for backup heating, and (d) high decarbonized gas where gas is replaced by biomethane, synthetic natural gas, and hydrogen for building heating.

Residential delivery cost of gas. The scenario analysis included a projection of the impact to the residential delivery cost of gas. It looked, in particular, at the impact to residential bills where electrification and increasing gas commodity costs to customers lead to lower gas demand and exodus of customers, thus leaving the remaining customers with a higher share of the system cost. Assuming no gas system cost reductions, and no changes to rate structure or design, in the high decarbonized gas scenario, residential delivery costs of gas will increase from $385/year in 2020 to $902/year in 2050. Under a high electrification scenario, it will go up to $28,685/year. A scenario where electrification is mitigated by a gas backup scenario (where all existing customers remain connected to the system for backup heat), reduces this to $920/year.

District System. A district system sensitivity analysis was performed, looking at impact on electric peak load if a percentage of load was served by the district. It found that installing district systems in new construction would result in electric system cost savings of about $1.2 billion in 2050.

Policy Recommendation – Rate Design and Utility Financing. The scenario analysis concluded with the recommendation to implement a stakeholder process to consider potential changes to rate design (for gas and electricity) and utility financing mechanisms to support transition to a decarbonized energy system. E3 presented the following for consideration:[6]

- *Natural gas customers switching to electricity could pay all or some portion of any stranded costs given the infrastructure was built to serve their original energy needs.*
- *It may be appropriate for electric utilities to pay for some natural gas system costs if the additional electricity sales from electrification are sufficiently beneficial to justify that payment.*
- *It may be appropriate for electric utilities to pay natural gas utilities for the capacity and demand benefits of backup heating provided by gaseous fuels.*
- *Securitization or other utility system financial tools to address transition costs.*

FUTURE ANALYSIS

Utilities are encouraged to file Innovation Plans showing how they can contribute to meeting the state's climate goals. These plans are to include system report and forecasts, projected capital and fuel investments, carbon emissions, and incentive programs. The first of these Innovation Plans are expected in the spring of 2023. The Commission is also required to establish GHG emission accounting and cost-effectiveness frameworks to evaluate the innovation plans.

[6] Decarbonizing Minnesota's Natural Gas End Uses, page 82.

7. COLORADO

On June 24, 2021, the Colorado state legislature passed SB21-264, requiring each gas utility to file a clean heat plan with the Public Utilities Commission (PUC). This plan must demonstrate how the utility will use clean heat resources to meet the clean heat targets of a 4 percent reduction below 2015 GHG emission levels by 2025 and 22 percent below 2015 GHG emission levels by 2030.

In response, the Colorado PUC opened proceeding 21R-0449G in October 2021.

KEY REGULATORY ACTIONS

- 21R-0449G: In The Matter Of The Proposed Amendments To The Commission's Rules Regulating Gas Utilities, 4 Code Of Colorado Regulations 723-4, Relating To Gas Utility Planning And Implementing Sb 21-264 Regarding Clean Heat Plans And Hb 21-1238 Regarding Demand Side Management
    - Decision C22-0760 – Rulemaking. Dec 1, 2022.

FUTURE ANALYSIS

To show they are meeting their clean heat targets, gas utilities are ordered to file "clean heat plans" starting in 2023. The clean heat plans will include a mix of supply-side and demand-side resources, including energy efficiency programs, recovered methane, green hydrogen, and beneficial electrification. The plans also include the following elements:

Rate Adjustment. Under the clean heat plans, the Commission allows a utility to propose a rate adjustment clause that provides for recovery of the utility's clean heat plan costs or any costs prudently incurred to meet additional emission reduction requirements.

Depreciation. The Commission requires a utility to identify potential changes to depreciation schedules or other actions to align the utility's cost recovery with statewide policy goals.

Cost Recovery. The Commission notes there could be value in assessing cost recovery mechanisms for gas infrastructure planning and clean heat plans, aligning the goals of the clean heat plan and the utilities. It notes it may elect to open such a proceeding in the following months.

Assessment of the Clean Heat Plans will be based on emission reductions/achievement of clean heat targets, probability of whether it can be implemented with the lowest reasonable cost and rate impact, and qualitative factors including benefits to air quality, the environment and health, and environmental justice impacts.

The first Clean Heat Plan will be filed on August 1st, 2023, by the Public Service Company of Colorado (Xcel Energy).

8. OREGON

In 2021, Oregon's Environmental Quality Commission adopted rules establishing the state's Climate Protection Program (CPP). The CPP limits emissions from the state's fossil fuel suppliers, including natural gas utilities, to 50 percent of 2017-2019 emissions by 2035 and 10 percent by 2050.[7]

KEY REGULATORY ACTIONS

- Docket No. UM 2178G-999/CI-21-566 – Natural Gas Fact Finding

EXISTING ANALYSIS

Natural Gas Fact Finding

In response to the CPP, the Oregon Public Utility Commission conducted a Natural Gas Fact Finding process.[8] The PUC described the purpose of this process as twofold: "The first was to conduct an initial analysis of the potential ratepayer bill impacts from the limiting of natural gas utilities' GHG emissions under the [Department of Environmental Quality's] CPP. The second was to identify appropriate regulatory tools to mitigate potential customer impacts and accommodate utility action."

In the Fact Finding process, each of Oregon's three gas utilities presented modeling results showing different pathways to decarbonization with different rate and utility impacts. Scenarios included cases with restricted access to renewable natural gas, declining customer counts, technological innovation, and no access to low-cost, state-level carbon credits. The PUC staff identified that rigorously vetted assumptions on a wide range of topics would be required for future integrated planning aimed at least cost and least risk pathways.

The PUC used the Fact Finding to identify a host of regulatory tools to use in managing energy transition for gas utilities. These tools include planning, programs, and ratemaking. For example, in the near term, the PUC staff recommended the development of maps with infrastructure age and depreciation information, analysis of demand-side and non-pipe options provided by IRPs, targeted energy efficiency programs to low-income and energy justice communities, and coordination of electrification assumptions between electric utility distribution planning and gas utility resource planning.

FUTURE ANALYSIS

The outcomes of the Natural Gas Fact Finding process are informing the PUC's evaluation of Northwest Natural's (NWN) integrated resource plan at the time of this writing. The NWN IRP was developed during the time of the Fact Finding, and it does not reflect the full integrated analysis that the Fact

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[7] Oregon Department of Environmental Quality. December 22, 2021. *Climate Protection Program Program Brief*. Available at: https://www.oregon.gov/deq/ghgp/Documents/CPP-Overview.pdf.

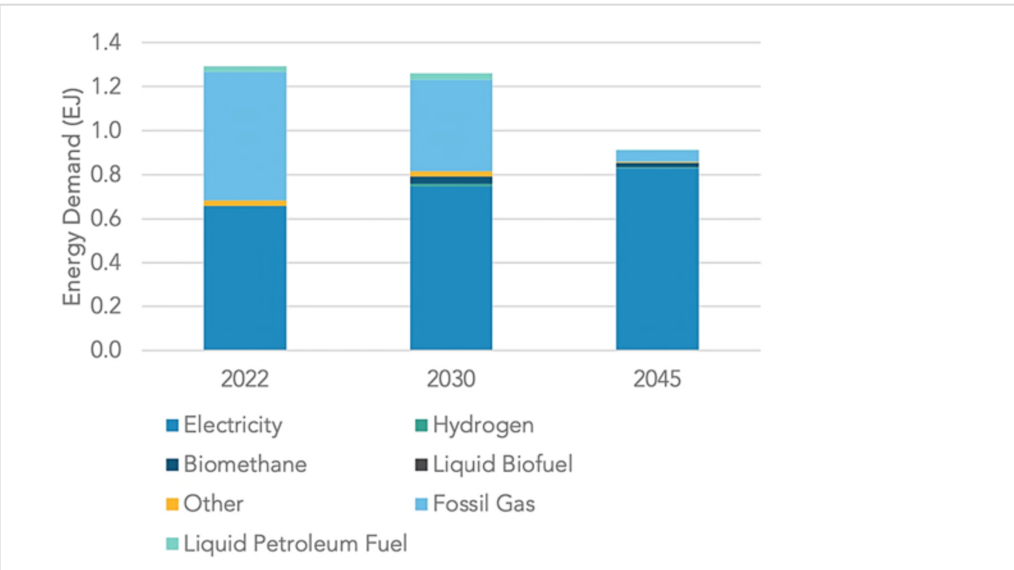
[8] Oregon Public Utility Commission. "Utility Regulation: Natural Gas Fact Finding." Available at: https://www.oregon.gov/puc/utilities/Pages/EO-20-04-UP-FactFinding.aspx.

Finding identified as a key component of the utility and regulatory response to decarbonization. The PUC may use future gas and electric IRPs, or may create a standalone process, to conduct this integrated analysis.

9. California

California has set an economy-wide target for net zero emissions by 2045. As part of this achievement, it would lower GHG emission by 85 percent below 1990 levels. The state's 2022 Scoping Plan for Achieving Carbon Neutrality[9] *lays out a pathway for all-electric new construction beginning in 2026 (residential) and 2029 (commercial). All residential appliance sales would be electric by 2035 and by 2045 in commercial buildings. Industrial demand would be partially electrified and partially use carbon capture and sequestration.*

Figure 1. Final energy demand in buildings in 2022, 2030, and 2045 in Scoping Plan Scenario



Source: Reproduction of building sector energy demand results from California's 2022 Scoping Plan for Achieving Carbon Neutrality.

KEY REGULATORY ACTIONS

1. **R.20-01-007:** Order Instituting Rulemaking (OIR) to establish policies, processes, and rules to ensure safe and reliable gas systems in California and to perform long-term gas system planning

[9] California Air Resources Board. Nov. 16, 2022. *2022 Scoping Plan for Achieving Carbon Neutrality*. Available at: https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp.pdf.

a. Track 2: long-term gas policy and planning
    - Staff Proposal on Gas Distribution Infrastructure Decommissioning Framework in Support of Climate Goals (Dec 21, 2022)

EXISTING ANALYSIS AND ONGOING PROCEEDINGS

The Challenge of Retail Gas Study

The California Energy Commission (the state's energy policy agency) commissioned a study entitled *The Challenge of Retail Gas in California's Low Carbon Future,* prepared by E3 and published in April 2020.[10] This report describes the technology options available for decarbonizing the end uses served by fossil natural gas today, including biomethane, hydrogen and synthetic methane, and electrification. The study was scoped prior to California's net zero 2045 target, so it examines pathways to 80 percent reductions in GHGs by 2050. Nonetheless, the general implications of its results carry over to the contemporary policy context.

The E3 report identifies challenges for the retail natural gas system driven by the high costs associated with either of the two prominent pathway approaches. Pathways that depend on non-fossil gases have high retail gas rates because of the cost of the fuels. Pathways that depend on electrification have high retail gas rates because reductions in throughput increase the per-unit cost to deliver gas to customers. E3 concludes that "the no building electrification scenario is unlikely to represent a stable, internally consistent future" because non-fossil gas blending "will lead to steady improvements in the economics of building electrification."[11] The report then takes an important next step and examines the regulatory and policy options to mitigate the challenges associated with moving to a largely electrified building stock.

The E3 report describes the underlying dynamic of the feedback loop between gas throughput reductions and higher gas rates and highlights that: "maintaining reasonable gas rates becomes imperative because of the substantial equity concerns that could follow from a world in which the wealthy are more likely to be able to electrify, or to afford paying higher gas costs if they do not, but low- and middle- income households are less able to do so."[12] E3 identifies that the financial viability of gas utilities is essential in order to meet both equity and safety objectives. The report describes the components of a strategy to maintain gas utility viability and advance equity in the face of energy transition:

- Reduce barriers to electrification

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[10] Aas, Dan, Amber Mahone, Zack Subin, Michael Mac Kinnon, Blake Lane, and Snuller Price. 2020. *The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs and Public Health Benefits of Reducing Natural Gas Use*. California Energy Commission. Publication Number: CEC-500-2019-055-F. Available at: https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf.

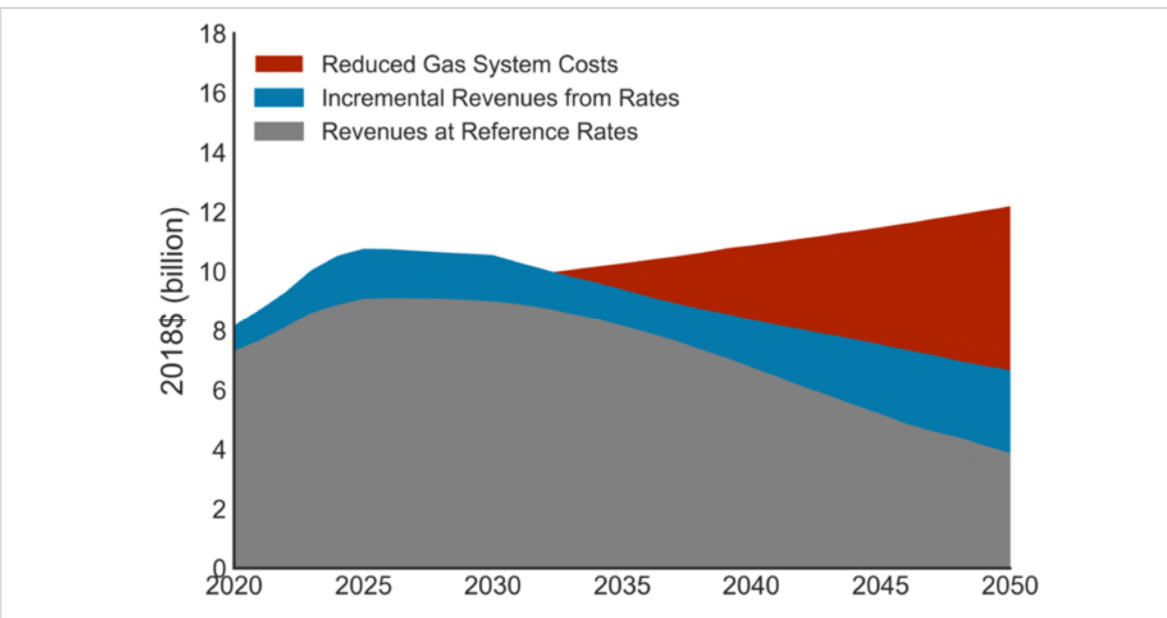
[11] Id., p. 56.

[12] Id., p. 57.

- Avoid gas system expansion
- Reduce costs of the existing gas system, such as through geographically targeted electrification and retirement of the gas system
- Accelerate depreciation
- Change cost allocation
- Recover gas system costs on the bills of electric ratepayers or other additional funds from outside the gas system
- Shut down uneconomic gas infrastructure built to serve building loads

The report includes quantitative analysis of how combinations of these components could allow the gas system to transition without creating undesirable safety or equity outcomes. For example, Figure 2 shows analysis of a combination of cost reductions and accelerated depreciation (red wedge) and modest rate increases (blue area) to enable a successful transition. E3 modeled scenarios with and without these mitigating strategies and showed the moderating impact on rates.

Figure 2. Revenue requirement with intensive reductions and accelerated depreciation



Source: Reproduction of figure from E3, The Challenge of Retail Gas in California's Low Carbon Future, showing combination of utility strategies to manage energy transition. E3 Notes: "The red wedge shows the cost savings associated with gas system cost reductions and accelerated depreciation. The blue wedge shows incremental revenue collected through gas rates. The blue wedge increases revenues substantially in the near term, but doing so enables deeper cost savings in the future than ca be achieved by reduced reinvestment alone."

CPUC Rulemaking R.20-01-007

Track 2 of California Public Utilities Commission (CPUC) Rulemaking R.20-01-007 is intended to address "Gas Infrastructure; Safety; Data; Process; Gas Revenues and Rate Design; and Workforce Issues" through the development of a long-term planning strategy. This rulemaking process included workshops on gas infrastructure planning and equity. The summary reports on these workshops provide a snapshot of the proceeding in action. The gas infrastructure workshops covered topics essential to infrastructure decision-making: when to repair, replace, or retire transmission and distribution lines; the importance of meeting the needs of hard-to-electrify customers; the role of storage; and the obligation to serve.[13] The equity workshop addressed: landlord-renter issues, issues specific to disadvantaged homeowners, and the importance of limiting gas rate increases during the transition.[14] This final panel explicitly discussed accelerated depreciation and units-of-production based depreciation as a way to recover more costs while more customers remain on the gas system.

Following the workshops, the CPUC took action related to the issues raised in these processes. First, it established a new process for the review of large gas system investments to parallel the system it uses to review investment on the electric system. Second, CPUC staff have put out for discussion a proposed distribution infrastructure decommissioning framework. Staff proposes dividing California's gas-served areas into five tranches to guide the order of system decommissioning:

1) high-benefits early adoption (areas with the most air quality challenges and greatest opportunity for ratepayer savings)

2) market transition (areas prioritized by high burdens, high pipeline risk, high ratepayer savings, and feasibility)

3) medium-term electrification (continuing the trend from tranche 2 with medium levels of key criteria)

4) market rate electrification (areas with lower-than-average need and benefits from decommissioning; aim for customers to electrify at market rates or with standardized approaches)

5) difficult-to-electrify customers and long-term electrification (the remainder, including large hard-to-electrify customers and areas with high potential for biomethane)

The CPUC's rulemaking process continues. The CPUC received numerous comments on staff's proposal in February and March 2023.

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[13] CPUC. *R.20-01-007 Track 2 – Gas Infrastructure: Final Workshop Report*. July 7, 2022. Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/long-term-gas-planning-oir/final-track-2-january-workshop-report---20220707.pdf.

[14] CPUC. *R.20-01-007 Track 2 – Gas Infrastructure Workshop 3: Equity Workshop Final Workshop Report*. July 7, 2022. Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/long-term-gas-planning-oir/final-equity-workshop-report---20220707.pdf.

Modelling the Strategic Transition of a Gas Utility White Paper

Modeling the Strategic Transition of a Gas Utility

With application to quantifying capital risk

May 1, 2023

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CONTENTS

1. INTRODUCTION

Future of Gas proceedings have been created in several states including New York, Rhode Island, Massachusetts, and California to discuss how to transition the gas system to meet state GHG emission reduction targets. Gas rate cases in Ontario and Quebec have raised issues regarding capital recovery risk in an energy transition scenario. All of these proceedings would be enriched by analysis that can demonstrate how the utility and its customers could manage a dramatic change in the gas utility's service provided, where a significant percentage of natural gas customers elect to exit the gas system and fully electrify their homes and businesses.

To contribute to these discussions, Synapse developed a financial model of a hypothetical utility, the Strategic Transition Model (STM). This simplified gas model calculates revenue requirements and financial metrics, providing insight into the impacts and correlates of a transition to a smaller gas utility.

This white paper documents the STM's characteristics, outputs, structure, calculations, assumptions, and simplifications. It provides illustrative results for a case in which gas use winds down to zero by 2050 in the building sector and among customers served by low-pressure mains, while gas use remains unchanged among industrial customers served by high-pressure mains and transmission.

2. MODEL SUMMARY

The STM is a simplified model of a hypothetical utility; the results can be scaled to approximate any gas utility if updated with the appropriate inputs. The STM calculates revenue requirements and financial metrics, providing insight into the impacts of a transition from today's state to a smaller gas utility.

The gas system in transition is characterized and driven by two factors: the rate of customer departure and the quantity of gas consumed. The STM assesses the impact of these changes.

The STM divides the current gas system into a *retiring* system and an *indefinite* system, with retirements based on assumptions about customer departures. The *retiring* system serves residential and commercial building consumers and is characterized by increased customer defection, since heating equipment and other building appliances are relatively easy to electrify. As modeled, this segment exits the natural gas system over time—the utility first retires meters and services as individual customers depart, and then mains as possible with neighborhood retirements. The indefinite system is composed of customers who need to retain the connection with the gas system as they will not fully electrify. For the purposes of model simplicity, we have assumed that these are the utility's industrial customers (or other customers directly served by high-pressure distribution mains or transmission).

The STM calculates the income statement for the entire utility, then produces separate income statements for the retiring system and the indefinite systems. Allocations between these two systems (for net plant, depreciation, and operations and maintenance—or O&M) are based on the same kinds of parameters used in cost allocation in rate cases, namely the number of customers and the amount of gas consumed. Because the STM does not track different types of assets at the level of resolution that more complex models might, cost allocation between these two systems, especially in the early years of the model, is approximate.

The STM is designed to have no stranded costs. A key element of the analysis is the depreciation treatment of the utility's assets (gas plant). In the model, all return *of* capital and return *on* capital is recovered as revenue. The model accomplishes this by adjusting straight-line and tax-related depreciation rates for the assets of the retiring system so that assets which retire in each year are fully depreciated at the time of their retirement. The model tracks deferred income taxes associated with each class of asset so that they also reach zero at the time of retirement.

It may seem confusing to use a model in which stranded costs are not possible to evaluate stranded cost risk. In fact, this structure makes the drivers of capital recovery risk associated with the clean energy transition clear and distinguishable: assets become stranded if rates rise to an unsustainable level. By unsustainable we mean that further rate increases reduce revenue by driving customers off the system, rather than increase revenue. In such a situation, it is possible that the utility will not recover its full cost of service, including return of and on its invested capital. Therefore, we can use the STM to look for cases in which gas rates rise to unsustainable levels, as an indication that the utility and regulator would need to work out an approach to managing or mitigating the resulting stranded costs.

The STM provides metrics to illustrate impacts on gas utility customers and other stakeholders. The STM calculates the hypothetical utility's annual revenue requirement and allocates it to customers of the retiring or indefinite systems. This allows us to calculate the potential rate impact per customer and financial metrics of interest to regulators, debt holders, and shareholders such as debt coverage ratios and return ratios.

The STM is designed to be a simple model, and there are numerous aspects of utility finance it does not capture. These simplifications include:[1]

- All assets are treated as part of a single asset type, with lifetime determined by the retirement date and uniform salvage costs.
- O&M costs are only roughly disaggregated.
- Assets retiring in a given year are assumed to be sampled evenly from all ages of existing plant (e.g., rather than targeting retirement of older assets first).[2]

[1] The appendix includes a full discussion of simplifications.

[2] This reflects the fact that asset ages are likely to be mixed throughout the utility's service territory, and that absent explicit targeted asset retirement programs customer departures are independent of the age of the gas system assets serving them. Specific utility planning could include such targeting, which would reduce near-term depreciation cost impacts.

These simplifications result in a tractable model that can capture important ratemaking principles, practices, and risks, and thereby provide useful results to inform planning and policymaking.

3. CALCULATIONS

In this section, we disclose assumptions and describe how the model calculates key accounts. We begin with an explanation of rate base and depreciation expense calculations. The second half describes how the model uses scaling factors to calculate other components.

Gas plant characteristics, growth, and depreciation. The model treats gas plant as broken into blocks of value and elides specific details. We assumed all assets have the same lifetime, depreciation rates, and salvage costs. No distinction is made between traditionally shorter-lived assets (e.g., meters) and longer-lived assets (e.g., mains).

Existing plant build-up to 2023 balance: We assumed existing plant have been added to the system in a linearly increasing amount over the last 50 years. For example, assume plant installed in 1974 is $1, plant installed in 1975 is $2, etc., increasing by $1 per year until plant installed equals $50 in 2023. The existing plant balance in 2023 in this case is $1,275. These values are in nominal dollars. This approximation reflects both inflation over the time period and increased capital additions over the last 10–20 years, along with retirement of some older assets. The user can adjust the starting date of the linear increase to a date after 1974 in order to match a utility's depreciation reserve balance, if the balance is lower than the default (indicating more recent investments than the default).

Straight-line depreciation method. The model depreciates gas plant using a straight-line method for each retirement year. (Note, this means they are consistent with utilization-based depreciation only if the assets are used steadily at their present level until they are shut off.) Assets retiring in a given year (excluding indefinite system assets being reinvested) are assumed to be sampled evenly from all ages of existing plant. This means the model does not address strategic withdrawal and does not consider targeting retirement of older portions of the system first. The model does not explicitly treat fully depreciated assets that are still in operation but not contributing to rate base (such as very old cast iron pipe).

Capital Additions. For retiring assets, STM adds 0.5 percent of plant each year by default (this percentage can be changed by the user). This minimal amount is to account for repairs to maintain system reliability and safety. For the indefinite system, 2 to 4 percent of plant is added each year to reflect a sustained level of investments for assets with a 50-year lifetime, accounting for inflation. Indefinite assets in the default configuration would be transmission and high-pressure pipe. The model also accounts for retirement of older indefinite-system assets and their replacement at a cost equal to the original cost, adjusted for inflation.

Capital Retirements. For retiring assets, all plant retires in its designated retirement year. For indefinite assets, the model assumes the utility retires and replaces plant in its designated retirement year, 50 years after installation.

Capital retirements and O&M change proportionally to customer counts and sales. Customer counts and sales (i.e., gas throughput) are the scaling factors. Increase or decrease of customer count and sales drive a proportional increase or decrease in capex retirement and O&M costs. Current load shape is preserved, thus peak load is adjusted proportionally to sales. O&M costs are simplified and based on FERC categories.

Straight-line depreciation converts to accelerated depreciation. At the beginning of the modeling period, STM depreciates all assets using the straight-line method, with a 50-year asset life. The user identifies one as the point at which the utility's approach to system planning changes, and gas plant in the retiring system is switched to an accelerated depreciation method in that year. Installed and partially depreciated assets see a change in their depreciation rates (both book and tax) to their retirement year. All future capital additions to the retiring system adjust to their new lifetime from their point of addition. For the indefinite system, the depreciation methodology remains unchanged at a 50-year book life approach, with 20 year MACRS (Modified Accelerated Cost Recovery System) used to calculate depreciation for tax purposes.

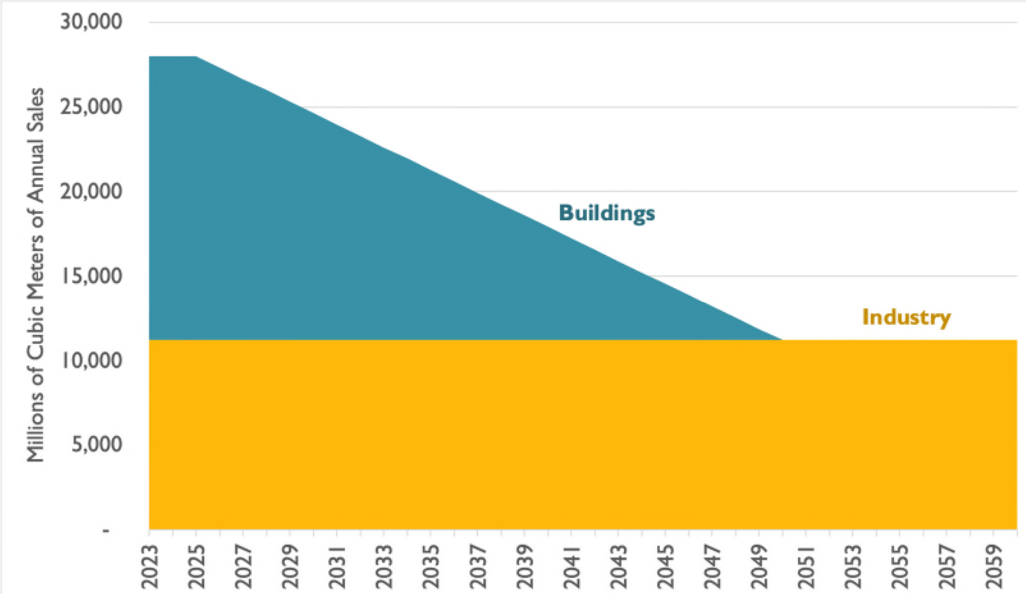
4. Illustrative Scenario

In this section, we present the results on an illustrative scenario, scaled to approximate Enbridge Gas, Inc. (EGI). EGI serves the province of Ontario, Canada, and is among the largest gas distribution utilities in North America. All dollar values in this illustrative case are Canadian dollars (CAD).

4.1. Scenario definition

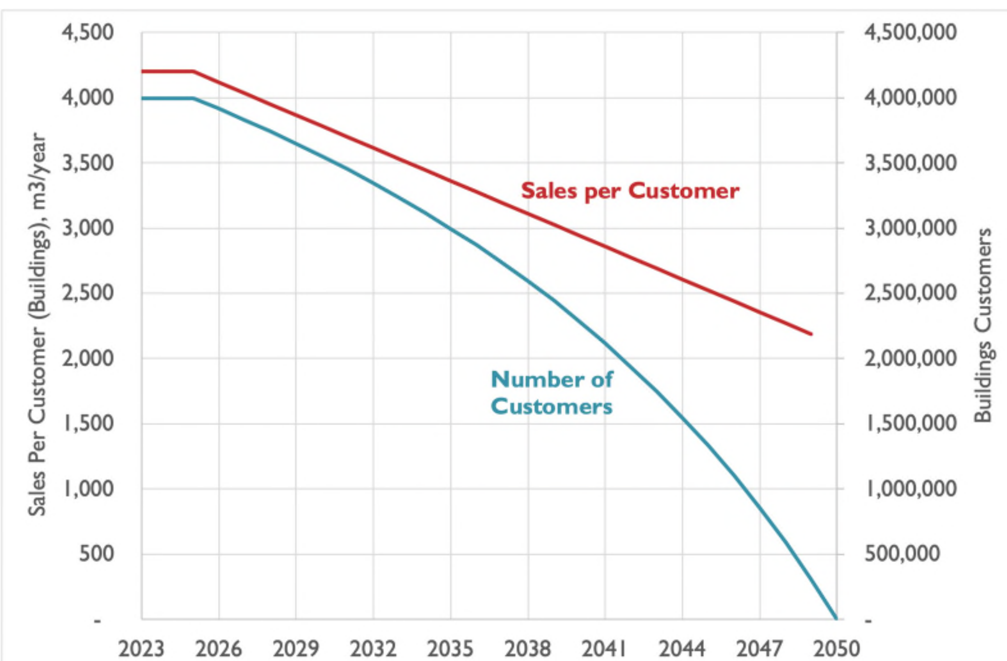
To highlight important issues regarding the future risks to gas utilities, Synapse scaled the STM to the key characteristics of EGI's system: its net plant, O&M costs, and allocation of sales and customers between classes. We present here the results of a case in which residential and commercial sales decline linearly to zero from 2025 to 2050, while industrial customers and associated sales remain unchanged.

Figure 1. Assumed STM example scenario sales of gas to buildings (blue) and industry (yellow)



The scenario assumes that gas demand per building customer declines linearly from today's level to half of that level by 2050, as shown in Figure 2. This reflects that customers would shift individual end uses away from gas as equipment reaches the end of its life, before making the final system transition and departing from the gas system. This also means that the number of building customers does not fall as quickly as sales to this sector.

Figure 2. Assumed STM example scenario sales per building customer (red line; left axis) and total number of building customers (blue line, right axis)

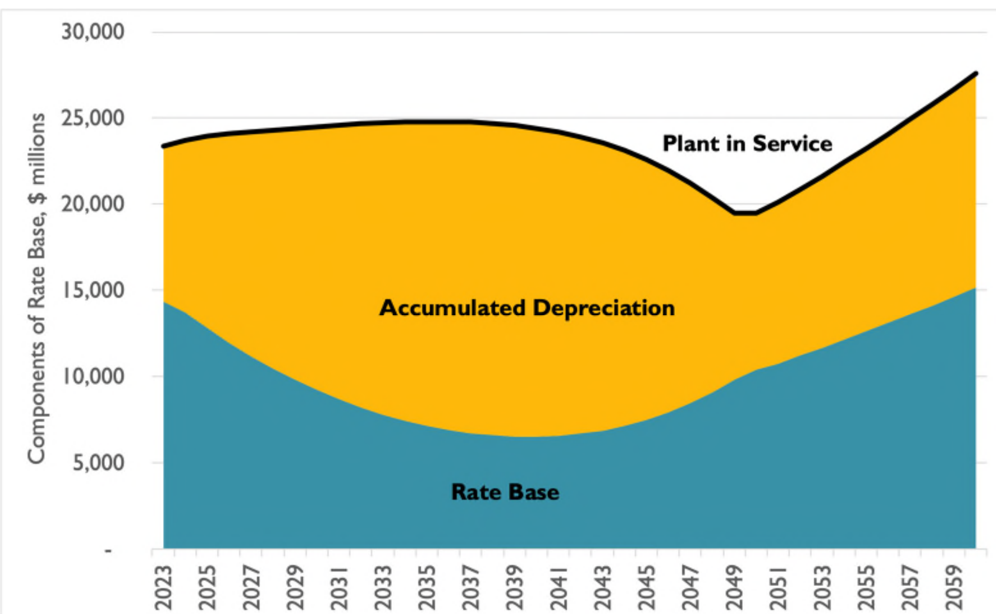


In this illustrative model, the assets required to serve the indefinite system (consisting primarily of high-pressure distribution pipe and the services and meters for industrial customers) constitute about 32 percent of the utility's plant in service. A portion of the plant in the retiring system is removed from plant each year, having been fully depreciated, including net salvage (assumed to be a 25 percent cost). This consists of the meters and services for customers who leave the gas system, as well as a part of the mains that serve the retiring system. The mains portion that retires increases each year, reflecting the increasing likelihood that a departing customer is the final customer on a segment of main which can then be retired.

4.2. Model results

Utility rate base consists of a utility's plant in service, minus the amount by which that plant has been depreciated.[3] Figure 3 shows these components in the modeled STM scenario; the blue area (comprising the net plant adjusted for income taxes) is the utility's rate base. Rate base declines through the mid-2040s, then begins to rise as the retiring system's assets retire, and the salvage cost funds (which are acting as a credit against rate base) are used to decommission the retiring system. The high-pressure system continues to grow throughout the study period. If the cost of pipe retirement (referred to as the net salvage cost) is higher, rate base can actually turn negative before becoming positive again.

Figure 3. Calculated rate base (blue area) in the STM example scenario as a function of plant in service (black line) and accumulated depreciation reserve (yellow area). Results in nominal dollars.

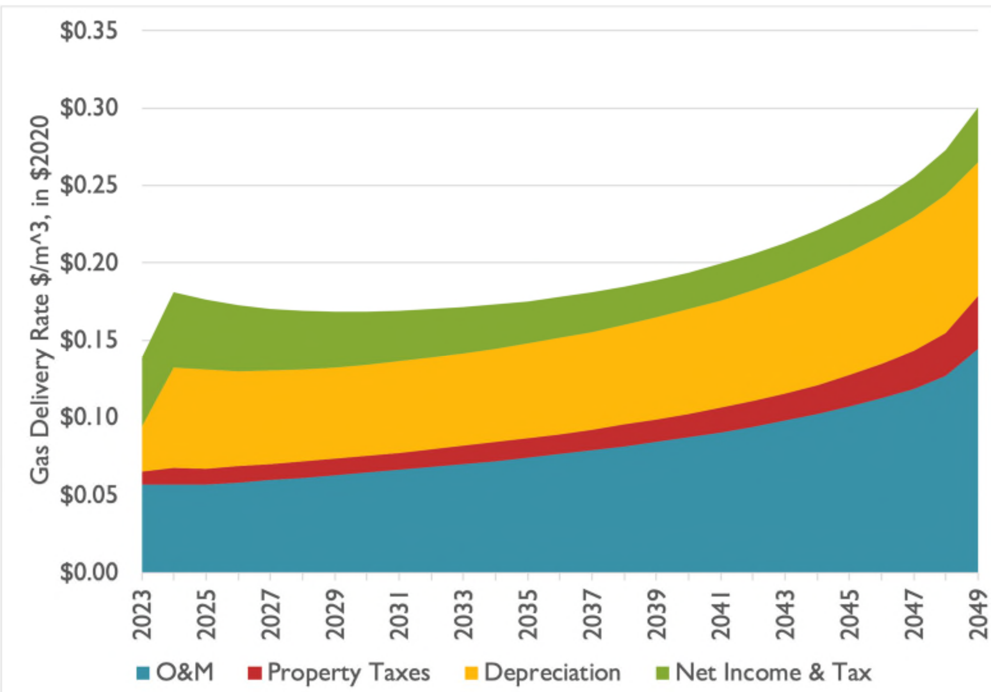


[3] There is no accounting for accumulated deferred income taxes because this illustrative model is set up for a Canadian utility, where this approach is common. EGI passes through its actual income taxes, after accounting for the accelerated depreciation allowed for tax purposes, rather than maintaining an accumulated reserve.

Figure 4 shows the average per-cubic-meter delivery rate for building customers (those served by the retiring system). While changes in depreciation rates are essential for eliminating stranded cost risk, it is the misalignment between the extent of assets in service and falling sales that is the primary driver of rising rates. Rising O&M costs per cubic meter, which dominate the increase over time, result from the fact that there is more distribution system per customer to maintain. Similarly, property taxes do not scale down with sales, and only fall when plant retires.

The near-term rate increase resulting from changing depreciation rates (to account for the retiring system) is noticeable, at about 3.6 cents per m^3. However, rates then fall due to the falling rate base before they rise again due to the fall in sales. Prudent utility management and regulation could surely find a smoother path for rates than the single sharp transition that this simplistic model calculates, which nonetheless allowed a just and reasonable return.

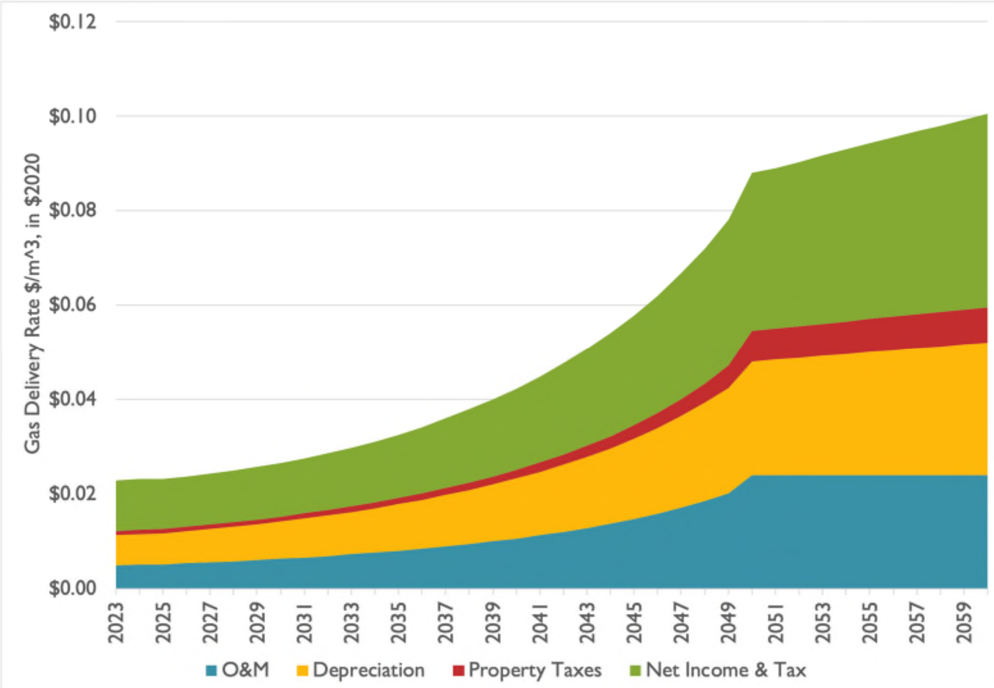
Figure 4. Gas delivery rate to buildings customers, calculated as revenue requirement divided by sales, showing cost components



Industrial customer rates rise slowly as customer departures from the retiring system begin to result in increased costs allocated to the indefinite system. Rates after 2050, on the smaller remaining system, are higher by a bit more than a factor of three from today's industrial rates (on an inflation-adjusted per-m^3 basis) but remain low compared with the cost of gas supply (and especially the cost of low-carbon gas supply, which could be required to meet net zero goals).[4]

[4] In a study conducted for Enbridge, Guidehouse estimates that fossil gas costs about 8.55 cents per m^3, while hydrogen costs 5 times as much on a per-m3-equivalent basis (about 43 cents per m^3-equivalent). (Guidehouse. 2022. *Pathways to Net Zero*

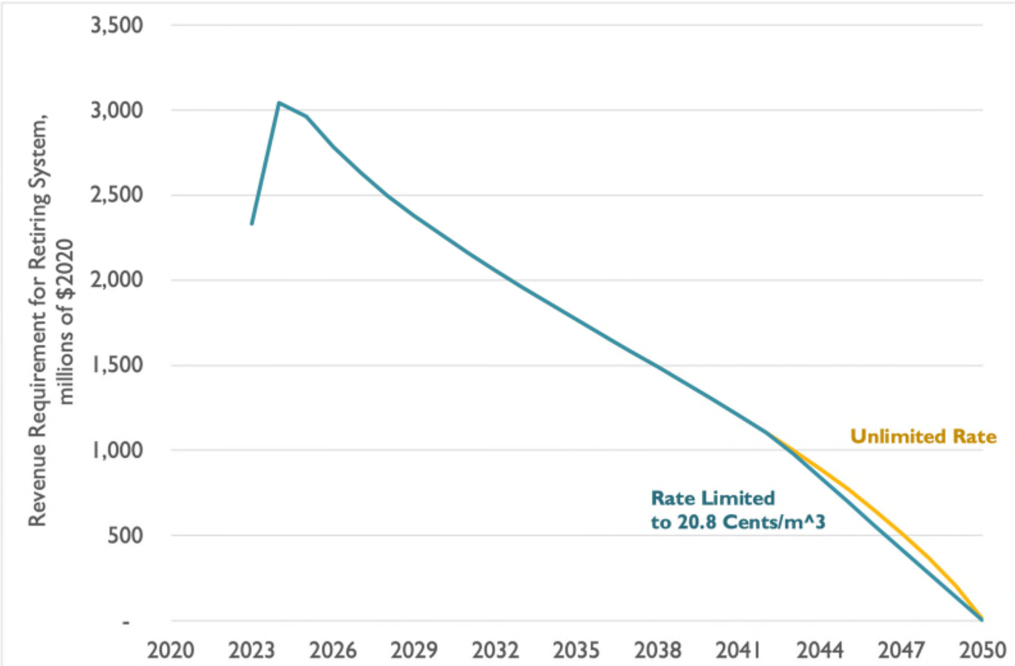
Figure 5. Gas delivery rate to industrial customers, calculated as revenue requirement divided by sales, showing cost components



While the increase in building-sector gas delivery rates is considerable, especially after 2043 as rates pass 50 percent more than today's levels (that is, about \$0.208 per m^3), the utility's overall revenue requirement has fallen substantially by this date. If rates were capped at \$0.208 per m^3, in order to limit the rate of customer departures and partially mitigate equity implications for the last decade of customers to electrify, utility revenues would fall short of the revenue requirement by about \$483 million (in nominal dollars), and about \$200 million in present value. On a present value basis, this shortfall is equivalent to a cost of only about 0.13 cents per m^3 collected between 2024 and 2043, when the hypothetical rate cap would kick in.

Emissions for Ontario. Prepared for Enbridge. Available via the Ontario Energy Board as EB-2022-0200, Exhibit 1, Tab 10, Schedule 5, Attachment 2.)

Figure 6. Revenue requirement for buildings customers (yellow line), and the revenue raised if rates were limited to an average of 20.8 cents per m^3 (in $2020). The difference reflects potential capital recovery risk.

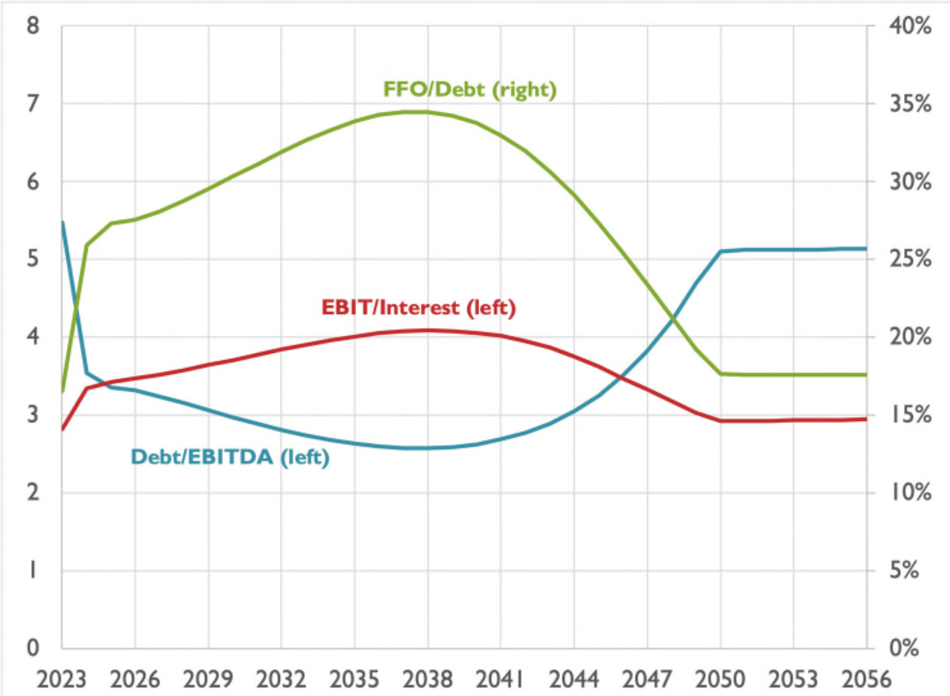


4.3. Financial parameters

Increasing depreciation rates and reducing rate base have substantial impacts on the utility's financial parameters. Figure 7 shows the pathways taken by three important financial ratios tracked by credit rating agencies:

- Funds from operations (FFO) to debt rises quickly from a starting point in the teens into the high 20s, peaks at almost 35 percent, and then falls back to a level close to the starting point as the utility settles into its new, smaller scale.
- Debt to earnings before interest, taxes, depreciation and amortization (EBITDA) falls immediately from its starting point over 5, into the mid-3s, before drifting down to almost 2.5 and then rising again as the system settles to its smaller scale.
- earnings before interest and taxes (EBIT) to interest rises more slowly from its starting point below 3 to a peak of about 4, before returning close to its starting value.

Figure 7. Financial parameters for the hypothetical utility, showing EBIT/Interest and Debt/EBITDA on the left-hand scale and FFO/Debt on the right

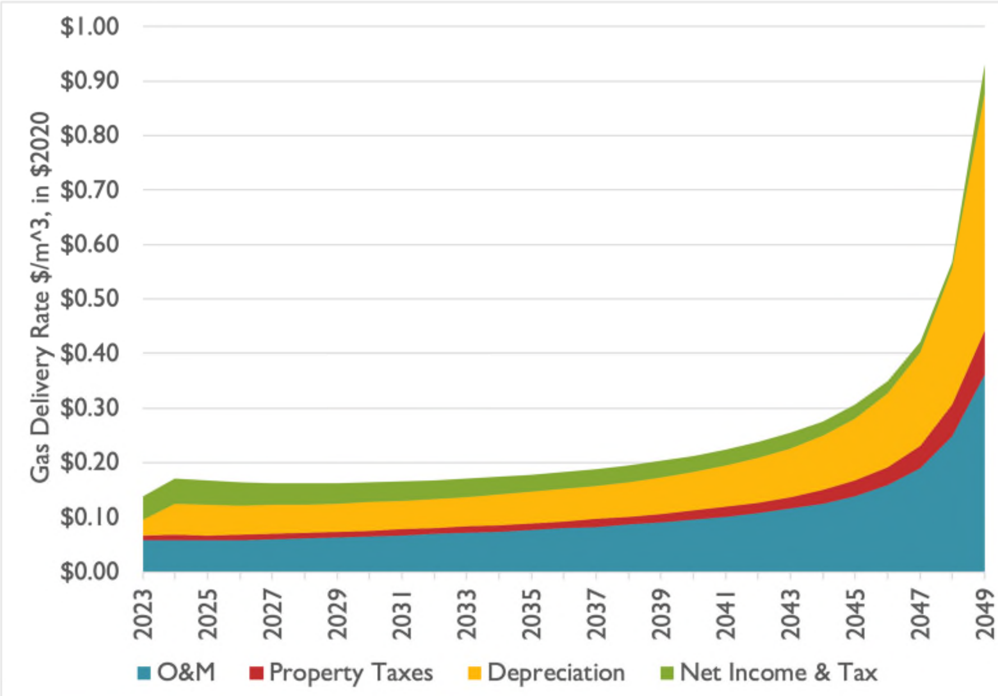


The changes in financial parameters could result in a substantial strengthening in the utility's credit position during the energy transition. This could result in a lower cost of debt or in regulators shifting the capital structure to include more debt and less equity. To illustrate the change in these parameters, we assumed no change in capital structure or cost of capital for this case. If the cost of capital were reduced throughout the central portion of the transition, rates would be lower. Accounting for lower capital costs could be part of the toolbox to help mitigate near-term rate increases from accelerating depreciation. Because financial parameters are largely returning to their base levels as 2050 approaches, these potential changes in capital structure are unlikely to be major levers for addressing the rise in building-sector rates as the retiring system winds down.

4.4. Alternate case: Delayed main retirement

In the event that the utility did not retire mains until 2050, the change in depreciation costs would lower near-term rates by about one cent per m^3. Figure 8 shows the rate trajectory in this case. Because the system is not strategically downsized along the way, O&M costs per building-sector customer drive much higher rates. There is no appreciable difference in this case for the industrial customers using the indefinite system, because the not-yet-retired low-pressure mains are not part of the system for which they pay.

Figure 8. Gas delivery rate to buildings customers, calculated as revenue requirement divided by sales, showing cost components, for a case in which distribution mains are not retired until all buildings customers depart the system



In addition, capital recovery risk would increase in this case because rates would rise much more quickly as 2050 approaches. If rates were capped at 20.8 cents/m^3 to limit competitive risk, the unrecovered revenue requirement would exceed $2.8 billion. This is still only equivalent (on a present value basis) to a cost of a transition charge of 0.81 cents/m^3 collected between 2024 and 2042. One objective of prudent utility capital planning in this illustrative energy transition scenario would be to avoid this additional cost to ratepayers and the associated unnecessary capital risk.

5. APPENDIX

5.1. Inputs

Input parameters:

- Financial parameters: Capital structure/ROE
- O&M costs: Broken out by broad FERC categories
- Capital assets: Plant in service and reserve for depreciation
- Allocation of the sales and customers between those served by retiring system and those served by the indefinite system
- Allocation of capital plant and O&M costs between retiring system and indefinite system, as of today
- Allocation of asset retirement over time based on whether customers who depart are clustered
- Average salvage costs
- Year in which the change in approach (between BAU and a retirement/accelerated depreciation model) is made

5.2. Calculations

Known simplifications (what the model doesn't do):

- All assets are treated the same (same lifetime, depreciation rates, salvage costs, etc.)
    - No distinction between shorter-lived assets (e.g., meters) and longer-lived (e.g., mains)
- Simplified disaggregation of O&M costs
- Simple scaling of capital retirements and O&M costs with customer counts and sales
    - Assumes peak load (and associated capital) scales with sales (e.g., no change in load shape)
- Straight-line depreciation for assets to each retirement year
- Assets retiring in a given year (other than indefinite system assets being reinvested) are assumed to be sampled evenly from all ages of existing plant
    - No allowance for targeting retirement of older portions of the system first
- Existing plant is assumed to have been added to plant in a linearly increasing amount over the last *N* years. These are values in nominal dollars. This approximation reflects both inflation over that time period and increased capital additions over the last 10–20 years.
    - If actual data are available (e.g., from a depreciation study) they could be used for a closer model of an actual utility
- The model does not explicitly treat fully depreciated assets that are still in operation but not contributing to rate base (such as very old cast iron pipe)

Scaling Trajectories:

The model uses a set of inputs to approximate how other model parameters change. This section describes how the model conducts each calculation and scaling.

Inputs:

- Sales and customers by group (retiring vs. indefinite)
- Allocation of distribution mains plant between retiring and indefinite (e.g., 75%/25%)
- Plant broken out by high-level FERC categories:
    - Land
    - Mains
    - Services
    - Meters
    - Storage
    - Transmission
    - General Plant
- Clustering parameter by year
    - This parameter set the proportionality between departing customers and reduction in miles of mains

Calculations:

Phase 1: Set foundational trajectories

- Each trajectory starts at 100% in the start year and changes based on inputs
- Retiring miles (or low-pressure miles if all of low-pressure system is being retired): Scales based on the reductions in number of customers of the retiring system, as modified by the clustering parameter, C:
    - Value = 100% - C*(1-$\text{customers}_{\text{year}}$/$\text{customers}_{\text{start}}$)
    - By default, C starts at zero and rises linearly to 1 by 2050
- Peak: Scales with change in total sales
    - Assumes fixed load shape

Phase 2: Apply foundational trajectories to categories of plant

- Mains
    - Retiring/low-pressure mains: Scales with retiring miles
    - Indefinite/high-pressure mains: Fixed at 100%
- Services
    - Scales w/ # of customers
- Meters
    - Scales w/ # of customers
- Storage
    - Scales with sales
- Transmission
    - Fixed at 100%
- Land
    - Weighted average of retiring and indefinite mains
- General Plant
    - Weighted average of all other types of plant

Phase 3: Apply foundational trajectories to categories of O&M

- Storage Expenses
  - Scales with sales
- Distribution Operations Expenses
  - Weighted average of separate trajectories for:
  - Mains
    - Weighted average of retiring and indefinite mains
  - Services
    - Customers
  - Meters
    - Customers
  - General operations
    - Weighted average of plant in mains and services
  - Supervision
    - Weighted average of plant in mains, services, meters, and land
- Customer Account Expenses
  - Scales w/ # of customers
- Customer Service Expenses
  - Scales w/ # of customers
- Sales Expenses
  - Scales w/ # of customers
- Transmission Expenses
  - Fixed at 100% (part of indefinite system)
- Administrative and General Expenses
  - Weighted average of all parts of O&M
- O&M expenses are also scaled up with inflation

Allocation of costs

Costs are allocated to customers on the retiring system (e.g., buildings) and those on the indefinite system (e.g., industry).

Capital cost allocation:

- All capital costs associated with the retiring system are assigned to the customers on that system.
- The indefinite system consists of high-pressure pipes and transmission assets that serve both indefinite and retiring system customers. Capital costs for these assets are allocated between the two groups on the basis of sales.

O&M cost allocation:

- O&M costs are divided into capital-related costs and customer-related costs
  - Administrative and general costs are allocated in proportion to all O&M costs

- Capital-related O&M costs are allocated according to the capital allocator just derived; customer-related costs are allocated based on the number of customers
- Capital-related O&M costs are: storage, transmission, the portion of distribution operations allocated to demand or volume in a COSS
- Customer-related O&M costs are: customer accounts, customer service, sales, and the portion of distribution operations allocated to customers in a COSS