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THE ONTARIO ENERGY BOARD GOT THE ECONOMICS RIGHT ON ENBRIDGE GAS

By Brandon Schaufele

On December 20, 2023, the Ontario Energy Board (OEB) released Decision and Order EB-2022-0200,[1] Enbridge Gas's first rate case in a decade. This decision attracted notable attention and is one of the most controversial and interesting Ontario regulatory decisions in years. It represents one of the OEB's first attempts to wrestle with the challenge of net zero and the energy transition for natural gas utilities.

The substance of the controversy is described in the summary:

"The energy transition poses a risk that assets used to serve existing and new Enbridge Gas customers will become stranded because of the energy transition." As a result, "the OEB has determined that for small volume customer connections, the revenue horizon that Enbridge Gas uses to determine the economic feasibility of new connections is to be reduced to zero, thus reducing the risk of stranded asset risk to zero, effective January 1, 2025." (OEB, 2023, pg. 2)

This decision has important legal and economic dimensions. The legal question is whether the Commissioners "strayed out their lane" as argued by Ontario's Minister of Energy.[2] Enbridge is appealing the decision,[3] so eventually Ontario's Divisional Court will issue an opinion on this.[4]

Legal issues aside, this note evaluates the more prosaic issue of the economics of the OEB's Order. In the end, the OEB got the economics right. Reducing the revenue horizon to zero is the best way to reduce the fixed cost share of customer gas utility bills in the face of energy transition risk, "protecting the interests of consumers with respect to price … [and] facilitating the rational expansion of the gas system" (OEB, 2023, pg. 22). Setting the revenue horizon to zero changes Enbridge's cost structure, increasing the importance of variable costs relative to fixed costs.

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[1] Ontario Energy Board, EB-2022-0200 – Decision, Enbridge Gas Inc. – 2024-2028 Natural Gas Distribution Rates - Phase One, Date Issued Dec 21, 2023.
[2] Jones, Allison, "Minister to overrule Ontario Energy Board, says decision will raise cost of new homes", Toronto Star, December 22, 2023.
[3] Jones, Allison, "Enbridge appealing Ontario Energy Board ruling on natural gas costs", Toronto Star, January 23, 2024.
[4] Read analysis from Ian Mondrow (https://gowlingwlg.com/en/insights-resources/articles/2024/independent-energy-regulator/), Power Advisory (https://www.poweradvisoryllc.com/reports/the-enbridge-gas-phase-1-decision-the-oeb-the-minister-of-energy-the-natural-gas-system-and-the-energy-transition) and BLG (https://www.blg.com/en/insights/2024/01/energy-planning-and-energy-transition-5-perspectives-on-ontarios-clean-energy-opportunity) for more on this.

Fixed Cost Constraint at the Center of the OEB Decision

Ultimately, the OEB's argument boils down to the following equation, which I refer to as the fixed cost constraint (Henderson, 1986):[5]

$$\frac{\text{Fixed Costs}}{\text{Revenues}} \leq -\frac{1}{\text{Long-run Elasticity of Demand}}$$

The left-hand side of this expression is the amortized, annual fixed cost share of revenues. These are the fixed costs that Enbridge recovers through rates. The right-hand side represents the upper limit on Enbridge's fixed cost share. This limit comes from decisions made by Ontarians, specifically how they choose to heat their homes in response to the relative costs of natural gas versus alternative heating systems. It arises from market competition combined with government policy. Strictly, it equals the negative of one divided by the long-run price elasticity of natural gas demand (which is a negative number). A fixed cost share greater than the right-hand side yields an unstable market due to feedbacks from bills to customers.

The fixed cost constraint is largely irrelevant in 2024. The energy transition means that it will be meaningful soon. The formula represents the necessary and sufficient condition for a stable natural gas market. Ontario's natural gas market is stable "if and only if the fixed cost fraction of customers' bills is smaller than the inverse of the demand elasticity" (Henderson, 1986, pg. 43).

If this formula doesn't hold, Enbridge will fail to meet its revenue requirement. Price increases will lead to *lower* revenues and the company will be placed in a financially precarious position, something that the OEB wants to avoid. Natural gas infrastructure is long-lived. The speed of the energy transition is unknown. The fixed cost constraint matters, because the OEB adjudicators must evaluate the full economic and physical lifespan of new capital expenditures, i.e., "the rational expansion of the gas system."

The OEB has limited ability to affect the long-run elasticity of demand. The elasticity of demand is primarily determined on the customer side of the market. It depends on price levels, carbon taxes and the availability of substitutes for natural gas. The OEB *can* influence the fixed cost share of revenues, however, which is precisely what it did in its Decision.

To appreciate the ideas underlying the fixed cost constraint requires several steps.

Fixed Costs and Customer Bills

First, utility bills are based on cost recovery where costs include a return to equity capital. To a first approximation, gas bills are determined by:

$$\text{Gas Bill} = \frac{\text{Total Network Costs}}{\text{\# of Customers}} + \text{Commodity Costs}$$

Total network costs include both fixed costs and variable costs. A core objective of the OEB is to keep customer bills as low as possible while ensuring Enbridge earns a return on invested capital.

[5] Henderson, S. J. (1986). Price Discrimination Limits in Relation to the Death Spiral. The Energy Journal, 7(3), 33-50.

Enbridge Gas is a natural monopoly. Natural monopolies recover fixed costs by spreading them over their customer base across time (Davis and Hausman, 2022).[6] (There is little that the OEB or Enbridge can do about commodity costs, so ignore them.)

There are both "mechanical" and "behavioural" relationships between customer bills, total network costs and the number of customers.

Mechanically, there are only two ways for gas bills to go down. Either the customer base can grow faster than total network costs, or total network costs can decrease faster than the customer base. If network costs increase faster than the number of customers, bills go up. Likewise, if the number of customers grows faster than total network costs, bills decrease.

The OEB isn't directly worried about the mechanics of rate setting. What they care about is the implicit behaviourial responses embedded in the gas bill. This is because *there is a feedback from gas bills to the number of gas customers*.

Gas bills this year influence the number of customers on the system next year. For example, if in 2024, total network costs increase faster than new hookups, all customers' bills will increase. Higher gas bills encourage some households to explore alternative technologies such as heat pumps or other forms of electric heating. As customers defect from the network, the customer base shrinks and prices for the remaining customers increase even more.

Four decades ago, Tussing and Barlow (1984) argued that faced with a decline in revenues,[7] utilities had two options. They could charge higher prices to remaining customers or they could reduce costs. Fixed costs dominate for natural gas utilities. When a customer leaves the network, only variable costs are reduced. Because variable costs are a small portion of total network costs, prices tend to increase for customers that stay.

This dynamic between fixed costs, bills and the number of customers is well understood by utilities and regulators. It has also been confirmed by research out of the United States. Lucas Davis and Catie Hausman (2023) found that when natural gas utilities increase their customer base by 10%, their regulated revenues go up by roughly 10%. When the number of customers falls by 10%, revenues only fall by 5%. There is an asymmetry on the up- versus down-side that is driven by the nature of fixed costs. It is easy to build to add new customers. It is difficult to "prune [the] existing system" (OEB 2023, pg. 2). Customers leaving the gas network saves variable costs, items such as account management and billing. Fixed costs endure. Fixed costs are merely spread over a smaller customer base.

Energy Transition and the Elasticity of Natural Gas Demand

None of this is an immediate concern in Ontario. Demand for natural gas in the province is currently relatively inelastic. The fixed cost constraint does not bind. Yet, pipes have 40+ year lifespans, so the OEB needs to forecast what the elasticity of demand will be in the coming decades. This is where energy transition risk and stranded assets enter.

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[6] Davis, Lucas and Catherine Hausman, Who Will Pay for Legacy Utility Costs? Journal of the Association of Environmental and Resource Economists, Vol.9, No.6, November 2022.
[7] Tussing, Arlon R. and Connie C. Barlow, The Natural Gas Industry: Evolution, Structure, and Economics, Ballinger Publishing Company, 1984.

The rate at which customers defect from the gas network due to higher utility bills is summarized by the long-run price elasticity of demand. Large elasticities mean a fast rate of defection. Small elasticities mean that prices have substantial room to increase before people look for alternative sources of home heating.

Internationally, estimates for the long-run price elasticity of natural gas range from -0.37 to -3.22. Unfortunately, none of these estimates are from Ontario or even Canada. Ontario's long-run elasticity of natural gas demand is unknown. Nonetheless, a plausible long-run price elasticity of demand for natural gas is -1.5, roughly the midpoint of the range.

Critically, an elasticity of -1.5 acts as an implicit starting point for the OEB, when they consider energy transition risk for natural gas utilities. Energy transition risk means that there are three forces pushing this number higher (in absolute value). In a few short years, the -1.5 could become -3.0. Larger elasticities (in absolute value) move the market closer to a state of instability.

What are these forces acting on the elasticity? First, electrical heating is quickly becoming viable competition for natural gas. As stated in Ontario's Electrification and Energy Transition Panel (EETP) report, "it is no longer clear that natural gas is the cheapest way to heat buildings."[8] Technological improvement and large subsidies are primary reasons for this. Enbridge is entering a period where gas and electricity will compete for home heating.

As heat pumps improve and become cheaper, the long-run elasticity of demand for natural gas will increase (in absolute value). The -1.5 value will get further away from zero.

The same thing happens when the carbon tax is levied on natural gas. The tax is currently \$65/tCO2 but is set to increase to \$170/tCO2 by 2030. Thus, gas bills will increase irrespective of what happens to Enbridge's costs or customer base. As the tax increases, the long-run elasticity becomes more elastic.

Finally, the *Canadian Net-Zero Emissions Accountability Act*, enshrines in legislation Canada's commitment to achieve net-zero emissions by 2050.[9] Forward-looking Canadians know where country is heading with respect to energy transition. Whether this goal is achieved by 2050, 2060 or 2070 is immaterial. Over the next few decades, steps will be taken to move away from fossil fuels. This too makes the demand for natural gas more elastic.

Therefore, the energy transition risk means making demand for natural gas more elastic. The -1.5 long-run elasticity of natural gas demand will get larger (in absolute value). The OEB implicitly recognized this in their analysis:

"The risk that arises from the energy transition results from gas customers leaving the gas system as they transition to electricity to meet energy needs previously met by natural gas. This departure gives rise to assets that are not fully depreciated but are no longer used and useful. This results in stranded asset costs that Enbridge Gas would seek to recover from the remaining gas customers. This in turn would increase rates for those gas customers, leading more customers to leave the gas system, potentially leading to a continuing financial decline for the utility." (OEB, 2023, pgs. 20-21).

[8] https://www.ontario.ca/page/electrification-and-energy-transition-panel#section-1
[9] https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/net-zero-emissions-2050.html

It is the fixed cost constraint that governs this possibility and the long-run elasticity of demand determines the upper bound in the formula. The effect of the energy transition is to reduce the upper limit of the constraint.

Stranded Assets are a Problem for the OEB, Not Enbridge

Throughout its Decision, the OEB devotes significant ink to stranded assets. Stranded assets are a problem for the OEB and Ontarians, not for Enbridge Gas. Stranded assets only occur because of policy and regulation. When unregulated businesses make bad bets by investing in money-losing infrastructure, the money isn't stranded. It's simply lost. Investors take the hit. It is only because the OEB "facilitates the rational expansion of the gas system" and guarantee's a reasonable rate of return on Enbridge's investments that stranded assets matter.

From the OEB's perspective, stranded asset risk arises from two factors. First, infrastructure built in 2024 may become economically worthless before reaching its physical end of life (i.e., "assets are not fully depreciated but are no longer used and useful"). The federal government has mandated net zero by 2050. Thus, 26 years should act as the maximum planning horizon for the regulator. 26 years, however, does not necessarily match appropriate economic planning horizon. That horizon is governed by the fixed cost constraint.

Notably, if Enbridge incurred the full costs and risk of future pipeline construction (i.e., if Enbridge did not capitalize new construction into its rate base), then the OEB could not take issue with stranded assets. The decision says as much. Enbridge incurs the business risk; Enbridge earns the economic returns. It is only because Enbridge's infrastructure is rate regulated that stranded assets matter.

Second, because customers are expected to trickle away from the gas network at varying speeds over the next 30 years, it is difficult for the OEB to match asset amortization to the evolution of the customer-base. This is where the fixed cost constraint enters. The formula describes the maximum fixed cost share of revenues that a utility can incur before customer utility bills increase so fast that the feedback from bills to defection leads to an unraveling. Eventually, "the need to raise price to cover average costs results is a loss of sales sufficiently large that price must be raised again – and so on, until the market must be abandoned" (Henderson, 1986, pg. 34).

If the long-run elasticity of natural gas demand in Ontario equals -1.5, the fixed cost share of Enbridge's revenues must be less than or equal to 67%. A fraction of fixed costs greater than this produces an accelerating dynamic where customers abandon the network at faster rates. This is a bad outcome for the remaining customers, it's bad for Enbridge and it is precisely what the OEB is designed to avoid. The fixed cost share of must decline as the elasticity increases to avoid putting Enbridge into financial difficulty.

Options Available to the OEB

What the OEB is trying to do in its Enbridge Decision is use the tools at its disposal to manage the feedback from bills to customer defection. To do this, they are attempting to change Enbridge's cost structure.

Enbridge's business model is based on economies of scale combined with the long-term recovery of investment in physical assets. This model makes utilities reluctant to abandon assets before the end of their physical life. The OEB, in contrast, wants to shift costs from fixed assets and towards variable costs.

Enbridge and the OEB have several specific instruments such as contributions in aid of construction (CIACs) and temporary rate surcharges on customer bills. However, it useful to focus on a more general set of options. The tools available to the OEB to are:

1. Matching the amortization schedule "to the average length of time that a customer is likely to remain on the system" (OEB, 2023, pg. 27)
2. Charging hook-up fees to new customers
3. Mandating disconnection fees
4. Disallowing capital expenditures

Options 1 and 2 are essentially the same thing. Option 2 is an extreme version of option 1 with the revenue horizon set to zero. Faster amortization schedules reduce the degree to which capital costs are shifted over time to a smaller set of customers. Charging new customers connection costs involves paying fixed costs upfront. Both options 1 and 2 reduce the fixed cost share for future customers. This means that when future customers leave the system, there fewer fixed costs to spread over remaining rate-payers. Effectively, these options reduce the left-hand side term of the fixed cost constraint, making it more likely that the market remains stable.

Option 3, charging disconnection fees, operates on the right-hand side of the fixed cost constraint. It represents one of the few methods the OEB has to influence the elasticity of demand. Disconnection fees work to make demand less elastic. Put differently, disconnection fees increase the cost of substituting from gas to alternative forms of home heating, relaxing the constraint on fixed costs from the consumer demand side. Still, it is not obvious that disconnection fees are viable in this context. The federal government has mandated net zero by 2050 and is subsidizing heat pumps. Therefore, charging disconnection fees appear to work against public policy, to say nothing of the fact that these fees would likely be extremely unpopular with rate-payers.

Finally, the OEB could disallow future capital expenditures. This is already starting to happen in other venues. As an example, several cities, such as Montreal, have banned natural gas connections for new homes.[10] Banning natural gas hook-ups and disallowing prudent network expansion limits customer choice and can make customers worse off, however. Effective regulation should ensure that customers pay the full social costs of their decisions. For many Ontarians, that still means natural gas home heating.

Taking these as the OEB's main options,[11] they selected option 2: "the revenue horizon should be reduced to address the risk of stranded assets resulting from the energy transition" (pg., 33). "The smaller the revenue horizon that is used, the larger the required CIAC will be. The larger the CIAC is, the smaller the stranded asset cost risk will be" (pg. 36).

The OEB's argument is that option 2 derisks the energy transition. Reducing the revenue horizon modifies Enbridge's cost structure. A smaller share of fixed costs will be recovered through rates.

[10] Canadian Press, "Montreal to ban most natural gas heating, cooking in new buildings", Toronto Star, October 23, 2023.
[11] There are a handful of other options such as segregated funds but these are more complex.

Shrinking the fixed cost share extends the period where the market remains stable.

Commissioner Duff's dissent argued that option 1 should have been selected. This dissent stated, "the change to 20 years [is] a measured, incremental approach to risk mitigation" (pg. 144).

Both options 1 and 2 are about lowering the fixed cost share of revenues paid by future customers in advance of the inevitable increases in the elasticity of demand. The difference between these options is that option 1 requires the OEB to ensure that the amortization schedule is faster than energy transition. This is a reasonable, if riskier, perspective to take. There is far less risk for the regulator in choosing option 2. There's merit in both approaches, but I'd argue that the panel's majority got it right on the economics. If possible, it's better to eliminate the risk than attempt to manage it.

Regardless of your opinion on the path selected, the OEB's Decision contains substantial foresight in how it tackled the energy transition. The OEB should be commended on this decision.

Final Thoughts

Two final comments are warranted. First, the OEB also appeared to forerun the recommendations of the EETP Panel. Specifically, Recommendation 15 from the EETP report states:

"The OEB should conduct reviews of cost allocation and recovery policies for natural gas and electricity connections, as well as natural gas infrastructure investment evaluations to protect customers and facilitate development of the clean energy economy." There is "a real risk of economically stranding the rate-regulated distribution assets used for home heating, with significant risk to customers, investors, and public finances."

By changing the structure of fixed and variable costs at Enbridge, the OEB is ensuring cost recovery for natural gas infrastructure investments is sustainable as Ontario proceeds with the energy transition.

Finally, the decision to set the revenue horizon to zero was accompanied by an increase in Enbridge's equity thickness to 38%. The energy transition creates more risk for Enbridge Gas. Higher risk should be compensated with higher reward:

"Given the increased risk for Enbridge Gas's business due to the energy transition … the OEB approves an increase in Enbridge Gas's equity thickness from 36% to 38%." (OEB, 2023, pg. 2)

Whether 38% is enough to compensate for the additional risk is a separate question. Regardless, Enbridge, over the medium to long-term, has two options: pivot their business model or manage the decline of their business. If this pivot includes hydrogen, renewable natural gas and carbon capture, then much of this Decision and Order will be a footnote in 2050. Yet, this, as with so many other variables in the energy transition, remains to be seen. As the EETP report argued, "There is growing doubt that it will be possible to replace the vast quantities of fossil fuel natural gas used today with clean alternatives, such as renewable natural gas (RNG) or hydrogen, in a cost-effective manner" (pg. 72).

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