EB-2024-0063

Cost of Capital Proceeding

POLLUTION PROBE
HEARING COMPENDIUM

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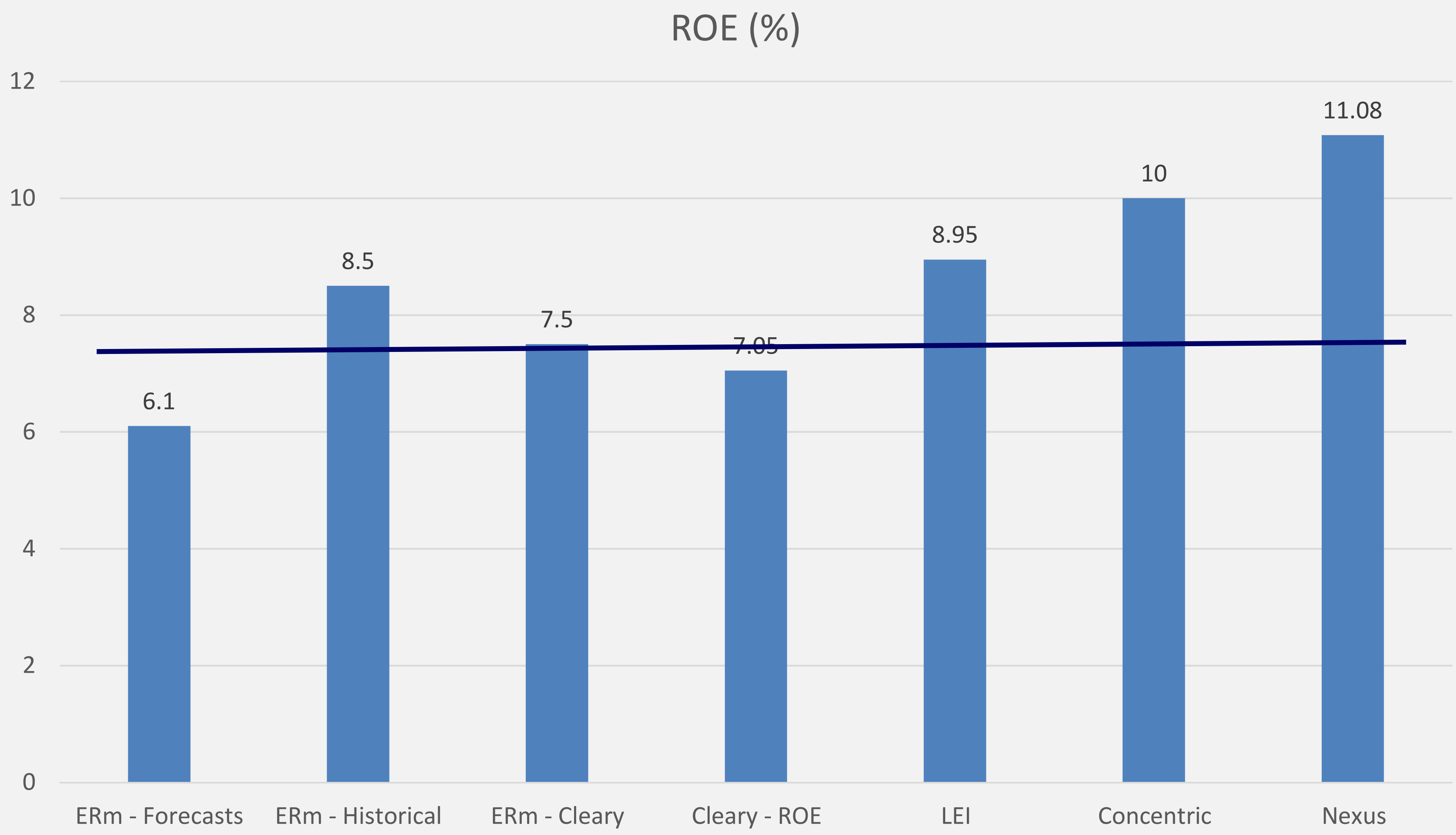
ROEs for Regulated Ontario Operating Utilities



EB-2023-0195

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15 (Sched. B) (the "Act");

AND IN THE MATTER OF an application by Toronto Hydro-Electric System Limited ("Toronto Hydro") for an Order or Orders made pursuant to section 78 of the Act, approving or fixing just and reasonable rates for the distribution of electricity.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

SETTLEMENT PROPOSAL

August 16, 2024

	2025	2026	2027	2028	2029	Total
Difference						
OM&A Expenses (incl. property taxes)	(19.5)	(26.7)	(30.8)	(38.1)	(43.8)	(158.9)
Depreciation and Amortization	(4.1)	(6.0)	(8.7)	(11.4)	(14.1)	(44.4)
Deemed Interest Expense	(1.8)	(3.0)	(4.5)	(6.3)	(8.0)	(23.5)
Return on Equity	(0.7)	(2.5)	(4.8)	(7.3)	(9.8)	(25.1)
Payments-in-Lieu of Taxes (PILs)	0.1	1.3	0.9	(0.8)	(0.7)	0.9
Service Revenue Requirement	**(26.0)**	**(36.9)**	**(47.9)**	**(63.8)**	**(76.4)**	**(251.0)**
Revenue Offsets	-	-	-	-	-	-
Base Revenue Requirement	**(26.0)**	**(36.9)**	**(47.9)**	**(63.8)**	**(76.4)**	**(251.0)**
Stretch Factor	-	1.7	3.6	5.9	8.5	19.6
Incremental Stretch Factor on Capital	-	(2.1)	(4.4)	(6.8)	(9.3)	(22.6)
Revenue	**(26.0)**	**(37.3)**	**(48.8)**	**(64.7)**	**(77.2)**	**(254.1)**

Note 1: The settled revenue requirement related to Deemed Interest Expense, Return on Equity, and PILs table includes an adjustment to the Working Capital Allowance as agreed upon by the parties. Please refer to Table 4 at Line 6 and Table 7 for more information about this adjustment.

1. *Plan Structure and Term*

The Parties agree to a five-year Custom IR Framework, commencing January 1, 2025 and ending December 31, 2029.

Pursuant to the agreed-upon framework, revenues for the first year of the period (2025) are determined using a cost of service forward test year approach, and for each of the remaining years (2026-2029) the revenues are determined by applying a custom index to escalate the prior year revenue in order to determine the revenue for the next year. The agreed upon Custom Revenue Cap Index ("**CRCI**") is expressed as **CRCI = I – X + RGF**, where:

- "**I**" an Inflation Factor ("**I**") to be set annually for the years 2026-2029 in accordance with the OEB's inflation parameters for electricity distributors applicable to the rate year in question;

- "**X**" is the Productivity Factor equal to the sum of (i) the Total Factor Productivity measure of zero percent and (ii) a 0.6 percent efficiency stretch factor. The proposed Performance Incentive Mechanism, and the performance stretch factor will not be implemented.

- "**RGF**" is a custom Revenue Growth Factor, which funds incremental capital and operational investment needs in the outer years of 2026-2029. The RGF is based on the incremental revenue required in years 2026-2029 to fund (i) the capital-related revenue requirement in accordance with this Settlement Proposal (less an incremental capital stretch factor of 0.3%) and (ii) growth in operational expenditures derived using an index-based approach comprised of OEB inflation and a 0.41% growth factor informed by customer and peak demand growth.

19. **DER Cybersecurity**:
Toronto Hydro will seek expert advice and recommendations on DER and EV cybersecurity best practices and incorporate these findings into its cybersecurity framework, as applicable.

20. **BCA Framework:**

Toronto Hydro will (i) apply the OEB's Non-Wires Solutions Guidelines as part of its planning process when making capital investments in the 2025-2029 rate period, and beyond, and (ii) will complete a BCA to assess the economic viability of demonstrated non-wires solutions use cases that can serve as viable alternatives to conventional investments where the expected capital investment cost is $2 million or more, subject to applicable regulatory requirements.

21. **DER and AMI 2.0:**
Where a customer is installing a DER and a meter replacement is needed to provide bi-directional capabilities, and Toronto Hydro would be installing an AMI 2.0 meter, the supply and install of the AMI 2.0 meter will be funded under the AMI 2.0 program.

22. **Dx Loss Study, Guideline and Plan**:
Toronto Hydro shall undertake a study to assess cost-effective measures to reduce distribution losses and shall file that study along with an investment plan to undertake any such cost-effective measures as it deems appropriate for reducing distribution losses in the next rebasing application. Toronto Hydro commits to completing the study by the end of 2026. The scope of the study will include the development of an internal losses guideline, which shall set out the steps to be taken to consider losses in applicable asset management and planning processes, including a methodology to calculate and account for the monetary value of distribution loss reductions.

23. **Commitment Regarding Net Zero 2040:**
Toronto Hydro confirms that its 2025-2029 plan and related execution is aligned to the Net Zero 2040 scenario set out in TransformTO.[14]

24. **Capital Work Commitment:**
Toronto Hydro will carry out the work in following programs and projects as described in the DSP and CQ-SEC 18: (a) Generation Protection, Monitoring and Control, (b) Non-Wires Solutions - Renewable Enabling Energy Storage Systems, (c) Stations Expansion - Sheppard TS, and (d) IT/OT - ADMS), with the caveat that complete execution of the work in items (a) and (b) is contingent on the actual DER uptake being sufficiently consistent with the forecast, coordination with the transmitter, ability to procure the necessary equipment, and technical feasibility.

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[14] For more information about the Net Zero 2040 scenario set out in TransformTO, please see EB-2023-0195, Exhibit 2B, Section D4 at page 6 and at Appendix A, Figure 1.

ENERGY TRANSITION

1. The purpose of this section of evidence is to describe how Enbridge Gas has quantitatively and qualitatively analyzed the potential impacts of decarbonization and energy transition on the St. Laurent Pipeline Replacement Project (the Project).

2. This Exhibit of evidence is organized as follows:
   A. Introduction
   B. General Service Customer Electrification
      1. City of Ottawa Climate Plan and Status
      2. Federal and Provincial Decarbonization Policies and Status
      3. Probabilistic Analysis of Customer Disconnection
   C. Contract Customers
   D. Planned Investments in the Electricity System
   E. Conclusion

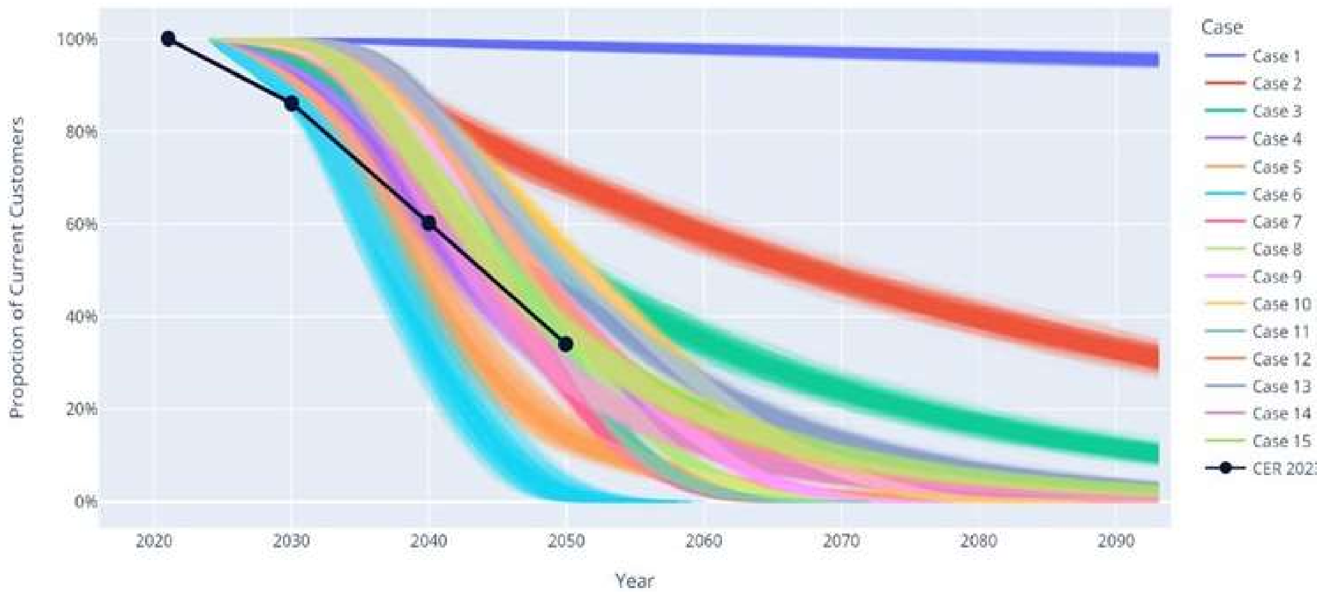
A. Introduction

3. Enbridge Gas has considered the potential impacts of decarbonization efforts and energy transition on the Project, including understanding the drivers of and trends in general service customer electrification, contract customers use of natural gas, and the planned investments in the electricity system.

4. While much of the discourse regarding decarbonization is focused on readily available consumer technologies like electric air-source heat pumps and end uses like building heat, this doesn’t capture the full picture. Particularly, the capacity of the electricity system to accommodate electrification is frequently omitted from the discourse, as are the energy needs of large commercial and industrial customers, many of which may not have readily available means to decarbonize. For these

disconnection, or a date beyond 2050 for when 100% likelihood of disconnection would possibly occur.

Figure 2 Summary of analysis results: Proportion of Remaining Customers



Key Findings

32. Integral's analysis found that varying the assumed probability that customers disconnect upon electric heat pump adoption significantly affects the total time there will be gas users on the system in the model. For example, Case 1, the dark blue curve in Figure 2, where the disconnection probability was assumed to be constant at 1% (consistent with the results observed in the HER+ Program) indicates customers would remain on the system well beyond 2100 without appreciable declines; this would be a conservative view. On the other hand, Case 6, the turquoise curve in Figure 2, where the disconnection probability was assumed to be constant at 100% (i.e., starting today, 100% of customers that install an electric heat pump disconnect from the gas system immediately, even if they have other gas-fired appliances), indicates that customers would remain on the system into the mid-

2050s, this would be an aggressive view. Both scenarios are unlikely as they assume a constant probability of disconnection from now into the future.

33. Under a range of scenarios, general service customers would still be present on the system long past 2050. 14 out of 15 scenarios have outcomes where customers remain on the system beyond 2060, and 11 of those 14 scenarios demonstrate that customers would remain beyond 2080.

34. Other than the six scenarios that have constant probabilities of disconnection (Cases 1 through 6), the remaining 9 scenarios have probabilities of disconnection which vary with time (which is more likely than a constant probability) and have highly aggressive assumed rates of disconnection. The results of these remaining 9 scenarios (Cases 7 through 15), indicate that the most likely year that there could be zero general service customers connected to the gas system is 2102. The results also indicate that the earliest year representing the 5th percentile (i.e., sooner than 95% of all the simulations) for these scenarios is 2066.

35. Even in Case 6, the most aggressive scenario considered, where starting today it is assumed that 100% of general service customers who choose to install a heat pump disconnect from the gas system immediately, general service customers would still be present on the system beyond 2050. The most likely year in which no general service customer would be present under this scenario is 2055, and the earliest year, representing the 5th percentile (i.e., sooner than 95% of all the simulations), is 2052. Additionally, it is worth noting that the results of Case 6 are largely consistent with the projected GHG emissions reductions goals of the City's Energy Evolution plan,[40] which as noted in the previous section are currently "off track".

[40] Energy Evolution: Ottawa's Community Energy Transition Strategy, 2020, p. 37. https://documents.ottawa.ca/sites/documents/files/energy_evolution_strategy_en.pdf

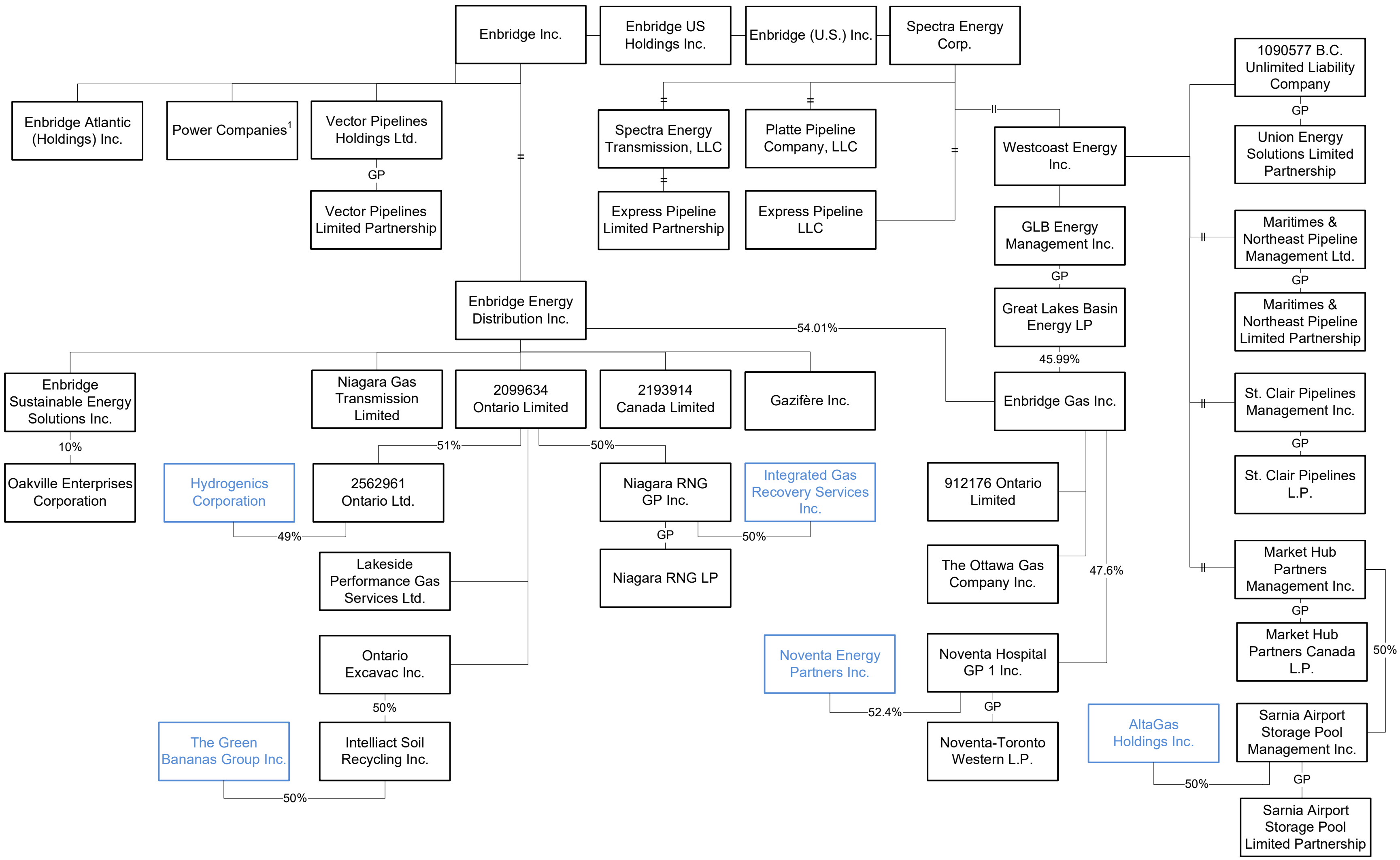
36. Overall, the results of this modeling exercise demonstrate that the SLP system will most likely be needed to serve general service customers until 2055 in the scenario with the most aggressive rates of adoption and disconnection modeled (Case 6), 2102 in the scenarios with more realistic modeling of the aggressive disconnection assumptions (Cases 7 to 15), and well beyond 2100 in the scenario with the most conservative rates of adoption and disconnection modeled (Case 1). Enbridge Gas suggests that the most aggressive and the most conservative scenarios are both unlikely, and that the likely pace of disconnection would likely fall somewhere in the range of the other scenarios.

C. Contract Customers

37. The Large Volume Contract Demand (LVCD) customers served by the SLP system generally fall into the institutional sector and include hospitals, medical research facilities, post-secondary institutions, and government. The gas supplied to these customers is critical for meeting their energy needs and the safe and reliable operation of their facilities. The operation of these facilities serves the public interest and is essential for the City.

38. Enbridge Gas has undertaken outreach with the LVCD customers served by the SLP system to understand their current and future energy needs. Table 1 provides an overview of the aggregated demand information for the six LVCD customers connected directly or indirectly to the SLP System.

GAS DISTRIBUTION & STORAGE GROUP OF ENTITIES
ORGANIZATIONAL CHART



Notes:
Ownership is 100%, unless otherwise noted
[1]These are various entities with renewable electricity generation assets (wind and solar) to whom EGI provides services
Blue font indicates a third party shareholder (non-Enbridge entity)

The information contained on this organization chart is strictly confidential and intended for internal company use only.