EB-2022-0200
Enbridge Gas 2024-2028 Rates

Interrogatories of Environmental Defence – Part 2

Interrogatory # 1.10-ED-74

Reference: Exhibit 1, Tab 10, Schedule 5, Attachment 2

Question:

This question is for Guidehouse:

(a) For the day corresponding to the winter peak demand, please provide the (i) peak hour demand (MW) for that peak day and (ii) the average hourly demand for that peak day. Please provide those figures for 2020, 2030, 2040, and 2050. Please make and state any simplifying assumptions as necessary to answer the question and state any caveats.
(b) For an air-source heat pump, what is the difference between the peak hour demand on the peak winter day and the average hourly demand on the peak winter day? Please provide the underlying calculations.

Interrogatory # 1.10-ED-75

Reference: Exhibit 1, Tab 10, Schedule 5, Attachment 2

Question(s):

These questions are for Guidehouse:

(a) Does Guidehouse agree that the cost of green hydrogen depends on the cost of net-zero power?
(b) What does Guidehouse assume for the cost of green hydrogen in 2050 ($/PJ)? Please provide a copy of or link to the study or report that serves as the basis for this assumption. Please indicate the cost of net-zero power ($/MWh, levelized) assumed in that study or report used to generate the green hydrogen at the relevant price point?
(c) What does Guidehouse assume for the average and marginal cost of net-zero power ($/MWh, levelized) in 2050 in its modelling?

Interrogatory # 1.10-ED-76

Reference: Exhibit 1, Tab 10, Schedule 2, p. 2; Exhibit 1, Tab 10, Schedule 5, p. 22

Question(s):

(a) Enbridge states that: "an electrification pathway to net-zero will require massive investment in new electrical generation, transmission, storage and distribution systems, and end user equipment." If all homes in Ontario were fully electrified with heat pumps, how much could the peak winter demand (MW) be reduced through electric thermal storage units (e.g. those from SSi Energy, Stash, and Steffes)?[62]
(b) Please describe the incentives available for Electric Thermal Storage in Quebec, Nova Scotia, and PEI.
(c) Enbridge states that: "an electrification pathway to net-zero will require massive investment in new electrical generation, transmission, storage and distribution systems, and end user equipment." If all homes in Ontario were fully electrified with heat pumps, how much could the peak winter demand (MW) be reduced through V2G/B technology?

Interrogatory # 1.11-ED-77

Reference: Exhibit 1, Tab 11, Schedule 1

Question(s):

(a) What relief is Enbridge seeking in relation to the evidence at Tab 11?
(b) Is it within the OEB's jurisdiction in this proceeding to "extend the terms of existing transportation contracts and set a floor on the ex-franchise demand factors used for allocating Dawn to Parkway costs for a period of ten years"?
(c) What is Enbridge's position on the relied set out in (b)?
(d) Please provide a link to the CME, FRPO & OGVG evidence referred to on page 1.
(e) Enbridge states on page 8: "The ICF analysis concludes that the Dawn Parkway System is highly likely to remain contracted through to 2034 at levels similar to today." Please explain the reference to 2034. The ICF report appears to relate only to 2022 to 2028. If ICF produced separate analysis up to 2034, please file that.
(f) Please provide a table listing all the ex-franchise contracts on the Dawn-Parkway system, including the geographic location, expiry date, the contracted capacity (GJ/d), and the actual capacity utilized (GJ/d) under that contract on the peak summer day and peak winter day over the past 5 years.

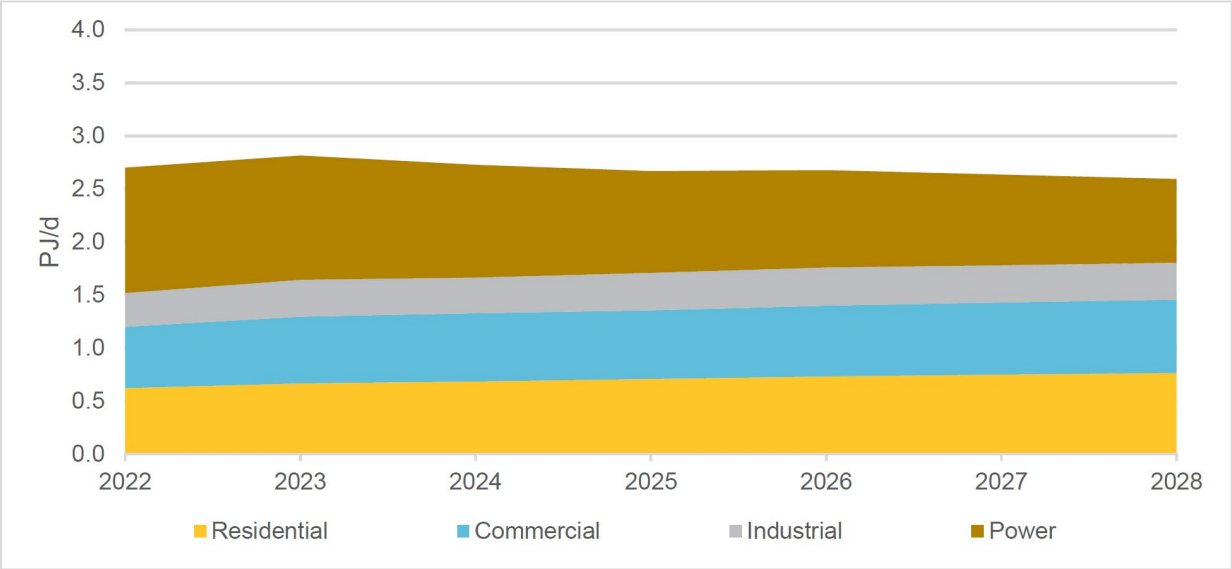
Interrogatory # 1.11-ED-78

Reference: Exhibit 1, Tab 11, Schedule 1, Attachment 1, p. 11

Preamble:

[62] See https://www.ssie.ca/products/, https://stash.energy/en/product/, and https://www.steffes.com/ets/comfort-plus-forced-air/.

Exhibit 3-5 New England Natural Gas Demand by Sector



Question(s):

These questions are for ICF:

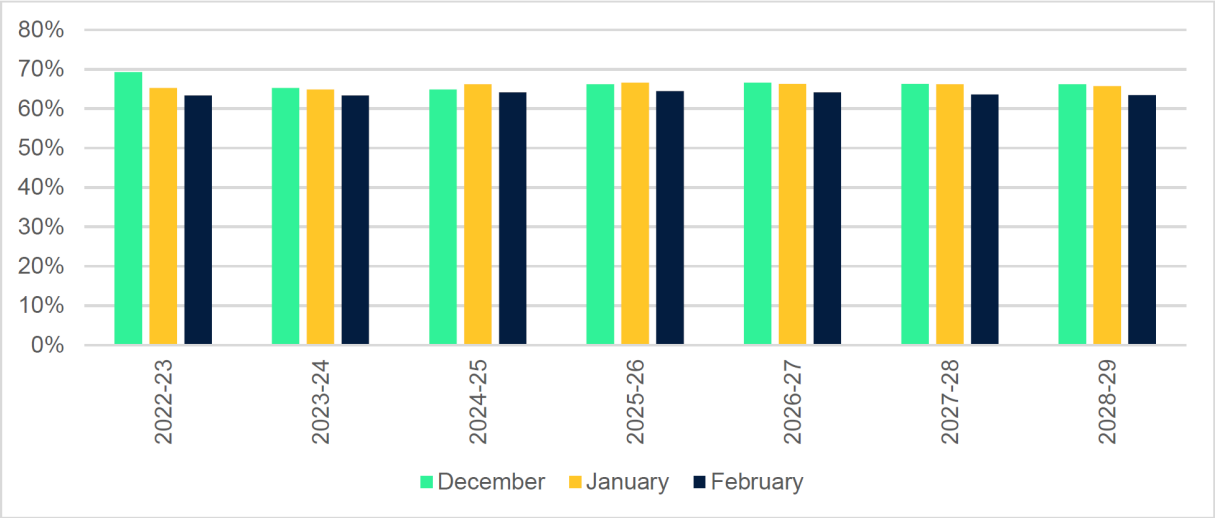
(a) In forecasting the contract demand on the Dawn Parkway system, did ICF consider the ISO New England Final 2022 Heating Electrification Forecast (link)? Did ICF consider Vermont's GHG emissions reductions legislation? Did ICF consider New York's decarbonization pathways study?
(b) If not, please do so.
(c) Please provide a breakdown of the forecast Ontario demand by summer and winter.

Interrogatory # 1.11-ED-79

Reference: Exhibit 1, Tab 11, Schedule 1, Attachment 1, p. 16

Preamble:

Exhibit 3-13 ICF Q2 2022 Dawn Parkway Winter Utilization (%)



Question(s):

(a) Please provide six versions of the above figure – one for each of the customer types listed in exhibit 2-2 on page 6. Alternatively, if it is easier, please provide the same information but in table format.

Interrogatory # 1.14-ED-80

Reference: Exhibit 1, Tab 14, Schedule 2, p. 2

Preamble:

Question(s):

(a) Please explain why Compressed Natural Gas (CNG) refuelling facilities, NGV fuel cylinders, Vehicle Refuelling Appliances (VRAs), and CNG tube trailers should be a regulated business, not an unregulated business. Please provide a separate answer for each item.
(b) Please explain this sentence on page 5: "RNG, with a cost up to 50% less than diesel fuel, blended into the NGV fuel supply has the opportunity to fully decarbonize the vehicle fuel supply, and depending on the RNG feedstock mix, provides a carbon-negative solution." What percent RNG blending is being proposed?
(c) Please compare the cost of a tank of fuel for a heavy truck at current prices as between (i) fossil gas, (ii) RNG, and (iii) diesel.
(d) How confident is Enbridge that heavy trucks will not be electrified in the future? Please estimate a probability.
(e) If the demand for this service declines due to improvements in electric batteries, what financial risks are borne by ratepayers? For instance, if by 2035 there is little or no

demand for this service, what liability, if any, would be left to non-participating ratepayers?

(f) Please provide a table listing each of the components of the NGV program and whether they are rate regulated or competitive in other provinces. Please includes at least Alberta, Quebec, and BC in the comparison.

Interrogatory # 1.14-ED-81

Reference: Exhibit 1, Tab 15, Schedule 1, Attachment 1 (Customer Connections)

Question(s):

(a) Pages 4 and 5 refer to three methods to bring a PI up to 1.0. Please provide a table indicating the dollar value of the capital shortfall made up by each method over the past 10 years and forecast over 2024-2028. This will assist in assessing the overall risks of these ongoing practice to existing customers, if any, in the context of decarbonization.

(b) Page 5 notes that customers can negotiate a premium to posted rates be paid to bring a project PI to the required threshold. Has this ever been used in relation to a residential development? Will this apply to residential developments going forward? If yes, who pays the premium – the developer or the eventual home owners?

(c) Page 5 notes that customers can negotiate a premium to posted rates be paid to bring a project PI to the required threshold. If there is a future unexpected shortfall (e.g. due to customer bankruptcy), are existing ratepayers responsible for covering the shortfall?

Interrogatory # 1.14-ED-82

Reference: Exhibit 1, Tab 15, Schedule 1, Attachment 1 (Customer Connections)

Question(s):

(a) Page 5 refers to the Investment Portfolio and Rolling Project Portfolio. We understand that this portfolio approach is meant at least in part to allow some projects to have a PI no lower than 0.8. Does a portfolio with a PI of over 1 help to cover the costs of (i) future revenue forecasts not coming to fruition and/or (ii) connection capital costs being higher than expected?

(b) Please describe how a shortfall is made up (e.g. from existing customers, from the connecting customers, from the IP or RPP, etc.) in the following examples:
    (i) A connection has a PI of 1. However, the final construction costs are significantly more than the estimate (including contingency).
    (ii) A connection has a PI of 1. However, in the decades after the connection is made, the forecast revenue does not come to fruition.
    (iii) The situation of (i) and (ii) specifically in the situation of a residential development.

(c) According to page 5, "the responsible Director may authorize exceptions, subject to a PI no lower than 0.8, as stipulated in E.B.O. 188." When is Enbridge more likely to authorize an exception? Please provide any internal policy/practice documents on this

question. How many times has an exception been authorized for a residential development over the past decade.

(d) Please provide a table of projects given approval for a PI lower than 1 over the last 10 years with columns showing the size and type of the project (e.g. residential development, industrial, community expansion, etc). If an itemized table cannot be provided, please at least provide a breakdown of the total by type.

(e) Please provide a table showing the connection costs for residential developments over the most recent 10 years with columns showing: the NPV of the total costs, the NPV of the forecast incremental revenue, any customer contribution, and the method of customer contribution (e.g. one of those listing in para. 7 on page 4).

Interrogatory # 1.14-ED-83

Reference: Exhibit 1, Tab 15, Schedule 1, Attachment 1 (Customer Connections)

Question(s):

(a) How does Enbridge classify connections of new residential developments (i.e. subdivision)? Are these "customers attaching to existing mains (infills)" as described on page 9?

(b) Please confirm which methods are available for connections of new residential developments to bring a project up to the required PI.

(c) If a shortfall must be made up to bring the PI to 1, can this be done through a premium that is applied to the bills of future residential homeowners?

(d) Please explain the rational for any significant differences between the gas and electric connection rules outlined in (e) below.

(e) To help us understand gas connections policy as they relate to residential housing developments and consider them in comparison to electric connection policies, please complete the following table:

Gas vs. Electric Connection Rules for Residential Housing Developments		
	Gas	**Electricity**
Feasibility testing & CIAC calculation		
Customer attachment forecast horizon		
Maximum customer revenue horizon		
Timing of CIAC payment		
Availability of contribution through a premium or surcharge paid by homeowners		

Deposit in support of revenue forecast[63]		
Timing of repayment of deposit in support of revenue forecast		
Liability for connection cost overruns (who is liable, and how it this enforced)		
Liability for revenue forecast shortfalls (who is liable, and how it this enforced)		
Availability and timing of refunds where connection cost is less than forecast		
Other		

Interrogatory # 1.14-ED-84

Reference: Exhibit 1, Tab 15, Schedule 1, Attachment 1 (Customer Connections)

Question(s):

(a) To help us understand gas connections policy as they relate to large customers (e.g. industrial facilities) and consider them in comparison to electric connection policies, please complete the following table:

Gas vs. Electric Connection Rules for Large Customers		
	Gas	**Electricity**
Revenue forecast parameters in CIAC calculations		
Timing of CIAC payment		
Availability of contribution through a premium or surcharge paid by the customer		
Deposit in support of revenue forecast		
Timing of repayment of deposit in support of revenue forecast		

[63] A deposit to protect against the risk that the number of forecast residential connections does not materialize, leading to a drop in forecast revenue.

Liability for connection cost overruns (who is liable, and how it this enforced)		
Liability for revenue forecast shortfalls (who is liable, and how it this enforced)		
Availability and timing of refunds where connection cost is less than forecast		
Availability and timing of refunds where distribution revenue is greater than forecast		
Other		

Interrogatory # 2.5-ED-85

Reference: Exhibit 2, Tab 5, Schedule 2, Page 6; Exhibit 2, Tab 6, Schedule 1, p. 53-55; Exhibit 2, Tab 6, Schedule 2, s. 5.1.6 & 5.1.9.3

Preamble: These questions relate primarily to the accuracy of the customer growth forecast, the forecast community expansion spending, and the USP and AMP sections noted above.

Question(s):

(a) Please provide table of all projects approved in phase 1 of the Natural Gas Expansion Program that have not been completed with columns for: the community's name, the expected number of customer connections, the NGEP funding, the total capital costs, whether the project is still expected to proceed, the expected in-service date (if applicable), and the expected date of an OEB application (if applicable).
(b) Please provide table of all projects approved in phase 2 of the Natural Gas Expansion Program that have not been completed with columns for: the community's name, the expected number of customer connections, the NGEP funding, the total capital costs, whether the project is still expected to proceed, the expected in-service date (if applicable), and the expected date of an OEB application (if applicable).

Interrogatory # 2.5-ED-86

Reference: Exhibit 2, Tab 5, Schedule 2, Page 6; Exhibit 2, Tab 6, Schedule 1, p. 53-55; Exhibit 2, Tab 6, Schedule 2, s. 5.1.6 & 5.1.9.3

Preamble: These questions relate primarily to the accuracy of the customer growth forecast, the forecast community expansion spending, and the USP and AMP sections noted above.

Question(s):

(a) Is the price of gas and/or the incentives available for electric heat pumps impacting the customer attachments in community expansion projects? Please explain the answer.
(b) To help us explore the question in (a), please complete the following tables and prepare a chart for each showing the trendline. For the second table, please divide the annual forecast by 12 to generate a monthly forecast figure.

Customer Attachments in Community Expansion Locations by Month				
	Jan 2020	Feb 2020	…	Dec 2022
Number of customer attachments				

Customer Attachments in Community Expansion Locations by Month Percent of Forecast				
	Jan 2020	Feb 2020	…	Dec 2022
Number of customer attachments as % of forecast				

Interrogatory # 2.5-ED-87

Reference: Exhibit 2, Tab 5, Schedule 3, Page 7

Preamble:

> "The project reduced the dependence on the Parkway Gate Station, improved supply chain diversity, reduced upstream supply risks and reduced expected gas supply costs by $1.6 billion over the 2015 to 2025 period. The GTA project was $171.4 million over budget due to several factors including escalation of the construction bid price, increased costs associated with greater construction complexity and increased overall duration due to longer permit acquisition times. However, the forecasted reduction of gas supply costs and overall benefits delivered by the execution of the project outweigh the cost overruns. Additional details regarding project costs were filed in the Post Construction Financial Report for the GTA Project5."

Question(s):

(a) Please estimate the actual gas supply cost benefits from the GTA project from 2015 to 2022 and reconcile that with the forecast in the GTA project application. Please explicitly account for the evidence of TransCanada in that case showing that avoided tariffs from the mainline would, fully or partly, be ultimately borne to ratepayers by future rate increases.

Interrogatory # 2.6-ED-88

Reference: Exhibit 2, Tab 6, Schedule 1, p. 6

Question(s):

(a) Per page 6: "Enbridge Gas owns and operates approximately 153,000 km of main and service pipelines for the transportation and distribution of gas." Please provide table listing the kms of Enbridge *transmission* pipelines by pipe size. Please also provide a table listing the kms of Enbridge *distribution* pipelines by pipe size.
(b) Please provide a map of Enbridge pipelines in Ontario, colour coded to differentiate between transmission and distribution pipelines.

Interrogatory # 2.6-ED-89

Reference: Exhibit 2, Tab 6, Schedule 1, p. 15

Question(s):

(a) Please provide a table of figures underlying Figure 1 on page 15. Please add rows to express the prices in $CAD/m3. Please also add rows for the more recent ICF forecasts.
(b) Please provide a table showing the ICF forecasts from (i) 2010 and (ii) 2015 compared to the actual prices from 2010 to today.

Interrogatory # 2.6-ED-90

Reference: Exhibit 2, Tab 6, Schedule 1

Question(s):

(a) Page 17 states: "Each year, Enbridge Gas completes a budget and multi-year LRP process. This process produces Enbridge Gas's forecast of annual volumes, revenues, operating costs, and capital investments." Please file the internal documentation referred to above for the latest year.
(b) Please reproduce figure 6 on page 36 with additional rows indicating the additional investments required for the "diversified" scenario described in the Guidehouse report regarding decarbonization pathways.
(c) Page 39 states: "Table 4 shows investments with total in-service capital that exceeds $50 million that meet the ICM-eligible criteria for materiality, need and prudence. Based on the 2023 to 2032 capital expenditure forecast (please see Figure 7), Enbridge Gas does

not anticipate seeking ICM recovery for these projects." What would need to change for Enbridge to decide to seek ICM recovery for these projects.

(d) How does Enbridge anticipate covering the costs of the projects listed in Table 4? If, say, 50% of the spending listed in Table 4 is not approved by the OEB in future leave to construct applications, how would those savings find their way back to ratepayers?

(e) Page 44 makes reference to the leave to construct application in the regulations being "presently $2 million." Does Enbridge anticipate this changing? Please describe any communications Enbridge has had with the Ministry of Energy regarding this.

Interrogatory # 2.6-ED-91

Reference: Exhibit 2, Tab 6, Schedule 1

Question(s):

(a) Please reproduce table 5 on page 44 adding (i) a column to indicate the total cost of the project and (ii) a row at the bottom with totals.

(b) Please reproduce table 5 on page 44 (i) adding a column to indicate the total cost of the project, (ii) only including the projects that would not require an LTC under the new LTC thresholds under consideration by the Ministry, and (iii) a row at the bottom with totals.

(c) Please reproduce table 6 on page 46 adding (i) a column to indicate the total cost of the project, (ii) a column to indicate the criteria that exempts it from the LTC requirement [e.g. as listed in para. 92], and (iii) a row at the bottom with totals.

Interrogatory # 2.6-ED-92

Reference: Exhibit 2, Tab 6, Schedule 1, p. 46-47

Preamble:

Table 6: 2024 Investments Not Subject to LTC

Asset Class	Investment Code	Investment Name	2024 Forecast	2023 to 2032 Forecast
Distribution Pipe	7660	VPM - Erin Township	$3,032,186	$11,695,807
Distribution Pipe	100339	A10: Wilson Avenue, Toronto, VSM Replacement	$36,134,725	$91,158,784

Question(s):

(a) Please explain why the Wilson Avenue, Toronto VSM Replacement does not require leave to construct application.

(b) Please provide the full project description, maps, and costing documentation for this project.

(c) Is Enbridge seeking any relief in relation to this project? If yes, please explain.

(d) Does the OEB have the jurisdiction to rule in this proceeding on the appropriateness of Enbridge's classification of this project as one that does not require a leave to construct application?

Interrogatory # 2.6-ED-93

Reference: Exhibit 2, Tab 6, Schedule 1, p. 46-47

Question:

(a) Please provide the full project description, maps, and costing documentation for Dawn C Compression Lifecycle project. Is Enbridge seeking any relief in relation to this project? If yes, please explain.

Interrogatory # 2.6-ED-94

Reference: Exhibit 2, Tab 6, Schedule 2, s. 5.1.4 (Customer Connections)

Question(s):

(a) Please complete the following table regarding customer connections, with three years of actuals (2020-2022) followed by the AMP forecast:

Customer Attachment Totals by #, m3, m3/d, and m3/h				
	2020	2021	…	2032
Customer connections (#)				
Estimated increase in annual demand (m3) from new customers				
Estimated increase in design day demand (m3/d) from new customers				
Estimated increase in design day/hour demand (m3/hr) from new customers				

(b) Please complete the following table in three versions – one with customer numbers, one with annual demand (m3), and one with design day demand (m3/day).

Customer Attachments by Sector, Before and After Energy Transition Adjustments				
	2020	2021	…	2032

Before Energy Transition Adjustments				
Residential				
Commercial				
Industrial				
Total				
After Energy Transition Adjustments				
Residential				
Commercial				
Industrial				
Total				
Difference				
Residential				
Commercial				
Industrial				
Total				

(c) Please complete the following table:

Residential Customer Attachments by Type				
	2020	2021	…	2032
Number of connections (#)				
Community expansion				
Fuel switching (excl. community expansion)				
Homes in residential housing development (subdivisions)				
New single-family dwellings				
Other				
Annual demand (m3)				
Community expansion				
Fuel switching (excl. community expansion)				

Homes in residential housing development (subdivisions)				
New single-family dwellings				
Other				
Design Day Demand (m3/day)				
Community expansion				
Fuel switching (excl. community expansion)				
Homes in residential housing development (subdivisions)				
New single-family dwellings				
Other				

Interrogatory # 2.6-ED-95

Reference: Exhibit 2, Tab 6, Schedule 2, s. 5.1.4 (Customer Connections)

Question(s):

(a) Is Enbridge's customer attachment forecast net of Enbridge account closures (e.g. due to fuel switching or bankruptcy)?
(b) Please provide a table showing customer account closures (e.g. due to fuel switching or bankruptcy), with three years of actuals (2020-2022) followed by a forecast for 2023 to 2032.
(c) How many applicants have applied for an incentive payment through the Greener Homes Grant and/or the Enbridge program for (i) an air-source heat pump, (ii) a ground-source heat pump, or (iii) a heat pump water heater. Of those applicants, how many applied for a payment for an air-source heat pump and an air handler for central ducting?
(d) What is Enbridge's forecast of the number of participants in its DSM program obtaining an incentive for an air-source heat pump for each year from 2023 to 2028? If possible, please provide an estimate for how many of those will be fully electric versus hybrid systems.

Interrogatory # 2.6-ED-96

Reference: Exhibit 2, Tab 6, Schedule 2, Appendix A

Question(s):

(a) How many kms of pipe are forecast to be built or replaced under the AMP from 2024 to 2028 (inclusive)?
    (i) What percent of these pipes could certainly be used for 100% hydrogen from a technical perspective if a 100% hydrogen system were to be sought in the future? If the answer is greater than 0%, please (A) describe the pipes that are 100% hydrogen compatible, and (B) provide references to studies to conclusively establish that they can be used for 100% hydrogen.
    (ii) What percent of these pipes could certainly be used for 20% hydrogen (by volume) if a 20% hydrogen system were to be sought in the future?

Interrogatory # 2.6-ED-97

Reference: Exhibit 2, Tab 6, Schedule 2,

Question(s):

(a) To help us understand the relative risks to Enbridge shareholders and customers relating to the decarbonization of the economy, for each of the following scenarios, please describe whether Enbridge shareholders would not likely, likely, or certainly be made whole for their investments in gas infrastructure:
    (i) Enbridge receives OEB approval to construct a transmission reinforcement to the Dawn Parkway system. However, the need only persists for five years, after which the demand falls below the incremental capacity. As a result, most of the forecast savings and revenue do not materialize. Are Enbridge shareholders (i) not likely, (ii) likely, or (iii) certain to be made whole for their investments? Please provide an answer, and discuss the relevant considerations.
    (ii) Enbridge receives OEB approval to construct a distribution reinforcement. However, the need only persists for five years, after which the demand falls below the incremental capacity. As a result, most of the forecast revenue does not materialize. Are Enbridge shareholders (i) not likely, (ii) likely, or (iii) certain to be made whole for their investments? Please provide an answer, and discuss the relevant considerations.
    (iii) A "death spiral" occurs from 2035 to 2040, leaving $5 billion in rate base uncollectable from the remaining customers. Are Enbridge shareholders (i) not likely, (ii) likely, or (iii) certain to be made whole for their investments? Please provide an answer, and discuss the relevant considerations.

Interrogatory # 2.6-ED-98

Reference: Exhibit 2, Tab 6, Schedule 2, Appendix A (AMP, Investments >$10M)

Question(s):

(a) Please provide a table of all items in Appendix A with columns for: name, planning portfolio, full cost, expected in-service date, whether it is a "must do", whether LTC is required.

Interrogatory # 2.6-ED-99

Reference: Exhibit 2, Tab 6, Schedule 2, Appendix A (AMP, Investments >$10M)

Preamble:

These questions relate to the Dawn C Compression Lifecycle project described at page 4.

Question(s):

(a) How long could this project be deferred for before becoming an intolerable risk?
(b) When was the concern that is driving this replacement first identified?
(c) Please provide all documentation detailing the risk.
(d) When was IRP first considered? Please provide details.
(e) Please provide all documentation detailing the efforts to consider IRP.

Interrogatory # 2.6-ED-100

Reference: Exhibit 2, Tab 6, Schedule 2, Appendix A (AMP, Investments >$10M)

Preamble:

These questions relate to the Wilson Avenue, Toronto, VSM Replacement

Question(s):

(a) Page 11 of Appendix A lists the Capex as $72,015,518 whereas Exhibit 2, Tab 6, Schedule 1, Page 46 lists the forecast cost as $91,158,784. Please provide a table reconciling both figures.
(b) Please provide a table indicating the total and a breakdown down of the full project cost, including capitalized overhead and pipeline abandonment.
(c) Has Enbridge confirmed that it will be able to abandon the pipeline in place without removing it, including concurrence from Toronto and ensuring that there are no conflicts with other future infrastructure plans.
(d) The investments summary report lists: “Moratorium - At Walsh Ave. W. past Matthews Gate, approximately 700 m expires December 31, 2024.” What is this?
(e) When was the concern that is driving this replacement first identified?
(f) Please provide all documentation detailing the risk.
(g) Does Enbridge anticipate replacing the pipe sections east and/or west of the project area in the future? If yes, when and why. If no, please explain why Enbridge believes they are safe whereas the subject pipe is not.
(h) If demand served by this pipe could be reduced, could any risks associated with the vintage pipe be mitigated by lowering the pressure? Please discuss.
(i) Please assess the possibility of relocating all or portions of the pipeline to the greenspace directly adjacent to highway 401, just south of Wilson Ave.

(j) Please provide all available documentation regarding this project, including in relation to the cost, risk, justification, DCF figures, route alternatives, and IRP consideration.

Interrogatory # 2.6-ED-101

Reference: Exhibit 2, Tab 6, Schedule 2, Appendix A (AMP, Investments >$10M)

Preamble:

These questions relate to the Wilson Avenue, Toronto, VSM Replacement

Question(s):

(a) Please provide a map showing the pipe to be replaced and all the pipes it serves.
(b) Please provide a map showing all customers served by the pipe.
(c) Please provide a map showing other nearby pipes that could serve some or all of the customers in question.
(d) Please provide a satellite image showing the customers served by the pipe.
(e) Please confer with the City of Toronto to determine when the stretch of Wilson Avenue in question is slated to be (i) resurfaced and (ii) reconstructed.
(f) Please estimate the cost savings, if any, of timing the project to coincide with scheduled (i) resurfacing or (ii) reconstruction.
(g) Will portions of lanes of Wilson Avenue ever need to be shut down for the project? If yes, approximately how many lanes at a time (maximum) and for how long?

Interrogatory # 2.6-ED-102

Reference: Exhibit 2, Tab 6, Schedule 2, Appendix A (AMP, Investments >$10M)

Preamble:

These questions relate to the Wilson Avenue, Toronto, VSM Replacement

Question(s):

(a) When was IRP first considered? Please provide details.
(b) Please provide all documentation detailing the efforts to consider IRP.
(c) Please complete the following table with as much detail as possible:

Load Served – Wilson Avenue, Toronto, VSM Replacement				
	2020	2021	…	End of depreciation period
# of customers				
Residential				
Commercial				

Industrial				
Total				
Annual demand (m3)				
Residential				
Commercial				
Industrial				
Total				
Design day demand (m3/day)				
Residential				
Commercial				
Industrial				
Total				
Design hour demand (m3/hour)				
Residential				
Commercial				
Industrial				
Total				
Capacity – NPS 12 pipe				
Capacity – next size smaller				

Interrogatory # 2.6-ED-103

Reference: Exhibit 2, Tab 6, Schedule 2, Appendix A (AMP, Investments >$10M)

Preamble:

These questions relate to the Wilson Avenue, Toronto, VSM Replacement

Question(s):

(a) When will the cost of this pipe be fully depreciated under the depreciation policies proposed by Enbridge in this application?
(b) When will the proposed pipe be at the end of its estimated useful life.
(c) How much of the project cost will be undepreciated by (i) 2040 and (ii) 2050.
(d) Please provide the NPV of the project, accounting for the forecast revenue from the customers served by the pipe. Please provide the DCF table.
(e) Please provide the NPV of the project, accounting for the forecast revenue from the customers served by the pipe ending in 2050. Please provide the DCF table.

(f) If they are not included, please calculate the NPV from (d) and (e) including all the O&M costs associated with serving the customers in question and provide the DCF table.

Interrogatory # 2.6-ED-104

Reference: Exhibit 2, Tab 6, Schedule 2, Appendix A (AMP, Investments >$10M)

Preamble:

These questions relate to St. Laurent Phase 3 and Phase 4

Question(s):

(a) Please confirm whether Enbridge is necessarily proceeding with St. Laurent Phases 3 and 4 in light of the decision in EB-2020-0293.
(b) Please provide a table comparing the state of the pipes at issue in St. Laurent Phases 3 and 4 with those at issue in EB-2020-0293.
(c) Please provide the NPV of the replace and repair options in St. Laurent Phases 3 and 4.
(d) Please recalculate the response to (c) with the economic life of the pipes ending in 2050.

Interrogatory # 2.6-ED-105

Reference: Exhibit 2, Tab 6, Schedule 2, Appendix A (AMP, Investments >$10M)

Preamble:

These questions relate to the Hamilton Industrial Reinforcement (p. 24)

Question(s):

(a) Please provide a breakdown of the total cost, including any abandonment costs and capitalized overhead.
(b) Please provide the NPV calculations and DCF tables underlying the calculation of the contribution in aid of construction.
(c) Please recalculate the NPV, DCF tables, and CIAC on the assumption that the pipeline is only used until (i) 2030, (ii) 2040, and (iii) 2050. Enbridge need not agree that the assumptions are possible outcomes.
(d) Please provide the NPV of the project, accounting for the forecast revenue from the customers served by the pipe ending in 2050. Please provide the DCF table.
(e) What would it cost to build an electrolyser with sufficient on-site storage to serve the load.
(f) When will the cost of this pipe be fully depreciated under the depreciation policies proposed by Enbridge in this application?
(g) When will the proposed pipe be at the end of its estimated useful life.
(h) How much of the project cost will be undepreciated by (i) 2040 and (ii) 2050?

(i) For how long will the customer in question be contractually obligated to buy gas from Enbridge (and thus generate revenue)? Will the customer be obligated to pay a penalty worth the lost revenue if it were to decide to stop using the pipeline?

(j) Please complete the following table comparing the available and required capacity for the pipeline serving the customer in question:

Hamilton Industrial Reinforcement – Capacity Surplus/Deficit Position Over Time				
	2020	2021	…	2032
Pipeline capacity (m3/hour)				
Target customer peak demand (m3/hour)				
Other customer design day demand (m3/hour)				
Surplus (deficit)				

(k) Please complete the following table showing a breakdown of the number of customers by type and demand by type for the relevant pipeline system. If possible, please complete this to the end of the period covered by the DCF tables underlying the CIAC, not only to 2032.

Hamilton Industrial Reinforcement – Demand & Customer Counts				
	2020	2021	…	2032
# of customers				
Residential				
Commercial				
Industrial (excl. power generation)				
Power generation				
Total				
Annual demand (m3)				
Residential				
Commercial				
Industrial (excl. power generation)				
Power generation				
Total				
Design day demand (m3/day)				
Residential				
Commercial				
Industrial (excl. power generation)				
Power generation				
Total				
Design hour demand (m3/hour)				
Residential				
Commercial				
Industrial (excl. power generation)				
Power generation				
Total				

Interrogatory # 2.6-ED-106

Reference: Exhibit 2, Tab 6, Schedule 2, Appendix A (AMP, Investments >$10M)

Preamble:

These questions relate to the East Kingston Creekford Road Reinforcement (p. 25)

Question(s):

(a) Why is this a "must do" investment?
(b) Would this project proceed but for the forecasted growth?
(c) Please provide the complete EBO 188 analysis justifying the economics of this project, including the NPV calculations and DCF tables.
(d) Please recalculate the NPV and DCF tables on the assumption that the pipeline is only used until (i) 2030, (ii) 2035, and (iii) 2040. Enbridge need not agree that the assumptions are possible outcomes.
(e) Please complete the following table showing a breakdown of the number of customers by type and demand by type for the relevant pipeline system. If possible, please complete this to the end of the period covered by the DCF tables underlying the EBO 188 analysis, not only to 2032.

East Kingston, Creekford Road Reinforcement – Demand & Customer Counts				
	2020	2021	…	2032
# of customers				
Residential				
Commercial				
Industrial (excl. power generation)				
Power generation				
Total				
Annual demand (m3)				
Residential				
Commercial				
Industrial (excl. power generation)				
Power generation				
Total				
Design day demand (m3/day)				
Residential				
Commercial				
Industrial (excl. power generation)				
Power generation				
Total				
Design hour demand (m3/hour)				
Residential				
Commercial				
Industrial (excl. power generation)				

Power generation				
Total				

Interrogatory # 2.6-ED-107

Reference: Exhibit 2, Tab 6, Schedule 2, Appendix A (AMP, Investments >$10M)

Preamble:

> These questions relate to the Wheatley-1B - Panhandle Distribution Reinforcement - Wheatley Lateral Replacement and Reinforcement

Question(s):

(a) Why is this a "must do" investment?
(b) Would this project proceed but for the forecasted growth?
(c) Please provide the complete EBO 188 analysis justifying the economics of this project, including the NPV calculations and DCF tables.
(d) Please recalculate the NPV and DCF tables on the assumption that the pipeline is only used until (i) 2030, (ii) 2035, and (iii) 2040. Enbridge need not agree that the assumptions are possible outcomes.
(e) Please provide a list of the CIAC for this project.
(f) In light of Enbridge putting its project on hold in EB-2022-0157, please provide an update on the need and timing of Wheatley-1B.

Interrogatory # 2.6-ED-108

Reference: Exhibit 2, Tab 6, Schedule 2, Appendix A (AMP, Investments >$10M)

Preamble:

> These questions relate to the Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48) at page 55.

Question(s):

(a) Please provide a breakdown of the total cost, including any abandonment costs and capitalized overhead.
(b) Why is this listed as a "must do" investment?
(c) Please provide the EBO 134 analysis justifying the project, including the NPV calculations and DCF tables for stages 1, 2, and 3.
(d) Please recalculate the NPV figures and DCF tables on the assumption that the incremental pipeline capacity is only needed until (i) 2035, (ii) 2040, and (iii) 2050. Enbridge need not agree that the assumptions are possible outcomes.
(e) When will the cost of this pipe be fully depreciated under the depreciation policies proposed by Enbridge in this application?

(f) When will the proposed pipe be at the end of its estimated useful life.
(g) How much of the project cost will be undepreciated by (i) 2040 and (ii) 2050?
(h) Please complete the following table comparing the available and required capacity for the pipeline in question, not including the proposed reinforcement.

Kirkwall Hamilton – Forecast Capacity Surplus/Deficit Position Over Time				
	2020	2021	…	End of EBO 134 DCF analysis period
Design day				
Pipeline capacity (m3/day)				
Design day demand (m3/day)				
Surplus (deficit)				
Design day - hourly				
Pipeline capacity (m3/hour)				
Design day demand - hourly (m3/hour)				
Surplus (deficit)				

(i) Please complete the following table showing a breakdown of the number of customers by type and demand by type served by the relevant pipelines.

Kirkwall-Hamilton – Forecast Demand & Customer Counts				
	2020	2021	…	End of EBO 134 DCF analysis period
# of customers				
Residential				
Commercial				
Industrial (excl. power generation)				
Power generation				
Total				
Annual demand (m3)				
Residential				
Commercial				
Industrial (excl. power generation)				
Power generation				
Total				
Design day demand (m3/day)				
Residential				
Commercial				
Industrial (excl. power generation)				
Power generation				
Total				
Design hour demand (m3/hour)				

Residential				
Commercial				
Industrial (excl. power generation)				
Power generation				
Total				

(j) Provide the customer attachments underlying the EBO 134 stage 2 analysis and the purported savings per customer type. Please describe the source of the purported savings (e.g. use of gas versus other fuels or saved cost versus other gas transmission pathways, such as the mainline).

Kirkwall-Hamilton – Stage 2 Customer Attachments and Savings				
	Year 1	…	Year n	Total
Number of Customer Attachments				
Residential				
Commercial				
Industrial (excl. power generation)				
Power generation				
Total				
Stage 2 Savings by Sector				
Residential				
Commercial				
Industrial (excl. power generation)				
Power generation				
Total				

Interrogatory # 2.6-ED-109

Reference: Exhibit 2, Tab 6, Schedule 2, Appendix A (AMP, Investments >$10M)

Preamble:

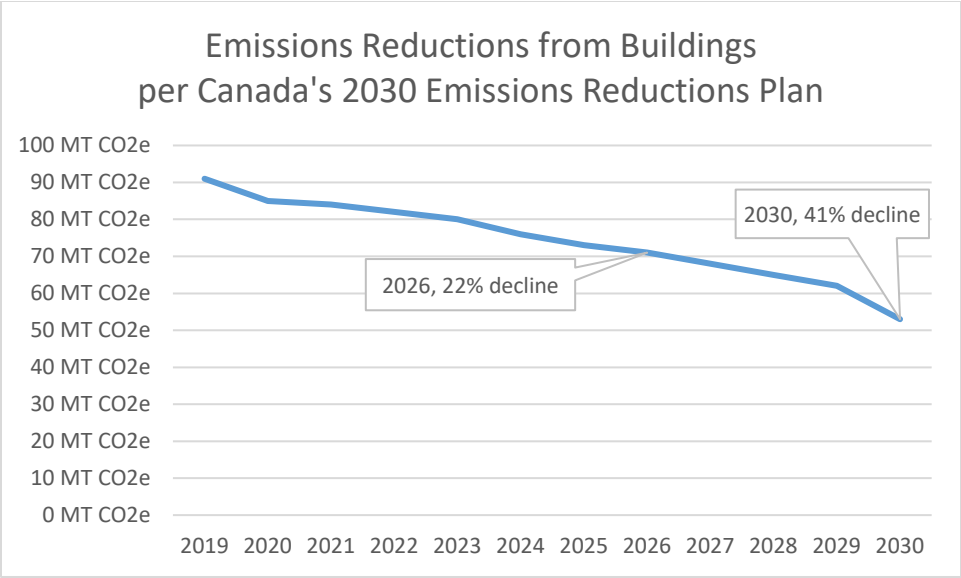
> These questions relate to the Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48) at page 55.

Question(s):

(a) What is the approximate probability that the incremental pipeline capacity is only needed until (i) 2035, (ii) 2040, and (iii) 2050?
(b) Canada's 2030 Emissions Reduction Plan includes targets for carbon emissions from buildings to decline by 22% by 2026 and by 41% by 2030 (illustrated below).[64] This is based on a reduction from 91 CO_2e in 2019 to 71 CO_2e in 2026 and 53 CO_2e in 2030.

[64] Exhibit I.ED.3(a), (f), & (g); see also: *2030 Emissions Reduction Plan – Canada's Next Steps for Clean Air and a Strong Economy* (link); for the full plan see https://publications.gc.ca/collections/collection_2022/eccc/En4-460-2022-eng.pdf.

How might this impact the demand for the incremental capacity from this project before the end of its economic lifetime? Please provide a quantitative answer on a best-efforts basis, stating any necessary caveats and assumptions, and providing a range of possible impacts if appropriate.



(c) Canada has committed to net-zero emissions from electricity generation by 2035, and re-affirmed its commitment in its 2030 Emissions Reduction Plan.[65] How might this impact the demand for the incremental capacity from this project before the end of its economic lifetime? Please provide a quantitative answer on a best-efforts basis, stating any necessary caveats and assumptions, and providing a range of possible impacts if appropriate.

Interrogatory # 2.6-ED-110

Reference: Exhibit 2, Tab 6, Schedule 2

Question(s):

(a) Please provide a table listing the total AMP investments driven by forecast growth in design day or design hour demand for each year from 2023 to 2032. Please also include a breakdown between transmission and distribution projects.
(b) What is the probability that a material portion of those investments will be underutilized before the end of their economic life in that the revenue or other benefits underlying the EBO 134 or EBO 188 analysis falls short of the forecasted amount?
(c) What is the probability that a significant portion of those investments will be stranded before the end of their economic life in that the incremental capacity is no longer needed because demand declined before that time.
(d) Please confirm the net benefits and revenue horizon user in EBO 134 and EBO 188.

[65] *Ibid.*

(e) Please comment on the pros and cons of decreasing the net benefits and revenue horizon underlying the economic analysis set out in EBO 134 and EBO 188 to account for the possibility that the relevant capacity may not required for the full time period.
(f) Is this proceeding the appropriate proceeding to consider adjustments to EBO 134 or EBO 188 such as the one described in (e)? Is it within the OEB's jurisdiction to do so? If Enbridge believes this is not the appropriate proceeding to consider these issues, what proceeding should they be considered in?

Interrogatory # 2.6-ED-111

Reference: Exhibit 2, Tab 6, Schedule 2, Appendix B (IRP)

Question(s):

(a) Please provide a live excel copy of the IRP spreadsheet in Appendix B. It is very difficult to review without being able to use the sort function that would be available in excel. Whenever future AMPs are shared, we would very much appreciate receiving excel versions of this appendix.
(b) How does Enbridge propose to prioritize which projects are technically evaluated for IRP sooner rather than later? For instance, would Enbridge start with growth projects, with the ones with the closest in-service date being analyzed first?
(c) Per page 71, please provide all IRP analysis completed to date on the Kirkwall-Hamilton project. The IRPA's to be considered are listed as follows: "Market side supply options to be assed prior to LTC application." Why are demand-side options not also being assessed?
(d) Per page 70, the Hamilton Industrial Reinforcement IRP technical assessment is listed as "planned." Why has this not been prioritized and undertaken already in light of the relatively short timeframe until the in-service date? When will this technical assessment start and finish?
(e) Per page 109, the "Wilson Avenue, Toronto, VSM Replacement" IRP technical assessment is listed as "planned." Why has this not been prioritized and undertaken already in light of the relatively short timeframe until the in-service date? When will this technical assessment start and finish?

Interrogatory # 2.7-ED-112

Reference: Exhibit 2, Tab 7, Schedule 1

Question(s):

(a) In relation to page 19, why is the contractual minimum delivery pressure to Brighton Beach Generating Station 1724 kPag whereas it is higher for some other generating stations?
(b) What equipment could Brighton Beach Generating Station install to allow for receipt of gas at a lower delivery pressure?

(c) If that constraint location was resolved, what constraint location would take its place, if any?

Interrogatory # 2.7-ED-113

Reference: Exhibit 2, Tab 7, Schedule 1

Question(s):

(a) Please reproduce Table 1 on page 22, including ex-franchise demand.
(b) Please provide a breakdown of the forecast design day demand increases set out in Table 1.
(c) Please provide a table showing the demand on the Dawn Parkway System with rows for (i) the peak day from 2010 to today, (ii) the computed design day demand from 2010 to 2032, and the (iii) capacity

Interrogatory # 2.7-ED-114

Reference: Exhibit 2, Tab 7, Schedule 1

Question(s):

(a) Please reproduce Table 2 on page 23, including ex-franchise demand.
(b) Please provide a breakdown of the forecast design day demand increases set out in Table 2.
(c) Please provide a table showing the demand on the Panhandle system with rows for (i) the peak day from 2010 to today, (ii) the computed design day demand from 2010 to 2032, and the (iii) capacity

Interrogatory # 3.2-ED-115

Reference: Exhibit 3, Tab 2

Question(s):

(a) The following factors can lead to greater or lesser rates to be collected. Please provide a table listing whether there is a revenue stabilizing mechanism (or a proposed one), and if yes, how it functions and whether it addresses both over collection and under collection: volume is lower than forecast because (i) hybrid heating lowers average use; (ii) partial fuel switching from gas lowers average use; (iii) full fuel switching away from gas lowers the number of customers; (iv) fewer customer attachments occur in comparison to forecast; and (v) temperatures are higher than expected.

Interrogatory # 4.2-ED-116

Reference: Exhibit 4, Tab 1, Schedule 1 & Exhibit 1, Tab 10, Schedule 6, Page 37

Question(s):

(a) Enbridge states: "With the changes in RNG percentage in the LCVP from five to four percent by 2028, an estimated 0.2 million tCO2e fewer GHG emission reductions are expected to occur in 2030."[66] Please explain the changes in RNG percentage discussed here and the reasons for them.
(b) Please provide a table comparing the forecast and actual participants in the LCVP thus far.
(c) Please provide a table showing, for each year since the LCVP program started, (i) the annual quantity of RNG procured for customers (m3), (ii) the average price paid ($/m3), (iii) the total paid for RNG that year ($), (iv) other LCVP expenses in that year (e.g. marketing and admin), (v) the $/CO2e including the incremental commodity cost only, and (vi) the incremental commodity cost including all costs.

Interrogatory # 4.2-ED-117

Reference: Exhibit 4, Tab 2, Schedule 1, Attachment 3

Question(s):

(a) Please reproduce attachment three, adding the following columns: (i) whole or part ownership by the applicant's parent or sister company, and (ii) the amount paid under the contract for the most recent year of data.

Interrogatory # 4.2-ED-118

Reference: Exhibit 4, Tab 2, Schedule 3 (Design Criteria)

Question(s):

(a) Please provide a table showing the forecast Dawn Parkway design day demand (per Exhibit 2, Tab 7, Schedule 1, Table 1) with columns for (i) the design day demand per that table and (ii) the design day demand calculated according to the probabilistic method currently used by EGD.
(b) Please provide a table listing the assumed temperature on the design day for each location/region for which Enbridge has a separate design day temperature assumption based on (A) the proposed methodology and (B) the current methodology.
(c) Please provide a map showing the locations/regions referred to in (b).
(d) Please reproduce Table 1 on page 18 replacing HDD with temperature.
(e) Is the design day temperature different from the design hour temperature? If yes, please provide a table listing the assumed temperature on the design hour for each location/region for which Enbridge has a separate design hour temperature assumption.
(f) What impact does Enbridge anticipate climate change having on the assumed design day temperatures?

[66] Exhibit 1, Tab 10, Schedule 6, Page 37, footnote 50.

(g) Please describe how Enbridge proposes to adjust the HDD for wind speed to arrive at the HDDw (or effective degree days)? Please provide the formula. Are the results for the HDDw similar to what would colloquially be known as the average of a day's temperature, accounting for "wind chill"?
(h) Enbridge states that "The proposed design criteria HDDw for each of the weather stations are determined by selecting the highest observed HDDw starting from November 1, 1979." Why was 1979 chosen?
(i) Please provide a full list of the current and proposed design day assumptions, such as that status of interruptible customers, demand from power generators, etc..

Interrogatory # 4.2-ED-119

Reference: Exhibit 4, Tab 2, Schedule 3 (Design Criteria)

Question(s):

(a) Enbridge states that "The proposed design criteria HDDw for each of the weather stations are determined by selecting the highest observed HDDw starting from November 1, 1979." Why was 1979 chosen?
(b) The World Metrological Organization states as follows: "The U.S. National Oceanic and Atmospheric Administration has updated the U.S. Climate Normals to the 1991-2020 baseline period to provide a most recent baseline for climate information and services to climate-sensitive sectors and a standard reference to compare variations in temperature, precipitation etc to the 30-year average."[67] Does Enbridge agree?
(c) Please update Table 1 on page 18 if the proposed design criteria HDDw for each of the weather stations are determined by selecting the highest observed HDDw starting from 1991.

Interrogatory # 4.2-ED-120

Reference: Exhibit 4, Tab 2, Schedule 3 (Design Criteria)

Question(s):

(a) Has Enbridge studied the likely impact of recent and ongoing climate change on the HDD on the coldest days in a year?
(b) Please provide any studies or analysis in Enbridge's possession regarding the potential impact of climate change on design day HDD assumptions.

Interrogatory # 4.2-ED-121

Reference: Exhibit 4, Tab 2, Schedule 3 (Design Criteria)

Question(s):

[67] https://public.wmo.int/en/media/news/updated-30-year-reference-period-reflects-changing-climate

(a) Please confirm that Enbridge's proposed design day HDDw for Toronto of 41.4 equates to an average daily temperature of -26.4°C, including a wind speed adjustment.
(b) Please complete the following table.

Coldest Day in Toronto Over Time			
	1979	…	2022
Average daily temperature (°C)			
Average daily temperature, adjusted for wind speed (°C)			
HDD (base 15)			
HDDw (base 15)			

(c) Please provide a chart with the data from the first two rows in the above table and a trendline for each row.
(d) Please complete the following table comparing the capacity of the pipeline system for Toronto based on the current and proposed design day assumptions and the actual measured peak day demand. Please choose an area that is feasible to model (ideally the area that would be designed based on Toronto weather data, if possible).

Design Day Capacity vs. Actual Peak Demand for Toronto Area			
	1979	…	2022
Capacity per current design day assumptions (TJ/d)			
Actual peak day demand (TJ/d)			
Capacity per proposed design day assumptions.			

Interrogatory # 4.2-ED-122

Reference: Exhibit 4, Tab 2, Schedule 3 (Design Criteria)

Question(s):

(a) Does actual peak day demand (PJ/d) ever surpass the system capacity (PJ/d)?
(b) If yes, how is this mitigated in Enbridge's system?

Interrogatory # 4.2-ED-123

Reference: Exhibit 4, Tab 2, Schedule 3, Attachment 1 (Design Criteria – Guidehouse Report)

Question(s):

These questions are for Guidehouse:

(a) Please provide a table indicating when each of the utilities studied most recently updated their design criteria.
(b) Please provide a table listing the date range used for selecting the highest observed HDDw or HDD for each of the utilities studied using the set temperature approach.
(c) Please provide a table listing the HDD and assumed design day temperature that each of the utilities studied would arrive at for Toronto.
(d) What are the design day assumptions in Vermont?

Interrogatory # 4.2-ED-124

Reference: Exhibit 4, Tab 2, Schedule 6 (Hydrogen) & Exhibit 2, Tab 6, Schedule 2, Appendix A, page 28

Preamble:

> These questions relate to the document entitled *Hydrogen Strategy for Canada, Seizing the Opportunities for Hydrogen, A Call to Action,* December, 2020.

Question(s):

(a) Was the *Hydrogen Strategy for Canada, Seizing the Opportunities for Hydrogen, A Call to Action,* December, 2020 approved by Cabinet or Parliament? If yes, when and in what instrument?
(b) Enbridge states that the Government of Canada has a national strategic vision involving a move to 100% dedicated hydrogen through "new dedicated hydrogen pipelines". This is cited to page 20 of the *Hydrogen Strategy for Canada*. Please provide the full except of the text that Enbridge is relying on. It is not clear from a review of the document itself.
(c) Please confirm that the *Hydrogen Strategy for Canada, Seizing the Opportunities for Hydrogen, A Call to Action,* December, 2020 does not:
    (i) Compare the cost of decarbonization with and without dedicated hydrogen pipelines;
    (ii) Commit the Government of Canada to a decarbonization pathway that is consistent with the "vision" set out in the document.

Interrogatory # 4.2-ED-125

Reference: Exhibit 4, Tab 2, Schedule 6 (Hydrogen) & Exhibit 2, Tab 6, Schedule 2, Appendix A, page 28

Question(s):

(a) On page 6, Enbridge states: "blending 20% hydrogen into the entire natural gas grid (subject to a full system feasibility study) could yield approximately 2.3 million tonnes of carbon dioxide equivalent (tCO2e) of GHG emissions reduction." Please provide:
    (i) An approximate best estimate of the incremental annual commodity cost of blending 20% hydrogen into the entire natural gas grid based on (A) the current

cost of fossil-fuel derived hydrogen without CCS (grey hydrogen), (B) an estimated cost of blue hydrogen, and (C) an estimated cost of green hydrogen;

(ii) An approximate best estimate of the incremental transmission and distribution costs of blending 20% hydrogen into the entire natural gas grid, both (A) total and (B) on an annualized basis;

(iii) An approximate best estimate of the $/tCO2e for blending 20% hydrogen into the entire natural gas grid based on (A) grey hydrogen, (B) blue hydrogen, and (C) green hydrogen.

For the above, please provide all underlying assumptions and calculations. Please make and state any simplifying assumptions and caveats as necessary.

(b) On page 6, Enbridge states: "blending 20% hydrogen into the entire natural gas grid (subject to a full system feasibility study) could yield approximately 2.3 million tonnes of carbon dioxide equivalent (tCO2e) of GHG emissions reduction." If this were done with blue hydrogen, approximately how many residual emissions (tCO2e) would be attributable to the hydrogen on an annual basis? Please include all lifecycle emissions, including those from leaks and uncaptured CO2e. Please either use the CCS and CO2e emissions assumptions from the following peer-reviewed study or provide a table comparing the Enbridge's assumptions with the peer-reviewed assumptions, with a justification for the deviation: Robert W. Howarth and Mark Z. Jackson, "How green is blue hydrogen?" *Energy Science & Engineering*, 26 July 2021 (link).

Interrogatory # 4.2-ED-126

Reference: Exhibit 4, Tab 2, Schedule 6 (Hydrogen) & Exhibit 2, Tab 6, Schedule 2, Appendix A, page 28

Question(s):

(a) What does blending 20% by volume of hydrogen into methane gas equate to in terms of a percent by energy content (%)?

(b) Enbridge states: "Based on current knowledge, Enbridge Gas's systems may require substantial changes above 20% hydrogen by volume." Please itemize each component (e.g. kinds of pipes, connectors, compressors, etc.) that may require substantive changes above 20% hydrogen by volume. For each component, please list how many there are in Enbridge's system (by km if it is a kind of pipe).

Interrogatory # 4.2-ED-127

Reference: Exhibit 4, Tab 2, Schedule 6 (Hydrogen) & Exhibit 2, Tab 6, Schedule 2, Appendix A, page 28

Preamble:

Enbridge states on page 10: "Moreover, because hydrogen has lower volumetric energy density compared to natural gas, existing networks will need additional capacity from

pipe reinforcement, station replacements or other upgrades to account for the increased volume of hydrogen that will be required to meet energy demand from customers."

Question(s):

(a) How many m3s of hydrogen have the same energy content of 1 m3 of methane?
(b) How much pipeline capacity (m3/day) carrying 100% hydrogen is required for the same energy content of 1 m3/day of capacity of a pipe carrying methane only?
(c) How much pipeline capacity (m3/hour) carrying 100% hydrogen is required for the same energy content of 1 m3/hour of capacity of a pipe carrying methane only?
(d) How much pipeline capacity (m3/day) carrying a 20%/80% hydrogen/methane mix is required for the same energy content of 1 m3/day of capacity of a pipe carrying methane only?
(e) How much pipeline capacity (m3/hour) carrying a 20%/80% hydrogen/methane mix is required for the same energy content of 1 m3/hour of capacity of a pipe carrying methane only?

Interrogatory # 4.2-ED-128

Reference: Exhibit 4, Tab 2, Schedule 6 (Hydrogen) & Exhibit 2, Tab 6, Schedule 2

Question(s):

(a) Per page 13, the LCEP phase 1 is "yielding GHG emissions abatement as predicted." Please provide:
    (i) The annual tCO2e being saved on average;
    (ii) The incremental distribution costs (annualized);
    (iii) The $/tCO2e accounting only for the incremental distribution costs;
    (iv) The $/tCO2e accounting for the incremental distribution costs and a commodity cost equal to the difference between the cost of methane and the cost of (A) grey hydrogen currently available and (B) the cost of blue hydrogen [please use these estimated costs as we understand that the hydrogen in this project is coming at no incremental costs through a special arrangement that would not be available through a scaled-up project].
(b) Please provide the figures from (a) for LCEP stage 2.
(c) Enbridge states at page 15: "Costs associated with the implementation of the LCEP phase 2 are estimated at $7 million and are included in Enbridge Gas's Asset Management Plan, provided at Exhibit 2, Tab 6, Schedule 2." Please provide the page numbers from the AMP for the figures that this project is included under. Please provide a breakdown of these forecast costs by year.

Interrogatory # 4.2-ED-129

Reference: Exhibit 4, Tab 2, Schedule 6 (Hydrogen) & Exhibit 2, Tab 6, Schedule 2

Question(s):

(a) Please calculate the cost of GHG emissions reductions ($/CO2e) from hydrogen injection including only the incremental commodity costs of replacing natural gas with hydrogen created via power-to-gas. Please use Enbridge's estimate of the cost to produce hydrogen by power-to-gas in Ontario. Please provide a table showing the underlying calculations. If the answer differs from what was provided in EB-2019-0294, Exhibit I.ED.11, please explain.
(b) What percent of energy is lost when converting electricity to hydrogen through electrolysis?
(c) Please complete the following table comparing the overall efficiency of using green energy to power heat pumps versus using green energy to generate hydrogen to be burned in a furnace and water heater. We have input initial values – if Enbridge believes different values would be more accurate, please use those and explain the change.

Energy Efficiency Comparison Between Hydrogen Combustion vs. Electric Heat Pumps Residential Space and Water Heating				
	Space Heating		**Water Heating**	
	Gas Furnace	**Heat Pump**	**Gas Heater**	**Heat Pump**
Energy input	1 kWh	1 kWh	1 kWh	1 kWh
Hydrogen conversion loss	25%	n/a	25%	n/a
Energy input minus loss[68]	0.75 kWh	1 kWh	0.75 kWh	1 kWh
Annual heating efficiency	95%	300%	67%	375%
Heat output[69]	0.7 kWh	3 kWh	0.5 kWh	3.75 kWh
Output difference[70]	430%		750%	

Interrogatory # 4.2-ED-130

Reference: Exhibit 4, Tab 2, Schedule 6 (Hydrogen) & Exhibit 2, Tab 6, Schedule 2, Appendix A, page 28

Question(s):

(a) Will the Hydrogen Blending Grid Study involve any testing of actual hydrogen blending in customer equipment aside from the LCEP phases 1 and 2? If yes, please provide details.

[68] Calculation: 1 kWh minus 25% loss for hydrogen conversion.
[69] Calculation: "Energy input minus loss" multiplied by "Annual heating efficiency."
[70] Calculation: heat output of heat pumps divided by heat output of the gas equipment.

(b) Please justify treating this as a capital expenditure.

Interrogatory # 4.2-ED-131

Reference: Exhibit 4, Tab 2, Schedule 6 (Hydrogen) & Exhibit 2, Tab 6

Question(s):

(a) Please provide a best estimate of the cost at which hydrogen can currently be produced in Ontario (per m3 and GJ) via power-to-gas. Please include and separately itemize the cost of electricity and the cost of converting electricity to hydrogen. Please make all assumptions as necessary and state all assumptions.
(b) If technological advancements are expected, please provide a best estimate of the cost at which hydrogen could be produced in Ontario in 2030 (per m3 and GJ) via power to gas. Please include and separately itemize the cost of electricity and the cost of converting electricity to hydrogen. Please discuss and provide a qualitative answer if a quantitative one is not possible.
(c) What is the going market rate for hydrogen in Ontario (per m3 and GJ)? If a single rate cannot be provided, please provide a range and some examples.
(d) What is the going market rate for hydrogen in Ontario (per m3 and GJ) created from power-to-gas? If a single rate cannot be provided, please provide a range and some examples.
(e) What is the going market rate for hydrogen in California (CAD per m3 and GJ)? If a single rate cannot be provided, please provide a range and some examples.
(f) What is the going market rate for hydrogen in California (CAD per m3 and GJ) created from power to gas? If a single rate cannot be provided, please provide a range and some examples.
(g) What is Shell Canada charging for hydrogen in its hydrogen refuelling stations in Quebec? An average, approximate, or point-in-time answer is sufficient. Would this hydrogen be mostly from natural gas reforming or power to gas?
(h) What is the percentage difference between the current cost for hydrogen and natural gas in Ontario of the same heating value (for hydrogen created via power to gas) Please provide the forecast difference between now and 2040, both annual and average over that period? Please provide the underlying calculations.
(d) For each of the above, if Enbridge provides a different answer from the answer provided in EB-2019-0294, Exhibit I.ED.6, please explain.

Interrogatory # 4.2-ED-132

Reference: Exhibit 4, Tab 2, Schedule 7

Preamble:

These questions relate to Phase 1 issues, including whether Enbridge has appropriately considered energy transition issues in relation to the capital spending is seeks, such as

whether Enbridge has overstated the ability of low carbon fuels to maintain the usefulness of pipelines in a decarbonized future.

Question(s):

(a) Please provide a table comparing the quantity of RNG that would be procured under its proposed low-carbon energy purchases with the amounts in the diversified scenario in the Guidehouse pathways report. Please provide the comparison both on an annual basis and on a trajectory basis (i.e. if the increase in purchases would occur at a trajectory that would be consistent with the diversified scenario).
(b) What total annual funding and total annual RNG (m3) corresponds to the maximum $2 per residential customers?
(c) Footnote 4 on page 5 lists 0.001958 tCO2e/cubic meter. Enbridge has previously used 0.001874 tCO2e/cubic meter. Please explain the different sources for these figures and explain which is the correct figure to be used throughout the application. What figure is used by the Guidehouse pathways report?
(d) What is the average price that Enbridge expects to pay for RNG if it is able to procure long term contracts as it proposes?
(e) If Enbridge is able to procure RNG as proposed, what does it anticipate the cost of emissions reductions to be($/tCO2e) including (i) only the community cost difference and (ii) the commodity cost difference and other incremental administrative costs.
(f) How to the responses to (d) and (e) compare to the RNG assumptions in the Guidehouse pathways report?
(g) Please estimate the carbon footprint of a m3 of RNG associated with RNG methane leakage from the distribution system and customer equipment. Assume for the purposes of this question that the feedstock would have entered the atmosphere as CO2e not unburned methane (e.g. landfill flaring).

Interrogatory # 4.3-ED-133

Reference: Exhibit 4, Tab 3, Schedule 1 (UFG)

Question(s):

(a) Please reproduce the tables in Attachment 1 adding rows for (i) estimated UFG from leaks (m3), and (ii) the carbon emissions arising therefrom (tCO2e).
(b) Why is the UFG so much higher in 2021 (359,555,000) versus 2020 (196,655,000).
(c) What is the total UFG as a percent of throughput for Enbridge as a whole on-average for the most recent 5-years?
(d) What is the total UFG estimated to arise from leaks as a percent of throughput for Enbridge as a whole on-average for the most recent 5-years?
(e) Please confirm that the UFG numbers do not include leaks from customer equipment.
(f) Per page 15, a considerable portion of the UFG leaks from storage facilities (e.g. 61,082,000 m3 in 2021). If those storage facilities were holding the same quantity of hydrogen instead of methane, approximately how much would leak annually? If those

storage facilities were holding the same quantity of a 20/80 hydrogen/methane blend instead of methane, approximately how much would leak annually?
(g) How many carbon emissions arise from 1 m3 of leaked (i) RNG and (ii) hydrogen.
(h) How much would it cost for Enbridge to reduce leaks in its system by 50%?
(i) Do the UFG figures include leaks from non-rate-regulated storage facilities in Ontario? Please explain.

Interrogatory # 4.3-ED-134

Reference: Exhibit 4, Tab 3, Schedule 1 (UFG)

Question(s):

(a) Please describe any research that has empirically studied economy-wide methane leaks in Ontario (e.g. via aerial surveys). Please file a copy or provide a link.
(b) Please provide a comparison between Enbridge's estimates of the gas that leaks from its facilities versus the methane leaks in Ontario estimated through empirical studies such as aerial surveys. If there is a significant deviation, please discuss the possible reasons for this.

Interrogatory # 4.5-ED-135

Reference: Exhibit 4, Tab 5, Schedule 1 (Depreciation)

Question(s):

(a) Enbridge states on page 17 that "CER-regulated pipelines have an expected end of life whereas [Enbridge's] assets are expected to be replaced over time and remain useful." For each of the following CER-regulated methane gas pipelines, please indicate which ones are and are not expected to be replaced over time and remain useful:
    (i) Alliance
    (ii) Emera Brunswick
    (iii) Foothills
    (iv) Many Islands
    (v) Maritimes & Northeast
    (vi) NOVA Gas Transmission Ltd. (NGTL)
    (vii) TransCanada's Canadian Mainline
    (viii) Trans Québec & Maritimes
    (ix) Vector
    (x) Westcoast
(b) Please confirm which CER-regulated pipelines are required to pay future abandonment funds into a segregated fund.
(c) Has Enbridge assess the probability that a significant portion of its pipelines will not be replaced or remain useful post-2050? If yes, please indicate the possibility or range of possibilities.

(d) If Enbridge's application is approved as filed, how much of existing rate base plus rate base added between now and 2028 would remain undepreciated by 2050?
(e) If Enbridge's application is approved as filed, by what date would the assets to be built between now and 2028 be depreciated?
(f) Please provide a complete description of how the CER abandonment fund is designed and structured, with a link to the relevant CER rulings, rules, and guidelines.

Interrogatory # 4.5-ED-136

Reference: Exhibit 4, Tab 5, Schedule 1 (Depreciation)

Question(s):

(a) What is the current balance of the funds that Enbridge has collected for site restoration?
(b) What is the forecast balance of the funds that Enbridge has collected for site restoration as of the end of 2028?
(c) Please provide an approximate estimate of the combined site restoration cost for all of Enbridge's pipeline assets (i.e. how much it would cost to abandon the pipes and restore the sites)? Please compare and reconcile this with Guidehouse's estimate that "Ontario's decommissioning costs could exceed $1.0 billion per year."[71]
(d) Please provide a table showing for each of the last ten years (i) what Enbridge has collected in rates for site restoration that year, (ii) what amounts have been used for site restoration that year, and (iii) the running annual balance for site restoration costs. If possible, please also forecast these figures for 2024-2028.
(e) Enbridge notes on page 18 that the "amounts collected are used to fund working capital requirements, which in turn reduces the need for financing and therefore has a favourable impact for customers in the form of lower rates, all else being equal." What is the current return (%) accruing to ratepayers on the funds Enbridge holds for future abandonment costs?
(f) Please provide a table showing for each of the last ten years what ratepayers have saved on account of site restoration costs being used to fund working capital, which in turn reduces the need for financing.
(g) What was the average return earned on the site restoration costs held in a segregated fund for CER-regulated pipelines for each for the last five years? If the return differs by pipeline or company, please provide some examples (e.g. for Enbridge-owned pipelines).
(h) Enbridge notes on page 19 that there would be "[a]dministrative costs required to set up, monitor and maintain the fund." What were the administrative costs as a percent of the total invested amount for site restoration costs held in a segregated fund for CER-regulated pipelines for each for the last five years? If the figure differs by pipeline or company, please provide some examples (e.g. for Enbridge-owned pipelines).
(i) Enbridge notes on page 19 that "tax issues associated with establishing a fund are complex and would require significant legal and tax involvement to resolve." How are those tax issues addressed for pipelines under the CER segregated abandonment fund model?

[71] Exhibit 1, Tab 10, Schedule 5, Attachment 2, p. 45

Interrogatory # 4.5-ED-137

Reference: Exhibit 4, Tab 5, Schedule 1 (Depreciation)

Question(s):

(a) If the OEB ordered a segregated fund for site restoration costs, would Enbridge recommend that the existing balance be phased into the segregated fund over time to smooth the impact on rate base and revenue requirement? If yes, over what period would Enbridge recommend doing so?

Interrogatory # 4.5-ED-138

Reference: Exhibit 4, Tab 5, Schedule 1 (Depreciation)

Question(s):

(a) Please provide a table showing the proposed depreciation periods for the five largest asset categories.

Interrogatory # 4.5-ED-139

Reference: Exhibit 4, Tab 5, Schedule 1, Attachment 1 (Concentric Depreciation Study)

Question(s):

These questions are for Concentric:

(a) At page 19, Concentric notes: "Consistent with the reduction in the utilization of the assets, it could be assumed that large scale retirement of assets may be required in the periods between now and 2050." Please discuss some possible changes to depreciation policies that could be implemented to hedge against this possibility short of implementing a 2050 economic planning horizon, such as other methods to shorten the depreciation period.
(b) At page 19, Concentric notes: "The introduction of hydrogen may have a life lengthening impact on the system if it is determined that hydrogen is a sustainable replacement fuel." Does Concentric agree that the introduction of hydrogen could also have a shortening impact on many Enbridge assets that cannot accommodate hydrogen fuel due to its chemical properties (e.g. interactions with steel) and its propensity to leak as the smallest molecule?
(c) Has Concentric conducted a jurisdictional scan to determine whether any other gas regulators or gas utilities have adjusted their approach to depreciation to account for the possibility of gas pipelines having a shorter economic life due to decarbonization? If yes, please provide a list of the gas regulators/utilities that were and were not examined.

Interrogatory # 4.5-ED-140

Reference: Exhibit 4, Tab 5, Schedule 1, Attachment 1 (Concentric Depreciation Study)

Question(s):

These questions are for Concentric:

(a) According to Enbridge's interpretation of the Concentric report, a 2050 economic planning horizon would mean that "the 2024 Test Year depreciation expense would increase by $282 million, from $921 million to $1.2 billion" per Exhibit 1, Tab 10, Schedule 4, Page 18. Is that accurate? Please provide the unrounded figures.
(b) Does concentric agree that the impact on the depreciation expense would likely be even higher if a 2050 economic planning horizon were to be implemented in, say, 2030?
(c) Approximately by what percent would the depreciation expense increase if a 2050 economic planning horizon were to be implemented in (i) 2024, (ii) 2028, (iii) 2030, or (iv) 2035. Please make and state any simplifying assumptions necessary to provide an approximate answer, as well as any caveats.

Interrogatory # 4.5-ED-141

Reference: Exhibit 4, Tab 5, Schedule 1, Attachment 1 (Concentric Depreciation Study)

Question:

This question is for Concentric:

(a) Approximately by what percent would the depreciation expense increase in 2024 if an adjustment was made to reduce the depreciation period for Enbridge's pipelines by (i) 25% or (ii) 50% to account for the *possibility* that early retirement may be necessary due to decarbonization-driven electrification or

Interrogatory # 4.5-ED-142

Reference: Exhibit 4, Tab 5, Schedule 1, Attachment 1 (Concentric Depreciation Study)

Question(s):

These questions are for Concentric:

(a) On page 438, Mr. Kennedy's CV includes the following: "Midwestern Gas Transmission Company: The assignment included development of a detailed depreciation study and Testimony to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Federal Energy and Regulatory Commission, incorporated the concepts of time-based depreciation for gas transmission accounts and development of Economic Planning Horizons. The Direct Testimony included significant discussion related to the topics of

Decarbonization and changing political climate towards removal of fossil fuel demand forecasts. (emphasis added)" Please provide a copy (or link) of the depreciation study and testimony.

(b) On page 438, Mr. Kennedy's CV includes the following: "Enbridge Lakehead System: A Technical Update to a 2016 full depreciation study was prepared and filed with the FERC in 2021 in support of updating depreciation rate and resultant depreciation expense. The technical update also included an analysis and recommendation of a 20-year Economic Planning Horizon (Economic Life). (emphasis added)" Please provide a copy (or link) to the technical update relating to an Economic Planning Horizon.

(c) On page 439, Mr. Kennedy's CV includes the following "Alliance Pipeline L.P. A number of depreciation studies have been completed by Mr. Kennedy for both the Canadian and US assets of Alliance Pipelines. The most recent studies completed in 2012 for Submission to the National Energy Board of Canada and to the Federal Energy Regulatory included operational discussions related to the gas transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the inclusion of an Economic Planning Horizon." Please provide a copy or link to this.

Interrogatory # 5.3-ED-143

Reference: Exhibit 5, Tab 3, Schedule 1 (Capital Structure)

Question(s):

(a) Please provide the difference in the total return on equity ($) that Enbridge would earn for each year from 2024 to 2028 as between (i) the current equity ratio and (ii) the proposed equity ratio. Please make and state simplifying assumptions as required to provide an answer (e.g. that other aspects of its application are approved in full, holding the other cost of capital parameters constant, etc.). Please provide calculations and an explanation of the calculations.

(b) Please describe in simple terms how increasing the equity ratio helps Enbridge to (i) mitigate risks or (ii) be compensated for assuming higher risks?

Interrogatory # 5.3-ED-144

Reference: Exhibit 5, Tab 3, Schedule 1, Attachment 1 (Concentric Cost of Capital Report)

Question(s):

(a) Concentric states: "Additionally, restrictions on gas use in buildings have advanced at the state or local level in at least six U.S. states that collectively represent approximately one quarter of gas use in the U.S. These restrictions threaten natural gas customer growth because they generally apply to new buildings, but in some cases, such as Washington and New York, state policymakers have also proposed plans that would phase gas use out of existing buildings."[72] Please provide a table listing these, including (i) the location, (ii)

[72] See page 22 of the evidence, which is page 18 of the report.

whether the restriction applies to new or existing buildings, (iii) whether the restriction is proposed or passed, and (iv) the gas consumption in the location [or population, if the gas consumption is difficult to locate].

(b) Concentric states: "Within the last two years, multiple regulators have determined that it is necessary to examine the future of gas utilities."[73] Please provide a table listing these proceedings, including: (i) the jurisdiction, (ii) the current status of the proceeding, (iii) a link to the relevant regulatory website, and (iv) a list of the measures that are proposed or under consideration to mitigate decarbonization-related financial risks.

Interrogatory # 5.3-ED-145

Reference: Exhibit 5, Tab 3, Schedule 1, Attachment 1 (Concentric Cost of Capital Report)

Question(s):

(a) Concentric states: "it is premature to draw conclusions regarding the viability of hydrogen in the Company's system on a broader scale."[74] Is this referring to technical viability (e.g. safety, CSA approval, etc.) or economic viability, or both? Please elaborate on why this may not be viable.

(b) Concentric cites a S&P report stating as follows: "[S]witching to hydrogen-based boilers requires a major overhaul of the gas network infrastructure. Upgrading grids to allow for hydrogen distribution would require a concurrent rollout of hydrogen boilers (or fuel cells) to all consumers affected by the switch from gas. A prerequisite is a new hydrogen transmission network to which to connect, since many applications would still rely on gas for decades to come."[75] Please elaborate on the challenges of this kind of concurrent rollout. Does Concentric agree with S&P's statement?

(c) Concentric states that "academics have noted a variety of financial, technical, and other barriers to widespread adoption of RNG."[76] Please provide copies of or links to any such reports or papers that make reference to the Ontario context.

(d) Please quantify the risk that hydrogen and RNG do not provide a pathway for Enbridge through the Energy Transition. Please provide as quantitative an answer as possible. Please use ranges of probabilities if necessary.

(e) If the risk described in (d) is so uncertain or remote that it cannot be quantified, please explain how it could justify the proposed change in equity thickness.

Interrogatory # 5.3-ED-146

Reference: Exhibit 5, Tab 3, Schedule 1, Attachment 1 (Concentric Cost of Capital Report)

Question(s):

[73] See page 31 of the evidence, which is page 27 of the report.
[74] See page 34-35 of the evidence, which are pages 30-31 of the report.
[75] See page 35 of the evidence, which is page 31 of the report.
[76] See page 36 of the evidence, which is page 32 of the report.

(a) Concentric cites: The Brattle Group, "The Future of Gas Utilities Series: Transition Gas Utilities To A Decarbonized Future" in footnote 94. Please provide a copy or link.
(b) Concentric cites the Brattle Group as stating: "In the past decade, gas utility capital expenditures have grown by around double the rate of water and electric utilities' spending, largely driven by safety and reliability. Utilities will need to recover their costs from a changing – and possibly shrinking – customer base. With energy and environmental policy targets rapidly approaching, gas utilities need to decide today how best to invest capital in long-lived assets and avoid stranded asset risks." Does Concentric agree?

Interrogatory # 5.3-ED-147

Reference: Exhibit 5, Tab 3, Schedule 1, Attachment 1 (Concentric Cost of Capital Report)

Question(s):

(a) Concentric states: "Another risk of the Energy Transition is that a significant portion of the Company's gas plant investments could become stranded. Generally, the term "stranded asset" refers to an investment that becomes no longer used or useful in the provision of service to customers before the end of its depreciable life. At that point in time, the undepreciated value of the asset (i.e., its net book value) is "stranded" with costs to be borne by either investors or customers. Gas distribution utilities such as the Company generally depreciate capital invested in their systems over the expected useful life of the underlying physical property, which is often many decades. Therefore, the Energy Transition creates stranded asset risk for the Company by introducing the possibility that significant portions of the Company's property will cease being used or useful before it is fully depreciated."[77]
Please quantify the risk that significant portions of the Company's property will cease being used or useful before it is fully depreciated. Please provide as quantitative an answer as possible. Please use ranges of probabilities if necessary. If the risk described is so uncertain or remote that it cannot be quantified, please explain how it could justify the proposed change in equity thickness.
(b) Concentric makes reference to risks under the heading "Going Concern." Is there a risk that the company could go bankrupt and no longer be a going concern by, say, 2050, due to decarbonization? If yes, is that risk material?
(c) Concentric states that "accelerating depreciation rates and approving SFV rate design may reduce the Company's stranded asset risk and volumetric risk."[78]
Please describe how accelerating depreciation would reduce stranded asset risk. Please describe the range of options for accelerating depreciation.

Interrogatory # 5.3-ED-148

Reference: Exhibit 5, Tab 3, Schedule 1, Attachment 1 (Concentric Cost of Capital Report)

[77] See page 44 of the evidence, which is page 40 of the report.
[78] See page 49 of the evidence, which is page 45 of the report

Question(s):

(a) Concentric states: "A future "death spiral" is far from certain, and we anticipate that the Company will work proactively to avoid such an outcome. However, it is possible."[79] Is this a material possibility? Please make best efforts to quantify the possibility.
(b) Concentric states: "In 2020, residential customers accounted for approximately 57% of the Company's revenues but just 32% of its sales volumes. If a meaningful portion of these customers switch to non-gas heating sources, whether due to technological advancements, environmental concerns, or policy mandates, costs will increase for the Company's remaining customers. Such a scenario could potentially spark a so-called 'death spiral.'"[80]
    (i) Please discuss how likely this is to occur.
    (ii) Please elaborate on the reference to "technical advancements."
    (iii) Why does Concentric single out residential customers as being at a particular risk of exiting the gas system?
(c) Concentric states that "the Company's assets are, on average, much less depreciated than the assets of any of the proxy groups."[81] Why is that?

Interrogatory # 5.3-ED-149

Reference: Exhibit 5, Tab 3, Schedule 1, Attachment 1 (Concentric Cost of Capital Report)

Question(s):

(a) Please provide details on the GHG emissions reductions laws passed in Vermont and Massachusetts, including the legislated reduction targets. Please discuss the impacts of these on Enbridge's business risks.
(b) Please comment on the conclusions of the decarbonization pathways studies commissioner in Vermont, Massachusetts, and New York, including the percentage reductions in annual and peak gas demand envisioned in the report. Please discuss the impacts of these on Enbridge's business risks.

Interrogatory # 7.0-ED-150

Reference: Exhibit 7, Tab 0, Page 3

Question(s):

(a) Are some areas of the province more expensive to serve than others both in terms of transmission and distribution, and also gas supply? If yes, please quantify the approximate percentage difference.
(b) Enbridge proposes to harmonize the rate zones into a single rate zone. Presumably some rate zones are more expensive to serve than others. Please approximately quantify the

[79] Evidence page 58, report page 54.
[80] *Ibid*.
[81] Evidence p. 92, report page 88.

impact on a typical residential customer's annual gas bill from the harmonization for (i) a customer in the rate zone that is the most expensive to serve and (ii) a customer in the rate zone that is the least expensive to serve.

(c) Enbridge proposes to create a single rate zone. Presumably some areas are more expensive to serve than others. Please approximately quantify:
    (i) How much a rural residential customer would be subsidized by other customers on a net annual bill impact basis (assuming rural customers are more expensive to serve); and
    (ii) How much a customer in the area of the province that is most expensive to serve would be subsidized by other customers.

(d) If Enbridge were to be directed to divide the province into 2 to 5 zones corresponding to cost of serving those customers, how would Enbridge do so? For instance, if it would do so based on geographic regions, please discuss which ones would be more and less expensive. If it would do so based on density (urban vs. rural), please explain.

Interrogatory # 8.2-ED-151

Reference: Exhibit 8, Tab 2, Schedule 3

Question(s):

(a) To help us understand the impact of moving from the traditional rate design to the proposed SFVD for residential customers, please provide the rates and total bill amounts for an average residential customer in the union rate zone in October of 2022 comparing (i) what they would be with the current rate design and (ii) what they would be under the SFVC rate design. For the design day demand charge ($/m3), please use a value that would represent what the rate would be for an average customer. Please describe how the demand charge and demand rate is calculated.

(b) Please provide (i) the current rates applicable to Toronto and (ii) an updated one for an average Toronto residential customer based on the proposed residential rate design.

(c) Please provide a summary in Enbridge's words explaining how the design day demand would be estimated for each customer.

(d) Would Enbridge consider implementing a mechanism whereby a customer could notify Enbridge if it implemented a measure to reduce its design day demand to ask that it be reflected immediately (to avoid the lag involved in waiting for the measure to be reflected in meter data)?

(e) Page 28 states: "Analyzing four years of billing information, Christensen verified that design demand can be reliably derived for each customer. Exceptions arising from data or statistical relationships can be managed under defined (automated) protocols." If the derivation of design demand is based on four years of data, would it therefore take four years for a demand reduction measure to become <u>fully</u> reflected in that customer's peak demand charges.

(f) What percent of Enbridge's meters, if any, can detect a customer's daily demand?

(g) Please discuss the impact of the move from the current rate design to the proposed design (SFVD) on the cost-effectiveness of hybrid heat pumps from consumer cost perspective?

Please quantify the difference in terms of the incremental change to the NPV of the forecast gas cost savings for a typical customer.

(h) Please discuss the impact of the move from the current rate design to the proposed design (SFVD) on the cost-effectiveness of installing an electric-only air source heat pump from consumer cost perspective? Please quantify the difference in terms of the incremental change to the NPV of the forecast gas cost savings for a typical customer.

Interrogatory # 8.2-ED-152

Reference: Exhibit 8, Tab 2, Schedule 3

Question(s):

(a) Please comment on the pros and cons of full decoupling.
(b) Would Enbridge support a true-up whereby the demand charges would be adjusted each year to capture any over or under recovery of the revenue requirement occurring over the previous year? Please discuss the pros and cons of this model.

Interrogatory # 8.2-ED-153

Reference: Exhibit 8

Question(s):

(a) Please provide a table showing all the service charges that Enbridge is currently able to charge its customers, including the name of the charge, the criteria for applying the charge, the basis for applying the charge (i.e. where the authority comes from), and the amount that can be charged (or how it is calculated). Please add a column and/or row indicating any changes proposed in this application (e.g. revisions or new charges).
(b) Does Enbridge currently charge a fee to residential customers who close their gas account because they have stopped using gas? If yes, please point to the authority to apply this charge and indicate how it is calculated.
(c) Is Enbridge currently *authorized* to charge a fee to residential customers who close their gas account because they have stopped using gas? If yes, please point to the authority to apply this charge and indicate any restrictions on how the amount is calculated.
(d) Is Enbridge seeking in this application the authority to charge a fee to residential customers who close their gas account because they have stopped using gas? If yes, please indicate any restrictions on how the amount would be calculated.