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February 10, 2023

Ontario Energy Board
By electronic filing and e-mail

Attn: Nancy Marconi, Registrar and Board Secretary

Dear Ms Marconi:

Re: EB-2022-0200, EGI 2024 Rebasing - GEC Interrogatories

Please find GEC's interrogatories to Enbridge Gas Inc. attached.

Sincerely,

C
c: All Parties

1649 Old Brooke Road, Maberly, Ontario K0H 2B0 e-mail: dpoch@eelaw.ca

Enbridge Gas Inc. 2024 to 2028 Rates Application

Interrogatories of the Green Energy Coalition (GEC)

Interrogatory # 1.10-GEC-1

1. E1/T10/S2, p. 1: Enbridge states that "an increasing amount of renewable natural gas (RNG) and hydrogen are also being transported by the gas system."
    a. Please provide the percent of energy (not volume) throughput in Enbridge's gas system that was RNG and the percent that was hydrogen for each of the past five years (2018 through 2022).
    b. Please provide Enbridge's forecast of the percent of energy (not volume) throughput that will be RNG and the percent that will be hydrogen for each year from 2023 through 2032. Please explain what this forecast is based upon.

Interrogatory # 1.10-GEC-2

2. E1/T10/S2, p. 2: Enbridge states that the highest hourly flow on its system last year was 8507 10^3m^3/hr at 9 a.m. on January 22, 2022.
    a. Please clarify whether this was for the hour ending 9 a.m. (i.e., 8 to 9 a.m.) or for the hour beginning 9 a.m. (i.e., 9 to 10 a.m.) or something else (please explain).
    b. Did this peak hourly flow occur at design load conditions? If not, what is Enbridge's best estimate of what the peak hourly flow would have been under design conditions? Please explain how this estimate is developed.
    c. What is Enbridge's best estimate of the fraction of that hourly demand that was from residential customers? Please explain how Enbridge defines a "residential customer" in its response. For example, does it include multifamily buildings with central heating systems or hot. Please also estimate the number of residential housing units associated with the portion of peak hourly demand that Enbridge estimates is "residential".
    d. What is Enbridge's best estimate of what peak hourly flow for residential customers would have been under design conditions.
    e. Please provide the total amount of residential gas sales in 2022, using the same definition as used in responding to part "b" of this question.

Interrogatory # 1.10-GEC-3

3. E1/T10/S2, p. 5: Enbridge discusses the role of natural gas generation in the supply of electricity to Ontario, including the fact that gas-fired power plants supplied 22-31% of electricity during the top ten peak demand periods.
    a. What was the total amount of natural gas consumed by gas-fired power plants during the top ten peak demand periods referenced by Enbridge?
    b. What was the total annual volume of gas consumed for electric power generation in Ontario in each year from 2018 to 2022?

c. What percent of Enbridge's total gas throughput was for gas-fired power plants in each year from 2018 to 2022?
d. What fractions of annual natural gas consumption and demand at time of electricity system peak demand at Ontario gas-fired power plants is taken through Enbridge's distribution system (vs. taking it directly from gas transmission/transportation system)?
e. Please provide any information available on the location of proposed new gas plants in Ontario and indicate whether they will be served by EGI and whether by existing distribution infrastructure or require new facilities.

Interrogatory # 1.10-GEC-4

4. E1/T10/S3 p. 2: Enbridge provides estimates of its 2021 Scope 1, 2 and 3 emissions.
    a. What are the boundaries for the estimate of fugitive emissions in Scope 1? Are they just emissions from Enbridge's distribution system or do they include emissions associated with leaks in the transportation to the Enbridge distribution system?
    b. For the Scope 3 emissions estimate, does Enbridge assume that every cubic meter of methane delivered to its customers' meters are combusted and turned into carbon dioxide (and other byproducts)? Or does it assume that a portion of methane delivered to customers' meters are either leaked or emitted into homes and businesses as a result of incomplete combustion? If leaks, incomplete combustion or other sources of methane emissions on customers' side of their meters are included, how were they estimated? What assumptions were used and what are the sources of those assumptions?
    c. In Table 1 Enbridge describes Scope 3 as "Emissions from combustion of natural gas by the Company's end use customers." Did Enbridge limit its Scope 3 emissions estimates to just combustion of its product by its end use customers? Or did also capture upstream emissions from the extraction, production and delivery of methane to its distribution system? If it included only combustion effects, please explain why?
    d. Please provide all of Enbridge's assumptions and calculations of Scope 3 emissions.
    e. Does Enbridge believe that Table 1 captures all lifecycle emissions associated with the extraction, production, movement and consumption of the gas it distributes? If so, please explain. Note that by "lifecycle" emissions we are referring to an accounting analogous to (i.e., the buildings and industry analogue to) the categories of emissions captured by the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model developed by the U.S. Department of Energy's Argonne National Laboratory (see: https://www.energy.gov/eere/bioenergy/articles/greet-greenhouse-gases-regulated-emissions-and-energy-use-transportation).

Interrogatory # 1.10-GEC-5

5. E1/T10/S4 p. 4: Enbridge states that its forecast was not adjusted to address future energy efficiency codes and standards. Would Enbridge agree that any such future codes and standards would almost certainly lead to reductions in (rather than increases in) average gas consumption? If not, what changes could lead to increases in gas consumption?

Interrogatory # 1.10-GEC-6

6. E1/T10/S4 p. 4: Enbridge states that it has not made adjustments to its average use forecast to reflect impacts of blending of hydrogen, as blending volumes are expected to be "minimal during the rate rebasing period."

a. What levels of hydrogen blending has Enbridge tested to date? Please express the blending levels as hydrogen percentages (the percent of total delivered gas that would be hydrogen rather than methane) both by volume and by energy content.
b. What levels of hydrogen blending does Enbridge currently have plans to test? Please express the blending as hydrogen percentages (the percent of total delivered gas that would be hydrogen rather than methane) both by volume and by energy content.
c. What does Enbridge believe to be the highest feasible level of hydrogen blending with methane that could be delivered through its distribution system and consumed by its customers heating systems and other appliances without modifications or capital investments? 5% by volume? 10%? 20% Some other value? Please explain the basis for the response, with references provided.

Interrogatory # 1.10-GEC-7

7. E1/T10/S4 p. 6, Table 2:
    a. What is the basis for the assumption that 10% fewer existing homes would convert to natural gas starting in 2030? Why would that trend not start before 2030?
    b. Footnote 5 references Enbridge's 2019 and 2020 Residential Natural Gas End Use Survey.
        i. Please provide a copy of all summary data and reports regarding this survey, as well as the prior survey (the one completed immediately prior to 2019/2020) and any new survey completed since the 2019/2020 one.
        ii. If not included in the Residential Natural Gas End Use Survey, please provide Enbridge's best estimates of the fraction of its residential customers that have each of the following:
            1. Forced air gas furnace heating?
            2. Hydronic gas boiler heating?
            3. Gas water heating
            4. Gas cooking?
            5. Gas dryers?
            6. Central air conditioning?
            7. Window/room air conditioning?
    c. On line 3 Enbridge states that it assumes that, starting in 2026, 10% of general service customers will replace gas equipment that reaches the end of its life with non-gas equipment.
        i. Does this apply to all forms of gas equipment – heating equipment, water heating equipment, cooking equipment, dryers, etc.? If not, what forms of equipment does it apply to?
        ii. How does this 10% assumption compare to actual retention of customers' gas end use equipment today?
        iii. Why does Enbridge assume that trends in retention of existing customers or existing customers' gas end use equipment will change sooner (2026) than the trend in gas conversions (no percentage change until 2030, per Table 2, line 2)?

Interrogatory # 1.10-GEC-8

8. E1/T10/S4 p. 7, Figure 1:
    a. Please provide the numeric values in the graph.
    b. Please provide actual customer additions for each of the five years prior to 2023.
    c. The note below the graph states that the depiction "excludes community expansion". Please provide the 2023-2032 values including community expansion.

Interrogatory # 1.10-GEC-9

9. E1/T10/S4 pp.7-8: Enbridge states its forecast includes an adjustment to account for its DSM program. It further states that the assumed "annual volume reductions are detailed in Enbridge Gas's Multi-Year Demand Side Management Plan (2022 to 2027) Application and provided at Exhibit 3, Tab 2, Schedule 7, Table 1.
    a. E3/T2/S7 Table 1 only covers 2023 and 2024. What assumptions were made beyond 2024?
    b. In EB-2021-002, Enbridge was ordered to make a number of changes to its proposed DSM Plan, as well as to plan to begin significantly ramping up its savings levels in 2026 to 2028. In a letter to the Board on January 27, 2023, Enbridge included an update to its estimate of 2024 Test Year Revenue Requirement to reflect the Board's DSM decision. Please explain what changes Enbridge made to its DSM savings assumptions, by year, for 2023 through 2032. Please include in the explanation what level of annual DSM savings the Company is now assuming it will achieve for every year from 2023 through 2032.

Interrogatory # 1.10-GEC-10

10. E1/T10/S4 p. 9: Enbridge states that its design hour demand adjustment factors are "based on peak hour trends observed in the ETSA Reference Case scenario, which includes impacts from future DSM programming, carbon pricing and natural gas commodity pricing, building performance and appliance efficiency improvements for existing customers…"
    a. Please explain how the effects of carbon pricing and natural gas commodity pricing are assumed to affect annual gas demand as well as peak hour demand?
    b. What did Enbridge assume about average annual, winter and winter peak hour commodity prices for each year from 2023 through 2032? What were those assumptions based on?
    c. Did Enbridge perform any sensitivity analyses for the ETSA reference case, including sensitivities in which the Energy Transition involves significantly more electrification of new and/or existing customers? If so, please provide:
        i. All assumptions for such sensitivities.
        ii. The impacts of those assumptions in forecast annual gas consumption and forecast design hour demand (e.g., relative to values in Figure 3)
        iii. The impacts of those assumptions on the forecast capital spending on the AMP (on p. 14, Enbridge states that the combined effect of its ETSA reference case assumptions regarding the energy transition results in a reduction of $66 million relative to the Distribution Reinforcement Capital forecast previously filed; how much larger of a reduction would be realized under greater electrification assumptions assumed in any sensitivity analyses performed by Enbridge?).

Interrogatory # 1.10-GEC-11

11. E1/T10/S4 p. 11, Figure 3:

a. Please provide the numeric values for each year for each of the three lines in an Excel file.
b. Please provide the comparable forecast assumptions (for each of the three scenarios represented by the three lines in Figure 3) for annual gas demand (e.g., the amount of annual consumption that would be associated with the nearly 12.3 million m3/h in 2023 and other values in subsequent years). Please also provide these values in an Excel file.
c. Please provide Enbridge's design hour demand for each year from 2013 through 2022.
d. Please provide Enbridge's actual historic peak hour demand for each of the ten years from 2013 through 2022. Please also provide the day and hour of day on which the peak hour was experienced in each of those years.
e. Please provide Enbridge's actual annual gas sales for each year from 2013 through 2022.

Interrogatory # 1.10-GEC-12

12. E1/T10/S4, p. 12: Enbridge lists three reasons why additional energy transition adjustments were not made. The first reason is that "specific locations for wider-scale injection of hydrogen have yet to be identified, creating uncertainty regarding the impact on the design day demand forecast."
    a. Is Enbridge referring to hydrogen blending with methane or to direct generation or direct supply of 100% hydrogen to individual customers?
    b. If locations for either hydrogen injection or complete conversion to 100% hydrogen for individual customers were known, how would that affect design day demand? How is the location of such injections related to design day demand?
    c. Would Enbridge agree that injection of hydrogen, because it is much less dense than methane (i.e., 70% less energy content per m3), reduces the peak demand capacity of its pipes? If not, why not?

Interrogatory # 1.10-GEC-13

13. E1/T10/S4 p. 17: Enbridge states that "there is also the possibility that service lives could be lengthened or maintained if low-carbon fuels, such as hydrogen and RNG, are determined to be viable sustainable alternatives to gas."
    a. When Enbridge refers to "lengthened", does it mean lengthened relative to how long investments would last with just fossil methane being consumed? If not, what does it mean? Lengthened relative to what?
    b. Does Enbridge believe that use of hydrogen or RNG could increase the physical longevity of any capital assets? If so, please explain how and why?

Interrogatory # 1.10-GEC-14

14. E1/T10/S4, pp. 17-18: Enbridge has suggested that an Economic Planning Horizon (EPH) for depreciating assets "is not appropriate at this time" because of uncertainty about how the energy transition would affect its system, but that "if a diversified pathway to net-zero is not adopted in Ontario, Enbridge Gas would seek to introduce an EPH on its system to mitigate the risk of stranded assets." Enbridge further states that "if a system-wide 2050 EPH were to be implemented starting 2024, the 2024 Test Year depreciation expense would increase by $282 million, from $921 million to $1.2 billion."

a. Why is uncertainty about how the energy transition will affect Enbridge's system a reason not to adopt an EPH? Doesn't the uncertainty about the impacts of the energy transition create risk for future ratepayers which an EPH can mitigate? In other words, isn't an EPH, at least in part, a ratepayer risk mitigating strategy? If not, why not?
b. Would Enbridge agree that there will always be uncertainty about the impacts of the energy transition twenty or more years into the future? If so, does that mean Enbridge would never find it appropriate to put an EPH in place? If not, please explain in detail how much "certainty" there must be for Enbridge to support adoption of an EPH?
c. How does Enbridge define a "diversified pathway to net-zero"? Please be specific about exactly what features a pathway would need to have to be considered by Enbridge to be "diversified". Is there a minimum or maximum amount of gaseous energy throughput through Enbridge's system? Is there a minimum or maximum amount of peak hour demand to be served by Enbridge?
d. What information would Enbridge need to have that it does not currently have in order to propose an EPH? Put another way, please provide the specific conditions under which Enbridge would pr
e. Would Enbridge agree that there is at least a significant possibility that Ontario's pathway to decarbonization will involve significantly lower annual volumes of gas distributed by the Company? If not, why is that not at least a significant possibility?
f. Is the estimated increase in 2024 Test Year depreciation expense of $282 million associated with the application of an EPH to all assets, both (1) those for which capital investments have already been made but not yet fully depreciated and (2) new assets? If so, what would the 2024 Test Year depreciation expense increase be if a 2050 EPH was just applied to new capital investments?
g. Please provide an Excel file, with formulae intact, showing the actual calculation of the $282 million increase in 2024 Test Year depreciation expensive associated with adoption of a 2050 EPH.

Interrogatory # 1.10-GEC-15

15. E1/T10/S5/Attachment 2, Figure ES-2 on p. 5 of 86:
    a. Did Guidehouse also develop a reference case with no decarbonization requirements? If so, what were the Total Energy System Costs, peak demands by fuel, and CO2e emissions for that scenario?
    b. Please confirm that the Total Energy System Costs shown in the upper left are expressed in net present value (NPV) terms using a 4% real discount rate? If not, please explain what they represent.
    c. Are Total Energy System Costs expressed in "societal" terms (in the sense that they represent total incremental costs to society) or in customer terms (i.e., based on retail energy prices customers would pay)?
    d. When computing electric peak demand impacts and related costs, did Guidehouse consider and assume deployment of demand response – either for electric vehicles or for building heating or other end uses – in its analysis? If so, what did it assume about how much winter peak load could be shifted in each year of its analysis? Please provide the assumption separately for electric vehicles and buildings. Please also provide the basis for any assumptions.
    e. Regarding the Energy Demand by Decade graphs:

i. Please explain what is meant by "energy demand". Is this the total amount of energy delivered to all energy end uses? Or is it the amount of energy need or energy load across all end uses? For example, if a home had an annual energy need of 1 GJ and that need/load was met with equipment with a coefficient of performance (COP) of 1.5, would that appear in this graph as 1 GJ of demand/load or 0.667 GJ of demand/energy supplied? Please explain.
ii. Please provide the numeric values underpinning each of the two graphs. Please provide them separately for each fuel type as well as totals across all fuels.

f. What are the comparable figures for Total Energy Costs, Peak Demands, Carbon Emissions and Energy Demand by Decade for just the buildings sector (residential and commercial).
g. Did Guidehouse assume that all RNG and all hydrogen was zero emitting, or did it base its estimate of emission reductions from RNG on a lifecycle emissions accounting basis such that different sources of RNG or hydrogen had higher or lower levels of emission reductions depending on the source (e.g., as shown in Table B-1 in a September 2022 Michigan RNG Potential Study which can be found here: https://www.michigan.gov/mpsc/commission/workgroups/renewable-natural-gas-study-workgroup)? If lifecycle emissions accounting was used, please explain what assumptions were made about the percent emission reduction, relative to fossil gas, that each type/source of RNG and hydrogen would produce and the basis for those assumptions.
h. In assessing costs, what did Guidehouse assume about when and how gas consuming heating equipment and other gas-consuming appliances would be replaced? For example, did it assume that all equipment would be replaced at the end of its useful life (e.g., assuming an average life 20 years, so 5% equipment stock turnover every year), so that the cost of decarbonization is just the incremental cost from a standard new piece of gas-consuming equipment to a lower-emitting piece of equipment? Or did it assume there would be early retirement or early replacement of some portion of equipment in buildings to either more efficient gas equipment (e.g., gas heat pumps) or electric equipment (e.g., electric heat pumps), such that the cost of converting to lower-emitting equipment was the total cost of new equipment (perhaps with credit for a future deferred replacement)? Please explain the basis for the approach taken.
i. The Energy Demand by Decade graph suggests that the vast majority of gaseous fuel delivered to meet energy demand in the Diversified Scenario in 2050 is hydrogen.
    i. What is Guidehouse's vision for how massive amounts of fossil gas consumption would be replaced by hydrogen consumption? Would this happen gradually, as customer's methane furnaces reach the end of their life and are replaced with hydrogen burning alternatives? Or would it happen at roughly the same time for all housing units in a neighborhood?
    ii. If Guidehouse's vision of switching to hydrogen is that it would happen at roughly the same time in a neighborhood, would Guidehouse agree that would require retrofit programs to both (1) convert existing methane-burning equipment to hydrogen-burning and/or to replace some methane-burning equipment well before the end of its useful life; and (2) convert existing methane carrying pipes in homes and businesses – from the customers' meters to locations of gas-burning appliances – to hydrogen-carrying pipes? Would Guidehouse further agree that

there would be a significant cost to such a program? If not, why not? If Guidehouse agrees, were such added customer equipment conversion/replacement program costs captured in its analysis? Please provide details and any cost estimates of such changeovers that Guidehouse or Enbridge are aware of.

j. The Energy Demand by Decade graph suggests that there is still a substantial amount (though less than the amount of hydrogen) of methane (in the forms of RNG and fossil gas + CCS) being consumed in the Diversified Scenario in 2050.
   i. What is Guidehouse's vision of how both very large amounts of hydrogen and smaller but still quite substantial amounts of methane would be simultaneously delivered to residential and commercial customer classes? Would there be some neighborhoods or communities with one just one of those fuels and other neighborhoods or communities with just the other fuel being supplied? Or would some or many neighborhoods or communities have two parallel sets of pipes – one for hydrogen and one for methane? Please explain.
   ii. To the extent that some neighborhoods or communities would have two parallel sets of pipes, did Guidehouse include the cost of maintaining and operating both sets of pipes in its estimates of Total Energy System Cost? If not, why not?

Interrogatory # 1.10-GEC-16

16. E1/T10/S5/Attachment 2, p. 6 of 86: In the discussion of sensitivity 1, Guidehouse states that lower renewable energy and battery costs would lead to more distributed renewables with cost savings of $12 billion for the Electrification Scenario and $13 billion for the Diversified Scenario. Why would the cost savings be greater (or even similar) in the Diversified Scenario since the Electrification scenario requires much more new generation and, presumably, much more T&D infrastructure (some of which could potentially be eliminated through distributed renewables deployment)?

Interrogatory # 1.10-GEC-17

17. E1/T10/S5/Attachment 2, p. 26 of 86: Guidehouse states that in the Diversified scenario it is assumed that gas supply shifts from fossil gas to low- and zero-carbon gases.
    a. How does Guidehouse define “low-carbon”?
    b. What did Guidehouse consider to be “low-carbon” gases in its analysis? For that gas, did it count the remaining emissions as requiring offsets? If not, please explain?
    c. Is RNG considered “low-carbon” or “zero-carbon”? Is that true for all sources of RNG, or did Guidehouse consider some to be low-carbon and others to be zero-carbon?
    d. What are the various forms of hydrogen that are considered to be “low-carbon” and what sources are considered to be “zero-carbon”? Please explain the rationale.

Interrogatory # 1.10-GEC-18

18. E1/T10/S5/Attachment 2, p. 38 of 86: Regarding the estimates of electricity peak demand by decade:
    a. Please provide a breakdown of the components of peak demand by scenario, by decade. Specifically, what fraction is associated with:
       i. residential space heating,
       ii. residential water heating,
       iii. other residential end uses,

iv. commercial space heating,
v. other commercial end uses,
vi. industrial uses,
vii. transportation (e.g., electric vehicle charging),
viii. hydrogen generation, and
ix. other end uses (please specify what these would be).

b. For residential space heating, please explain how Guidehouse estimated the impact on the electric grid at the time of system winter peak. Please address the following in the response:
   i. Was a heat pump load shape used to convert total annual heating energy into peak hour demand? If so, please provide that load shape, describe how it was generated or where it comes from, and provide all underlying assumptions about heat pump efficiency under different weather conditions.
   ii. What was assumed about the time of day and temperature at which peak demands would occur?
   iii. What was assumed about electric heat pump efficiencies (including any back-up systems) at temperatures experienced in peak hours? Please explain the basis for the assumption.
   iv. Please provide all assumptions and calculations used to estimate peak demands from residential and commercial space heating.

Interrogatory # 1.10-GEC-19

19. E1/T10/S5/Attachment 2, p. 42 of 86: Guidehouse states that the "share of natural gas with CCS installed at the end user and natural gas used to create blue hydrogen increases significantly over time in both scenarios."
    a. For what types of customers did Guidehouse assume end user CCS? Is this only for large industrial customers or smaller residential and commercial customers as well? What is the CCS technology (or technologies) assumed to be deployed for end user CCS and what was assumed about its (or their) cost(s).
    b. How much of the CCS is end user CCS vs. blue hydrogen CCS. Please provide the breakdown by scenario and by year.

Interrogatory # 1.10-GEC-20

20. E1/T10/S5/Attachment 2, p. 46 of 86: Figure 18 presents Energy System Costs by decade for each scenario analyzed. Costs are broken down into four categories: gas system, electricity system, emissions and end users.
    a. Please explain whether the values presented per decade are expressed in net present value (NPV) terms, discounted back to 2020 using a 4% real discount rate. If not expressed in NPV terms, please explain what these costs represent (e.g., are they simply the sum of inflation adjusted, but undiscounted annual costs?).
    b. Please further break down gas system costs, by decade and by scenario, into the following:
       i. Capital costs for connecting hydrogen generating facilities to transmission or distribution pipelines
       ii. Capital costs for hydrogen transmission pipelines – either new or refurbished methane pipelines

iii. Capital costs for carbon capture and storage systems (if included in gas system costs, if included in electric system costs, please explain)
iv. Capital costs for connecting RNG facilities to transmission or distribution pipelines
v. Capital costs for methane transmission pipelines (if any)
vi. Capital costs for hydrogen distribution pipelines and related distribution infrastructure – whether new or refurbished methane distribution components
vii. Capital costs for methane distribution system upgrades
viii. Hydrogen energy costs (if these are captured in electric system costs, please explain)
ix. Hydrogen transmission system operating costs
x. Hydrogen distribution system operating costs
xi. RNG energy costs
xii. Fossil methane energy costs
xiii. Fossil methane + CCS energy costs
xiv. Methane transmission system operating costs
xv. Methane distribution system operating costs
xvi. Any other relevant costs (please separate capital from variable operating costs and explain what these are)

c. Please further break down electricity system costs, by decade and by scenario, into the following:
    i. Capital investment in new electric generation and storage – if possible, break these down between new generation needed for end use electricity and new generation needed for hydrogen production
    ii. Capital investment in electric transmission lines (new or upgrades) – if possible, break these down between transmission investments needed for end use electricity consumption and investments need for hydrogen production
    iii. Capital investment in electric distribution system additions or upgrades
    iv. Electric fuel costs
    v. Other electric system costs (please explain)
d. Please further break down end user costs, by decade and scenario, into the following
    i. Capital investment in end use energy consuming equipment (e.g., heat pumps, water heaters, furnaces, etc.) in buildings
    ii. Capital investment in building envelop efficiency (e.g., weatherization) upgrades
    iii. Capital investment in end use equipment in industry
    iv. Capital investment in retrofitting existing end use energy consuming equipment so that it can burn hydrogen instead of methane
    v. Capital investment in converting pipes that currently carrying methane inside buildings (i.e., on the customer side of the meter, from the meter to different gas burning appliances in homes and businesses) to pipes that can safely carry hydrogen
    vi. Customer operation and maintenance costs (if any)
    vii. Any other end use costs (please break down between capital and operating costs and explain)

e. Please explain what “emission costs” represent. Are these assumed emissions taxes or are these societal costs of remaining emissions? If the latter, why would costs be highest in the 2030s when emissions are lower that decade than in the 2020s?

Interrogatory # 1.10-GEC-21

21. E1/T10/S5/Attachment 2, p. 47 of 86: Guidehouse discusses the various costs included in its analysis as well as “out of scope costs”.
    a. Under “Gas System Costs”, Guidehouse lists “T&D network costs”. T&D means “transmission and distribution”. This would imply that gas ***distribution*** system costs – or at least a portion of them – are included in the analysis. However, under out-of-scope costs, it states that “cost for upgrading gas and electricity distribution systems (last-mile delivery) are out of scope.” Please clarify this apparent discrepancy. Are any gas distribution system costs – capital or operating – included in the analysis? If so, which are included and which are excluded.
    b. Under “Electricity System Costs”, Guidehouse states that “CAPEX and OPEX…of new or reinforced T&D infrastructure” are included. T&D means “transmission and distribution”. Also, in Appendix A (p. A-9), Guidehouse presents Electricity Distribution Infrastructure Investment Cost Inputs. This would imply that electric ***distribution*** system costs – or at least a portion of them – are included in the analysis. However, under out-of-scope costs, it states that “cost for upgrading gas and electricity distribution systems (last mile delivery) are out of scope.” Please clarify this apparent discrepancy. Are any electric distribution system costs – capital or operating – included in the analysis? If so, which are included and which are excluded.
    c. Under out-of-scope costs, Guidehouse notes that the potential costs of decommissioning portions of the gas network are excluded from its analysis. Would Guidehouse agree that there are also potential cost savings from decommissioning portions of the gas system, both from avoiding gas infrastructure replacements or upgrades and from avoiding maintenance costs? If not, why not?

Interrogatory # 1.10-GEC-22

22. E1/T10/S5/Attachment 2, p. 48 of 86: Figure 19 shows somewhat lower emissions for the Electrification Scenario from the early 2030s through the mid- to late-2040s. For example, in 2040 emissions under the Electrification Scenario are 49 MTCO2e whereas they are 55 MTCO2e under the Diversified Scenario.
    a. Why wasn’t the modeling done to achieve exactly the same level of emission reduction?
    b. Would Guidehouse agree that if the pace of electrification was slowed somewhat under the electrification scenario, so that total emission reductions were the same in both scenarios, there would be some cost savings relative to the costs for the Electrification Scenario shown in its study results? If not, why not?

Interrogatory # 1.10-GEC-23

23. E1/T10/S5/Attachment 2, p. 59 of 86: Guidehouse states that Ontario's existing gas pipeline network "is ideally suited to be repurposed to a hydrogen network, as the province's newer pipelines, typically made of polyethylene, are already largely hydrogen-ready. Metal pipes will require integrity assessments and internal coatings before they can be used to transport hydrogen."
    a. What fraction of transmission pipelines in Ontario are the "newer" type, made from polyethylene? Please provide the response in both percentage terms and in kilometer terms.
    b. What fraction of distribution pipe in Ontario is made from polyethylene? Please provide the response in both percentage terms and in kilometer terms.
    c. Guidehouse's scenarios, particularly the Diversified scenario, appear to rely on both hydrogen and methane (e.g. from RNG). How can the existing gas pipes be repurposed for hydrogen if there is still a need to transport and distribute RNG and other forms of methane? Doesn't this require two sets of pipes? If not, why not?
    d. How could existing gas pipes designed to carry methane be repurposed to carry hydrogen fuel that has only ~30% as much energy content per cubic meter. Wouldn't the pipes have to be replaced with versions that are three times the size – or supplemented with significant additional pipe? If not, why not?

Interrogatory # 1.10-GEC-24

24. E1/T10/S5/Attachment 2, Appendix A:
    a. Are all of the cost assumptions presented in the Appendix expressed in nominal dollars? Or are they expressed in constant dollars for a given year? Or are they a mix of the two? If a mix of the two, please indicate which cost assumptions in the different Appendix A tables are expressed in constant dollars, as well as what year's dollars they are expressed in, and which are expressed in nominal dollars.
    b. Regarding Table A-2: why would the carbon price be different for two different pathways? Isn't the social cost of carbon the same regardless of the emission source? If this is intended to reflect carbon taxes, why would the tax be different for different emission sources?
    c. On p. A-2 Guidehouse states that "all electricity capacities are forecast to remain the same in the IESO 2020 APO, except for nuclear power; reactors at the Bruce and Darlington Nuclear Generating Stations are expected to be refurbished in the next 10-12 years." How were such refurbishments assumed to change the Bruce and Darlington generating capacities?
    d. On p. A-2 Guidehouse states that it assumes all existing gas turbines will be phased out from 2030 to 2050 and that new planned gas turbines in 2030 will be decommissioned by 2050, so that the only gas-fired turbines operating in 2050 will be hydrogen-powered turbines.
        i. Why was this assumption made?
        ii. Did Guidehouse consider the potential to run existing and new gas turbines with RNG instead of using RNG in the gas distribution system? If not, why not?

iii. Did Guidehouse consider the potential to run existing and new gas turbines with fossil gas only to meet electric system peak demands, with limited carbon capture to offset such limited emissions? If not, why not?

e. On p. A-3 Guidehouse states that it assumes wind and solar capacity factors will improve by 0.5% per year.
    i. Is that 0.5 percent per year or 0.5 percentages points per year?
    ii. Does Guidehouse's assumption about annual improvements to wind and solar capacity factors continue throughout the entire analysis period – i.e. up through 2050? If not, for how many years is the assumption in place?
    iii. Guidehouse says "resulting capacity factors are presented in Table A-4." For what year do the capacity factors in Table 4 apply?
    iv. What are the assumed capacity factors for wind and solar for 2030, 2040 and 2050?

f. Regarding Table A-5
    i. Do costs of green hydrogen decline over time for any reason other than improved capacity factor of wind and solar? If so, what are the reasons and related assumptions used by Guidehouse to develop the cost estimates presented?
    ii. Please provide the assumptions and calculations performed to estimate Green hydrogen costs for Ontario for 2030, 2040 and 2050.

g. Regarding Table A-10: Guidehouse estimates the cost of RNG crop feedstock cost to be $42/MW in 2020, declining to $36/MW in 2050. This is based on "the techno-economic parameters presented."
    i. What is meant by "techno-economic parameters presented"? How were these values derived? What is the basis for the assumption that they will decline over time?
    ii. If this is the just cost of crop feedstock, what is the resulting cost per m3 of RNG delivered to the Enbridge distribution system in each year? What other assumptions and calculations were used to derive that cost per m3? Please specify in detail.
    iii. Does Guidehouse believe that crop feedstocks would be the most expensive source of RNG? If so, what is the basis for that assumption? Please provide appropriate references.
    iv. Did Guidehouse assume that the most expensive source of RNG would set the market clearing price for all RNG – and did its model assume that all RNG consumed in a scenario had a cost equal to the market clearing price set by the most expensive unit of RNG? If so, what did it assume would be the market clearing price in 2030, 2040 and 2050? If not, why not?
    v. Did Guidehouse assume that the average cost per m3 of RNG would be lower under the electrification scenario than under the diversified scenario, since there would be much lower demand under the electrification scenario (and therefore the market would not have to move as high up the RNG cost curve)? If not, why not?
    vi. Please provide the following:

1. Guidehouse's estimates of the total bcm of RNG consumed each year from 2020 through 2050. Please provide the estimate separately for the diversified and electrification scenarios (i.e., expanding Table A-8).
2. Guidehouse's estimates of the total cost of all RNG delivered to the Enbridge distribution system in each year from 2020 through 2050. Please provide this value separately for the diversified and electrification scenarios.

h. Regarding Tables A-14, A-15 and A-16:
   i. How many km of each type of new gas transmission pipeline and refurbished transmission pipeline (provide separately) were assumed to be required in each year for each scenario (diversified and electrification)?
   ii. What was the total available km of methane pipeline and hydrogen pipeline in each year from 2020 through 2050?
   iii. What was the basis for Guidehouse's estimates of how many km of new gas transmission line and how many km of refurbishing of existing gas transmission line would be required in each year for each scenario?
   iv. How did Guidehouse determine how much existing methane pipeline could be reburbished (vs. having to be replaced) to take hydrogen instead of methane?
   v. There are no tables presented for CAPEX costs for new or refurbished gas distribution pipe? If not, why not? If new/refurbished distribution pipe costs were estimated, please provide all assumptions about costs, as well as total assumed capital costs per year per scenario.
   vi. Were costs estimated for reburbishing or replacing gas pipe on the customers' side of the meter (in homes and businesses) to carry hydrogen instead of methane? If not, why not? If they were estimated, please provide all assumptions about costs, as well as total assumed capital costs per year per scenario.

i. Regarding cost of Electricity Infrastructure discussed on p. A-9:
   i. How many MW-km of transmission lines were assumed to be added, by year, in each scenario?
   ii. How did Guidehouse estimate how many MW-km of new transmission capacity would be required each year?
   iii. For electric distribution system costs, did Guidehouse simply multiply the year-over-year increase winter peak demand by the $99,700 cost per kW of distribution capacity in table A-19? If not, how were new electric distribution costs estimated?
   iv. Why did Guidehouse model electric distribution system upgrade costs but not gas distribution system costs – particularly the costs associated with converting from a system delivering methane to a system delivering primarily hydrogen?

j. Regarding end user costs on pp. A-10 and A-11:
   i. Guidehouse states that its analysis does not include "the cost of existing heating system and end-of-life replacements." What does that mean? Did Guidehouse assume a one-time cost (consistent with Table A-20) for equipment replacement and no subsequent replacements at the end of the equipment life, even if before 2050? If so, why? If not, please explain.

ii. How many residential households were assumed to install each of the pieces of heating equipment listed in Table A-20 in each year from 2020 through 2050. Please provide the response separately for the diversified and electrification scenarios.
iii. Are the gas heat pump and hybrid heat pumps included in Table A-20 systems that would consume methane or hydrogen? Or did Guidehouse assume that the cost would be the same, regardless of the type of gaseous fuel? If the latter, what is the basis for that assumption?
iv. What did Guidehouse assume about the cost of other gas-consuming appliances (water heaters, stoves, dryers) and their electric alternatives?
v. What did Guidehouse assume – implicitly or explicitly – about the heating capacities (BTUh) of the different heating equipment listed in Table A-20.
vi. What did Guidehouse assume about the average annual heating Coefficient of performance (COP) and the average SEER cooling efficiency rating for piece of equipment listed in Table A-20? What was the basis for each assumption?
vii. What did Guidehouse assume about the peak heating hour heating COP for each piece of equipment listed in Table A-20? What was the basis for each assumption?
viii. Did Guidehouse make any assumptions about whether (1) the costs of any building heating, water heating or other equipment would change over time (other than for inflation); (2) the average seasonal COP/efficiency of new equipment would improve over time; and/or (3) the peak hour COP/efficiency of new equipment would improve over time? If so, please provide all such assumptions about cost and/or efficiency changes over time, including the type of equipment, magnitude of change and specific years in which the changes were assumed to occur. If not, why not?
ix. What did Guidehouse assume about the percent annual energy savings and percent peak hour savings associated with the two levels of building efficiency retrofits in Table A-21.
x. How much more efficient did Guidehouse assume new homes would be relative to existing homes? How much less energy consumption would be needed per home for heating? How much less energy consumption would be needed during the peak heating hour in winter? What was the basis for these assumptions?
xi. What did Guidehouse assume about the measure life for each type of gas consuming equipment (heat pumps, water heaters, etc.), as well as for building efficiency improvements?

k. Does Guidehouse have all of the inputs to its model in an Excel file, database file or other electronic file? If so, please provide a live copy of the file (or files) with formulae intact.

Interrogatory # 1.10-GEC-25

25. E1/T10/S5/Attachment 2, p. 85 of 86: Guidehouse states that "capital costs are converted to a levelized amount using an annuity factor based on the economic lifetime of each type of investment and a real discount rate of 4%.

a. Were all capital costs – whether on the gas system, electric system or for end users (heating equipment, weatherization, etc.) – levelized in this way? If not, which capital costs were levelized and which were not?

b. Does this mean that if a heat pump costing $10,000 was assumed to have a 15-year life that Guidehouse would have included a levelized cost for each year of the heat pump's life (or each year of its life within the study analysis period through 2050) of $899? If not, please explain.

Interrogatory # 1.10-GEC-26

26. E1/T10/S5 p. 5: Enbridge states that each of the four scenarios assessed in its ETSA project considered key drivers that have the potential to affect gas demand. The critical drivers listed by Enbridge does not appear to include either (1) government incentives for electrification; or (2) the potential for municipal incentives for electrification, banning of new gas connections or other municipal policies. Were these factors not considered in the scenario analyses? If not, why not?

Interrogatory # 1.10-GEC-27

27. E1/T10/S5, p. 9: Figure 2 shows that the volume of gas demand would increase under a "diversified portfolio". Enbridge explains that this is because of assumptions regarding growing use of hydrogen which delivers only about 30% as much energy per m3 as methane.

    a. Please provide volumetric gas demand for the diversified portfolio, by year, separately for hydrogen and methane.

    b. Please clarify how much of the hydrogen demand in each year is associated with hydrogen blending with methane and how much is delivery of 100% hydrogen through hydrogen only pipes.

    c. Please clarify how much of any 100% hydrogen delivery, by year, is assumed to be for (1) industrial customers, (2) commercial customers and (3) for residential customers.

    d. To the extent that, if any of the 100% hydrogen gas is assumed to be delivered to residential customers or commercial customers on the Enbridge distribution system, what is Enbridge's vision for how that would occur? Specifically:

        i. Does Enbridge envision that a 100% hydrogen distribution pipe to a neighborhood or community would be constructed to run parallel to an existing methane pipe and customers then, gradually over time, converting from methane to hydrogen (e.g., as their methane burning furnaces and other equipment are replaced at their natural end-of-life cycle)? Or does Enbridge envision that the hydrogen pipe would be built alongside the existing methane pipe, and once constructed every customer in the neighborhood or community would be converted from methane to hydrogen at roughly the same time so that the methane pipe could be decommissioned?

ii. In either case, would Enbridge agree that it could not repurpose methane distribution pipes to deliver hydrogen because the methane pipes would need to carry methane until 100% of all customers' equipment, as well as gas-carrying pipes inside buildings on the customers' side of the meter, are converted to hydrogen for a distribution area. If not, why not?

iii. If Enbridge's vision is that that all customers in a neighborhood or community would be expected to switch from methane to hydrogen at roughly the same time, how would that happen? How could Enbridge ensure that all customers would choose to convert to hydrogen? What if some customers wanted to continue to burn methane?

Interrogatory # 1.10-GEC-28

28. E1/T10/S5 p. 14: Enbridge states that "energy efficiency is a key aspect of both scenarios" for pathways to achieve net zero GHG emissions by 2050. How does the amount of energy efficiency assumed in the Guidehouse study between 2020 and 2030 compare to the levels Enbridge will have achieved between 2020 and the end of its currently approved three-year DSM plan (i.e. through 2025)?

Interrogatory # 3.2-GEC-29

29. E3/T2/S5 Has Enbridge installed equipment that allows for collection of hourly gas consumption data from any of its residential customers. If so, please provide the following information about the sample of homes being metered:

    a. How many homes are being metered? How has that number changed over time (i.e., how many homes were added in each month over the past two years)?

    b. What types of homes are being metered? Are they only single-family homes, or are their townhomes, apartments and/or other housing types being metered? How many homes of each type are being metered?

    c. What are the locations of the metered homes? In which cities or towns or parts of Enbridge's service territory are they located?

    d. Please provide the average gas consumption, by hour, across that sample for each of the last two years. To the extent that the metering is at the end use level (rather than just whole home consumption), please provide the average hourly consumption by hour for each end use. Please also identify the specific hour and day of the year associated with each hourly average.

    e. To the extent that Enbridge has the information, please provide the outdoor temperature for each hour for the Ontario weather station most representative of the weather experienced by the sampled homes.

Interrogatory # 1.10-GEC-30

Ex.1, Tab 10, S.2: "Enbridge Gas has over $14 billion in regulated assets". What proportion of those assets (in dollar value) will need to be modified to enable the predominantly hydrogen-based pathway the evidence suggests?

Interrogatory # 1.10-GEC-31

Exhibit 1, Tab 10, Schedule 4, Page 18 of 20 EGI notes that a 2050 EPH would increase 2024 depreciation expense by $242 million. If no such adjustment is made between now and 2050 but these assets are retired in 2050, what would be the resulting amount of stranded assets? If the adjustment is made starting in 2030, what would be the resulting impact on depreciation expense in that year?

Interrogatory # 1.10-GEC-32

Exhibit 1, Tab 10, Schedule 5, Page 5 refers to external stakeholders consulted as having "encouraged Enbridge Gas to continue with energy transition planning, and to work towards a goal of absolute zero GHG emissions by 2050." Please elaborate on the choice of the phrase "absolute zero" rather than 'net zero'. Is that wording indicative of stakeholder concerns about reliance on CCUS?

Interrogatory # 1.10-GEC-33

Exhibit 1, Tab 10, Schedule 5, p. 6

"While the steady progress scenario assumes the adoption of higher carbon pricing ($170/tCO2e by 2030) and the introduction of more stringent building codes and standards, modeled results indicate the emission reductions from these measures alone are not sufficient to meet net-zero emission goals by 2050."

In light of that observation, what more stringent building codes and standards has the company included in its load forecasts?

Interrogatory # 1.10-GEC-34

Exhibit 1, Tab 10, Schedule 5, p. 16

A. Given that hydrogen has roughly one third the energy content of methane, would Enbridge agree that there are three possibilities in a predominantly hydrogen carrying grid – (if not please explain):
    i. distribution system capacity is increased three-fold to serve existing peak loads, or

ii. if the system is not dramatically increased to accommodate hydrogen, distribution costs roughly triple for the third of customer demand that can be accommodated by the gas grid and be served by hydrogen at peak, or

iii. a combination of the above alternatives with a combination of increased system and customer asset-related costs to accommodate hydrogen and increased rates as fixed distribution costs are borne by fewer customers (as would appear to be the case in the Diversified Scenario)?

B. Does Enbridge agree that while there may be significant investment required on the electricity system in an electrification scenario, there will be significantly more electrical load and accordingly, the electricity rate impacts will be moderated?

C. Please provide gas rate impact estimates for the two scenarios in the P2NZ study.

D. Please provide electricity rate impact estimates for the two scenarios in the P2NZ study.

Interrogatory # 1.10-GEC-35

Exhibit 1, Tab 10, Schedule 6, Page 27

The company cites Ontario based CCUS as a 'safe bet'. To what extent are the storage basins being considered for CCUS in Ontario currently utilized for methane?

Interrogatory # 1.10-GEC-36

Exhibit 1, Tab 10, Schedule, Attachment 2, Page 3 of 86

Guidehouse indicates that its study mandate included examining each pathway in terms of feasibility. Please describe in detail the assumptions used by Guidehouse for the physical change-over of the distribution system from methane to hydrogen. For example, would a neighborhood being switched require simultaneous appliance upgrades and universal changeover or would there be a need for the duplication of portions of the system to accommodate gradual transitions? Please indicate what costs and timing were assumed for each aspect of this changeover. How has Guidehouse spread the transition from methane to hydrogen out over time to make the transition manageable?

Interrogatory # 1.10-GEC-37

Exhibit 1, Tab 10, Schedule, Attachment 2, Page 6 of 86

Guidehouse finds that adoption of hybrid heating technologies leads to the least cost pathway. Please provide a comparison of hydrogen, RNG, and CCUS requirements for that scenario vs the two primary scenarios. Please indicate how the relative energy intensity of hydrogen vs methane was captured in the cost estimates for storage employed in costing the scenarios.

Interrogatory # 1.10-GEC-38

Exhibit 1, Tab 10, Schedule, Attachment 2, Pages 45 and 46 of 86

Guidehouse attributes some of the higher costs of the electrification scenario to the timing of carbon emissions (where emissions occur later when carbon pricing has escalated). It finds emissions costs of $120 billion for the diversified scenario vs $191B for electrification ($71 billion of the $181 billion difference).

A. Please reconcile the above with the graphics at Guidehouse figure 19 and at Posterity Ex. 1, T 10, S 6, Att 1 p. 25 of 34 (ETI Exhibit 17) both of which appear to depict equal or lower emissions for the electrification scenario at all times.

B. Does Guidehouse agree that carbon taxes affect rates but are not a net societal cost (as opposed to emissions)?

Interrogatory # 1.10-GEC-39

Exhibit 1, Tab 10, Schedule, Attachment 2, Pages 45 of 86

Guidehouse notes:

"Electricity system costs are $111 billion higher than in the Diversified scenario. This is driven by a much larger electricity peak demand in the Electrification scenario (94 GW) compared to the Diversified scenario (51 GW). This increase in peak is driven by higher penetration of electric heat pumps and the electrification of transport, triggering significant investment in hydrogen gas turbine capacity and T&D infrastructure."

Did Guidehouse consider alternate scenarios to find gas/electric mixes that reduce total costs? Please provide details. Would an electrification scenario that utilized more hydrogen and RNG for the transportation load reduce electricity generation and T&D costs without requiring full gas grid switchover costs?

Interrogatory # 1.10-GEC-40

Exhibit 1, Tab 10, Schedule, Attachment 2, Pages 45 of 86

Guidehouse cites the costs of building retrofits indicating:

"To provide adequate heating in winter conditions, electrically heated homes need to be well-insulated and weatherized to minimize heat leakage…. A regular-sized gas furnace usually provides 20 to 35 kW of heat output, while a whole-home heat pump may only provide 5 to 15 kW of heat output at colder outdoor temperatures."

A. When Guidehouse states that a regular-sized furnace usually provides 20 to 35 kW of heat output, does it mean that a regular-sized furnace is capable of providing that output (i.e., those are the rated capacities of regular-sized furnaces) or does it mean that is the actual level of heat output typically provided, on average over the course of peak heating hours, by furnaces? If the latter, please provide data and analysis supporting the conclusion. If Guidehouse is referring to furnace nameplate capacities, would Guidehouse agree that gas furnaces are commonly significantly oversized relative to design heating loads? If not, why not?

B. What assumptions has Guidehouse used for heat pump capacities at cold temperatures and the hours per year when heat pumps cannot meet heating needs?

C. How and to what extent has Guidehouse incorporated the improving trend for air source heat pump cold climate performance?

D. How has Guidehouse optimized the tradeoff between customer retrofit costs and system capacity and energy costs to address the few extreme cold days when heat pumps need to be paired with retrofits or auxiliary heating to meet heating needs?

Interrogatory # 1.10-GEC-41

Exhibit 1, Tab 10, Schedule, Attachment 2, Pages 49 of 86

Please reconcile these two statements:

“CCS does not capture 100% of emissions, some residual emissions remain in both scenarios.”

“residual emissions are offset via the use of bioenergy with CCS in power generation”

Interrogatory # 1.10-GEC-42

Exhibit 1, Tab 10, Schedule 5, Attachment 1, Page 25 of 116

Posterity indicates that the maximum level of DSM considered was that mandated in the recent OEB DSM Decision: “Starting in 2022, a 3% year-over-year real increase in DSM spending. Starting in 2028, a 10% annual increase.” At page 27 it is noted: “DSM savings potential: This was not a CD, but a DSM budget was specified in the scenarios and the associated energy savings potential was included in the scenario results.” Did Enbridge direct that higher levels of DSM spending not be considered? If not, why was this limitation in place?

Interrogatory # 1.10-GEC-43

Exhibit 1, Tab 10, Schedule 5, Attachment 1, Page 26 of 116

Posterity includes hydrogen blending at 14% in 2038. Please indicate how this level is achieved having regard to distribution and end-use limitations on the mixing of methane and hydrogen.

Interrogatory # 1.10-GEC-44

Exhibit 1, Tab 10, Schedule 5, Attachment 1, Page 7 of 116

Posterity notes that "Peak load is also impacted by Enbridge Gas' expected growth in some Industrial customers that have a higher portion of their load used for HVAC, as HVAC accounts for approximately 60% of industrial peak but only 16% of annual volume."

Given this high contribution to peak load, did Posterity or Guidehouse consider scenarios where dedicated Hydrogen or RNG facilities (including local storage) meet a greater proportion of these particular industrial loads and thereby alleviate capacity costs on the electricity system? Please provide details.

Interrogatory # 1.10-GEC-45

Exhibit 1, Tab 10, Schedule 6, Attachment 1, Page 11 of 34

Please update the ETI report to reflect the impact of DSM spending resulting from the EB-2021-0002 Decision and an extrapolation thereof.

Interrogatory # 5.3-GEC-46

Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 35 of 164

Concentric cites S&P's observation that "…switching 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. Affordability is a key consideration because both hydrogen and fuel cells are 1.5x-2.5x more expensive than conventional gas-based household heating, at least in Northern Europe according to a Hydrogen Council report (January 2020)."

A. Does Guidehouse agree with these observations? If not, please elaborate.
B. To what extent are they consistent with the diversified scenario and its costing that Posterity and Guidehouse have utilized?

Interrogatory # 5.3-GEC-47

Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 36 of 164

Concentric notes a 2020 California Energy Commission study that found "relatively inexpensive RNG (for example, biomethane from landfills and wastes) is limited and cannot alone reduce the GHG intensity of pipeline gas enough." The study went on to conclude that, after factoring in the more expensive forms of gas, "the commodity cost of blended pipeline gas is more than four to seven times that of natural gas today." Concentric also notes: "A study conducted by Washington State University's Energy Program indicated that "adequate opportunities exist for RNG production equivalent to 3 percent to 5 percent of current natural gas consumption."

Please compare those findings to the assumptions in the P2NZ report.

Interrogatory # 1.10-GEC-48

Ex.1, Tab 10, S.6 p. 10: Enbridge references Canada's federal hydrogen strategy suggesting that the strategy envisions a role for hydrogen in buildings. The quote that Enbridge references to support this conclusion discusses "low carbon fuel for high-grade heating applications where electric heating is not the best option…" and also states that "In regions with heat pumps, hydrogen can also be used to provide heat during winter season with hybrid heating systems."

A. What is Enbridge's interpretation of "high-grade heating applications"? Is that not a reference to certain industrial uses? Please explain the basis for the response.
B. Does Enbridge believe that the federal hydrogen strategy contemplates use of hydrogen as the sole heating fuel in some residential or commercial buildings, or just as a fuel to address peak loads when part of a hybrid system that relies on heat pumps for heat for most of the winter? Please explain the basis for the response.

Interrogatory # 1.10-GEC-49

Ex.1, Tab 10, S.6 p. 16: Enbridge states that it plans is to both offer a "Low-Carbon Voluntary Program" for large customers and to procure up to 1% of planned gas supply as "low-carbon energy" beginning in 2025, ramping up to 4% by 2028.

A. What types of energy alternatives to fossil methane will Enbridge consider "low-carbon".
B. Does Enbridge agree that different sources of RNG have very different lifecycle GHG emissions profiles? If not, why not?
C. Will Enbridge distinguish between different sources of "low-carbon" energy – between those that have lower lifecycle GHG emissions and those that have higher lifecycle GHG emissions – in determining which low-carbon energy sources to procure? If so, please explain how that will be done. What sources will be prioritized? If not, why not?

Interrogatory # 1.10-GEC-50

Ex.1, Tab 10, S.6 p. 16: Enbridge has no proposal to address industrial fuel-switching. Given that switching to hydrogen and/or other low-carbon fuels may be the only way to decarbonize many industrial operations, why is Enbridge not proposing anything for such customers?

Interrogatory # 1.10-GEC-51

Ex.1, Tab 10, S.6 p. 17: Enbridge is proposing to expand its NGV program.

A. Would Enbridge agree that NGV vehicles emit far more greenhouse gases (GHGs) than electric vehicles? If not, please explain the basis for the disagreement?
B. Has Enbridge conducted an assessment of the relative economics of NGV vehicles, electric vehicles and/or internal combustion vehicles? If so, please provide the assumptions, calculations and analysis conducted.

C. If NGV vehicles emit more GHGs than electric vehicles, and where the amount of RNG available to displace fossil gas is far less than the amount of fossil gas being consumed today, why would it make sense to promote NGV vehicles?

Interrogatory # 1.10-GEC-52

Ex.1, Tab 10, S.6 p. 19: Section 2.1 has the heading "maximizing energy efficiency". What does "maximizing" mean to Enbridge? Is it something less than achieving all cost-effective energy efficiency? If not, why not? Please explain.

Interrogatory # 1.10-GEC-53

Ex.1, Tab 10, S.6 p. 25: Enbridge makes reference to supporting industrial customers in switching from higher emitting fuels to natural gas.

A. When investments for such conversions involve new equipment that will last 15 or 20 years or more, wouldn't a conversion to fossil gas make it more difficult to achieve medium-term to longer-term GHG emissions reductions? If not, why not?
B. Shouldn't Enbridge instead only provide technical and/or financial support to such customers if they are making a conversion to low-carbon fuels such as green hydrogen (i.e., not precluding a switch to fossil gas, but not promoting it technically or financially supporting it)? If not, why not?

Interrogatory # 1.10-GEC-54

Ex.1, Tab 10, S.7 pp. 4-5: Enbridge states that is has completed field trials of hybrid heating technology in over 40 single family homes and subsequently seen it installed it in more than 100 homes in London.

A. Please describe the initial 40 home field test, including the type of homes into which the technology was installed, where they were located, the hybrid heating technology tested (the specifics of the heat pump and furnace or other technologies tested), the rated efficiencies of the technology, how smart controllers were used to optimize cost, etc.
B. Please describe and provide data regarding the results of the field tests including:
    a. the typical or average temperature at which heat pump operation switched to gas heating,
    b. the average reduction in gas use relative to a gas-only heating system,
    c. the average change in heating energy bills relative to gas only or electric only (heat pump with electric resistance back-up) alternatives,
    d. the cost of the technology relative to both an electric-only (heat pump with electric resistance back-up) and gas furnace only alternative, and
    e. other impacts measured by the Company.
C. When were the systems installed in the 100+ homes in London?
D. Are there any performance or cost data yet available from the London homes? If so, please provide those data in summary form (e.g., averages across the population).

Interrogatory # 1.10-GEC-55

Ex.1, Tab 10, S6, Attachment 1, p. 9 of 34: ETI RNG supply is estimated at 1% of 47.1% of “system supply customers” in 2024, increasing to 5% for 45.5% of “system supply customers” in 2028 and beyond.

A. What is the definition of a “system supply customers”? Please identify all rate classes to which that definition applies.
B. Why is the percent of system supply customers’ load falling?

Interrogatory # 1.10-GEC-56

Ex.1, Tab 10, S6, Attachment 1, p. 9 of 34: ETI annual hydrogen volumes are 175,148 m3/year for 2022 to 2024, increasing to 778,437 m3/year in 2025 and subsequent years. What fraction of Enbridge gas sales do those values represent, both as percent of gas volumes and as percent of gas energy content? Please explain key variables in the calculation.

Interrogatory # 1.10-GEC-57

Ex.1, Tab 10, S6, Attachment 1 p. 16 of 34 has a graph that shows Enbridge’s annual hourly peak demand for 2019 through 2050.

A. Please provide the numeric values for depicted in the graph for Residential, Commercial and Industrial peak demands (provide separately for each sector) by year.
B. The graph shows total peak demand as a little more 11 million m3/hour for 2022. By comparison, in E1/T10/S4 p. 11 Enbridge provides a graph (Figure 3) which shows peak demand in 2022 of about 12.3 million m3/hour. What explains this difference? Please provide a detailed, numeric breakdown of all factors contributing to the difference.
C. The Posterity graph shows peak demand per hour declining from what appears to be a little more than 11 million m3/hour in 2022 to what appears to be a little less than 9 million m3/hour in 2032 – a roughly 20% reduction. By comparison, in E1/T10/S4 p. 11 Enbridge’s graph of peak demand shows it increasing from about 12.3 million m3/hour in 2022 to about 12.5 million m3/hour in 2032 (with energy transition assumptions in the customer forecast and demand per customer) – or a roughly 2% increase. What explains this dramatic difference in forecast trends, particular given Enbridge’s description of Posterity’s direction (E1/T10/S6 p. 37) being to “model a scenario that examines the gas demand and GHG emissions between 2019 and 2050 based on the energy transition initiatives proposed within this rebasing application, as well as energy transition initiatives under review or already approved by the OEB in separate applications (e.g. DSM Plan, LCEP Phase 1).”? Please provide a detailed, numeric breakdown of all factors contributing to the difference.

Interrogatory # 1.10-GEC-58

Ex.1, Tab 10, S5, Attachment 1 p. 21 of 116: Posterity states that it bases estimates of GHG emissions solely on emissions from end-use combustion of a fuel, not lifecycle emissions.

A. Would Posterity agree that actual emissions from end-use combustion of RNG are identical to those from fossil methane since the molecules being burned are identical?

B. Would Posterity agree that the only reason for considering emissions from RNG to be lower than emissions from fossil methane is that GHG emission reductions would have been higher had the so-called renewable methane not been captured and burned? If not, why not?
C. Would Posterity agree that if the amount of GHG emissions that (1) would be released into the atmosphere *without* the capture and combustion of a particular source of renewable methane are identical to (2) the GHG emissions that would be released to the atmosphere *with* the capture and combustion of that same source of renewable methane, then there is no climate benefit from combustion of that source of RNG? If not, why not? Would Posterity agree that the answer to this question is not different depending on whether the source of the RNG is biogenic or not?
D. Would Posterity agree that RNG that is collected from a landfill that was otherwise venting methane to the atmosphere would produce greater net GHG emission reduction after combustion – and greater climate benefits – than RNG that is collected from a landfill that was flaring methane? If not, why not?
E. Would Posterity agree that some portion of RNG will leak (between its source and a residential or commercial gas appliance) and/or not be 100% completely combusted by a furnace, water heater or cookstove? If not, why not?
F. Would Posterity agree that if GHG emissions impacts from leaks and/or incomplete combustion of methane are not accounted for in emissions modeling, that the result will be a bias against electrification measures fueled by zero-carbon sources (because they have no comparable leaks or incomplete combustion)? If not, why not?

Interrogatory # 1.10-GEC-59

Ex.1, Tab 10, S5, Attachment 1 p. 42 of 116: Posterity notes that the Reference Case assumption for gas commodity prices is 11.75 cents/m3 in 2019 rising to 15.9 cents/m3 by 2038.

A. Are these values expressed in real dollars or nominal dollars? If real dollars, for which year?
B. Current gas commodity prices are more than double those assumed by Posterity at the time its report was developed. Please provide your best estimate of how that would affect:
   a. Annual gas demand through 2030
   b. Peak hour gas demand through 2030
   c. The number of current customers (or percent of current load) that would electrify.

Interrogatory # 1.10-GEC-60

Ex.1, Tab 10, S5, Attachment 1 p. 46 of 116: Posterity describes the seven steps in its scenario modeling process.

A. The first step involves establishing initial estimates of unit energy consumption (UEC). The third and fourth steps involve modifications to those UECs. The seventh step which accounts for energy savings from DSM presumably results in further UEC adjustments. Please provide all of Posterity's UEC assumptions by sector (residential, commercial, industrial), building type (e.g., Residential single family detached, residential single family attached/row house, etc.), end use (e.g., heating, water heating, cooking, etc.), equipment type (e.g., furnace, boiler, etc.), and year (2019 through 2050). Please provide them in an Excel file.

B. On p. 13 of 116 Posterity makes reference to “researched load shapes for different end uses”. Please provide the load shapes for each sector/building type/end use/equipment type that it analyzed. Please provide the load shapes in an Excel file. If the load shape assumptions changed for different years of the analysis, please include the changes and the years in which they were assumed to occur. Please indicate which hour in the load shape was assumed to represent the hour coincident with Enbridge system peak hour demand.

Interrogatory # 1.10-GEC-61

Ex.1, Tab 10, S5, Attachment 1 p. 84 of 116: Exhibit 75 shows Posterity’s assumptions about Residential End-Use Shares by Segment.

A. Please provide the table in Excel format with percentages extended to one decimal point.
B. Please add to the table the number of housing units associated with each row for 2023 for Enbridge’s entire customer base. If not available for 2023, provide for the most recent year available.
C. Please add the system-wide average gas appliance penetration for each end use.
D. Please add to the table the average total annual gas consumption per housing unit for Enbridge’s entire customer base for each row for 2023. If not available for 2023, provide for the most recent year available.

Interrogatory # 1.10-GEC-62

Ex.1, Tab 10, S5, Attachment 1 p. 85 of 116: Posterity states that “electric UECs for space heating, water heating, cooking and washing/drying appliances were determined by multiplying the gas UECs by assumed efficiencies of 85%, 65%, 55% and 85% respectively.”

A. How were the electric UECs used in the analysis. What affect do they have on Posterity’s scenario analyses?
B. What are the bases for the assumed average gas efficiencies for each of the four end uses.
C. Why would electric UECs be solely the product of gas UECs multiplied by average gas efficiencies? Wouldn’t such multiplications simply produce electric end use loads? To obtain electric energy UECs, electric end use loads then be divided by average electric efficiencies for heat pumps, heat pump water heaters, induction cooktops and electric dryers? If not, why not.

Interrogatory # 1.10-GEC-63

Ex.4, Tab 5, S1, p. 19: Enbridge concludes that it is not in the best interest of customers to set up a segregated fund for SRC amounts. The Company explains that it “believes its system will be a key contributor to Ontario’s ability to achieve net-zero” and that it “does not anticipate that large sections of its system will be retired in the foreseeable future.” In E1/T10/S5 Attachment 2, Figure 11 on p. 31 of 86, Guidehouse shows peak volumetric demand for methane to drop to only about 2 million m3/hour (a roughly 80% reduction relative to 2020) under the Diversified Scenario that it prefers and to only about 1 million m3/hour (a roughly 90% reduction) under the Electrification Scenario.

A. If peak demand for methane drops that dramatically, would that not mean that significant portions of Enbridge's current methane distribution system could be retired? If not, why not?
B. If Enbridge's response to part A of this question is that some of its methane pipe will be converted to hydrogen and therefore remain useful, please provide the estimated portion of the 16 million m3 of peak demand assumed to be delivered under the Diversified Scenario that it assumes would flow through refurbished methane distribution pipes. Please provide the basis for this assumption.
C. Would Enbridge agree that if the Electrification Scenario came to pass, with a roughly 40% reduction in gas peak demand by 2050, even including hydrogen, that significant portions of the Company's distribution system could and likely would be retired by 2050? If not, why not?

Interrogatory # 1.10-GEC-64

Ex.4, Tab 5, S1, Attachment 2: Please provide the assumed useful lives of each type of asset shown in the table.

Interrogatory # 1.10-GEC-65

Ex.4, Tab 5, S1, Attachment 2, p. 19 of 451: Concentric states that there is uncertainty regarding how climate policy will affect Enbridge's system: "The introduction of hydrogen may have a life lengthening impact on the system if it is determined that hydrogen is a sustainable replacement fuel. The same may be true of renewable natural gas or other low carbon fuels. However, it may also be true that the move from carbon based fuels necessitates a greater electrification, in which case there may be a life shortening impact on some or all of the EGI system."

A. What does Concentric mean by "a life lengthening" impact? Lengthening relative to what? How would the introduction of hydrogen provide such a lengthening impact?
B. In E1/T10/S5, Attachment 2, p. 21 of 86, Guidehouse states that RNG potential in Ontario "represents roughly 4-26% of Ontario's (current) annual natural gas demand." Does Concentric have any reason to dispute the conclusion that RNG, by itself, could not enable Enbridge to continue to serve the vast majority of its current customers' load? If not, why not?
C. Would Concentric agree that even under the most optimistic assumptions, due to technical challenges with both distribution pipe and consumers' gas-burning equipment, no more than 3-6% of energy (10-20% of volume) could be provided to gas customers through hydrogen if blended with methane? If not, why not?
D. Given the limitations on the amount of energy that hydrogen can provide when blended with methane, would Concentric agree that for hydrogen to be the fuel that enables Enbridge's current distribution system assets to remain fully used and useful while meeting future greenhouse gas emission reduction goals, existing distribution pipe would have to be refurbished so that it could carry hydrogen instead of methane? If not, why not?
E. What is Concentric's view for how a transition from methane-burning to hydrogen-burning could occur while using existing methane-carrying distribution pipe? If the pipe has to carry

either methane or hydrogen, wouldn't that mean that there would have to be an essentially immediate switch from one fuel to the other by the neighborhood or community served by the distribution pipe? How would it be possible for the entire neighborhood or community to instantaneously convert? Does Concentric view that as realistically possible? If not, wouldn't there have to be a new hydrogen pipe running parallel to the methane pipe locally and upstream to enable customers to switch over time? If not, why not?

F. Given Concentric's responses to parts "B, C and D" of this question, how could the emergence of hydrogen as a low carbon alternative to fossil methane – even if it turned out to be economically or otherwise preferable to electrification – significantly affect the usefulness of existing methane distribution pipe and other methane related distribution assets? Please explain.

Interrogatory # 1.10-GEC-66

Ex.4, Tab 5, S1, Attachment 2, p. 19 of 451: Regarding the basis for adoption of an Economic Planning Horizon (EPH):

A. Is it Concentric's view that there must be an expectation of retirement of assets in order to justify an EPH? If so, why?
B. If assets are not expected to be retire, but are expected to serve significantly fewer customers, isn't there an inter-generational argument for placing more of the cost recovery burden on current customers (when there are many more of them using an asset) and less on future customers (when there are considerably fewer of them)? If not, why not?
C. If the number of customers expected to use an asset is expected to decline significantly over time, wouldn't an EPH improve inter-generational equity by placing more of the cost recovery burden on early years when there is greater use of the asset? If not, why not?
D. Are there other forms of adjustment to cost recovery, other than an EPH, that Concentric believes would more effectively address the inter-generational equity issues raised in parts "B" and "C" of this question? If so, what are they? Please describe them in detail, with references to how and where they are used today (if any).

Interrogatory # 1.10-GEC-67

Ex.4, Tab 5, S1, Attachment 2, Appendix 1: Please provide the tables in the Appendix in an Excel file, with formulae intact.

Interrogatory # 1.10-GEC-68

Ex.3, Tab 2, S5, Figures 1 through 6:

A. Please provide the actual numeric values for each year in each figure. Please provide them in the Excel files used to generate the graphs.
B. Please provide Enbridge's best estimate of the portion of normalized residential gas consumption per year for each graph that was, is and is forecast to be associated with space heating (i.e., data comparable to what is in each graph, but just for space heating instead of for all gas end uses).