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January 12, 2021

Ontario Energy Board
Attn: Christine E. Long, Registrar

By e-mail and electronic filing

Dear Ms Long

Re: EB-2020-0091 EGI IRP Proposal – GEC IRs to EGI

Please find attached interrogatories from the Green Energy Coalition to Enbridge Gas Inc.

Sincerely,

David Poch

Cc: all parties

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GEC Interrogatories to Enbridge Gas Inc.

1. On p. 9, paragraph 19 of its reply evidence, Enbridge reaffirms its support for "a staged economic evaluation standard for IRPAs…that ultimately resembles a modified version of the OEB's E.B.O. 134 guidelines or a DCF+ test."

    a. Is Enbridge aware of any other jurisdiction that it considers to be seriously considering either non-wires alternatives or non-pipe alternatives that is using a similar economic test? If so, please:
        i. List all such jurisdictions.
        ii. Provide references to document the economic tests that they are using to determine whether or when to proceed with non-wires or non-pipe solutions.
        iii. Describe and document the policy each jurisdiction has taken with respect to non-pipe solutions and/or non-wires solutions.
        iv. Document the number of actual non-pipe and/or non-wires solutions projects each jurisdiction has undertaken in the past decade under the existing cost-effectiveness policy.
    b. Please describe exactly what Enbridge means by a "modified version of the OEB's E.B.O. 134 guidelines".
    c. Please list all costs that would be included in Enbridge's proposed DCF+ test.
    d. Please list all benefits that would be included in Enbridge's proposed DCF+ test.
    e. Would the value of avoided gas commodity purchase resulting from a geotargeted efficiency program be considered a cost, a benefit or not considered at all in Enbridge's proposed DCF+ test? Please explain how and why it would be a cost, benefit or not considered.
    f. Would the value of avoided carbon emission taxes resulting from a geotargeted efficiency program be considered a cost, a benefit or not considered at all in Enbridge's proposed DCF+ test? Please explain how and why it would be a cost, benefit or not considered.
    g. Please provide the calculation formula(e), including all applicable benefits and costs, that would be used to under the DCF+ test proposed by Enbridge.
    h. Has Enbridge ever used the DCF+ test in the past? If so, please provide the two most recent examples, with references that show how the calculations for the test were performed in those examples.
    i. If Enbridge has not previously used the DCF+ test, please provide a hypothetical example of how the calculation for the test would be performed for a geotargeted efficiency program.

2. On p. 10, paragraph 22 of its reply evidence, Enbridge states that the "perspective, drivers and objectives" of ConEd's benefit-cost analysis (BCA) framework for IRP projects "are not entirely applicable to natural gas IRP for Enbridge Gas in Ontario."
    a. What does Enbridge interpret to be the ConEd BCA "perspective"?
    b. What aspects of the ConEd BCA "perspective" are applicable to Enbridge and Ontario?
    c. What aspects of the ConEd BCA "perspective" are not applicable to Enbridge and Ontario? Please explain in detail why they are not applicable.
    d. What does Enbridge interpret to be the "drivers" underpinning the ConEd BCA framework? Please list and describe all such drivers.
    e. Which of the "drivers" underpinning the ConEd BCA framework does Enbridge consider to be applicable in Ontario?
    f. Which of the "drivers" underpinning the ConEd BCA framework does Enbridge consider not applicable in Ontario? Please explain in detail, for each such non-applicable driver identified, why it is not applicable to Enbridge and Ontario.
    g. What does Enbridge interpret to be the "objectives" underpinning the ConEd BCA framework? Please list and describe all such objectives.
    h. Which of the "objectives" underpinning the ConEd BCA framework does Enbridge consider to be applicable in Ontario?
    i. Which of the "objectives" underpinning the ConEd BCA framework does Enbridge consider not applicable in Ontario? Please explain in detail, for each such non-applicable objective identified, why it is not applicable to Enbridge and Ontario.

3. On p. 10, paragraph 23 of its reply evidence, Enbridge states that "Forcing alignment where it may not be appropriate between natural gas planning policy frameworks should be avoided."
    a. Please explain the conditions under which "it may not be appropriate" to have alignment between gas planning frameworks?
    b. Would Enbridge consider it appropriate to use the DCF+ test to assess the merits of investing in renewable natural gas (outside of the context of a non-pipe solution)? If not, why not?

4. On pp. 11-12, paragraph 27 of its reply evidence, Enbridge states that the "The Board should be cautious to not simply accept the principles and magnitudes established for cost/benefits set out in the ConEd BCA as they may not reflect Ontario's market and regulatory realities." Enbridge goes on to identify three key differences: (1) that peaking services are the marginal source of supply for ConEd and that Enbridge "does not rely upon peaking services to comparable extent"; (2) that ConEd is a dual fuel utility; and (3) that Enbridge "owns and operates ex-franchise natural gas transmission and storage assets."

a. Why would different levels of reliance on peaking services affect the cost-effectiveness test (not the inputs to the test, but the test framework itself) used to assess non-pipe alternatives?
b. Why would the fact that Enbridge is a single fuel utility affect the choice of cost-effectiveness test to assess the economic merits of non-pipe alternatives? Is the Company suggesting that the choice of cost-effectiveness test should be a function of what is best for utility shareholders rather than consumers? If not, how is the fact that Enbridge is a single-fuel utility relevant to the question of what is in the best interest of gas ratepayers?
c. Why would the fact that Enbridge owns ex-franchise transmission and storage assets affect the choice of cost-effectiveness test to assess the economic merits of non-pipe alternatives? How is that relevant to what is in the best interest of gas ratepayers?

5. On p. 15, paragraph 32 of its reply evidence, Enbridge states that in the context of "natural gas facilities planning where decisions to advance or delay projects are based on regularly updated growth projections" a planning committee modelled on Vermont' System Planning Committee "may prove overly cumbersome to navigate given the complexities of system design and planning."
    a. Is Enbridge suggesting that the context in which "decisions to advance or delay projects are based on regularly updated growth projections" is different for gas facilities planning than for electric facilities planning? If so, please explain why? Isn't the planning for electric facilities also based on load growth projections that also change over time?
    b. Is Enbridge suggesting that such a committee would be more cumbersome for gas planning than for electric planning? If so, why? What specifically would make it more cumbersome for gas?
    c. What is Enbridge's understanding or assumption regarding the role that the Vermont System Planning Committee plays in developing load forecasts upon which transmission and/or distribution system investment decisions are made?
    d. What is Enbridge's understanding or assumption regarding the role of the Vermont System Planning Committee in delving into the transmission and/or distribution system design?

6. On pp. 17-18, paragraph 37 of its reply evidence, Enbridge states that "screening of virtually all projects identified in the asset management plan…is not reasonably possible without dedicating exponentially increased resources to such work and without incurring substantial incremental administrative costs."
    a. What is Enbridge's best estimate of the annual cost it currently incurs to develop its asset management plan? Please provide a breakdown of those costs by task, including load forecasting, engineering assessments, management and any other relevant cost categories.

b. What is Enbridge's best estimate of the annual cost of project screening that it would incur annually under its proposed screening process? Please describe the basis for the estimate and provide all assumptions and calculations used to develop the estimate. Also, please indicate whether the extent to which this is an additional cost over and above what is provided in response to part "a" of this question for development of the Company's asset management plan.
c. What is Enbridge's best estimate of the annual cost of project screening that it would incur annually if it had to screen "virtually all projects identified in the asset management plan"? Please describe the basis for the estimate and provide all assumptions and calculations used to develop the estimate. Also, please indicate whether the extent to which this is an additional cost over and above what is provided in response to part "a" of this question for development of the Company's asset management plan.
d. How does Enbridge define "screening" in answering these questions? What level of analysis does it assume would be necessary?
e. How would the answer to part "c" of this question change if only projects with a cost greater than each of the following thresholds were screened:
    i. \$2 million
    ii. \$5 million
    iii. \$10 million

7. On p. 18, paragraph 38 of its reply evidence, Enbridge appears to suggest that allowing for consideration of a broader range of potential IRPA projects could affect the nature and severity of outage risks. Why would that be the case? If the Company is forecasting needs 10 years into the future, couldn't the Company consider IRPAs with enough lead time to ensure that such consideration would not affect outage risks (i.e. such that consideration of IRPAs is started early enough to allow for deployment of a supply-side solution if the IRPA proves to be infeasible or uneconomic)? If not, why not?

8. On p. 22, at the end of paragraph 43 of its reply evidence, Enbridge states that volatility in carbon emissions policy since 2016 make it unreasonable to "speculate" on the cost of future carbon emissions and that uncertainty regarding future efficiency programming and the timeline for commercialization of new low carbon technologies make forecasting of carbon emission reductions "even more challenging and unreliable."
    a. Is Enbridge effectively saying that because forecasting the effects of future climate policy is difficult that forecasts of gas infrastructure investment needs should be based solely on current policies – i.e., assuming they will not change? If not, please explain.
    b. Is Enbridge suggesting that analyses of the cost-effectiveness of non-pipe alternatives (relative to gas infrastructure investments) should be based solely on cost impacts under current policies, ignoring entirely – in cost-effectiveness

calculations at least – how future changes in climate policies might alter cost-effectiveness? If not, please explain.

c. How does Enbridge propose to deal with uncertainty in the future cost forecasts of gas commodity, and of alternative fuel costs, and uncertainty of load in its IRPA analyses?

9. On pp. 22-23, paragraph 45 of its reply evidence, Enbridge states that “Despite the establishment of GHG emissions reductions targets by the governments of Ontario and Canada, the ultimate path to achieving such reductions remains uncertain…”
   a. Would Enbridge agree that the only ways to substantially reduce carbon emissions otherwise resulting from consumption of natural gas are to (1) increase efficiency of gas use (i.e. reduce gas consumption); (2) electrify gas end uses (i.e. another way to reduce gas consumption); or (3) to switch from burning of fossil gas to burning of renewable gas, hydrogen or another GHG-neutral fuel? If not, please explain what other options exist and what portion of GHG emissions resulting from current gas consumption in homes and businesses they could potentially eliminate.
   b. In its report, EFG made reference to a 2019 study by ICF for the American Gas Foundation which found that the marginal cost of renewable gas under optimistic assumptions about quantities available would be on the order of $55 (CDN) per Gj – or nearly 20 times the recent Henry Hub spot prices.
      i. Does the Company have any reason to believe that renewable gas could be produced in volumes comparable to current gas consumption levels at costs appreciably lower than $55 per Gj? In responding, please assume that all jurisdictions have the same goals – i.e., Enbridge could only access RNG in proportion to its current gas consumption levels relative to other jurisdictions in Canada and/or North America)?
      ii. If the answer to subpart (i) of this question is yes, at how much lower cost?
      iii. Please provide all references to support conclusions reached in response to this question.
   c. What is Enbridge’s best estimate of both the short-term and long-term price elasticity of demand for natural gas from customers in its service territory? Please specify the periods of time the Company assumes to be “short-term” and “long-term” in providing the answer. Also, please provide the basis for the response.

10. On p. 25, paragraph 48 of its reply evidence, Enbridge states that its system infrastructure “will remain used and useful”, especially when considering “that development of RNG and hydrogen in Ontario and in many other jurisdictions is linked to maintaining high utilization of natural gas systems.”

a. Is Enbridge aware of any studies suggesting that the amount of RNG and/or hydrogen that could be produced in the future in Canada is as large as current Canadian natural gas consumption? Note: Enbridge may provide estimates of North American production potential relative to current North American gas consumption levels if it prefers.
b. If the answer to part "a" of this question is yes, please provide the forecast marginal cost (or market clearing price) for such levels of production.
c. Please provide Enbridge's understanding of what proportion of the gas mix provided to end users can be hydrogen while ensuring the safe operation of current end use technologies, and please provide Enbridge's understanding of any other limiting factors to hydrogen use such as hydrogen permeation in plastic piping, pipeline embrittlement etc.

11. On p. 3 of Appendix B of its reply evidence, Enbridge states that it has analyzed data from its Deep River study for the period between mid-February 2020 through October 2020. No further information is provided.
    a. Please explain how the data were analyzed. For example, what questions was the analysis attempting to address and how was the analysis designed to address those questions.
    b. Please provide the results of the analysis of the period described.

12. With regard to ICF's initial May 2018 report, filed by the Company on July 22, 2020, Exhibit ES-8 on p. ES-29:
    a. Are the costs shown net of other benefits (other than the benefit of deferring a capital expenditure for infrastructure investment) such as the net present value (NPV) of avoided energy costs or avoided carbon taxes?
    b. Please provide the graph net of such other benefits.

13. With regard to ICF's initial May 2018 report, filed by the Company on July 22, 2020, Exhibits ES-9 through ES-12 (pp. ES-29 through ES-33):
    a. What do the costs on the vertical axis represent? What are they the present value of?
    b. In determining where the lines that define whether DSM is cost-effective, what cost-effectiveness test was used? Are other system benefits, such as avoided energy costs and avoided carbon taxes, treated as benefits (or negative costs)?

14. With regard to ICF's initial May 2018 report, filed by the Company on July 22, 2020, on p. ES-34, ICF states that for the amount of peak demand reduction it estimates to be possible would only be enough to defer about 20% of Enbridge's planned facility investments.
    a. Is 20% the fraction of infrastructure projects, infrastructure capacity additions or infrastructure investment costs? If it is 20% of infrastructure projects, please

   provide the percent of both (i) infrastructure capacity additions (which would put more weight on larger projects) and (ii) infrastructure investment costs (which would put more weight on more expensive projects).
   b. Please provide a table with ICF's assumptions regarding the following for each efficiency measure considered:
      i. peak hour m3 savings;
      ii. peak day m3 savings;
      iii. annual m3 savings;
      iv. the ratio of peak hour to annual m3 savings; and
      v. the ratio of peak day to annual m3 savings.
   c. Did ICF assess how much larger the 20% could be if gas demand response measures were also considered? If so, please provide that assessment.

15. With regard to ICF's initial May 2018 report, filed by the Company on July 22, 2020, on p. 38 ICF states that it found "peak hour swing over average peak day consumption" to be 8-9% in New England and 11-13% in northern Illinois.
    a. Please define what is meant by "peak hour swing". What do the percentages represent (what is in the numerator and what is in the denominator of the calculatins)?
    b. Given the results presented, wouldn't a 1.1 multiplier be more appropriate than the 1.2 multiplier being used?
    c. Would use of a 1.1 multiplier instead of a 1.2 multiplier result in a smaller estimate of peak demand reduction required? If not, why not?

16. With regard to ICF's initial May 2018 report, filed by the Company on July 22, 2020, on p. 58 ICF states that "A general residential and commercial load profile for a representative design day was created by scaling the general load profile for a typical cold winter day based on the Gas Utilities' design day HDDs." On p. 66, in Exhibit 16, ICF presents the aggregate residential and commercial load profiles for a typical cold day and representative design day.
    a. When ICF scaled the general load profile to a design day profile, was the scaling linear based on HDDs? If not, how as it performed?
    b. Was the scaling applied only to the space heating portions of residential and commercial loads or to the entire loads? If the latter, please explain why non-space heating loads would need to be scaled up based on HDDs.
    c. How were the utility design day HDDs developed? What were they based on?
    d. What city is the proxy for Enbridge Central region shown in Exhibit 16?

17. With regard to ICF's initial May 2018 report, filed by the Company on July 22, 2020, p. 74, please provide the "hours use factors" developed for each end use and each region.

18. With regard to ICF's initial May 2018 report, filed by the Company on July 22, 2020, Exhibit 92 on p. 137:
    a. Why is the top of the graph at $2500? Is the last 5% of Union and last 10% of Enbridge more expensive than that? If so, please provide a graph that show the actual costs for without a cut-off for the most expensive projects.
    b. Please provide a similar graph where the horizontal axis is expressed in percent of facility expansion investment by dollar of investment (rather than by capacity as in the current graph).
    c. Please provide the underlying data for the graph as presented.

19. With regard to ICF's initial May 2018 report, filed by the Company on July 22, 2020, Exhibit 93 on p. 138:
    a. Please provide a similar graph where the horizontal axis is expressed as percent of facility expansion portfolio investment by dollars of investment (rather than by capacity as in the current graph)
    b. Please provide the underlying data for the graph as presented.

20. Exhibit B, Page 13, Figure 2.1
    The diagram indicates that IRPA screening does not start until 5 years before the need date.

    a) Does Enbridge agree that some DSM programs may take several years to plan and implement and that multiple years of implementation may be needed to achieve the optimal level of reduction?

    b) If so, why would screening not occur during the preceding five year period?

    c) How does Enbridge propose to integrate IRP with the regulatory requirements for a five year gas supply plans and for USPs so that gas supply contracts and other infrastructure investment commitments don't constrain IRPAs and so that gas supply and system plans capture the impact of IRPAs?

21. Exhibit B, Page 14

> "26. Baseline Facility Setting – A second step following identification of a system need is
> to understand the baseline facility that would have been suggested in the absence of
> the IRP process. It is necessary to know what that baseline facility is so that the IRPA(s) can be compared against that solution."

Please explain why the baseline study needs to precede, rather than be simultaneously conducted with, IRPA(s) screening and evaluation?

22. Exh. B, Page 18

> "Consistent with the Guiding Principle of Cost Effectiveness, given that the least cost option is a central driver for selection of either a facility or non-facility solution, the recommended solution should be a lesser cost for customers on-the-whole."

How will competing government policy goals such as GHG goals be addressed if the least cost option is not the optimal alternative for addressing the policy goal?

23. Exhibit B, Page 20

> "Community Expansion & Economic Development – If a project has been driven by policy and related funding to explicitly deliver natural gas into communities to
> help bring heating costs down, then it is not reasonable to conduct an IRP analysis."

Does the company submit that this policy should apply even if an IRPA could lower heating costs even more (for example if building shell improvements and air source heat pumps and electricity could meet heating needs in a new subdivision at a cost lower than new pipeline, gas and gas furnaces)?

24. Exh. B, p. 27

> "Enbridge Gas's commercial and industrial customers have been moving away from interruptible rates for their natural gas volumes as they value certainty of supply over the cost reduction."

Does the company agree that this phenomenon is to some degree a function of the price difference between firm and interruptible? Please provide any analysis of the elasticity of response dependent upon that differential.

25. Exh. B, p. 28

> "61. While all traditional DSM measures positively impact daily peak period demands to
> varying degrees, not all necessarily have a positive impact on hourly peak demand.
> An example includes space heating controls for temperature setback, where the temperature setpoint is reduced overnight resulting in lower heating consumption
> and annual bills. However, at the end of the setback period, building setpoints are
> returned to daytime levels which may result in higher peak hourly flows on the natural gas system. This reality may require a prioritization of the differing goals and
> objectives of DSM and IRP in some instances."

Has the company investigated the potential to control thermostats and offer incentives to obtain staggered return to higher temperature, and thereby mitigate the impact on peak demand (as is done with electric water heater load control programs)? Please provide any study insights the company may have on this option.

26. Exh.B, p. 28

> "62.Contrary to traditional DSM, which is focused on ensuring broad-based participation, ETEE is focused on programs that achieve a high penetration in a specific
> geography to reduce peak period system demands corresponding to an identified
> system constraint/need."

Can an IRPA approach be applicable where the geographic region driving the need is the entire system or a large portion of?

27. Exh.B, p.31

> 70. The project horizon will be set to align with the OEB-approved depreciable life of the
> infrastructure asset(s) to which the IRPA is being compared.

Please clarify the meaning of "project horizon". How will the full life cycle impacts of all alternatives be compared?

28. Exh. B, p. 33

The Company does not seek incentives apart from rate basing. How fully does rate basing address the differential impact of supply versus demand alternatives on the company, its parent company and its shareholders given related upstream business interests?

29. Exh. B, p. 36

The company is not seeking approval of AMI at this time but anticipates federal meter approvals within a year. What cost is anticipated for AMI? Can limited AMI sampling facilitate IRPA analysis?

30. Exhibit B, Page 38

The company proposes monitoring and reporting on IRPA's that are implemented. What reporting will there be of screened out IRPAs? What will be the timing of any such reporting? What mechanism does the company foresee will allow interested parties to review and challenge such determinations in a timely fashion?

31. In EB-2019-0159 19 Exh A. Tab 7, pp. 24-25, Enbridge offers several reasons why it stated that geo-targeting of DSM "is not a reasonable solution". A part of the third

reason is that "…given the need to evaluate the impacts of the IRPA, the program would need to be completed or demonstrating measurable results, at least three years prior to the date at which the additional capacity provided by the infrastructure project was initially proposed to be required" which means that "a successful IRPA would need to be approved and put into motion no less than four years prior to the expected in-service date of the preferred facility alternative".

a) Is this still the company's position? If not, please explain.

b) Can smaller projects have shorter IRPA lead times?

c) What additional lead time is needed for the planning and approval of the IRPA before it is "put in motion"?

d) Please indicate the range of lead times that the company experiences for various types of supply projects.

32. Where the company is found to have failed to propose a lesser cost IRPA on a timely basis, what regulatory consequence is the company proposing?