June 19, 2024

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street
P.O. Box 2319
Toronto, Ontario
M4P 1E4

Dear Ms Marconi

**EB-2024-0111 – Enbridge Gas Inc. – Rebasing Application 2024-2028 – Phase 2**

Please find, attached, interrogatories for Enbridge Gas Inc. from the Consumers Council of Canada regarding the evidence filed in the above-referenced proceeding.

Please feel free to contact me if you have any questions.

Yours truly,

**Julie E. Girvan**

Julie E. Girvan

CC: All parties

**INTERROGATORIES FROM THE CONSUMERS COUNCIL OF CANADA**

**FOR ENBRIDGE GAS INC.**

**RE: EB-2024-0111 – DISTRIBUTION RATES 2024-2028 – PHASE 2**

**1.3-CCC-1**
**Re: Ex. 1/T3/S1**
What is the current status of the Motion to Review Phase I of this proceeding? What is the current status of the appeal to the Divisional Court regarding Phase 1 of this proceeding? Please provide the impact on 2024 revenue requirement and rates and 2025 revenue requirement and rates assuming each of these reviews are successful.

**1.3-CCC-2**
**Re: Ex. 1/T3/S1**
Please explain how the passage of Bill 165 will impact Enbridge Gas's proposals in this proceeding. Please explain how the passage of Bill 165 could potentially impact the approved 2024 revenue requirement and rates. Please explain how the passage of Bill 165 could impact the 2025 revenue requirement and rates.

**1.3-CCC-3**
**Re: Ex. 1/T3/S1**
The evidence indicates that the impact of approvals requested in Phase 2 is that the revenue requirement and 2024 revenue deficiency would increase by $17.8 million. What is the total 2024 (relative to 2023) bill impact for a typical residential sales service customer for both Phase 1 and Phase 2? What is the total 2024 revenue deficiency?

**1.7-CCC-4**
**Re: Ex. 1/T7/S1/p. 4**
The evidence states that in 2019 the main reasons for not meeting the Meter Reading Performance Metric were extreme weather conditions and a key vendor exiting the meter reading market and ending its contract with Enbridge. In addition, Enbridge Gas refers to additional challenges tied to the pandemic including public concerns about the safety of meter reading activities, closed businesses, increased customer sensitivities and access issues which impacted 2021 to 2023:

a) Has Enbridge resolved the vendor issue?

b) For each year 2018-2023 please provide the number of meters that have had 4 or more months of consecutive estimates?

c) For each of those years how many meters have access issues?

d) Please explain the process Enbridge undertakes if the meter cannot be read for 4 consecutive months?

**1.10-CCC-5**
**Re: Ex. 1/T10/S7/p. 2**
Currently the Research and Innovation Fund (RIF) included in the 2023-2025 OEB-approved DSM Plan provides some funding support for technology research, development and pilots for energy conservation. Please provide a list of the initiatives undertaken through the RIF in 2023 and 2024 and the associated costs. What is the budget for 2025 and what are the proposed projects?

**1.10-CCC-6**
**Re: Ex. 1/T10/S7/p. 3**
Enbridge Gas supported collaboration with manufacturers and other stakeholders to advance hybrid heating technology. This supports the development of hybrid heating systems including smart controllers to optimize cost, increase efficiency and reduce GHG emissions. The technology has been fully commercialized and has been installed in 100+ homes in London through a pilot program:

a) Please provide further detail regarding Enbridge Gas's collaboration with manufacturers and other stakeholders regarding hybrid heating.

b) Please provide any reports or studies produced through this initiative.

c) What was the cost of this initiative and how it was funded?

d) How was the pilot program funded?

**1.10-CCC-7**
**Re: Ex. 1/T10/S7/p. 5-8**
Enbridge Gas has set out three areas that it intends to focus on with respect to its proposed ETTF - supply and cost of low-carbon fuel (RNG and hydrogen), end-use technology innovation and carbon capture utilization and storage (CCUS):

a) Please provide any proposed project details and the potential cost of those projects.

b) Please indicate what other specific areas Enbridge Gas may focus on with its ETTF.

c) How did Enbridge Gas determine the $5 million annual amount? Is that $5 million a cap?

d) How was the $.11 per customer/per month determined?

**1.10-CCC-8**

**Re: Ex. 1/T10/S7**
With respect to the proposed ETTF:

a) Will the projects/programs/initiatives funded by the ETTF be subject to a prudence review? If not, why not?

b) Please provide a detailed explanation as to how the projects/programs/initiatives will be selected.

c) Provide a detailed explanation as to how the fund will be managed internally (governance structure).

d) Does Enbridge Gas intend to partner with other entities with respect the ETTF projects/programs/initiatives? If not, why not? If so, please explain what type of collaboration will be undertaken.

e) Has Enbridge Gas sought funding from Natural Resources Canada to pursue this research? If not, why not?

f) Please explain how Enbridge Gas will avoid duplication with respect to the ETTF given research is being undertaken all over the world regarding low-carbon fuel (RNG and hydrogen), end-use technology and CCUS.

g) Did Enbridge Gas consider making the ETTF funding optional for its customers? If not, why not?

**1.10-CCC-9**
**Re: Ex. 1/T10/S7/p. 6**
Enbridge Gas intends to use the ETTF to support initiatives to develop end-use energy efficient technologies not covered by DSM funding. Please explain how Enbridge Gas will distinguish between projects funded through the DSM budgets and ETTF funding.

**1.10-CCC-10**
**Re: Ex. 1/T10/S7/p. 7**
The ETTF will support the research, development demonstration and commercialization of CCUS technologies for industrial and large commercial applications in Ontario. Please explain why residential customers should be required to fund this research.

**1.10-CCC-11**
**Re: Ex. 1/T10/S7/pp. 8-10**
Enbridge Gas refers to the research undertaken by Fortis Energy Inc. (FEI) and SoCalGas. Rather than undertaking its own research, please explain why Enbridge Gas cannot draw upon that research.

**1.13-CCC-12**
**Re: Ex. 1/T13/S2/p. 13**
Please provide a table that shows all new storage assets, with costs greater than Enbridge Gas's materiality threshold, placed in-service since NGEIR. In the table, please provide: (a) the name of the asset; (b) the year that the asset went in-service; (c) the capital cost of the asset; (d) a description of the asset; (e) the category of cost allocation applied (categories 1 to 3 and the sub-categories for option 3 (i.e., replacing and enhancing an asset at end of life or before end of life)); and (f) rationale supporting the category of cost allocation that was applied.

**1.13-CCC-13**
**Re: Ex. 1/T13/S2/p. 13 and Ex. 1/T13/S2/Attachment 1/pp. 10-11**

a) Please further explain how the allocation between utility and non-utility is determined when an asset is replaced at end of life and the replacement asset enhances storage operations. More specifically, how does Enbridge Gas determine the costs of the "replacement" aspect of the asset and the "enhancement" aspect of the asset. If any historic examples exist of this type of replacement, please provide the allocation between utility and non-utility and rationale supporting that allocation.

b) Please describe how Enbridge Gas determines whether a new storage asset enhances storage operations. More specifically, what are the criteria that Enbridge Gas considers in determining whether a new storage asset enhances storage operations as opposed to maintaining those operations. If there are any reports, memos, etc. showing the application of this analysis to new storage assets that have been placed in-service historically, please provide those documents.

**1.13-CCC-14**
**Re: Ex. 1/T13/S2/Attachment 1**
Please advise whether Enbridge Gas, or a consultant on its behalf, has undertaken a full cost allocation study of its storage operation (both utility and non-utility) post-amalgamation that seeks to establish, based on the integrated storage operations in place after amalgamation and the principle of cost causality, which business the costs should be assigned. If yes, please file this study. If not, please explain whether Enbridge Gas has, more generally, looked at other allocation options relative to the proposed allocation methodology for its storage plant (excluding related allocations of general plant, etc.). Please describe those alternative methodologies and any allocators that were considered.

**1.13-CCC-15**
**Re: Ex. 1/T13/S2/Attachment 1/pp. 13-14**

a) Please explain how the legacy EGD administrative buildings and land used in the harmonized general plant allocation approach were selected. Are those all the legacy EGD administrative buildings?

b) Please confirm that the $2.48 million of general plant allocated to the non-utility business for the EGD rate zone includes both administrative buildings/land and vehicles/work equipment.

**1.13-CCC-16**
**Re: Ex. 1/T13/S2/Attachment 1/p. 33 and Ex. 1/T13/S2/Attachment 2/p. 4**

Please advise whether it is possible for Enbridge Gas to separate UFG related to storage operations from transportation operations for the legacy Union rate zones. If yes, please provide an update to Exhibit 1, Tab 13, Schedule 2, Attachment 2, page 4 using only storage-related UFG and activity. If not, please advise whether UFG from transportation assets is likely higher or lower than storage assets.

**1.13-CCC-17**
**Re: Ex. 1/T13/S2/p. 15 and Ex. 1/T13/S2/Attachment 1/pp. 21 and 27-28**

a) Please advise whether the only difference between Table 2 at Exhibit 1, Tab 13, Schedule 2, page 15 and the Summary of Impacts Table at Exhibit 1, Tab 13, Schedule 2, pages 27-28 is the timing of the analysis (2024 vs. 2020). If not, please explain.

b) Please provide a revised version of Table 2 at Exhibit 1, Tab 13, Schedule 2, page 15 that shows the 2024 impacts in a similar format to the Summary of Impacts Table at Exhibit 1, Tab 13, Schedule 2, Attachment 1, pages 27-28 (i.e., showing the changes for each of the legacy rate zones relative to the harmonized methodology).

c) Please confirm that if the legacy Union methodology (i.e., total non-utility storage operations O&M as a percentage of total O&M costs (including O&M support costs)) was unchanged, the storage operation expenses related to administrative and general activities allocated to the non-utility business would be $5.83M (using 2020 figures).

d) Please provide the amount of storage operations expenses related to administrative and general activities that would be allocated to the non-utility business in 2024 if the legacy Union Gas approach ((i.e., total non-utility storage operations O&M as a percentage of total O&M costs (including O&M support costs)) was maintained. Please provide the amount broken down between legacy Union and EGD.

e) Please explain why removing the storage support costs from the formula used to allocate storage operation expenses related to administrative and general activities "enhances accuracy of the storage support allocations."

**1.13-CCC-18**
**Re: Ex. 1/T13/S2/Attachment 2**

a) For any allocators in Attachment 2 that are calculated based on 2022 actuals, please update those schedules to reflect 2023 actuals.

b) Please discuss the rate order adjustments that were applied in Attachment 2 and explain how they were calculated with reference to the rate order.

c) Please provide detailed support for the storage operations allocators (%s) at page 6 of Attachment 2.

d) At Attachment 2, page 10, the non-utility storage asset capital amount appears to be $465M (column A + G). At Attachment 2, page 1, the non-utility storage asset capital amount is $436.8M. Please reconcile and provide the total 2024 net non-utility storage asset capital amount. Please also provide the total 2024 net utility storage asset capital amount (with, and without, Dawn to Corunna-related assets included in the figure) that is comparable to the non-utility storage asset capital amount.

**1.13-CCC-19**
**Re: Ex. 1/T13/S2/pp. 12-13**
Please further explain the planned implementation of the proposal whereby all excess utility storage space that previously existed in the Union rate zones will be used to serve all Enbridge Gas in-franchise customers. More specifically, does the implementation require any changes to costs going back to January 1, 2024, or will this be implemented on a go-forward basis after the final rate order is issued in Phase 2 of the proceeding?

**1.13-CCC-20**
**Re: Ex. 1/T13/S4/p. 10 and Ex. 1/T13/S4/Attachment 1/ pp. 4, 7, 12**

a) Please advise whether similar analysis as Table 1 at Exhibit 1, Tab 13, Schedule 4, page 10 and Table 2 at Exhibit 1, Tab 13, Schedule 4, Attachment 1, p. 4 is available for injection capability. If so, please provide this analysis.

b) While the change in withdrawal capability in the combined model relative to the separate models is immaterial (Tables 1 and 2 referenced in part (a) of this question), the result is counter intuitive. Please explain why there would be a decrease in withdrawal capability in the combined model.

c) Please explain why there is a change in withdrawal capability between Tables 1 and 2 (as referenced in part (a) of this question). More specifically, what would drive any change in the combined model in the absence of a change to the underlying storage assets?

**1.13-CCC-21**
**Re: Ex. 1/T13/S4/Attachment 1/ pp. 7**

a) Enbridge Gas stated that the integration of the storage systems at amalgamation provided it with more flexibility to manage outages required to complete construction and maintenance activities. Does this operational flexibility benefit Enbridge Gas's non-utility business? If so, how is this reflected in the allocation of costs between the utility and non-utility businesses?

b) Please discuss any other benefits (beyond outage flexibility) that were provided by the integration of the Union Gas and EGD storage systems after amalgamation.

**1.13-CCC-22**
**Re: Ex. 1/T13/S4/p. 12 and EB-2022-0086/Exhibit I.SEC.18**
Enbridge Gas stated that the Dawn to Corunna Project replaces existing system capacity and does not provide ability for Enbridge Gas to offer new or expanded market-based services (p. 12).

Enbridge Gas previously stated that due to the integrated nature of the Dawn Hub, and as the Dawn Hub has grown over time, utility and non-utility space and molecules are inherently interconnected and cannot be separated operationally. As such, the Project will serve both utility and non-utility operations (SEC-18).

a) If the Dawn to Corunna Project does not provide Enbridge Gas the ability to offer new or expanded market-based services, how does it serve non-utility operations? Did the underlying compression assets that were replaced by the Dawn to Corunna Project, which were fully allocated to the regulated business at the time of the one-time separation, also serve non-utility operations? Was there any change in the provision of utility and non-utility service between the former operation of the replaced compression assets and the current operation of the Dawn to Corunna Project?

b) Based on the statement that "due to the integrated nature of the Dawn Hub, and as the Dawn Hub has grown over time, utility and non-utility space and molecules are inherently interconnected and cannot be separated operationally", is it Enbridge Gas's view that all its storage assets serve both utility and non-utility operations? Please advise whether Enbridge Gas's response is applicable to both before and after amalgamation or only after amalgamation.

**1.13-CCC-23**
**Re: Ex. 1/T13/S4/p. 19**

a) Please provide a revised version of Table 3 at Exhibit 1, Tab 13, Schedule 4, page 19 that compares the updated facility alternative analysis to the original version of that analysis (with both versions of the analysis excluding indirect overheads).

b) Please discuss, in detail, the various assumptions, updated labour and material costs, etc., that were applied when completing the updated facility alternative analysis in March 2023. Please provide rationale supporting those updated assumptions, costs, etc.

**1.13-CCC-24**
**Re: Ex. 1/T13/S4/p. 17 and Ex. 1/T13/S4/Attachment 2/ p. 6**
The original capital cost of the Dawn to Corunna Project was $250.8M (inclusive of $44.4M of indirect overhead). The current capital cost of the Project is $376.9M (inclusive of $74.3M of indirect overhead). Enbridge Gas is seeking to add to rate base $338.8M related to the Project.

a) With respect to the proposed rate base figure ($338.8M) for the Dawn to Corunna Project, please provide a breakdown between direct capital costs and indirect overheads. Please further explain the indirect overhead amount that is being sought for inclusion in rate base. Please provide the indirect overhead amount that Enbridge Gas has already included in 2024 rate base for the Dawn to Corunna Project in Phase 1 of the proceeding and the indirect overhead amount that it is seeking to add to rate base as part of Phase 2 of the proceeding.

b) Please confirm that $302.6M is the final direct capital cost of the Dawn to Corunna Project and Enbridge Gas will not be seeking to recover additional direct capital costs for the Project in future years. If this is not correct, please explain and provide the forecast total direct capital cost for which Enbridge Gas seeks recovery in rates in 2024 (and any future years).

c) Please confirm that the appropriate comparison of direct capital costs between actual and forecast for the Dawn to Corunna Project is $302.6M and $206.4M (or $96.2M variance).

**1.13-CCC-25**
**Re: Ex. 1/T13/S4/Attachment 2**

a) Please provide a revised version of Table 1 at Exhibit 1, Tab 13, Schedule 4, Attachment 2, page 6 that provides a breakdown of estimate and actual costs using the same categories of costs as set out in EB-2022-0086, Exhibit D, Tab 1, Schedule 1, Table 1.

b) (Page 9) Please advise whether Enbridge Gas considered delaying Dawn to Corunna Project construction due to high market prices for material costs and a tight labour market caused by a number of other large pipeline projects under construction at the same time. If not, please explain.

c) (Page 9) Please provide the timing of the issuance of purchase orders for materials related to station scope, the timing that those materials were needed in the context of the planned project schedule and reconcile with the expected timelines for delivery as was determined by Enbridge Gas's supply chain team.

d) (Pages 9-10) Please discuss whether more advanced ordering of materials for the station scope (similar to what Enbridge Gas did for the pipeline scope) could have avoided the delivery delays experienced.

e) (Pages 10, 18) Please further discuss the NPS42 pipeline removal and how the costs of the incremental activity (i.e., excavation and backfill of pipeline that was 2.5 metres deeper than expected) would cause $8M (page 10) (or $10.7M at page 18) in additional costs. Please also confirm the correct incremental cost of the NPS 42 pipeline removal ($8M, $10.7M or some other amount). Please also explain what options Enbridge Gas considered to mitigate this incremental cost.

f) (Page 14) With respect to the contracting strategy for pipeline construction:

   i. Did the RFP set out the basis for the bid (i.e., base lay plus unit costs)?
   ii. Please further discuss Enbridge Gas's selection of the base lay plus unit price contracting approach and advise why it was selected over other contracting strategies.
   iii. For other recent large pipeline projects completed by Enbridge Gas, please provide the form of contract applied.

g) (Pages 16-18) With respect to facility scope, please further discuss what changed from preliminary to detailed design.

h) (Pages 16-18) With respect to the contracting strategy and negotiations for facility construction:

   i. Did the original RFP set out the basis for the bid (i.e., lump sum)?
   ii. Was the $63.6M average bid from the three shortlisted proponents based on a lump sum contract?
   iii. Were the reduced bids received of $58.8M resulting from the scope change also on the basis of a lump sum contract?
   iv. Was the result of revising the contract structure to reimbursable with fixed fee, a reduction of the $58.8M bid to $58.4M?
   v. Was the remaining reduction from $58.4M to $52.1M a result of further negotiations (or was that also related to the change to contract structure)?
   vi. Please further discuss Enbridge Gas's change to the contract structure from lump sum to reimbursable with fixed fee. More specifically, please explain the costs and benefits of each contract structure in the context of the concerns noted by Enbridge Gas (i.e., awareness of emerging delays to Company-supplied materials and anticipated revisions to drawings that were expected to arrive from Feb. 2023 to June 2023). Please also discuss whether a lump sum contract structure would have protected Enbridge Gas (and its ratepayers) from the cost overruns that were experienced, on an actual basis, with respect to facility construction.

vii. For other recent facility/stations projects completed by Enbridge Gas, please provide the form of contract applied.

**1.16-CCC-26**
**Re: Ex. 1/T16/S1/p. 22**
Enbridge Gas intends to conduct a jurisdictional scan to review how other natural gas utilities present energy comparison data in their marketing materials and identify best practices. The Company will use this information to determine if further changes should be made, and will consider if additional energy technologies, such as, but not limited to electric CCASHPs should be added. When does Enbridge Gas expect to complete this scan? When will it be filed with the OEB?

**1.17-CCC-27**
**Re: Ex. 1/T17/S1/pp. 1-2**
The ALE scope is expected to be initially focussed on Enhanced Distribution Integrity Management Program projects; however, with increased data collection and program maturity this could evolve. Please explain this statement and describe how this could evolve.

**1.17-CCC-28**
**Re: Ex. 1/T17/S1/p. 3**
Please provide all evidence references from Phase 1 regarding the Enhanced Distribution Integrity Management Program.

**1.17-CCC-29**
**Re: Ex. 1/T17/S1/p. 3**
The evidence states that based on initial risk modeling of the DIMP system, EDIMP pipelines account for approximately 7000 km of approximately 32,000 km of steel pipelines within DIMP. Please explain how that number was derived.

**1.17-CCC-30**
**Re: Ex. 1/T17/S1/p. 4**
The evidence indicates that the EDIMP approach proposed is similar to what is currently employed by Enbridge Gas for transmission pipeline assets. Please provide a detailed description regarding the approach to integrity and risk assessments for Enbridge Gas's transmission pipeline assets.

**1.17-CCC-31**
**Re: Ex. 1/T17/S1/p. 7**
The evidence states that as part of the new more in-depth approach to assessing integrity related alternatives to replacement, Enbridge Gas will incorporate energy transition sensitivity analysis, which will examine how long the pipeline is expected to be needed under different energy transition scenarios, and additional statistical modelling of residual risk for repair alternatives. Please fully describe how Enbridge Gas will "incorporate energy transition

sensitivity analysis" when determining whether an asset should be fully replaced or its life extended through targeted repairs.

**1.17-CCC-32**
**Re: Ex. 1/T17/S1/p. 7**
The core component of EDIMP targets condition assessments of higher priority distribution pipelines annually. Following data collection and evaluation, additional effort will be required to assess risks on this subset of distribution pipelines. A risk evaluation will be completed using information collected (including through ILI, operating history, and other surveys) to complement the analysis of the potential threat likelihood and consequences. Please provide an example of this risk evaluation.

**1.17-CCC-33**
**Re: Ex. 1/T17/S1/p. 9**
The ALE analysis of all feasible alternatives will incorporate the financial benefit of risk reductions in comparison to the cost to implement the mitigation actions. Has Enbridge Gas undertaken this type of analysis before? If so, please provide an example of this analysis.

**1.17-CCC-34**
**Re: Ex. 1/T17/S1/p. 10**
Enbridge Gas has set out incremental required labour resources in Table 1 to support the new ALE analysis and associated incremental activities (risk evaluation and assessment). When does Enbridge Gas expect to hire the required FTEs. What is the expected annual cost of these new resources for the rate plan term?

**1.17-CCC-35**
**Re: Ex. 1/T17/S1/p. 10**
The evidence states that the implementation of an ALE alternative could result in costs that are in excess of what is currently included within the annual base Integrity Capital or O&M spend. Non-capital costs for activity related to the new ALE assessment including identification, analysis and implementation will also be recorded in the DIMP Variance Account, which allows for recovery of amounts related to these activities above the amount embedded in rates. Please set out the specific types of costs that will be recorded in the DIMP Variance Account. Please break out all of the components of the $12.5 million of DIMP and EDIMP costs included in base rates.

**1.18-CCC-36**
**Re: Ex. 1/T18/S1**
Please provide the following with respect to Enbridge Sustain:

a) When was Enbridge Sustain created?
b) What was the rationale for structuring it as an unregulated line of business within the utility?

**1.18-CCC-37**
**Re: Ex. 1/T18/S1/pp. 4-5**
The evidence states that Enbridge Sustain indirect costs relate to advisory services from Enbridge Gas employees to provide services like consulting, legal and technical support to design each product. How are these advisory services costed? Where is the revenue accounted for? Was the revenue included in the derivation of the 2024 revenue requirement?

**4.2-CCC-38**
**Re: Ex. 4/T2/S1/Attachment 1**

a) (Page 2) Please explain the costs included in Line 25 – "Storage (Injection) / Withdrawal".

b) (Page 2) Please confirm that the 2024 cost of $25.3M set out in Line 26 reflects 28PJ of market-based storage.

c) (Page 2) Please confirm that the forecast 2024 average cost of market-based storage is $1.11/GJ. If not, please correct.

d) (Page 2) Please provide the total 2024 revenue requirement related to cost-based storage and the unit cost ($/GJ) for cost-based storage that can be compared to the unit cost of market-based storage (as calculated in part (c) of this question).

e) (Page 2) If available, please provide the total 2024 cost (and unit cost) for the incremental 10PJ of storage recommended by ICF for load balancing purposes.

f) (Page 5) Please explain the demand-related load balancing costs at Line 7.

**4.2-CCC-39**
**Re: Ex. 4/T2/S1/Attachment 2**

a) (Page 15) ICF stated, "the three alternate weather cases which are based on actual weather show significant variation in year-to-year price patterns. Since ICF assumes all the other assumptions to be consistent across the four cases, the change in prices at Dawn is strictly driven by different weather assumptions which in turn impact the demand conditions." Please describe these other assumptions that form part of the modeling and discuss the appropriateness of holding these other assumptions constant.

b) (Page 15) At Exhibit 3-3, there are time periods where the Dawn price is highest in the warm weather case. Please explain that result. Similarly, there are time periods where the typical weather case has the highest Dawn price. Please explain that result.

c) (Page 18) At Exhibit 3-4, please discuss the large decrease in supply portfolio costs due to a 5PJ decrement in storage capacity in 2026/2027 in the warm and typical weather scenarios. More generally, please discuss the large variances year-over-year in the impact of the 5PJ decrement in storage capacity across the various weather scenarios.

d) (Page 19) At Exhibit 3-5, please explain the cost of replacing lost deliverability. What services would Enbridge Gas be purchasing that cost approximately $2.15M / year.

e) (Page 19) ICF stated that, “the optimum level of storage capacity was determined by optimizing for the lowest gas supply portfolio cost consistent with existing infrastructure and contractual agreements, and Enbridge Gas supply requirements.” Please confirm that this means that the optimization exercise did not include consideration of Enbridge Gas changing its contractual arrangements for gas supply going forward (i.e., the assumption is that the gas supply portfolio as it exists today, with the exception of storage capacity, is held constant). Provide rationale for that assumption.

f) (Page 20) Exhibit 3-6, the optimization model appears to be suggesting that additional levels of storage are more beneficial in the later years of the term under the typical weather scenario. Please explain why ICF’s recommendation is to add 10PJ of incremental storage capacity in every year over the 5-year term. What is ICF’s view on a strategy whereby Enbridge Gas considers the future need for incremental storage as part of its annual gas supply planning process as opposed to contracting for 10PJ of incremental storage for all five years of the term now.

**4.2-CCC-40**
**Re: EB-2022-0200/Ex. I.4.2-FRPO-82; EB-2023-0111/OEB Staff Report Re: EPCOR 2023 GSP; and NRRI Survey Responses on Long-Term Gas Contracting and Hedging**

In response to a FRPO interrogatory, Enbridge Gas stated that it does not purchase gas at fixed prices for terms greater than 3 months in advance of the transaction date.

Enbridge Gas noted that EGD was directed by the OEB to cease its risk management program in EB-2006-0034 and subsequently in EB-2007-0606 and EB-2007-0615, the OEB ruled that it will disallow the recovery of the costs associated with the risk management programs of EGD and Union.

Prior to this direction from the OEB, Union considered fixed-price transactions extending beyond three months from the transaction date as physical hedges. These transactions formed a portion of the risk management activities conducted with the goal of managing future natural gas market price volatility for ratepayers.

a) Please advise whether it is Enbridge Gas’s position that the above noted OEB decisions require Enbridge Gas to not purchase gas at fixed prices for terms greater than 3 months. If so, please explain. If not, please confirm that it is Enbridge Gas’s own policy to not purchase gas at fixed prices for terms greater than 3 months.

b) Please advise whether Enbridge Gas agrees that other natural gas utilities, both in Ontario and the US, purchase natural gas based on fixed price contracts for terms greater than 3 months.

c) Has Enbridge Gas, or a consultant on its behalf, studied price differentials between longer term fixed price contracting for winter natural gas supply relative to the manner in which Enbridge Gas purchases winter supplies currently. If so, please file that information. As part of this response, please discuss the types of contracts Enbridge Gas enters into for natural gas commodity purchases to be delivered in the winter (index, short-term fixed, etc.) and the proportion of its winter purchases subject to each type of contracting approach.

**4.2-CCC-41**
**Re: Ex. 4/T2/S4/pp. 3, 8, 12 and Ex. 4/2/1/Attachment 2/p. 8**

a) (Page 3) Please confirm that, on a planned basis, 4.8PJ of storage capacity is left empty for the entire year. If this is not correct, please explain.

b) (Page 3) Using the average 2024 market-based storage costs, please provide the annual value of 4.8PJ of storage capacity.

c) (Page 3) Enbridge Gas stated that, "purchasing additional supply to fill this space is unnecessary and will lead to higher gas supply costs since additional winter supply is more expensive than summer supply." Using the ICF seasonal gas price spread (Exhibit 2-3), please provide the incremental cost of filling 4.8PJ of storage capacity with winter gas instead of summer gas and provide the supporting calculation.

d) (Page 8) Please explain why a cross-charge to the non-utility business is applied with respect to operational contingency. More specifically, please explain why operational contingency that supports the non-utility business is not allocated to that business directly (as opposed to using a cross-charge approach) similar to other storage assets.

e) (Page 8) Please provide the cross-charge amount, a description of how it was calculated and rationale supporting that calculation.

f) (Page 12) In the hypothetical scenario that the OEB ordered that no operational contingency is necessary, please advise whether this would result in a 15.6PJ reduction to the proposed 2024 storage capacity. If not, please explain. If yes, please confirm that the 15.6PJ reduction would operate to reduce the proposed 2024 market-based storage capacity from 28PJ to 12.4PJ.

**4.2-CCC-42**
**Re: Ex. 4/T2/S5**

a) (Pages 2-3) Please advise whether the 1.9PJ/d withdrawal capability and 0.8PJ/d injection capability for in-franchise customers from legacy EGD storage operations is the same as it was at the time of NGEIR. Please advise whether this is set out anywhere in the NGEIR proceeding or in subsequent EGD filings to the OEB with respect to EGD's storage operations?

b) (Page 5) Please further explain the connection between dehydration and withdrawal capability. More specifically, please explain why, on the design day, dehydration capacity equals withdrawal capability.

c) (Page 5) Union storage operations provide 1.9PJ/d withdrawal capability and 0.9PJ/d injection capability (with 100PJ of storage space). Similarly, the EGD storage operations provide 1.9PJ/d withdrawal capability and 0.8PJ/d injection capability (with 99.7PJ of storage space). This implies that there is no difference in withdrawal and injection capabilities between the two legacy storage operations. Please explain why there would be no difference in those capabilities between the two legacy storage operations based on factors like the design, location, etc. of the storage operations. In Enbridge Gas's view is withdrawal and injection capability simply a function of storage capacity?

**4.2-CCC-43**
**Re: Ex. 4/T2/S7**

a) (Page 3) Using the most up-to-date QRAM bills for a typical residential customer, please provide the annual residential bill impact (in percentage) on a total bill basis of a \$2/month increase and a \$8/month increase.

b) (Pages 7-8) Enbridge Gas stated, "the maximum bill impact will be incremental to the commodity costs charged to customers excluding the low-carbon energy commodity costs. As the FCC increases…the price differential between conventional natural gas and low-carbon energy will narrow." Please further explain how the maximum bill impact will be calculated. More specifically, is Enbridge Gas including carbon charge differentials between RNG and conventional natural gas as part of the calculation? Please provide an illustrative calculation that highlights how Enbridge Gas will determine that it has reached the maximum bill impact on a forecast basis and should stop procuring RNG. If possible, please provide one illustrative example that excludes any LCVP participation and one example that includes LCVP participation.

c) If available, please provide a high-level estimate of the RNG procured that will be funded through LCVP participation (e.g., 10%, 50%, etc.) at each target percentage of RNG in the gas supply commodity portfolio (i.e., 1%-4%).

**4.2-CCC-44**
**Re: Ex. 4/T2/S8/p. 17**

Enbridge Gas stated that it continues to provide 199.4 PJ of cost-based storage space service to in-franchise customers as established in the NGEIR Decision. Please confirm that Enbridge Gas uses 199.7 PJ of cost-based storage space for planning and ratemaking purposes, and considers 199.7 PJ the actual cap on cost-based storage available to in-franchise customers.

**4.5-CCC-45**
**Re: Ex. 4/T5/S2/ pp. 4, 8**

a) (Page 4) Please confirm that Column C is the estimated amount collected in rates related to site restoration costs and Column D reflects the estimated amount to be spent on site restoration in 2024.

b) (Page 4) Using the estimated SRC amounts in Table 1, please provide the forecast 2024 entries for the SRCVA. As part of this response, please advise whether the credit balance in the account is carried forward and whether there is any interaction with accumulated depreciation. At what point will Enbridge Gas seek disposition of credits amounts recorded in the SRCVA?

c) (Page 4) In the hypothetical scenario that Columns C and D were reversed (i.e., more costs than provision), please provide the forecast 2024 entries for the SRCVA. As part of this response, please advise whether the debit balance in the account is carried forward and advise whether there is any interaction with accumulated depreciation. At what point will Enbridge Gas seek disposition of debit amounts recorded in the SRCVA?

d) Please advise whether Enbridge Gas is seeking any OEB approval of its long-term site restoration costs in the current proceeding. If yes, please explain. If not, please advise whether Enbridge Gas intends to bring forward a proposal with respect to potential changes to site restoration cost recovery at its next rebasing.

**9.1-CCC-46**
**Re: Ex. 9/T1/S3/p. 11**
Enbridge Gas proposes to establish an OEB Directive Deferral Account to record the incremental costs incurred by Enbridge Gas to respond to OEB directives and requirements from this proceeding. The account is proposed to be effective starting in 2024, and to continue through the IR term. Please confirm that in the absence of a Phase 2 to this proceeding Enbridge Gas would have had to fund these initiatives through rates as there would have been no opportunity to seek such an account during the IR term.

**10.1-CCC-47**
**Re: Ex. 10/T1/S1/pp. 5-8**
Enbridge Gas has set out its proposal to implement the OEB's Phase 1 Decision to implement the annual migration of an incremental $50 million in indirect overheads from capital to O&M. Did Enbridge Gas consider other approaches with respect to the implementation of the OEB's

Decision? If so, please explain those approaches and indicate why the proposed approach is the most appropriate.

**10.1-CCC-48**
**Re: Ex. 10/T1/S1/p. 12**
The evidence states that a productivity factor of -1.5% is generally consistent with the productivity offsets that have been approved for U.S. gas distributors. Please provide evidence to support this statement and cite examples of recent regulatory decisions.

**10.1-CCC-49**
**Re: Ex. 10/T1/S1/p. 16**
Enbridge Gas is seeking approval of an ICM as part of its Price Cap IR plan. Enbridge Gas is proposing a modified approach for ICM funding, where it is proposing to combine the "advanced" element of the ACM with ICM. In addition, Enbridge Gas is also proposing a modification to the ICM mechanism in relation to Asset Life Extension projects:

a) How many Leave to Construct ICM projects does Enbridge Gas expect to apply for during the period 2025-2028?
b) What are those projects and what is the expected cost of each of those projects?
c) What is the expected annual amount for Asset Life Extension projects for the period 2025-2028?

**10.1-CCC-50**
**Re: Ex. 10/T1/S1/p. 22**
Did Enbridge gas consider a dead band with respect to its proposal for the additional off-ramp regarding changes in government legislation or policy or a change in OEB policy and requirements? If not, why not? Please describe the regulatory process Enbridge Gas intends to follow with respect to the additional off-ramp.

**10.1-CCC-51**
**Re: Ex. 10/T1/S1/p. 25**
Assuming the OEB approves changes to both the calculation of the Return on Equity and capital structure for Enbridge Gas what is Enbridge Gas's current proposal regarding how those changes would be incorporated into its rates? Does Enbridge Gas expect the OEB panel in the generic proceeding to determine how those changes would be incorporated into its rates or the OEB panel in this proceeding?