<u>1.2-FRPO.1-3</u>

REF: Ex. 1, Tab 2, Schedule 1, pg. 11

Preamble: We would like to understand the rigour of EGI's customer engagement program.

1) Please provide the number of apartment owners that participate in each of the three distinct forms of engagement.

REF: Ex. 1, Tab 2, Schedule 1, pg. 21

2) Has EGI recognized the value of investing in distribution system stations to reduce the pressure drop to serve load as opposed to increasing the pipe size?
   a) Please describe EGI's views on that assessment as part of IRP.
   b) Beyond an IRP pilot, where else has EGI considered this alternative?

REF: Ex. 1, Tab 2, Schedule 1, pg. 21

Preamble: EGI evidence states: *Other savings were achieved in areas where services were scaled back or no longer needed, processes and procedures were streamlined, and where modes of operational interaction were modified. For example, pandemic-related travel restrictions led Enbridge Gas teams to rely more on virtual interactions in 2020 and 2021, and even with the lifting of restrictions, travel budgets have been reduced.*

3) Please provide a description what was learned from this evolution.
   a) How much does EGI expect to save in office costs in 2024 vs 2019?
   b) How much does EGI expect to save in travel costs in 2024 vs 2019?
   c) Where would one find these specific savings identified in the evidence?

<u>1.6-FRPO.4-7</u>

REF: Ex. 1, Tab 6, Schedule 1, Attachment 1, pg.263

Preamble: Under the customer engagement segment for Making Choices – Cut off at Main, the evidence provides a response to the choice of ratepayers bearing the cost: *Enbridge Gas should charge the homeowner $750, and the remainder would be shared* *among all residential customers at an annual cost of $0.25 in 2024 increasing to $1.23 in 2028 for all projected cut-offs.*

4) What factors contribute to the 5 times increase in costs for this activity in a five year period?
   a) What assumptions generate that forecast of cost escalation?

REF: Ex. 1, Tab 6, Schedule 1, Attachment 1, pg. 41-42 & Tab 3, Schedule 1, Attach. 1

Preamble: We would like to understand more about the Related Party Transactions.

5) For each year since 2015, for each of Tidal Energy Marketing Inc & US LLC, please provide the operating revenues and Gas commodity and distribution costs transferred between EGI and those companies.
   a) Please provide the forecast for 2023 and 2024.
   b) Please provide any transactions that were sole-sourced to Tidal including purchases, assignments or other commercial transactions.

6) Please provide each of the actual capital and operating expenditures to Lakeside Performance Gas Services from 2015 to 2022 and the forecasts for 2023 & 2024.
   a) Please provide actual capital and operating expenditures to all other companies who provide meters and meter services for those same periods.
   b) How does EGI assess prevailing market prices?

7) Please provide each of the actual capital and operating expenditures to Ontario Exavac from 2015 to 2022 and the forecasts for 2023 & 2024.
   a) Please provide actual capital and operating expenditures to all other companies who provide meters and meter services for those same periods.
   b) How does EGI assess prevailing market prices?

<u>1.7-FRPO.8-12</u>

REF: Ex. 1, Tab 7. Schedule 1, pg. 10-14

Preamble: Notwithstanding EGI's Assurance Voluntary Compliance dated 20220912, we are concerned about how the meter reading and billing issue has been managed since FRPO first tried to raise this issue with EGI through interrogatories in EB-2021-0148 in late 2021.

8) For each of the four years of 2019, 2020, 2021 and 2022, separately for each rate zone, please provide the cost of:
   a) Meter-reading
   b) Bill production
   c) Customer accounting/receivables.

9) For each of the four years of 2019, 2020, 2021 and 2022, please provide the number of bills produced by:
   a) Electronic meter read (instrument on meter through phone line)
   b) Manual meter read with handle held equipment
   c) Estimated meter read
   d) No read.

10) Please provide the monthly reports submitted to the Board as a result of this Voluntary Compliance.

11) Please confirm that some Direct Purchase contracts have been required to balance their deliveries and consumption even though the balance was in question due to missing or estimated reads.
   a) How has EGI handled those situations?
   b) Will that approach be maintained going forward until ongoing billing issues have resolved?
   c) If not, why not?

12) Please confirm that some Direct Purchase contracts were not in a position to make balancing transactions due to uncertainty caused by missing or estimated reads.
   a) If a customer transacts to balance their contract and the consumption is subsequently changed through a billing adjustment resulting in out of tolerance balances, how has EGI handled those balancing fees.
   b) Will that approach be maintained going forward until ongoing billing issues have resolved? If not, why not?

<u>1.11-FRPO.13-15</u>

REF: Ex. 1, Tab 11, Schedule 1

13) Please provide the Transportation and Storage index of customers reports for January 2014, January 2019 and January 2023.
14) Please provide the contract details for all new Transportation and Storage service agreements that EGI expects to go into effect between January 2023 and December 2028.

15) Please provide the contract details for all existing Transportation and Storage service agreements that EGI expects will terminate, or be modified, between January 2023 and December 2028.

1.12-FRPO.16-26

REF: Ex. 1, Tab 12, Schedule 1, Attachment 1, pg. 4

Preamble: In the EB-2015-0179: Community Expansion Proposal - Post Construction Financial Report, the evidence shows a 65% contractor cost overage variance for the Milverton project. The variance explanation states: *Contract Costs were higher than estimated due to challenges with hydrostatic testing, dewatering and odourization of the steel main as well as challenges with the running line. The Milverton portion of the Project also required additional contracted resources to accomodate a compressed timeline.*

We would like to understand more about this project and the cost consequences.

16) Who bears the cost of this project overage?
   a) What was driving the compressed timeline?
      i) What was the original commitment to be completed? To whom was this commitment made?
      ii) When was the project completed?
   b) Please confirm that the hydrostatic testing, dewatering and odourization of the steel main was part of the final stages of the project.
      i) In the pre-construction estimate from the contractor, what was the expected cost of these components of completion?
      ii) What was the final original invoiced amount from the contractor prior to financial approval?
      iii) What amount was paid by Union to the contractor?
      iv) Please file all emails and other correspondence associated with this part of the project, its challenges and its eventual costs.

17) For each of the projects identified in this Post Construction Report, please provide:
   a) The long term forecast of the number of customers, filed with the Board as part of the application(s), to be added by year and customer type (i.e., residential, commercial, industrial).
   b) The actual number of customers added and customer type from year of installation until 2022.

REF: Ex. 1, Tab 12, Schedule 1, Attachment 1, pg. 15

Preamble: In the EB-2017-0180: 2018 Sudbury Replacement Project - Post Construction Financial Report, the evidence shows an $18.2M or 31% overage variance. The variance explanation states: *Construction and Labour costs were higher than estimated due to permit conditions and challenges during pipeline installation. Environmental permitting was required (in several areas along the right of way) to be completed earlier than planned, requiring additional resources and overtime to meet permit conditions. Environmentally sensitive areas along the right of way were larger than expected resulting in the use of several thousand additional access mats. Construction and Installation costs also exceeded the Project Estimate due to unexpected rocky conditions. Further, safety processes and procedures required to work within Vale property were more costly than anticipated.*

We would like to understand more about this project and the cost consequences.

18) Please provide the original estimate of construction and labour costs filed with the application.
    a) In the pre-construction estimate from the contractor, what was the expected cost of contractor costs and days to complete?
    b) What was the final original invoiced amount from the contractor prior to financial approval?
    c) What amount was paid by Union to the contractor?
    d) Please file all emails and other correspondence associated with this part of the project, its challenges and its eventual costs.

REF: Ex. 1, Tab 12, Schedule 1, Attachment 2, pg. 1-3

Preamble: In the Scugog Island – Community Expansion Project (EB-2017-0261) - Post Construction Financial Report on Costs and Variances, the evidence shows a 177% overage variance for Labour and Construction Costs. The description of the variance points to environmental and highway authority’s requirements for the project which changed and delayed the proposed construction.

We would like to understand more about this project and the cost consequences.

19) Who bears the cost of this project overage?
    a) What was driving the requirement to do winter construction?
    b) What was the original commitment to be completed? To whom was this commitment made?
    c) When was the project completed?

d) When the method of construction was determined to require horizontal directional drilling and other components, what held EGI back from starting the project the following October after the nesting season?

20) For the Scugog Island project, please provide:

a) The long term forecast of the number of customers, filed with the Board as part of the application(s), to be added by year and customer type (i.e., residential, commercial, industrial)
b) The actual number of customers added by and customer type from year of installation until 2022.

21) For each year since the approval of the New Community Expansion Projects in EB-2016-0004, please provide the PI of each project completed in that year and the Rolling Project Portfolio at the end of the year.

REF: Ex. 1, Tab 12, Schedule 1, Attachment 2, pg. 6-8

Preamble: In the Dow-Moore Well Drilling Project, the evidence states: *The two new horizontal wells will form part of Enbridge's regulated storage operations and the abandoned and converted wells are a part of regulated storage assets…The capital costs will be capitalized and included in rate base…There is not anticipated to be a rate impact to Enbridge customers from the drilling of the wells until the costs are included in rate base in 2024.*

We would like to understand more about this construction and the capabilities of the pools.

22) Please summarize the purpose of drilling two new horizontal wells.

a) Please provide the total storage space and deliverability of the Dow-Moore pool in:
    i) 2007
    ii) 2022
b) Please provide a description and costs associated with any additional capital work on this pool, besides the horizontal wells, in this project since 2007.

REF: Ex. 1, Tab 12, Schedule 1, Attachment 2, pg. 30

Preamble: In the POST CONSTRUCTION FINANCIAL REPORT - Owen Sound Reinforcement Project - EB-2019-0183, the evidence states that the Total Project had a 2% overage variance which include a 29% overage variance in Indirect Overheads.

We would like to understand more about how the Indirect Overhead variance occurred.

23) For these incremental costs, were more people hired in the company?
   a) If so, how many at what costs?
   b) After accounting for those costs and keeping all other factors constant, what was the net reduction in actual O&M expenses to the company?

REF: Ex. 1, Tab 12, Schedule 1, Attachments 1 & 2

Preamble: We would like to understand the role of project and cost management for the projects included in these attachments.

24) Please list all of the projects whose contractor cost was greater than 30% over the Board approved cost.
   a) For each project, please provide how much of the total cost over-run was borne by the contractor. Asked differently, please provide the respective contractor's final invoice amount and what was disallowed through negotiation with project management.
   b) For each of these projects, were any changes made to contractual arrangement with the respective contractors to incent lower costs?

25) In general, what incentives does:
   a) the contractor have to control costs on a project?
      i) Please explain the consequences of not controlling the costs.
   b) the company have to control costs on a project?
      i) Please explain the consequences of not controlling the costs.

26) Please file the Post Construction Financial Report for the London Lines (EB-2020-0192)
   a) If not available, please file a breakdown of the budgeted costs and actual costs to this point.
   b) Is EGI applying for the inclusion of the London Lines in rate base?
      i) If so, what evidence does the Board have to ascertain the appropriateness of inclusion of the London Lines cost?
   c) Please file EB-2020-0181 Exhibit I.FRPO.28.

   i) Please explain the Value Measures associated with this project.
   ii) In context of those measures, please explain the priority placed on the project.
d) Prior to the project being undertaken, the feed from the Byron Transmission Station to the London Lines was removed. Please file all internal communications (emails, requisitions, studies) that pertain to the removal of that feed to the London Lines.

1.13-FRPO.27-28

REF: Ex. 1, Tab 13, Schedule 1

Preamble: On page 3, EGI evidence states: *Enbridge Gas is proposing to introduce an Enhanced DIMP to improve the understanding of the condition of distribution pipeline assets. This program would ensure that Enbridge Gas has the ability to thoroughly assess the condition of these assets to allow appropriate action to be taken, whether that is maintenance work or replacement of the pipeline.*

We would like to understand better EGI's proposal to establish an Enhanced Distribution Integrity Management Program.

27) Please confirm that EGI is required to have a Distribution Integrity Management Program as required by the Technical Standards and Safety Authority (TSSA)
   a) Please file the TSSA's Pipeline Compliance Standard Summary Checklist - Pipeline Owners and Operators.
   b) Please file the CSA Z662 Annex N.
   c) Please confirm that the CSA Z662 and the TSSA regulations define minimum standards.

Preamble: On page 4, EGI evidence states: *As part of the Enhanced DIMP, Enbridge Gas has identified a sub-set of the DIMP pipelines that could benefit from a more extensive condition monitoring program. Given available monitoring technique limitations as well as the cost/benefit assumptions, the recommendation is to include distribution pipeline assets in the Enhanced DIMP that are:*
a) Operating at pressures above 700 kPa;
b) NPS 6 or greater;
c) Over 1 km in length; and
d) Greater than 50 years old.

28) Please confirm that establishing standards that are above minimum Code standards is within the discretion of the gas utility.
   a) Using the filed documents from the TSSA and CSA code, please identify where the utility did not previously have the discretion to apply a *more extensive condition monitoring program* prior to the St. Laurent decision.
   b) Given that the TSSA and CSA code expect that condition monitoring to ensure safe and reliable operation is a core responsibility of the utility, please explain why EGI requires the proposed deferral account to invest the appropriate level of resources to this core responsibility.

<u>2.5-FRPO.29-35</u>

REF: Ex. 2, Tab 5, Schedule 1, pg. 5-6 & Table 1

Preamble: EGI evidence states: *Through consultation with internal stakeholders and in consideration of the asset class strategies, management of risk, ability to complete mandatory work, Customer Engagement Survey results and total in-service capital spend, a constraint of $1.2 billion with a 2% escalation factor was recommended. Enbridge Gas is not able to complete mandatory work or support the demand for growth at a constraint below $1.2 billion.*

We would like to understand more about this assessment.

29) Please file the study, summary report or memo from which the $1.2B constraint was determined.
   a) If there is no documentation of an assessment that lead to a $1.2B value, please provide a summary of how that value was determined.

30) Please file the study, summary report or memo from which EGI determined that $1.2B constraint was not sufficient to complete mandatory work or support demand.
   a) If there is no documentation of an assessment that lead to a $1.2B value, please provide a summary of how EGI determined that $1.2B was not sufficient.
   b) If not contained in the study, report or memo, please provide a list of all projects or programs over $20M that are mandatory or growth related.
      i) For each project or program, please describe the impact of deferring one or more years.
      ii) For program, please provide the 2018 to 2022 spending.

REF: Ex. 2, Tab 5, Schedule 1, pg. 5

Preamble: EGI evidence states: *Capital projects that supported the integration of EGD and Union were excluded from the respective AMP's and the revenue requirement for these projects was funded through synergy savings during the deferred rebasing term.*

31) Is EGI applying to put those integration funded projects into rate base? Please explain fully.

REF: Ex. 2, Tab 5, Schedule 3, pg. 7 and Table 3
& EB-2012-0451 FRPO Final Submissions 20131116
& Enbridge Gas Distribution Inc. ("Enbridge") – GTA Project Ontario Energy Board ("Board") Docket No. EB-2012-0451 - Conditions of Approval – Post Construction Financial Report

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

In the second reference on pages 12-13, FRPO submitted: *The need to reduce the pressure in these lines is important but the weight of evidence would suggest that it is not urgent. Of all of the projects in this combined proceeding, we would view Segment B as being least critical from a strict time point of view. One factor that was insufficiently canvassed in this proceeding is the inflationary effect that would be caused if all of the proposed projects were being constructed simultaneously. Both utilities have evidenced that these are the biggest projects that they have undertaken. Combining these projects along with TCPL's King's North would put enormous pressure on the costs to deliver these projects, especially the cost of skilled labour. In our view, one possible constructive recommendation at this juncture would be a condition added to Segment B that indicates if the quoted prices for construction more than 20% above the estimated costs for the project that the company re-tender for the next year of construction possibly phasing in a two to three year construction project to spread the scarce resources. This approach would allow a staged reduction of pressure in the lines reaching their desired goal over a multiple year period.*

Page 7 of the Post Construction Report referenced above indicates that the majority of over-run was a result of bid prices relative to estimate.

32) When the contractor bids came in significantly higher than the estimates filed with Board in the Leave-to-Construct proceeding, did Enbridge Gas Distribution (EGD) consider phasing construction and deferring Segment B to move construction away from this peak period?
   a) If not, why not?
      i) Did EGD inform the Board to seek acceptability of these escalated costs?
      ii) Please file EGD's criteria at the time on acceptability of escalated costs on major projects.
   b) If phasing was considered, please file documentation of the considerations involved in the potential deferral.

33) Has EGI performed an analysis of what the actual savings in gas supply costs have been up until the end of 2022?
   a) If so, please file.

34) For the WAMS project, please file documentation of the quantification of actual realized benefits from the implementation of the project.

REF: Ex. 2, Tab 5, Schedule 3, pg.13

35) Please file a revised version of Table 6 breaking down the respective expenditures by utility rate zones of EGD and Union.

<u>2.6-FRPO.36-59</u>

REF: Ex. 2, Tab 6, Schedule 1, pg. 11

Preamble: EGI evidence states: *The objectives of Enbridge Gas's ETP are to 1) support an orderly energy transition in Ontario by identifying and proposing safe bet actions, defined as actions that will be needed in the future regardless of the pathway to net-zero that is taken…*

We would like to understand in the context of *an orderly transition* how EGI/EGD has allocated the capital that were funding EGD's Site Restoration Costs.

36) Please provide a reference to the evidence in this proceeding that speaks to how the merged utility will ensure proper funding if and when assets need to be retired more quickly than they are being added to.
   a) Has EGI considered segregated funding similar to the model the TCPL/TCE has developed?

REF: Ex. 2, Tab 6, Schedule 1, pg. 14-15

37) Please file the ICF Forecast: Natural Gas – Strategic, Q2 2022 Outlook referenced in this section.

38) In figure 1 on page 15, please reproduce the Figure while adding the Henry Hub forward market prices to the graph from the same data as the Q2 2022 Outlook.

REF: Ex. 2, Tab 6, Schedule 1, pg. 42-43

Preamble: EGI evidence states: *Examples of opportunities anticipated over the 2024 to 2028 IR term include organizational alignment within Enbridge Gas's regional construction teams, productivity gains in alliance partner agreements and real estate optimization.*

39) What productivity has been seen in alliance partner agreements through 10 years of rebasing?
   a) Please file documentation of productivity gains over the 10 year period.
   b) What incentives are in place for pipeline contractors to minimize costs?

REF: Ex. 2, Tab 6, Schedule 1, pg. 51-52

40) In the Process for Connecting Residential Infill Customers, the evidence states that there is no minimum load.
   a) For an average 20m service, would a pool heater generate sufficient margin to achieve a PI of 1.0? Please explain.

REF: Ex. 2, Tab 6, Schedule 2, pg. 32

Preamble: The integrity management section speaks strongly to identify risks to determine *fitness for continued service.* We would like to understand more about what EGI has done to examine the opportunity to enhance aging assets to create fitness to, not only continue service, but also, to extend service life.

41) Please provide a list of projects that EGI has undertaken to consider investments in the betterment of assets to extend service life.
   a) Please provide the amount that EGI has invested in these projects.

REF: Ex. 2, Tab 6, Schedule 2, pg. 32

Preamble: EGI evidence states: *Create alignment in the organization by establishing an asset management policy, strategies and objectives that link to company strategic priorities.*

We would like to understand better the strategic priorities which figure prominently in this section.

42) Are there any EGI strategic priorities linked to return on investment, explicitly or implicitly?
   a) Are there any Enbridge Inc. strategic priorities linked to return on investment, explicitly or implicitly?

43) Are there any management incentives tied to an increase of capital installation completion?
   a) Are there any management incentives tied to reducing actual capital invested?

REF: Ex. 2, Tab 6, Schedule 2, pg. 45-47 & Appendix A

And https://www.copperleaf.com/blog/innovation-copperleaf-how-the-value-model-library-helps-organizations-make-better-decisions/

and EB-2020-0181 EGI_APPL_ PHASE 2_20201015 Section 7 Appendix: *EGI Asset Management Plan 2021-2025 Appendix*

Preamble: Pg. 45-46 of the EGI evidence states: *EGI aims to have a clear framework for asset investment decision-making that balances risk, cost and performance throughout the asset life cycle. The strategies to achieve this are:*
• *Optimize portfolio based on asset management principles.*
• *Improve decision-making through transparency, clear accountabilities, stakeholder engagement and use of a common tool.*
• *Extend asset management decision-making to further include operations and maintenance activities to ensure that optimal asset value is attained over each asset's life.*

• *Improve decision-making through an understanding of the asset context and timing considerations for outages.*

The evidence goes on to describe the role of the Copperleaf C55 in this process. From the Copperleaf reference, the company's description is: *Once we've identified all the value measures, we then construct a series of "value models" that enable the organization to quantify the value of every proposed investment. These value models can come "off the shelf" from the library or can be based on models that already exist but tweaked to accommodate a particular client's needs. We can also develop models from scratch for clients with extremely unique requirements.*

At the end of this process, the Copperleaf Value Framework provides an enterprise-wide view of all the value measures that support the organization's goals—as well as the models used to calculate how individual investments or projects contribute to those measures. The result is that everyone can understand the rationale behind each decision, driving consensus and linking day-to-day decisions with business strategy. This helps create a culture of transparency, accountability, and trust."

Table 4.1-3 on page 47 presents EGI's descriptions of the Value Measures.

Appendix A presents the Investment Summary reports but not the Value Function Measures.

44) For the completed ICM projects for which EGI is seeking inclusion in rate base in 2024, please provide the entire "Investment Summary Report" including Value Function Measures.

45) Please provide the entire "Investment Summary Report" including the Value Function Measures for the Projects identified in Appendix A.

REF: Ex. 2, Tab 6, Schedule 2, pg. 66

Preamble: Figure 5.1-2 graphically presents the Customer Growth Forecast. We would like to understand the scale of the Ottawa growth relative to other regional areas.

46) Please provide EGI's perspective on why the Ottawa region is more than twice other regions.

REF: Ex. 2, Tab 6, Schedule 2, pg. 68

Preamble: Figures 5.1-4 and 5.1-5 graphically represent the growth forecast by customer type for the respective rate zones. We would like to understand the substantial difference in the forecast of multi-family growth between the EGD zone at 4% and the Union zone at 29%.

47) Please provide EGI's perspective on the drivers behind the difference in growth of the multi-family growth forecasts.

REF: Ex. 2, Tab 6, Schedule 2, pg. 85

Preamble: EGI evidence states: *The risks associated with these pipelines are mitigated through the TIMP by identifying and remediating (as required) pipeline defects prior to failure. These inspections allow EGI to determine whether a pipeline is fit for service and provide quantitative data that can be used to forecast maintenance activities, inform models and the expected life of the asset. Understanding pipeline condition allows EGI to make informed decisions on service life* ***extensions***. (emphasis added)

48) Please provide a summary of some significant initiatives being undertaken and the number and cost of resources being invested in developing approaches to generate service life extensions.

REF: Ex. 2, Tab 6, Schedule 2, pg. 97-98

Preamble: Figure 5.2-28 and 5.2-29 graphically present the Historical Steel Main Corrosion Leaks (Post-1970) for EGD and Union respectively. We would like to understand how initiatives throughout the deferred rebasing period have contributed to improvements.

49) Please update and re-present the figures to include data from 2020, 2021 and 2022.
   a) Please provide a list of initiatives and incremental investment in the remediation of these systems to reduce the number of leaks.

Preamble: Figure 5.2-30 graphically present the Post-1970 Steel Mains Corrosion Leak Projections (2020 to 2040) for EGD and Union respectively. We would like to understand how initiatives throughout the deferred rebasing period have contributed to improvements.

50) Please update and re-present the figures including data from 2020, 2021 and 2022 including any adjustments to future years as a result of recent data.
   a) If there are no adjustments to future years, please explain why not.
   b) What investments are planned to be made to reduce the number of leaks in the 2024-2029 period?

REF: Ex. 2, Tab 6, Schedule 2, pg. 114

Preamble EGI evidence on the Martin Grove Rd project states: *Depth of cover (DOC) has been identified as a significant concern for these main segments as identified by 2018 and 2019 DOC surveys that found over 52% of the survey locations had DOC less than 90 cm, with 77 survey locations measuring less than 60 cm of cover.*

We would like to understand EGI's approach to consideration of risk management for these types of projects.

51) Using both total number and percentages, please disaggregate the results of the survey into categories that define the surface condition (e.g., asphalt, cement, median cover (including grass), sidewalk, grass on the boundaries of the road allowance, etc.).
   a) How does EGI distinguish the risks associated with the respective surface conditions? Please explain fully.

REF: Ex. 2, Tab 6, Schedule 2, pg. 115-117 & Appendix A, pg. 9

Preamble: EGI evidence on p. 115 states: *Erin Township investment is replacing Aldyl-A PE pipe that is prone to slow crack growth (SCG) due to its known material and manufacturing flaws (large inner bore spherulitic structures and surface oxidation of the inner surface). The presence of stress intensification factors (for example, rock, service connections, and bend radius) can accelerate SCG and lead to loss of containment. Erin Township has seen several loss of containment Aldyl-A crack failures (see Figure 5.2-59), due to rocky soil where rocks create a stressor on the pipe that accelerates the cracking failures. This is a multi-year investment that will replace about 13.2 km of Aldyl-A mains and service pipe. See Appendix A, Pg. 9 for additional detail on this investment.*

We are trying to reconcile this above evidence with that found in Section 5.2.3.6.5.1 while striving to seek the additional information in the Appendix A reference.

52) Please provide additional information on the number of loss of containment failures by providing the number and year of these failures.
   a) Please provide a map that shows the location of these failures along the subject pipeline.
   b) Using Section 5.2.3.6.5.1, please provide some form of threshold or metrics that triggers EGI to shift from responding to loss of containment periodically to initiatinge the process of replacement.
   c) Please correct the reference or provide the evidence that was intended in the Appendix A reference as page 9 refers to the Wabuno Compressor.

Preamble: Figure 5.2-61: Copper (AMP-Fittings) Riser Leak Projection – Reactive vs. Proactive Strategy shows the projections going forward from 2020 to 2060.

53) Please add the last 10 years of actual data on leaks and proactive replacements.

REF: Ex. 2, Tab 6, Schedule 2, pg. 128

Preamble: EGI evidence states: *Under-pressure Event: Under-pressure at a station can lead to loss of service for customers. This is of particular concern for industrial customers, who expect a reliable natural gas supply for processes, and other customers for heating needs during colder periods. Stations approaching design capacity could experience under-pressure situations, loss of service to customers and station equipment performing beyond recommended operating limits.*

54) Please confirm that a gate station that is approaching its design capacity or performing beyond recommended operating limits can create a risk of loss of service.
   a) In the last 10 years, please list the gate stations that contained a large, dry gas filter that have been rebuilt and their respective age at time of replacement.
   b) Please provide a list of the ten oldest remaining gate stations whose large dry gas filter has not been replaced.

REF: Ex. 2, Tab 6, Schedule 2, pg. 133

Preamble: EGI evidence states: *The system station replacement programs are informed by condition surveys to reduce the risk of any issues observed. For example, boot-style regulators, which use a combination of a flexible boot element and gas pressure to regulate downstream flow and pressure, may be more susceptible to higher failure rates due to their design. This type of regulator station design has demonstrated susceptibility to failures caused by debris, particulates, hydrates and* *sulfur deposits. Adopting a new design philosophy to use alternative regulator models or including filtration minimizes the potential for downstream overpressure events.*

55) How many over-pressure events have occurred at distribution stations in each of the last 5 years?
   a) How many of those incidents have been attributed to the flexible boot (i.e., not other components such the pilot being plugged).

REF: Ex. 2, Tab 6, Schedule 2, pg. 140-141

Preamble: EGI evidence states: *A subset of the Customer Stations population are called Pressure Factor Metering (PFM) stations. Many PFMs in the Union rate zones do not have built-in bypasses or provisions for a bypass which does not allow for standard operation inspections to be performed. These installations are operationally inspected every five years and during this period the total population will be assessed. Those that require a rebuild will be identified within the next five-year window. The mitigation of this configuration will be completed before the next inspection within the following five-year window.*

56) Please explain why portable bypass equipment could not be used to allow for an inspection every 5 years versus rebuilding the station to incorporate a bypass.

REF: Ex. 2, Tab 6, Schedule 2, pg. 141

Preamble: EGI evidence states: *The new CNG Station Strategy involves the acquisition of new large and mobile Natural Gas Transportation (NGT) and small Vehicle Refueling Appliances (VRA) station customers and the installation of the necessary fueling equipment. The timing and scope for new NGT assets are based on the likelihood of contract confirmation and historical station installations of similar size and scope.The renewal and upgrade of existing stations to ensure the continued safe, efficient, and reliable operations of all NGT stations.*
This approach includes the following activities:
- *Small NGT Stations (VRAs)*
- *Proactively replacing/rebuilding VRA compressors (~35 units per year)*
- *Proactively replacing/rebuilding remote panels (~33 units per year)*
- *Reactively replacing gas detectors as needed (~5 units per year)*

57) How were the original station installations funded?
   a) How much has been spent in each of the last 10 years on CNG stations?
   b) How much is EGI expecting to spend each year to follow this approach?

c) Is EGI expecting to recover these costs from ratepayers?
d) What has changed that necessitates increasing expenditures?

REF: Ex. 2, Tab 6, Schedule 2, pg. 153

Preamble: Table 5.2.5-4 presents Meter Replacements (Historical) while Figures 5.2-78 and 5.2-79 provide Typical Causes of Non-Program Meter Exchanges. We would like to understand more about the rate zone differences seen in the data.

58) Please provide the factors which result in the variability in EGD Rate Zone Program Meter Exchanges over the years and why that variability is not seen in the Union Rate Zone.
   a) Did EGD and Union purchase the same type of meters in the period of reporting?
   b) Please explain the difference in the respective percentages for the criteria of "damaged"?

REF: Ex. 2, Tab 6, Schedule 2, pg. 153

Preamble: EGI evidence states: *Customer-owned systems, as described in Section 5.2.5.1, may consist of:*
• Customer-owned piping refers to the gas piping or tubing downstream of the meter outlet tailpiece and extending from the meter outlet to customer appliances.
• Service jumpers refer to a specific type of customer-owned pipe installed from an outside meter to inside the building, entering the building below ground.

59) Under what circumstances does the CSA B149 Code allow for pipe to enter a building below ground?
   a) How does EGI ensure that Service Jumpers are sealed properly?

2.7-FRPO.60-67

REF: Ex. 2, Tab 7, Schedule 1, pg. 5

Preamble: EGI evidence states: *On design day, the flow of gas is easterly from Dawn towards Parkway. Additional supply is received at Kirkwall and Parkway which reduces the need for pipeline infrastructure and diversifies gas supply pathways.*

60) Can Bundled-T customers deliver at Kirkwall and deliver a prorated PDCI relative to their impact on making these facilities smaller?
   a) If not, why not?
   b) If so, what would need to be done to undertake this change? Please explain fully.

REF: Ex. 2, Tab 7, Schedule 1, pg. 7

Preamble: EGI evidence states: *Would EGI consider a delivery commitment credit available at Ojibway structured in a similar way to the PDCI as an IRPA? If not, why not.*

155) Can Bundled-T customers deliver at Ojibway and deliver a prorated PDCI relative to their impact on making these facilities smaller?
a) If not, why not?
b) If so, what would need to be done to undertake this change? Please explain fully

REF: Ex. 2, Tab 7, Schedule 1, pg. 13

Preamble: EGI evidence states: *Ex-franchise customers include customers in Québec, the Maritime provinces and the Midwestern and Northeastern United States, other Ontario based natural gas utilities, unbundled in-franchise customers and* ***Union South rate zone in-franchise customers transporting their PDO. (emphasis added).***

61) Please identify the transportation contracts that are currently being used, either by the customer or by a third party, to meet an in-franchise customer's Parkway Delivery Obligation.
   a) Please specify what amount of PDO deliveries are meet by Dawn deliveries coupled with M12 capacity.

REF: Ex. 2, Tab 7, Schedule 1, pg. 17

Preamble: EGI evidence states: *Enbridge Gas's transmission systems have operating criteria to ensure safe and reliable operation. Each transmission system:*
a) Cannot operate above its MOP;
b) Must operate above minimum contractual delivery pressures contained in customer contracts;
c) Must operate above minimum suction pressure at compressor stations;
d) Must operate within the aero assembly flow and head boundary conditions at the compressor stations;

62) Please explain these compressor stations terms and how they affect design.
   a) Please provide the aero assembly flow and head boundary conditions for the compressors on the Dawn Parkway system (including Dawn transmission and Parkway).

REF: Ex. 2, Tab 7, Sch. 1, pg. 22-26, Table 1 & EB-2019-0159 Ex. A, Tab 7, pg 17 & Sch 1

63) For Table 1, please break out the total Design Day Demand numbers in column (b) of Table 1 to show the projected design day demands for 2023/2024 through 2031/2032 for each of the following categories: (1) Total Union South Rate Zone, (2) Total Union North Rate Zone, (3) Total EGD Rate Zone, (4) Ex-Franchise Dawn-to-Kirkwall, (5) Ex-Franchise Dawn-to-Parkway, (6) Ex-Franchise Kirkwall-to-Parkway.

64) From EB-2019-0159, please update Table 7-2 with annualized actuals and extend the information through January 1, 2024.
   a) Please provide the contract details for the Dawn to Parkway capacity of 12,334 GJ that was turned back in 2019/2020, and the 88,728 GJ that was turned back in 2020/21.

65) From EB-2019-0159 Schedule 1, please provide the same Dawn Parkway System Demands schematic with data for Winter 2023/2024.

66) For the winter of 2023/24, please provide schematics in the same format for the:
   a) Panhandle System (with & without the proposed expansion of EB-2022-0157)
   b) Sarnia Industrial Line System
   c) In each of the schematic, please identify the constraints that define the capacity and any surplus or shortage at those locations.

REF: Ex. 2, Tab 7, Schedule 1

67) Please file a business case for any North American Gas only utility that shows a positive NPV for AMI.

<u>3.2-FRPO.68-72</u>

REF: Ex. 3, Tab 2, Schedule 1, Attachments

Preamble: For all of the attachments, the data provided includes gas supply revenues and costs which tends to obscure the information on trends in delivery revenues and costs.

68) Please provide the data in these attachments net of gas supply revenues and costs.

REF: Ex. 3, Tab 2, Schedule 2, page 29

Preamble: EGI's Guidehouse Report states: *In addition to this a majority of the comparator utilities (unlike EGI) are also subject to some mechanism that provides bilateral protection to customers and utilities from the natural volatility of weather (HDD) around its projected mean value. Such mechanisms are not always symmetric: under-collection variance recovery is capped for half of the utilities where the mechanism exists. No such mechanism is in place for EGI.*

69) Please summarize the mechanisms for the half of the utilities where the variance recovery is capped exists including:
   a) Parameters
   b) Off-setting or mitigating attributes of their respective rate constructs

REF: Ex. 3, Tab 2, Schedule 5

Preamble: On pg. 4, EGI evidence states: *Unavailability of the historical meter reading heating degree days for the Union rate zones made using the calendarized data an optimal choice for Enbridge Gas.*

70) What period was unavailable?
   a) What percentage meter readings were missing?

b) What does calendarized mean and how was the missing data determined to make it calendarized?

REF: Ex. 3, Tab 2, Schedule 5, Attachment 1, pg.2 & 5

Preamble: EGI's evidence states: *To determine an appropriate harmonized base temperature, Enbridge Gas conducted an analysis similar to what was provided to the OEB when the current base temperatures for EGD were approved. Based on the analysis summarized in Table 1, a 15°C is found to be the most appropriate base temperature for calculating degree days. This conclusion is reached based on regression analysis and the regression results from that analysis. The results used to reach this conclusion include R-squared, Mean Absolute Percent Error (MAPE) and Root Mean Square Error (RMSE). As explained in the sections below high R-squared values and lower MAPE and RMSE values support this proposal. Enbridge Gas proposes to use 15°C in the calculation of its HDD starting in 2024.*

It is not clear to the reader what analysis was done. We would like to understand this analysis undertaken beyond the summary outputs provided.

71) Please describe the analysis undertaken including:
   a) What is the determinant variable whose error is being measured?
   b) If it is an assessment of forecasted consumption versus actual given a defined base temperature, please describe:
      i) Was baseload used for the analysis for all evaluations? Please explain why or why not.
      ii) If baseload was not used, how were the summer months treated for resulting error assessment?
   c) If this error assessment is focused on a different measurable, please describe in detail.
      i) Please provide the evidentiary reference to the previous evidence and approval by the Board.
   d) Please explain specifically how this analysis and the regression that was done can *determine the precise base temperature below which natural gas is required for heating purposes* (pg. 5).

REF: Ex. 3, Tab 2, Schedule 5, Attachment 2

Preamble: EGI's evidence states: *Enbridge Gas used the standard deviation of the year-over-year percentage change in normalized average use as the stability measure. A lower standard deviation indicates a more stable normalization method.*

72) Is the EGI inference of this statement that a more stable result from a methodology makes it more appropriate for use? Please explain.
   a) Was a baseload adjustment used in this methodology?
   b) If not, please provide in tabular fashion, using a 15 degree base temperature, what does the model generate as an intercept for 0 Heating Degree Days for each of the proposed weather zones for forecasted monthly consumption?
      i) In that same table, please provide the average of July and August consumptions for each of those zones.

<u>3.4-FRPO.73-78</u>

REF: Ex. 3, Tab 4, Schedule 1

Preamble: Pg. 4 of the Schedule states: *As of 2024, the Dawn Parkway System will no longer be considered upstream to any Enbridge Gas customers and therefore, the benefit of the use of the Dawn Parkway System to transact these exchange sales, will not be shared 90/10 in the proposed Upstream Transportation Optimization deferral account.*

73) If EGI uses these assets, alone or in combination with other EGI transmission assets, how will the margins be tracked?
   a) Is it EGI's proposal to share these margins 90/10 in favour of ratepayers?

Preamble: Pg. 7 of the schedule states: *If circumstances arise where upstream transportation assets are not fully required (i.e. temporarily surplus), then those assets can be made available to generate revenue through exchanges.*

74) Using the various Vector transportation contracts moving gas from the Chicago area (incl. Alliance & Northern Border) to Dawn that EGI held from at Nov. 1, 2021, for each month during the period of Nov. 1, 2021 to Oct. 31, 2022, please populate the following table:

PATH	Month	Contracted Capacity	Gas Delivered using Contracted Path	Amount Assigned to Third Party	Gas Delivered at Dawn by Assignee	Capacity Cost	Net Revenue from Assignee
		(TJ/day)	(TJ)	(% Cap)	(TJ)	(C$)	(C$)

75) Using the definition of "temporarily surplus" approved by the Board in EB-2013-0046, please describe how these respective contracts meet that definition.

76) In a separate table, please provide the paths that were either contracted new or extended by 2021 decisions of the Gas Supply department.

77) Please provide the landed cost study that underpinned the 2021 decisions to either enter into a new contract or extend an existing contract.

78) Please provide the forward market prices for basis differential of each Chicago and Dawn for the one year terms starting Nov. 1st of each year for the 5 years starting Nov. 1/21.

<u>3.6-FRPO.79-81</u>

REF: Ex. 3, Tab 6, Schedule 1

Preamble: We would like to understand the impact of EGI's Heat Value proposals.

EGI evidence on pg. 6-7 state: *The AHV alternatives reviewed focused on two evaluation criteria: 1) simplify/harmonize and 2) minimize impact to system users and customers. To further assist with the evaluation, six years of historical annual heat values (2016 to 2021) were reviewed to understand the historical heat value changes and relationships between the EGD (ECDA and EEDA), Union North, and Union South rate zones.*

79) For the purposes of AHV, please clarify all of the uses of the AHV figures (e.g., converting volumetric forecasts for Direct Purchase DCQ, converting forecast system gas volumetric data into gas supply forecasts for the plan, etc.).

80) Please file the review study that evaluated the alternatives.
   a) In Excel format, please file the monthly data from the respective locations that the data was drawn from.
      i) Please also include data for 2022.
      ii) If a map showing the locations is not in the study, please provide a map locating the heat value measurement points.
      iii) If the data did not include the monthly Heat Values of the TCPL system for the following locations, please include in the Excel file:
         (1) Spruce
         (2) EGD EDA
         (3) EGD CDA
         (4) UNION CDA

(5) UNION EDA (please confirm precisely where measured)
(6) Kirkwall (please confirm precisely where measured)

b) In tabular form, please provide a summary of the range of differences in heat value in comparing the Union North values that been used by Union Rate Zone over the 2016-2022 period.
c) If not included in the study, please present in a table the summary results that considered seasonal effects of varying monthly heat values across the measurement points.
d) Please file EGI's most recent reconciliation of heat value done for the purposes of ensuring appropriate recovery of gas costs,
e) Please provide EGI's views on the efficacy of a quarterly adjusted heat value at the time of QRAM.
    i) Please provide data in support of those views.
f) Please provide EGI's views on the efficacy of quarterly or annual heat value reconciliations for these quarterly figures for the purposes of recovering the difference between forecast and actual.

Preamble: EGI evidence on pg. 10 states: *For existing Union South T-Service and Rate M7 customers, Enbridge Gas proposes to eliminate third-party energy sampling and install three chromatographs in required locations to work in alignment with existing live daily gas chromatograph data. The Union South T-Service and Rate M7 customers will be mapped to a live chromatograph, or blend of live chromatographs to calculate the MHV. This heat value proposal simplifies the process for the customer and Enbridge Gas, eliminating the reliance on a third-party process, the two-month data lag, and the annual reconciliation process, as well as maintaining required data integrity.*

81) Please provide a map that shows the locations in which third-party sampling has been done historically.
    a) Please provide the monthly data from those locations for the same 2016-2022 period.
    b) On the same map, please specify where EGI intends to *install three chromatographs in required locations.*
        i) Please describe how those locations have been chosen.

4.2-FRPO.82-147

REF: Ex. 4, Tab 2, Schedule 1, pg. 7-8

Preamble: EGI evidence states: *The final step in the planning process is the execution of the Gas Supply Plan which includes the evaluation of transportation, supply, and storage options. This evaluation must have a long-term strategic focus, taking into consideration future growth and asset requirements by analyzing each decision as part of a balanced portfolio which adheres to the guiding principles. Enbridge Gas will execute on its Gas Supply Plan by contracting for any assets required, then implementing a layered approach to procuring supply at various points. Supply purchase decisions are made regularly throughout the year to allow Enbridge Gas to continuously update its supply purchase plan to account for changes in market conditions and customer demands.*

82) How many months in advance can EGI fix the price on purchases of monthly gas deliveries of gas at Dawn?
   a) What is the source of this limitation? Please provide a specific reference to any Board decision that limits these advanced, fixed-priced purchases either directly or indirectly.
   b) If indirectly, please provide the internal policy document that EGI relies upon to limit the duration of time allowable to fix the price of future deliveries at Dawn.
   c) If not defined in any internal policy document or Board decision, please provide the practice that EGI maintains to limit the maximum duration in which it can fix a natural gas contract for a monthly delivery of gas at Dawn in a future period.
   d) If not clear from above answers, please provide specific rationale for the limitation.

83) What is the maximum duration ahead of the initiation of a storage contract that EGI will agree to contracting terms for storage services?
   a) What is the maximum term of any storage contract EGI/Union has signed in the last 10 years to support in-franchise deliveries?
   b) Consistent with the above questions on fixing gas purchase contracts, please provide:
      i) What is the source of this limitation? Please provide a specific reference to any Board decision that limits the timing of this advanced contracting and term of the storage contract either directly or indirectly.
      ii) If indirectly, please provide the internal policy document that EGI relies upon to limit the duration of time allowable to contract for storage and term of the storage contract.
      iii) If not defined in any internal policy document or Board decision, please provide the practice that EGI maintains to limit the maximum duration it can

enter into a storage contract in advance of the start of said storage contract, as well as the duration of the term of the storage contract.
iv) If not clear from above answers, please provide specific rationale for the limitation.

Preamble: We are interested in understanding the load balancing option to purchase delivered gas at Dawn during the winter period that has its price fixed 9 months or longer ahead of the start of those deliveries. To do this, we are asking for data on the spread between summer (Apr.-Oct.) and winter (Nov.- Mar.) strips of gas as a measure.

84) For each of the last 5 gas winters, starting with 2018/19 going to 2022/23, using forward market prices at Dawn (providing reference to published source) on the dates provided , complete the following table using 2018/19 as an example:

DATE	APR-OCT PRICE	NOV-MAR PRICE	DIFFERENCE
FEB. 1/18			
NOV. 1/17			
MAY 1/17			
NOV. 1/16			

For clarity, for each year used, please start the provision of data with Feb. 1st of that year and prior dates, 12, 18 and 24 months prior to Nov. 1st.

REF: Ex. 4, Tab 2, Schedule 1, pg. 8

Preamble: EGI evidence states: *With OEB approval, beginning in 2024, Enbridge Gas will create and operationalize the Gas Supply Plan as one integrated utility without separate rate zones for EGD, Union North and Union South.*

85)Does EGI propose to have only one gas supply rate, including commodity and transportation, for the entire EGI franchise?
a) If not, please explain.
b) If so, please provide the transportation rates, on a C$/GJ basis for:
   i) Empress to Thunder Bay (WDA)
   ii) Empress to Sarnia (SWDA)
   iii) Empress to Toronto (EGD CDA)
   iv) Empress to Ottawa (EGD EDA)
   v) Please confirm that the above transportation rates are expected to remain relatively constant through 2026.
c) How will the variance in the above transportation rates be handled in establishing a single gas supply rate, including transport? Please explain the

company's views on the equity of this approach for customers from a historic perspective.

REF: Ex. 4, Tab 2, Schedule 1, pg. 10, Table 1

86) Please explain the drivers that generate the difference in supply for the Bridge Year and Test Year for each of the respective supply sources:
   a) Ontario / Dawn
   b) Unsecured
   c) Western Canadian Sedimentary Basin

87) Please define Unsecured and describe how Unsecured would be differentiated from Ontario/Dawn.

REF: Ex. 4, Tab 2, Schedule 1, pg. 10-11, Table 2 & Attachment 1

and EB-2022-0072 EGI Gas Supply Update, page 57, Table 25

Preamble: Table 2 shows an almost tripling of Vector's contribution to Demand between the Bridge Year and Test Year.

88) Please reconcile these amounts with those provided in the Gas Supply update Table 25 referenced above.
   a) Using forward market pricing from a published source (e.g. Platts), please provide the landed cost price at Dawn for 2023 and 2024 for gas delivered on Vector and gas sourced at Dawn.
   b) Please provide justification for the almost tripling of commitment to this path.
   c) Please explain why the transportation costs for Vector in Attachment 1, pg. 1 are very flat between 2023 and 2024.
   d) For the now current winter of 2022/23, what percentage of transportation contracts on the Vector path are assigned to a third party?
   e) If these current contracts contribute to in-franchise demand, please describe how the contracts are deemed to be temporarily surplus aligned with the definition approved by the Board in EB-2013-0146 Decision and Order, pg. 5.

REF: Ex. 4, Tab 2, Schedule 1, pg. 15 & Table 3

Preamble: EGI evidence states: *Finally, the capacity contracted with 2193914 Canada Limited is required to move gas to Brampton and the Greater Toronto Area on the design day*.

We would like to understand more about this pipeline.

89) Please confirm this pipeline is owned by Enbridge Gas Distribution Limited.
   a) Is this a separate pipeline or is it somehow a fraction of the pipeline that was built between Parkway and Albion as a result of approvals in the GTA Reinforcement proceeding EB-2012-0451?
      i) If this pipeline is the one described in a), what is the total capacity of that pipeline?
      ii) Does the pipeline deliver capacity to the GTA as part of the EGD rate zone?
   b) Is this capacity regulated by the OEB or NEB?
      i) If the NEB, please describe why.
   c) What is the purpose of segmenting ownership of this pipeline under an affiliate company?
      i) Are decisions in regard to capacity allocation, preventative maintenance, etc., under the direct control of EGI?
      ii) Is the capacity in EGI rate base or is there a transfer price in the Enbridge Inc. organization to recover costs?

REF: Ex. 4, Tab 2, Schedule 1, pg. 17 and EB-2022-0086 Exhibit JT1.4

Preamble: EGI evidence states: *EGD managed operational contingency requirements through cost-based storage injection and withdrawal targets rather than procuring incremental storage space for operational contingency purposes. Effective 2024, Enbridge Gas plans to adopt the approach of managing operational contingency using cost-based storage inventory targets and has incorporated the storage space and molecule requirements provided at Exhibit 4, Tab 2, Schedule 4 in the Gas Supply Plan.*

We are interested in the evolution of the storage owned and operated by EGD prior to amalgamation and the evolution of storage utilization once the companies were merged, or, perhaps, initiated prior to when notice was given the Board of the request to merge.

90) The following questions are specific to EGD-owned storage:
   a) Please confirm or correct that:
      i) At the time of the 2013 rebasing of rates, of the 99.4 PJ of storage held for in-franchise customers, EGD targeted a February 28th minimum inventory level of 18.5 PJ to provide late season deliverability.
      ii) After re-evaluating its approach to purchasing after the winter of 2013/14, EGD increased its targeted February 28th minimum inventory level to 43.5 PJ.
   b) Beyond adjusting Month End Storage Balances in QRAM and other applications, did EGD first provide evidence of this change in gas supply strategy to adjust targeted February 28th inventory to the Board to seek approval?
      i) If so, please specify the evidentiary reference and any approvals received from the Board.

ii) In a table, for each winter starting in 2012/13, please provide the amount of market-based storage under contract to EGD to use to meet in-franchise needs.
iii) In a table, for that same period, for each winter, please provide the amount of non-utility storage that EGD had available for customers (both ex-franchise and any incremental purchases for in-franchise customers).

c) Prior to the Enbridge Inc. (EI) purchase of Spectra, did EGD allocate any of the costs associated with increasing the Feb. 28th inventory including incremental storage purchases to the non-utility storage?
   i) If not, why not?
d) After EI purchased Spectra, was there any change to the targeted Feb. 28th minimum inventory in the EGD storage assets?
   i) If so, what was the change and how was it determined and evidenced to the Board?
e) In a scenario where the Feb. 28th inventory had dropped to a much lower level, say 18.5PJ, would EGI be able to meet all in-franchise peak day deliverability from Dawn and all non-utility storage firm contractual commitments?
   i) Please explain fully.
   ii) Are any of the costs associated with the 43.5 PJ minimum threshold allocated to the non-utility including:
      (1) Cost of storage space?
      (2) Cost of inventory?
      (3) Cost of additional market-based storage to facilitate an increase in minimum inventory to 43.5 PJ on Feb. 28th?
      (4) If not, why not?
f) Please provide the first completed analysis of the integration of Union Gas' Dawn assets with those of EGD providing storage.
g) Please provide the completed Injection Withdrawal schedule for EGD Storage assets for the year prior to integration with Dawn.
h) Please provide the completed Injection Withdrawal schedule for the assets previously held by EGD Storage for the year after integration with Dawn.
i) Please provide the completed Injection Withdrawal schedule for the assets previously held by EGD Storage for the winter of 2022/23.

Preamble: For the purposes of comparison, we would like to understand how Union Gas approached the issue.

91) In a table, starting the winter of 2012/13, for each winter, please provide the amount of non-utility storage that Union Gas Ltd. had available for customers (both ex-franchise and any incremental purchases for in-franchise customers).

92) What was the targeted minimum February 28th balance for the Union Gas in-franchise storage for each of the winters starting with 2012/13?

REF: Ex. 4, Tab 2, Schedule 1, pg. 18-20

Preamble: EGI evidence states: *The total storage space of 217.7 PJ was determined using the aggregate excess calculation of 202.7 PJ and t-service storage requirement of 15 PJ.*

93) Please specify the existing rate classes that are under the “t-service storage.”
   a) What distinguishes the characteristics of the t-service storage from the remaining storage?
   b) Please provide the existing allocation of space and deliverability to these rate classes and a description of the methodology.
      i) If this determination of the existing allocation and associated deliverability is available in evidence, please provide the specific reference.
   c) Please provide the allocation to these rate classes and a description of the methodology for the 2024 proposed allocation.
   d) Please provide the existing allocation of the 202.7 PJ and associated deliverability to each of the existing rate classes.

94) How much total space and market-based storage did EGI hold for the winter of 2022/23?
   a) Please confirm or clarify that this amount of market-based storage would be included in the total space.

Preamble: Footnote 12 on the bottom of page 19 states: *As noted above, effective January 1, 2024, Enbridge Gas will utilize cost-based storage injection and withdrawal targets rather than procuring incremental storage space for operational contingency purposes.*

95) Please provide the monthly storage targets in tabular form for the following scenarios:
   a) Please provide the Union Rate Zone monthly storage targets throughout the year for the years 2019-2022.
   b) Please provide the proposed Union Rate Zone monthly storage targets for 2024-2025.
   c) Please provide the Enbridge Rate Zone monthly storage targets throughout the year for the years 2019-2022.

d) Please provide the proposed Enbridge Rate Zone monthly storage targets for 2024-2025.

96) Please reconcile the above referenced statement with the evidence on Operational Contingency in Ex. 4, Tab 2, Schedule 4.

REF: Ex. 4, Tab 2, Schedule 1, pg. 21 & Attachment 1, pg. 2, line 25

Preamble: EGI evidence states: *Storage (injection)/withdrawal costs are comprised of the cost associated with the net injections to/withdrawals from storage to balance the difference between annual gas supply and annual demand.*

97) Please provide a comprehensive description and a numeric example of how storage injection and storage withdrawal costs are determined.

a) For clarity, please provide an example using M1 in the Union Rate Zone.

98) Please describe and quantify the drivers of the variation in storage injection/withdrawal costs that result in significant year over year swings in actual cost and an overall reduction of 96% between 2017 and 2021, as shown in Attachment 1.

a) Please ensure the description refers also to the components of cost provided for the determination requested above.

REF: Ex. 4, Tab 2, Schedule 1, p.22-23

Preamble: EGI evidence states: *On an actual basis, load balancing requirements may be higher than planned due to customer demand being above normal. Enbridge Gas will manage these unplanned load balancing requirements for system customers only. Unplanned load balancing requirements may be met through storage withdrawals, incremental supply purchases, and third-party services. Bundled DP customers will be responsible for their own unplanned load balancing requirements through their obligation to meet their checkpoints at the end of February and September each year.*

99) Historically, has EGI bought additional load balancing gas if storage level does not project to meet target even if system supply balance is on track?

a) In this application, is EGI proposing any change to its approach with this application? If so, please explain.

REF: Ex. 4, Tab 2, Schedule 1, p.26

Preamble: EGI evidence states: *Enbridge Gas plans to use purchases at Dawn to meet planned load balancing requirements in the winter months.*

We would like to understand more about these planned purchases for load balancing requirements. Please understand that the following questions relate to load balancing purchases as opposed to specific commodity purchases associated with system gas only requirements. If system gas needs are included in these planned purchases, please differentiate the system gas purchases in the answers.

100) For these load balancing requirements, planned purchases at Dawn, please provide:
   a) How much will EGI plan to purchase for:
      i) For each month for the Union Rate Zone
      ii) For each month for the Enbridge Rate Zone
   b) How long in advance will the price of those purchases be fixed?
   c) What is the maximum period of time in advance of delivery that EGI will fix the price?
   d) Please provide the specific Board reference ordering this limitation.
      i) Whether there is a specific Board order or not, please provide the internal EGI policy that guides the purchase strategy.
   e) What are EGI's views on the opportunity to stabilize its load balancing costs through Dawn deliveries of gas for which the price is fixed months or a year or more in advance?
      i) What are EGI's views on whether the Board would need to approve or order such an approach or is it in the discretion of a utility with a balanced load balancing portfolio?

REF: Ex. 4, Tab 2, Schedule 1, Attachment 1

Preamble: We would like to understand the derivation of the provided costs.

101) For Supply Costs on page 1, please provide the unit costs used for each of the Bridge Year and the Test Year.
   a) What is the forecast date when the data was drawn?
   b) Were the forecasted receipt point costs sourced from the forward market or provided by ICF or another study?
      i) If the forward market, please provide an extract of the prices used and the publishing source.

c) If ICF provided the data, please provide the forward market prices from a published source produced for the same date that ICF produced their forecast.
d) On lines 12 and 13, the costs for TCPL Transport increase significantly. Given that TCPL's tolls are virtually fixed or perhaps decreasing, what causes the increase for both lines going from 2023 to 2024?

102) On page 3, please explain why, although about 20% of the system supply source originates in the WCSB, there are no costs for TCPL from Empress for system gas.
   a) How can the transportation costs be separated from supply costs for the purposes of setting the gas supply rate?

103) On page 4, EGI provides the storage costs on line 2. Please provide a disaggregation of the costs associated with cost-based storage and market based storage:
   a) In tabular form, please provide the unit demand costs associated with:
      i) Space demand costs
      ii) Deliverability (withdrawal and injection demand costs)
      iii) Fuel unit costs
      iv) Other costs, if any, not included above.
   b) Specific to deliverability, please describe how the deliverability demand costs are derived.
      i) Please provide the working Excel sheet that provides the components of this calculation complete with evidentiary references.
   c) Please provide the annual actual measures of space and deliverability for both cost based and market based storage for the 2018-2022 period by Rate zone.

104) Page 5 provides the load balancing deliveries. To be able to see these deliveries in context, please provide the monthly deliveries to Dawn for system supply.
   a) Please explain how the profile of load balancing supplies is developed.
   b) Please ensure the explanation provides reasoning for zero supplies for a high demand month such as March.

105) Page 6, line 8 presents the Customer Supplied Fuel.
   a) How does EGI calculate the amount of fuel forecasted for Customer Supplied Fuel?
   b) How does EGI determine the actual amount of fuel used by Customers who supply their own fuel?
   c) Please file the most recent reconciliation of Customer Supplied Fuel between forecasted and actual.
   d) Please confirm that some market-based storage contracts have no fuel requirements for injection or withdrawal.

i) How is that fuel provided? Please describe who is accountable for that fuel and explain how the company ensures that there are appropriate allocations that shield in-franchise customers from this cost obligation.

REF: Ex. 4, Tab 2, Schedule 1, Attachment 2

106) Please provide the source of the pricing data for each of the individual columns.

REF: Ex. 4, Tab 2, Schedule 1, Attachment 6

107) Please provide the commercial arrangements and instructions associated with the ICF study in Attachment 6 including but not limited to:

a) The RFP, if any.
   i) If there was no RFP, the over-arching contract under which this study was undertaken.
b) The terms of engagement.
   i) If no specific terms of engagement, the documentation from the company to ICF detailing the analysis that was being requested.
c) All written documentation between EGI and ICF associated with feedback, edits, revisions and/or further instructions.
d) Specifically, did the company ask ICF to consider and analyze the opportunity to purchase winter month deliveries at a price that was fixed months, or longer in advance as part of the load-balancing portfolio?
   i) If so, please file that analysis.
   ii) If not, why not?
e) Please provide the final cost to generate the study.
   i) Please provide the cost to generate the report for filing with the EGI evidence package.
   ii) Please provide the hourly rate(s) of ICF to provide:
      (1) Assistance with Interrogatory Responses
      (2) Testimony at the Technical Conference
      (3) Testimony at the Oral Hearing

Preamble: On pg. 5 of the Attachment, the study states: *We also tested each weather scenario using a lower storage capacity gas supply scenario developed with 5 PJ less storage than indicated by the Aggregate Excess methodology to evaluate the impacts of replacing storage capacity with winter purchases at Dawn on supply portfolio costs.*

108) For the purposes of determining cost impacts, when was it assumed that the price of the gas would be fixed:
   a) On the day needed, week ahead of the forecasted need, month ahead of the forecasted need, etc.
   b) What is the maximum amount of time that EGI fixes the price for the delivery of gas:
      i) At Dawn?
      ii) At other supply receipt points?
   c) When the study uses the term "supply portfolio costs," please explain the presumed allocation of costs for these winter purchases (e.g., landed gas cost, separation of costs between commodity and other accounts, etc.).

Preamble: The ICF study is dated October 12, 2002 and Exhibit 2-10 is entitled ICF's April 2022 Base Case.

109) For Exhibit 2-10, please distinguish the date of the graph to distinguish between prices that are historical and what are forecast.

110) For Exhibit 4-1, please:
   a) Confirm that the HDD's are on the basis of degrees Fahrenheit.
   b) Explain how the location is derived (i.e., specific city, geographical area, population or consumption weighted, etc.).

Preamble: Appendix E asserts: *Contribution of Storage Deliverability to Design Day Capacity Requirements. Storage deliverability provides a direct contribution to design day system capacity requirements. In the Gas Supply Planning model analysis, changes in storage capacity are addressed through incremental purchases at Dawn. However, purchases at Dawn do not have the degree of reliability provided by storage deliverability. The different in reliability provides significant economic benefit to the use of incremental storage that is not captured in the Gas Supply Planning model analysis.*

111) During the last major North American test of the gas pipeline systems ability to deliver (known as Super Storm URI during Feb. 13-17, 2021), did EGI experience any failures to deliver of its contracted Dawn deliveries that were not authorized to divert?

a) If so, were these failures to deliver covered by contractual remedies to keep EGI whole? Please explain.
   i) What was the impact to ratepayers?
b) For each of the last five years, please provide the number of compressor failures or unavailability of storage or storage pool compression at Dawn or Corunna.

Preamble: On pages 68-69, the study estimates: *Using the ICF assessment of the likely cost of deliverability associated with high deliverability storage ICF estimated an initial cost of delivered services at $3.72/GJ/Day for 10 days of delivered services.*

The study goes on estimating the incremental storage value in the remaining pages.

112) Please provide the complete derivation of the estimated cost including the sources of data and assumptions made.
a) Please ensure the derivation includes stated $0.41/GJ and the formula in footnote 35.
b) Please provide Appendix D referred to later on the same page.
c) In comparing the information in footnote 36 (the Storage Revenue Report) and footnote 37 (the Storage Parameter Report), it is clear there is no observable linkage between the revenue generated and the parameters associated with the specific contract.
   i) How did ICF make that linkage for the purpose of the analysis?
   ii) Would the source of that linkage be available to those using those sources as accessed on EGI's website?
      (1) If not, why not?
   iii) While these reports are available through the hyperlinks provided by the study, does EGI provide access to historic indices of customers with this data?
      (1) If not, why not?
d) The Storage Parameter Report provides contract identifiers with acronyms LST and LTP.
   i) Please distinguish these type of contracts
   ii) Are there any LTP contracts that provide proportional deliverability to the current balance in storage?
      (1) If so, how is the Maximum Firm Daily Withdrawal reported for those customers.
      (2) How were the unit cost/deliverability used in the ICF analysis for those customers?
e) Please explain the absence of any storage contracts with deliverability between 1.2% and 1.8% in Exhibit E 1 that are evident in the Storage Parameter Report that is referenced in footnote 37.
   i) Please provide an updated graph of Exhibit E

f) Please provide a full derivation of the incremental storage value including source of data and assumptions made.

REF: Ex. 4, Tab 2, Schedule 2, pg. 1

Preamble: EGI evidence states: *The reference price is used to price sales service commodity, gas in storage (a component of rate base), unaccounted for gas (UFG), company use, and compressor fuel, as part of the revenue requirement for the 2024 Test Year. As these costs have been consolidated for the amalgamated utility, a common reference price is required to support the 2024 Test Year Forecast as part of this Application.*

113) Where has EGI evidenced, using the current Board-approved methodologies for the calculation of the 2024 Test Year Forecast, to allow comparison with the new proposal?
a) If not provided in evidence, please provide.

REF: Ex. 4, Tab 2, Schedule 2, pg. 1-6, 13 and Ex. 4, Tab 2, Schedule 1, Attachments 1-3 & EB-2022-0286 EGI QRAM2023Q1, FRPO_SUB_EGI_ QRAM 2023Q1_20221214

Preamble: Understanding that EGI planned to respond to the Board's direction to advance a harmonization **proposal** (emphasis added), FRPO attempted to understand how EGD was allocating some transportation to load balancing costs in the 2022 QRAMs. Our inquiry stemmed from the rising costs of load balancing as identified in the applications. Having not received clarifications requested, we committed that we would pursue understanding in this proceeding (QRAM reference above).

Given that there is limited information available on gas supply costs allocated under current Board-approved policies, we would like to understand the load balancing allocation process currently in place that eventually flows into rates and deferral accounts such as the PGVA.

114) Using the November 1, 2022 Upstream Transport Contract Summary in Schedule 1, Attachment 3 reference:
a) In an Excel spreadsheet, for each line of transportation, please provide the current allocation of the demand contract quantity to:
   i) Gas Supply Commodity
   ii) Gas Supply Transportation
   iii) Load Balancing
   iv) Other?

Indicating to which existing Rate Zones the allocation is being made.

b) For each Rate Zone, please provide the rationale, or at least the guiding principles, that provide the allocation methodology.
c) Please explain how this previously applied rationale or guiding principles would change in the new proposal.

Preamble: On pg. 13, the evidence states: *In 2023, Enbridge Gas will also develop harmonized consolidated QRAM schedules to be filed in support of reference price changes as part of the January 1, 2024 QRAM Application.*

We have been challenged in the past to get transparency from the Union Gas QRAM ratemaking. We would like to understand it in comparison to the EGD Rate Zone examples provided in the Attachments.

115) Please provide comparable schedules to demonstrate the April 2022 QRAM ratemaking for Union South, Northwest and Northeast.
   a) Please confirm, that to achieve transparency, EGI will commit to providing QRAM schedules comparable to the EGD Rate Zone schedules, evolved for the 2024 rates, if the Board were to approve that approach.
      i) Please explain and clarify.

REF: Ex. 4, Tab 2, Schedule 3, pg. 2 & EB-2022-0133 Exhibit I.FRPO.5 , Attachment 1

Preamble: EGI evidence states: *Enbridge Gas's proposed approach to determine design demand and its selection of design criteria aligns with the no failure approach in that it captures the coldest weather event experienced. It is a proven method used by Union and a majority of other utilities. It is an approach that is clear, simple, and repeatable…*

The design criteria and design demand processes need to consider not only the design conditions but also the impact on day-to-day system operations when evaluating potential changes in approach.

116) How does EGI test to ensure that their design philosophy does not lead to over-design?
   a) Please explain using the Dawn-Parkway system as an example.
   b) Please file the most recent system verification for the Dawn-Parkway system.
   c) Please explain fully how day-to-day system operations are considered in the design criteria.

117) Please reproduce the FRPO.5 exhibit referenced above updated for any information that may have changed since its original production.

REF: Ex. 4, Tab 2, Schedule 3, pg. 3

Preamble: EGI evidence states: *To prevent distribution system failures, a condition that is unacceptable to its customers, EGD also included engineering assumptions that further reduced the risk of not meeting the design day demand. As an amalgamated utility, this approach is not appropriate for integrated transmission, distribution, and storage assets. Design demands need to be granular and aligned to actual observed customer behaviour and very cold weather.*

118) Please explain fully:
   a) The engineering assumptions that further reduced the risk of not meeting the design day demand.
   b) What approach is not appropriate for integrated transmission, distribution, and storage assets.

REF: Ex. 4, Tab 2, Schedule 3, pg. 15-20

Preamble: The reference pages explain the company's proposals for the selection and use of historical data and selected criteria to establish design condition, including the use of the current base temperature of 18 degrees Celsius vs. the proposed 15 degrees. On page, once the formula is expressed, the evidence states: "*Once the hourly wind speed adjusted temperatures are calculated they are converted into HDDw using a base temperature of 15°C.*

We would like to understand the basis for proposing a change to the heating degree day base that has been used by the legacy utilities for decades.

119) What analysis has EGI performed to justify the change of base temperature to 15°C while removing the utilization of baseload for the purposes of creating the design day load?
   a) Please confirm that Marquette Analytics still uses 65 degrees Fahrenheit or 18.3 degrees Celsius.
      i) How does EGI propose to adjust the associated baseload in moving to 15°C?
      ii) What would be the impact of moving from an 18 degree with baseload to a 15 degree base without baseload on the demands fed by the Dawn-Parkway system (please include Union South and Enbridge CDA impacts)? Please provide the numeric amounts under both 18 degree with baseload and 15 degree without baseload scenarios.
         (1) Please provide the results of both methodologies on the Dawn-Parkway schematic that shows laterals and demands.

iii) Please do the above analysis in ii) using 18 degree without baseload as a comparison to 15 degree base without baseload.

b) Viewing Table 1, it is clear that the only difference between the 18 and 15 degree bases moves the HDD by the 3 degrees lower. Mathematically, and for the purposes of forecasting, this lower total HDD serves to increase the forecasted load when extrapolating from a given temperature to the peak design temperature. Please confirm or explain by use of numeric example(s).

REF: Ex. 4, Tab 2, Schedule 3, pg. 24

Preamble: On page 24, EGI evidence states: *Using the previous winter's (most recent) data is the most appropriate starting point for determining design day demand. This process closely follows the Union approach to determine design day demand. It ensures the most recent customer behaviour is incorporated into the design day demand. The previous winter's data reflects the myriad of factors which impact demand including demand side management, economic factors, customer behaviour, and energy efficiency*.

120) Does the use of only one year create variability in forecasted demand especially if a warmer than normal winter occurs? Please explain.

a) Please provide the analysis that supports the use of one year vs. multiple years.

b) Pages 26-28 show comparison figures and tables for the winters of 2018/2019 and 2021/22. Please provide the same figures and tables for the winters of 2019/2020 and 2020/2021.

i) Please provide the missing footnotes 23 and 24.

REF: Ex. 4, Tab 2, Schedule 3, pg. 29

Preamble: EGI evidence states: *h) Daily demand is converted into design hour demand*[27]*…*
[27]*Using empirically derived profiles based on actual hourly flow data from the same gate stations.*

121) Please provide a full description of the methodology for the determination of the design hour demand using this process.

REF: Ex. 4, Tab 2, Schedule 3, pg. 32-33

Preamble: Table 3 shows that the proposed implementation increases the CDA design day demand by 2.9% and overall, by 0.4%. In spite of that increase, page 33 states: *As a result of the proposal of using the existing design hour process with the inclusion of the two Union refinements and the harmonized Company's demand forecasts, energy transition assumptions and interruptible curtailment processes, there are significantly less distribution facilities required to serve the design hour demand in the EGD rate zone.*

122) Please explain what factors that lead to a reduction in distribution facilities required to serve the design hour in the EGD rate zone.

Preamble: EGI evidence states: *As a result of the proposal to use the Union design day demand method, there are no incremental transmission or storage facilities required to serve the design day demand as the process was refined but did not materially change.*

123) Please clarify if the incremental demand is served by existing unutilized capacity from either transmission or storage.
   a) Please specify the component to meeting the net increase in EGD rate zone demand.

REF: Ex. 4, Tab 2, Schedule 3, Attachment 1, pg. 6-7

124) Of the comparison utilities reviewed and shown in Table 2-1, which are using a 60° Fahrenheit or 15° Celsius base temperature.

REF: Ex. 4, Tab 2, Schedule 4 & EB-2022-0086 Decision and Order, page 15

Preamble: We would like to understand more about EGI's proposal for operational contingency, how it is determined, and how it is proposed to be utilized and provide value for ratepayers.

125) For each of the respective storage locations of Dawn and Corunna, please provide the total space and total delivery for each of the following years (interpreted as the year including Nov.1st of the winter season).
   a) 2007
   b) 2013
   c) 2018
   d) 2022
   e) 2024 (forecasted)

Preamble: Page 15 of the Dawn Corunna Pipeline Decision states: *The OEB agrees that Enbridge Gas has not provided any analysis from a post-amalgamation integrated storage system perspective and notes that Enbridge Gas will have an opportunity to do this in its rebasing application, if it seeks to include this project in rate base.*

126) Please provide the study that EGI has prepared to integrate the assets of the former Union Dawn and Enbridge Tecumseh to optimize asset utilization.
  a) If a study is not available, why has this not been completed?
    i) In lieu of the study, please provide all studies, analysis or reports that inform operators of the integrated operation of the pools including injection/withdrawal schedules.

127) Referring to the 4PJ of empty space for the fall injection season, what is the empty space used for after withdrawals have started?
  a) How is the filled space used after injections started?
    i) If it is not filled, why not?

128) Please provide the study that determined the 43.5PJ of storage was required for deliverability.
  a) How was that storage space and molecule cost recovered in rates subsequent to the increase to 43.5PJ?
  b) Please provide the Board approval for those cost allocations and recovery.

129) If not provided above, please provide the source of the 13.5PJ of space and molecules determination.
  a) How are the costs of the molecules allocated and recovered?

Preamble: EGI evidence states: *The total EGD and Union rate zone space available for operational contingency for Winter 2023/2024 is 23 PJ.*

130) Please provide the EGI study which assesses the combined capability of Dawn and Corunna.
  a) If no study is available, how did EGI determine the 23 PJ?
    i) If it is a simple sum, please explain why EGI has not studied how these assets could be used more efficiently.
    ii) Please provide the determination of the individual components.
  b) If those documents are not available, please provide the results of simulations, analysis or other technical determinations of the components requested for operational contingency.
  c) Please indicate the amount of deliverability allocated to the contingency space and how it is developed using the components described.

Preamble: EGI evidence states: *Each component is modeled separately to determine the total operation contingency requirements.*

131) Please file the analysis and models that determined the specific components in Table 3.
   a) Please file the summary recommendations that went through the senior management approval process to support this approach.
   b) If these component values were determined independently, please explain why some of the space could not be used for multiple purposes if it is unlikely to have coincident occurrences?
      i) Please explain why storage space left open in the fall could not be filled on a planned basis in December to form part of the withdrawal contingency for the spring.
   c) If events do not occur at the same time, why does one need to sum the contingencies?
      i) Please show the need assessment in a presentation, such as a Venn diagram.

132) For the components in Table 3, please provide the actual utilization of the components of contingency over the last 5 years by component and the cause for that utilization.

133) Please provide the total output of Dawn including Corunna on a peak day.

Preamble: EGI evidence states: *To determine the operational contingency space required for injection, variances in weather data for the end of the injection season is used.*

134) If not provided in the requested information above, please provide the expected end of season injection amounts along with the level of variability expected in the shoulder season (e.g., expected forecast temperature variability and resulting change in planned injections).

Preamble: EGI evidence states: *Daily gas requirements are determined based upon a weather forecast prepared prior to the beginning of the gas day. Weather that is colder than forecasted will require additional gas from storage than planned.*

135) Please quantify the impact of a one degree difference in forecast to actual.
   a) Please provide the Oct. & Nov. and the Feb, Mar. & Apr. daily percentage full reports for both Dawn and Corunna over the last 10 years.
      i) Is the contingency only critical at the very full and very empty scenarios?

Preamble: We would like to understand the categorization of the storage pool effects.

136) Are these hysteresis effects taken into account in EGI's preparation of its injection/withdrawal schedule?
   a) If not, why not?
   b) How much deliverability was associated with the system integrity space in union rebasing?

137) Please provide the cost of OBA/LBA tiers for the top 3 major interconnecting pipelines.
   a) Please provide actual OBA/LBA costs for each of the last 5 years by month and by pipeline.
   b) Using TCE/TCPL as an example, does EGI have the ability through remote setting of receipt station pressure to adjust the quantities of gas received to receive measured gas closer to nomination.

138) In the case of UFG, how much contingency space was allocated previously by Union Gas?
   a) Why was this space set aside since UFG is determined retrospectively through accounting at times of stabilization not in operation?

139) Please breakdown the components that are being reduced to go from 23.5 to 15.6PJ. a) For the Winter of 2022/23, under normal March weather conditions for the EGD territory and forecasted daily deliveries, how much gas would be withdrawn from Corunna storage throughout the month?
   a) If EGI contracted for firm Dawn deliveries for half of the forecasted EGD withdrawals, please determine what remaining contingency space would be required.

140) For the 10.8 PJ of space filled by molecules, please provide a monthly injection/withdrawal schedule for that space.

141) Since these Dawn and Corunna space requests are made as Operational Contingency for the secure operation of the integrated storage facility for utility load balancing services, please provide the role that the reliable operation of the storage facility plays in the operation of non-utility storage.
   a) Are any of the costs for space or molecules for Operational Contingency charged to the non-utility operation?
      i) If so, please provide each components allocation to the non-utility operation.
      ii) If not, does the non-utility have its own Operational Contingency?
         (1) If it does not, is the non-utility reliant in any way on the reliability created by Operational Contingency.

REF: Ex. 4, Tab 2, Schedule 5

142) Please provide the specific reference in the Board's decision in the NGEIR proceeding that allocated 1.7 PJ/day of injection capability and 3.8 PJ/day of dehydration capacity.

Preamble: For the Tecumseh injection capability cited as 0.8 PJ/day, EGI provides a reference to the last annual IRM rate-setting proceeding of EGD.

143) Is EGI asserting that this is when this level of injection capability was first approved?
   a) If not, please provide the specific approval from the Board for this injection capability.

REF: Ex. 4, Tab 2, Schedule 5

Preamble: EGI evidence states: *Union sold storage services at the time of the NGEIR Decision that were deemed to be non-utility. Union also had excess deliverability at the time. The costs related to firm deliverability were allocated to regulated and unregulated customers, including the cost related to excess deliverability.*

144) Please provide the evidentiary reference to Union's excess deliverability to regulated and "unregulated" customers.
   a) What was the total deliverability at the time of NGEIR?
      i) Please provide an evidentiary reference for that total.
   b) What were the principles behind the allocation methodology?
   c) How was the excess deliverability managed in the time since the NGEIR decision?

Preamble: EGI evidence states: *Since NGEIR, the Company has made significant capital investment to increase non-utility withdrawal capacity at Dawn by 1.0 PJ/d and injection capacity of 0.6 PJ/d with all associated costs allocated to the non-utility business.*

145) Please identify the specific projects undertaken, the docket under which the projects received Board approval and their respective contributions to deliverability on a PJ/day basis.

Preamble: EGI evidence states: *The maximum capacity is set based on the one-time separation of existing storage and general plant assets between the utility and non-utility businesses.*[11] *As described above, the maximum utility firm withdrawal capacity for the storage operations for the EGD rate zone is 1.9 PJ/d, and the maximum firm utility injection capacity is 0.8 PJ/d.*

Enbridge Gas has defined the utility maximum firm withdrawal and dehydration capacity as 1.9 PJ/d and firm injection capacity as 0.9 PJ/d for the storage operations for the Union rate zones. Storage withdrawals require dehydration; therefore, design day dehydration capacity is equal to the withdrawal capacity.

11 The one-time separation defined an allocation for existing storage and general plant assets but did not define the maximum firm withdrawal, dehydration and injection capacity associated with those assets.

146) Please confirm that EGI is saying the maximum firm withdrawal capacity for the utility on a peak day is set by the dehydration capability of 1.9 PJ/day.
  a) If not, please explain.
  b) Please file the dehydration schedule for the last 5 years.
  c) Prior to the merging of the company, did EGD have a contract with Union Gas for dehydration services?
    i) If so, please file the contract.
    ii) If not, please explain why EGD storage does not need dehydration for late withdrawal season deliverability.

REF: Ex. 4, Tab 2, Schedule 6

147) What specific approval(s) is EGI seeking in this proceeding?
  a) If seeking, would this approval(s) be included in phase 2 of the proceeding?

<u>4.3-FRPO.148-153</u>

REF: Ex. 4, Tab 3, Schedule 1

Preamble: We would like to understand better the sources of UFG and the steps that EGI has undertaken to reduce the cost to ratepayers.

148) Many of the figures and tables in this schedule depict data dating back to 2008 including Figure 2 of Attachment 3, page 4. For each utility/Rate Zone, please provide the unaccounted for gas disaggregated into the categories of storage,

transmission and distribution along with the respective category activity parameters utilized to present percentages.

a) Please explain how EGI determines the amount of UFG on the transmission system as depicted in Table 6 on page 15 of Schedule 1.

149) Please provide the utility and non-utility space separately for Dawn and Tecumseh for each year starting in 2007.

a) Please provide the cost in each year to increase the non-utility space.
b) In the respective years, please indicate if any brand new pools were developed versus other techniques, such as delta-pressuring the existing pools, to increase the non-utility space.

150) For the data in Table 7 regarding annual adjustments for storage pool inventories, please provide:

a) A more fulsome description of the process to determine these adjustments.
b) For the years since 2002, please provide the actual annual adjustments by utility/rate zone storage space and:
    i) Since 2007, the adjustments broken down between the utility and non-utility storage space.

151) Has EGI performed any study to reconcile the heat values it has derived from its measuring equipment to consider whether improving or upgrading its equipment would contribute to reducing UFG?

a) Has EGI worked with TCE or other companies on a reconciliation?
    i) If not, why not?
b) How does EGI test for variations in actual heat value?
    i) How many chromatographs does EGI employ?
        (1) Please provide the locations on the system.
    ii) Please provide the cost of the installation of a chromatograph from EGI most recent installation.

152) Does EGI have non-utility storage contracts that do not have a fuel component for injections or withdrawals?

a) If so, how is the fuel provided?
b) How is that amount reconciled to ensure ratepayers are not subsidizing?

153) EGI indicated that it implemented an update to gas quality parameters to derive an improved supercompressibility factor after the 2019 ScottMadden report. Please estimate the under-recovery of gas from 2014-2018 as a result of not updating the gas quality.

<u>4.4-FRPO.154-160</u>

REF: Ex. 4, Tab 4, Schedule 1

Preamble: EGI references the shift to 'as a service' model many times in Tab 4.

154) Please provide a definition and the range of contexts to which it applies.
   a) Please describe how this shift will contribute to cost pressures.
   b) Please describe how this shift will improve the efficacy of the organization and outcomes for ratepayers.

REF: Ex. 4, Tab 4, Schedule 2, pg. 26-27

Preamble: In Table 5, line 5, EGI forecasts a substantial increase and relates it to Covid lifting and corporatization of insurance. However, earlier years present a revenue as a result of third-party damage recoveries.

155) Has EGI included a forecast of some recoveries for third-party damages to partially offset these substantial increases?
   a) If not, why not?

Preamble: On page 27, EGI attributes some its cost pressures to merit increases.

156) For each of the years of 2019 to 2022, please provide:
   a) The total amount of merit increases to management
   b) The merit increase amount as a percentage of total salary
   c) The percentage of management employees received a merit increase
   d) The average percentage increase provided to these employees as a merit increase
   e) The Board-approved inflation factor for that year

REF: Ex. 4, Tab 4, Schedule 2, pg.37

Preamble: EGI evidence states: *The 2024 Test Year Forecast includes $51.1 million for locate delivery costs. $45 million of the costs are for locate delivery services provided to customers and locate delivery services required for Enbridge Gas's own operations. $6.1 million of the costs include internal company resources that provide administrative support to respond to locate requests.*

157) Please provide the supporting documents that generated these forecasts.

REF: Ex. 4, Tab 4, Schedule 3, pg. 3, Table 1

158) Please update Table 1 with actual FTE's for 2022 and refine 2023 and 2024 as appropriate.

REF: Ex. 4, Tab 4, Schedule 3, Attachments 7, 8 & 9

Preamble: The referenced attachments state Enbridge corporate policies regarding, among other things, contracting for pipeline contractors. We would like to understand better EGI's approach to engaging pipeline contractors in major projects and how ratepayers' interests are protected.

159) Please file any additional policies or studies that address EGI's approach to retaining pipeline contractors.

160) In tabular form, for each ICM project during the most recent ICM projects, please indicate the name of the project, the total cost of the project, the cost of pipeline contractor services and whether EGI produced an RFP for the retention of the pipeline contractor.

a) Please provide any analysis or study that EGI has done to assess the value for money of the contractor services.
b) What incentives does the contractor and the company have to minimize the cost of a major ICM-type project? Please describe fully.

<u>4.7-FRPO.161-171</u>

REF: Ex. 4, Tab 7, Schedule 1, pg. 5 & Ex. 4 Tab 2, Schedule 1, Attachment 3, pg. 3

Preamble: EGI evidence states: *Enbridge Gas is proposing to expand the PDO and PDCI offering to customers located in the EGD rate zone who currently are contractually obligated to deliver gas at the Enbridge CDA*[9] *…*
[9] *The Enbridge CDA is an interconnect between TransCanada and Enbridge Gas located at the east end of the Dawn Parkway System.*

161) For the purposes of delivery, does TC Energy view the east end of the Dawn Parkway System and the Enbridge CDA as the same delivery point. Please explain.

a) Please explain the location of Union Parkway Belt, including suction or discharge, relative to Parkway.
b) Please explain why EGD holds over 300,000 GJ/day from Union Parkway Belt to the EGD CDA.
c) Does EGI accept deliveries to the east end of the Dawn Parkway System as an alternate delivery point for Bundled Transportation contracts with EGD CDA obligations?
   i) If requested by the customer, do they have a right to deliver to Parkway to fulfill their obligation to the EGD CDA? Please explain.

Preamble: EGI evidence states: *These customers provide a similar system benefit as the DP customers in the Union South rate zone with a PDO, as they have the option to deliver gas to Dawn, which would otherwise increase the Dawn Parkway System demand.*

162) Please explain how these customers have the option to deliver at Dawn when Union South customers, west of Dawn, can only access the option to move deliveries from Parkway to Dawn when EGI offers it. Please explain fully.

Preamble: EGI evidence states: *As part of the current service offerings in the EGD rate zone, Enbridge Gas offers a bundled DP service option to deliver gas at Parkway as part of the Ontario TService. These customers currently do not pay gas supply transportation charges to transport gas to Parkway as they deliver their gas directly to Parkway.*

163) Currently, to which rate zone customers does EGI offer an Ontario Tservice that has an option to deliver at Parkway?
   a) If EGD Rate Zone customers, do they pay any additional transportation charges from Parkway to EGD CDA? Please explain why or why not.

REF: Ex. 4, Tab 7, Schedule 1, pg. 7-8

Preamble: EGI evidence states: *At its sole discretion, Enbridge Gas would consider the use of Dawn Parkway System turnback to reduce the PDO provided any quantities turned back were first offered to the market through an existing capacity open season. The priority for using excess Dawn Parkway System capacity is to serve contracted long-term demands.*

164) Does EGI consider *its sole discretion* to be subject to Board approval?

a) Please confirm the Board could also order EGI to implement such a use.

165) Please provide the Board order or directive that stipulates that the priority for using excess Dawn Parkway System capacity is to serve contracted long-term demands.

REF: Ex. 4, Tab 7, Schedule 1, pg. 9

Preamble: EGI evidence states: *The quantity of gas delivered to Parkway has increased each year because of increased demands on the Dawn Parkway System*.

166) In tabular form, please provide the amount of PDO for each winter starting with 2014/15.

REF: Ex. 4, Tab 7, Schedule 1, pg. 13

Preamble: EGI evidence states: *PDO fuel costs included in rates provides recovery of the incremental compressor fuel requirements to transport gas on the Dawn Parkway System as customers shift their deliveries from Parkway to Dawn.*

167) Please describe the methodology that EGI uses to determine the amount of fuel to be allocated to the PDO costs for each month of the year.

a) How does EGI reconcile this estimate to ensure that actual fuel used is reconciled to the forecasted amount of fuel in this determination?

REF: Ex. 4, Tab 7, Schedule 1, pg. 14
AND EB-2017-0306/EB-2017-0307 Exhibit J2.5 Attachments 1 & 2

Preamble: EGI evidence states: *At the time of Union's 2013 Cost of Service proceeding, 210 TJ/d of excess Dawn Parkway capacity existed relative to the forecast demands of the Dawn Parkway System. The full cost of the Dawn Parkway System was included in the Company's revenue requirement and allocated based on the forecast demands, consistent with a cost of service treatment.*

168) Over what forecasted utilization was the full cost including the 210 TJ/d of excess Dawn Parkway capacity recovered?

a) What was the revenue requirement of the full Dawn-Parkway system including the excess 210 TJ/d for 2015 prior to any additional recoveries as a result of the 2015 expansion?

b) Please provide the actual revenue generated in 2015 from:
   i) In-franchise rates
   ii) Ex-franchise M12 rates
   iii) PDO revenue from in-franchise customers

169) Using the presentation of J2.5 Attachments 1 & 2 from the merger proceeding, please show the period from W18/19 through W22/23.
   a) For any year in which there was a shortfall of capacity, please provide the costs of resources to overcome the shortfall.

REF: Ex. 4, Tab 7, Schedule 1, Attachment 1

Preamble: EGI evidence states: *Bundled and semi-unbundled direct purchase (DP) customers are contractually obligated to deliver gas to Enbridge Gas at various points of receipt upstream or on Enbridge Gas's system, including the interconnect with TransCanada at Parkway and with the Enbridge CDA.*

170) Please indicate all points of delivery embedded in DP contracts where the counterparty could be obligated to deliver their gas in the Enbridge CDA.
   a) Please provide all other points that EGI can require obligated deliveries from DP customers.
   b) If parties were willing to obligate deliveries to Kirkwall, would EGI consider providing an incentive comparable, but not necessarily equal, to the PDCI?
      i) If not, why not? Please explain.

171) Using forward market pricing, in tabular form, please provide the annual Nov.1-Oct.31 basis differential at Dawn and Parkway for the five years starting the winter of 2023/24 and include the difference between the two.
   a) Please provide a reference to the source of the forward prices.

7.1-FRPO.172-188

REF: Ex. 7, Tab 1, Schedule 2, pg. 7 & Ex. 4, Tab 2, Schedule 1, Attachment 3

Preamble: Section 2.1 describes the proposed Gas Supply classification. Reconciling legacy EGD and Union approaches, while dealing with a merged utility and gas supply contracting, creates a lot of moving parts. As a starting point for clarification, we believe understanding the classification of Transportation between Gas Supply and Load Balancing is an important starting point.

172) Using the November 1, 2022 Upstream Transportation Contract Summary found at Ex. 4, Tab 2, Schedule 1, Attachment 3, please replace the Contract Expiry found in column (e) with a designation of whether the contract demand charges are considered Transportation Demand or Load Balancing Transport for the purposes of classification.
   a) If a particular contract is used for both, please split the row into 2 rows showing the amounts classified to either Transportation Demand or Load Balancing Transport.
   b) Please provide an Excel file for this developed table.

REF: Ex. 7, Tab 1, Schedule 2, pg. 8

Preamble: EGI evidence states: *Load balancing commodity includes gas supply load balancing costs to meet above average day demands. These costs are incurred by contracting for peaking services and purchasing incremental gas supply over the winter period to meet seasonal and design day demands for all customers.*

We would like to understand how these commodity costs are handled for the purposes of matching the revenue generated when selling the molecules.

173) Please describe how the commodity costs are allocated in the following scenario.
   a) If the current WACOG is $5 and the peak season commodity is purchased at Dawn for $7, does load balancing commodity get allocated the full $7 cost?
      i) If so, how does the revenue generated from selling the molecule get properly allocated to recognize that the load balancing premium is, in our view, actually $2? Please explain fully.
      ii) If, however, the peak season commodity cost is split as $5 to Gas Supply and $2 to Load Balancing, we would like that confirmed.

REF: Ex. 7, Tab 1, Schedule 2, pg. 9-10

Preamble: EGI evidence states: *The 2024 Test Year revenue requirement includes the cost of regulated storage and excludes unregulated storage costs. Regulated storage costs are classified as storage demand and storage commodity…*
Market-based storage demand costs are incurred to meet the Utility's storage space and storage deliverability requirements. The market-based storage demand costs are classified in proportion to total utility storage space and deliverability net plant excluding base pressure gas and linepack.

174) Please clarify if unregulated storage costs refer to the non-utility storage whose prices are unregulated (market-based).
   a) Please clarify how the demand and commodity costs for market-based storage contracts executed to meet in-franchise demand are treated. The referenced statement above seems to suggest it is asset-based when we would have expected the allocations to be contract-based. Please explain fully.

REF: Ex. 7, Tab 1, Schedule 2, pg. 18

Preamble: EGI evidence states: *The operational contingency space of approximately 15.6 PJ allows Enbridge Gas to meet its operational needs. Operational contingency storage space costs are allocated to in-franchise and ex-franchise customers based on how operational contingency space is used. Please see Exhibit 4, Tab 2, Schedule 4 for a description of the operational contingency components.*

We would like to understand how these costs are allocated.

175) For the components listed in Ex.4, Tab 2, Schedule 4, please define the parameters used for the purposes of classification and the drivers to allocate the component costs.
   a) Currently, are any operational contingency costs from the Union Dawn storage allocated to ex-franchise customers?
      i) If so, how? Please explain.
      ii) If not, why not?

176) How are storage commodity costs allocated to the non-utility storage? Please explain fully.

REF: Ex. 7, Tab 1, Schedule 2, pg. 19

Preamble: EGI evidence states: *Kirkwall Station costs are allocated between in-franchise and ex-franchise rate classes in proportion to bi-directional design day demands at Kirkwall. In-franchise costs are allocated to in-franchise bundled rate classes using design day demands with the costs allocated to semi-unbundled and unbundled services based on the design day demands of the respective service area.*

177) Please provide the design day flows that underpin allocations for the Kirkwall station.
   a) Please ensure the direction is clearly specified and what assumptions are made regarding the TCE contract from Kirkwall to Union CDA for 135,000 GJ/day.

178) Please explain more fully this concept that is repeated in this section that states: *using design day demands with the costs allocated to semi-unbundled and unbundled services based on the design day demands of the respective service area.*
   a) If a semi-unbundled customer is situated in the eastern service area vs. the central service area, how are their design day demands treated differently? Please explain fully with the help of a numeric illustrative example.

REF: Ex. 7, Tab 1, Schedule 2, pg. 19

Preamble: EGI evidence states: *Panhandle/St. Clair System costs are allocated to in-franchise bundled rate classes in proportion to design day demands with the costs allocated to semi-unbundled and unbundled services based on the design day demands of the South service area.*

179) Does this mean that Panhandle/St. Clair System costs are allocated to all bundled customers of EGI and to semi- & unbundled customers in the South service area by their design day demand (i.e., proportional to their design day demand as a fraction of the total design day demand of the South service area)?
   a) Alternatively, is the design day demand of these South service area semi- & unbundled customers in proportion to the design day demand of all EGI customers?
   b) Please explain fully.

REF: Ex. 7, Tab 1, Schedule 2, pg. 22

180) Please explain the distinction of greater than or less than NPS 4 for Distribution Demand High Pressure.
   a) What functional difference does this sizing make?

REF: Ex. 7, Tab 1, Schedule 3, pg. 2 & Exhibit 8, Tab 2, Schedule 1, para. 34

Preamble: EGI evidence states: *The Company was not able to recreate two stand-alone cost allocation studies for the EGD and Union rate zones in the same format that was approved in EGD's and Union's respective 2013 Cost of Service proceedings.*

While this statement may have merit when viewing integrated distribution rates, EGI should not have the same issue with Gas Supply rates by current Rate Zones (see para. 34 referenced above).

181) Please confirm that EGI could use the current information available to provide Gas Supply rates to the newly proposed service areas.
   a) Please provide comparison rates to compare the One Rate Zone approach to individual Service Area rates for Gas Supply.

REF: Ex. 7, Tab 1, Schedule 3, pg. 4

182) Please explain how Tecumseh Gas storage division costs are functionalized to transmission and compression or storage.
   a) Please explain why this separation is warranted.

Preamble: EGI evidence states: *Costs were directly assigned to the functional categories where possible, and the remaining indirect costs were functionalized based on analysis of use and the Company's knowledge of its operations. Union further divided the storage function into dehydrator and excluding dehydrator at the function level and divided the transmission function into Dawn Station, Dawn-Trafalgar Easterly, Dawn-Trafalgar Westerly, Other Transmission, and Ojibway/St. Clair at the function level.*

183) Please define the *remaining indirect costs* and what drivers or principles are used for their allocation from the company's knowledge.

184) Please explain why the storage function was divided into dehydrator and excluding dehydrator at the functional level.
   a) Is EGI continuing to use that division in its proposal? Please explain.

REF: Ex. 7, Tab 1, Schedule 3, Attachment 1

Preamble: Under the Gas Supply Comparison by Rate Zone, in Union North, *A portion of costs directly assigned to interruptible based on winter sales volumes.*

185) Are these costs assigned to Rate 25?
   a) If so, how is the transfer price determined?
   b) If not, to what are the costs assigned?
   c) Is this service proposed to be discontinued or harmonized? Please explain.

Preamble: Under the Methodology Comparison for Storage by Rate Zone, the distinction of including or excluding dehydrator comes up in many boxes.

186) Please explain the reasoning behind the methodology applications of dehydrator costs.

REF: Ex. 7, Tab 1, Schedule 4, pg. 17

Preamble: EGI evidence states: *In Union's Hagar Liquefaction Service Rate proceeding[22], the OEB approved a non-utility cross charge of $1.59/GJ. The charge was based on the forecast of customers at the time of the application. As there are no customers contracted for the liquefaction service, Enbridge Gas is not able to update the Cost Allocation Study or cross charge amount as part of this Application.*

187) Does this approach infer that if, for whatever reason, non-utility storage is not contracted, the cost should fall back to the utility customers until it is contracted? Please explain.

REF: Ex. 7, Tab 1, Schedule 4, Attachment 1

188) Please provide the evidence associated with the significant rate increase from DSM to Rate 6.

<u>7.2-FRPO.189-191</u>

REF: Ex. 7, Tab 2, Schedule 1, Attachment 1, pg. 2, line 8

189) Please provide allocation basis for the costs in Line 8.
   a) Please provide an Excel copy of the working papers to show the allocation.

REF: Ex. 7, Tab 2, Schedule 1, Attachment 1, pg. 3, line 9

190) Please provide allocation basis for the costs in Line 9.

a) Please provide an Excel copy of the working papers to show the allocation.

REF: Ex. 7, Tab 3, Schedule 1, Attachment 12, pg. 11-14

191) Please provide detailed workpapers to show how the "Total" and "Rate E70" allocation factors were calculated for "D-PTRANS".

<u>8.2-FRPO.192-195</u>

REF: Ex. 8, Tab 2, Schedule 2, pg. 12

Preamble: EGI evidence states: *Bundled DP customers with an Enbridge CDA point of receipt8 will pay the transportation charge and will also receive the PDCI credit for their deliveries at the Enbridge CDA to harmonize with the current approved approach for Union South customers with a Parkway Delivery Obligation (PDO).*

192) Does the charge for these Bundled DP customers include the cost of transportation from Parkway to the Enbridge CDA?

a) If not, why not?

REF: Ex. 8, Tab 2, Schedule 2, pg. 13

Preamble: EGI evidence states: *As provided at Exhibit 8, Tab 4, Schedule 3, Section 4, Enbridge Gas proposes to shift the point of receipt from Empress to Dawn for these customers eliminating any deliveries at Empress by DP customers over the IR term.*

193) Is this move by customer election or is EGI asking the Board for approval to force DP customers from Empress to Dawn for their gas supply?

a) If the latter, how much notice is EGI proposing?

b) Please comment on the consistency of this approach with the Dawn Access commitments made by EGD in that proceeding.

REF: Ex. 8, Tab 2, Schedule 2, pg. 14, para. 40

194) Does the rate class specific component vary by Service area?
   a) Please explain as the description is ambiguous.

REF: Ex. 8, Tab 2, Schedule 2, pg. 17

Preamble: EGI evidence states: *The derivation of the rate class specific component of the gas supply transportation charge for load balancing transportation is prepared by dividing the allocation of load balancing transportation costs from the Cost Allocation Study by the total sales service and bundled DP volumes.*

195) If this process is to allocate load balancing costs, why is the allocation of costs not proportional to design demand over average?
   a) Please explain fully.

<u>8.3-FRPO.196-198</u>

REF: Ex. 8, Tab 3, Schedule 1, pg. 26, Table 5

196) Please provide the expected gas loss from an NPS 6 HPPE pipeline that has been:
a) punctured leaving a 3 in/75 mm hole
b) severed completely
In each of the above case, the scenario is located where the pipe is near a close gate station resulting in an unconstrained flow for a period of 60 minutes.

197) For each of the above examples, please provide the cost of gas using 30 cents/m3.

198) What was used as a framework or model to determine the charges in Table 5?

<u>8.4-FRPO.199</u>

REF: Ex. 8, Tab 4, Schedule 7, pg. 7

Preamble: EGI evidence states: *For purposes of the analysis, Enbridge Gas used the average negotiated interruptible rate for the rate class where applicable. Customer specific negotiated rate is not available since the customer is currently contracted for firm service. The actual negotiated rate may be different than the rate class average and may not result in the same impacts as presented in Figure 1.*

199) How long has each of EGI, Legacy EGD and Legacy Union been negotiating interruptible rates?

a) Are these rates negotiated below Board-approved rates? Please explain.
b) How does EGI ensure that these rates do not represent a cross-subsidization? Please explain fully.
c) If EGI and/or its legacy company found the need to negotiate interruptible rates to attract customers to move from firm to interruptible, what has held the company back from asking the Board for approval of a revised interruptible rate or class? Please explain.
d) Please confirm that ratepayer representatives have been asking EGI to review interruptible rates for several years.

8.5-FPRO.200

REF: Ex. 8, Tab 5, Schedule 1, pg. 9-13

200) What level of customer engagement did EGI undertake prior to proposing these changes to the Terms and Conditions of these contracts.

a) Please be specific to the different customer groups with which EGI engaged?