REF: Exhibit A, Tab 2, Sch. 1, pg. 5

Preamble: In the above referenced page, EGI provides the rate impact for each rate zone. The CCA applied obscures the rate impact. We would like to understand the rate impact without the benefit of the CCA which diminishes quickly.

1) For each of the Rate zones, what would the forecasted rate impacts be for the applied for projects in the first year after CCA reductions have ended for the respective projects.

REF: Exhibit A, Tab 2, Sch. 1, pg. 8, footnote 15

2) Please outline the factors that feed into the conversion from as spent to in service.
   a) Please demonstrate by providing the calculation for System Renewal in line 3 of Table 3.

REF: Exhibit A, Tab 2, Sch. 1, pg. 10

Preamble: We would like to understand more about the increases summarized in the EGD Rate Zone table.

3) Please breakdown the increases of $40M and $15M into the major components and the justification associated with those components.

REF: Exhibit B, Tab 2, Sch. 1, Appendix A, pg. 2, Table B, line 7

Preamble: We would like to understand more about the significant increase in the Union Gas rate zone for General Plant Improvements.

4) Please provide a description and breakdown of costs that drove the substantial increase in line 7 starting in 2021 and continuing through the forecast period.
   a) Please provide the three largest projects and their cost estimates

REF: Exhibit B, Tab 2, Sch. 1, Appendix A, pg. 4, Table E, line 4

Preamble: We would like to understand more about the significant increase in the EGD rate zone for Gate & Feeder Stations.

5) Please provide a description and breakdown of costs that drove the substantial increase in line 4 starting in 2020 and continuing through the forecast period.
   a) Please provide the three largest projects and their cost estimates

REF: Exhibit B, Tab 2, Sch. 1, Appendix A, pg. 5, Table F, line 14

Preamble: We would like to understand more about the significant increase in the Union Gas rate zone for Station Rebuilds - Gate & Feeder.

6) Please provide a description and breakdown of costs that drove the substantial increase in line 14 starting in 2021 and continuing through the forecast period.
   a) Please provide the three largest projects and their cost estimates

REF: Exhibit B, Tab 2, Sch. 1, Appendix A, pg. 6, Table G and pg. 7, Table H
And EB-2020-0181 Exhibit B, Tab 2, Sch. 1, Appendix A, pg. 6, Table G

Preamble: We would like to understand more about the significant increase for both rate zones for Integrity Initiatives.

7) Please provide a description and breakdown of costs that drove the substantial increases starting in 2021 and continuing through the forecast period.
   a) Please detail why these initiatives are categorized under System Service vs. System Renewal
   b) For each rate zone, please provide the three largest projects and their cost estimates
   c) Please explain the factors or drivers that resulted in a significant increase in Integrity Initiatives for the EGD rate zone starting in 2022 compared to

REF: Exhibit B, Tab 2, Sch. 1, Appendix A, pg. 7, Table H, line 14

Preamble: We would like to understand more about the significant increase in the Union Gas rate zone for Transmission Reinforcement.

8) Please provide a description and breakdown of costs that drove the substantial increase in line 14 starting in 2020 and continuing through the forecast period.
   a) Please provide the three largest projects and their cost estimates

REF: Exhibit B, Tab 2, Sch. 2, pg. 11-12

Preamble: We would like to understand the mitigation of risk associated with the decision to expand/re-build the Byron Transmission station.

9) Will the rebuild of the station expose EGI to noise complaints of new facility or will there be a post construction noise assessment to compare to baseline?

REF: Exhibit B, Tab 2, Sch. 2, Appendix A, pg. 3-16

Preamble: EGI evidence states: *"The existing Dawn to Cuthbert pipeline consists of approximately 1.1 km of NPS 42 ST pipeline running in an easement paralleling two adjacent NPS 26/30 and NPS 34/30 ST pipelines*."

And

"*Furthermore, integrity inspections that are required as part of the Enbridge Gas Integrity Management Plan on any of the adjacent Dawn Parkway System pipelines requires the manipulation of gas flow in order to push or pull ILI tools through pipelines. Isolation of the NPS 42 Dawn to Cuthbert pipeline and adjacent NPS 26 and NPS 34 during a failure prevents these activities from taking place until the failure event is rectified.*"

We would like to understand the priority placed on the NPS 42 pipeline from a condition assessment perspective.

10) Please provide the year of installation of the two parallel pipes in the easement in the area of the proposed replacement.
   a) Please provide the operating hoop stress of those parallel pipes.
   b) Please describe their condition in comparison to the section that is proposed to be replaced.
   c) Is the picture in Figure 3 of pipe in the section that is proposed to be replaced?
      i) If the picture shows typical corrosion, why is EGI not proposing a longer replacement?
   d) Why must the NPS 26 and 34 be isolated in the event of a failure on the NPS 42?
      i) Can the NPS 42 be shut-in separate from the other two pipelines?
      ii) Please explain and provide a diagram showing the valving and dimensions to describe the reasoning.

11) Does the second excerpt translate to: EGI does not do integrity inspections during a contemporaneous failure event?
   a) If so, is that not common sense and not any different from any other parallel piping systems?
   b) If not, please explain the relevance of the excerpt.

REF: Exhibit B, Tab 2, Sch. 2, Appendix A, pg. 16, 125, 163, 232, 439 and 449

Preamble: We provide the following excerpts from the series of technical reports provided in Appendix A and have underlined concluding statements from these reports.

Pg. 16 August 27, 2001 - **Excavation Summary:** *This corrosion was documented as corrosion area number six and <u>determined to be within the acceptable axial length</u> for the measured maximum depth of 1.7mm.*

Pg. 125 October 25. 2005 – ***Summary:*** *Thirteen areas of corrosion were noted having wall loss of less than 10% the actual wall thickness and six areas were found having wall loss of up to 12%. Most of the corrosion was located next to the long seam. Five areas of mechanical damage were recorded with MD-02 and MD-03 having linear indications within the gouging. The linear indications could not be sized for depth due to their location in the gouge and their lengths.*

Remediation action required the removal of five areas of mechanical damage and the linear indications found within the gouges of MD-02 and MD-03 by following the approved grinding procedure specifications. A rubber backed 120 grit buffing disc was used to remove the linear indications and mechanical damage, ensuring minimal grind lengths and a smooth transition to the adjacent surface. Magnetic particle testing was performed to ensure the removal of all defects. All defects were removed below 10% NWT.

Pg. 163 Sept. 3, 2019 - ***Mechanical Damage Summary:*** *All damage features were successfully removed as per the Enbridge Gas Engineering remediation report for this site. No further repairs were required, site to be recoated.*

Pg. 232 Sept. 20, 2019 - ***Metal-Loss Assessment Summary:*** *There was a total of 12 metal loss features noted in the NDE assessment area. All metal loss areas were existing grinds and did not exceed 3%NWT. All metal loss areas are to be recoated, no further repairs are required as per the Enbridge Gas Remediation Report for this site. Site to be recoated and backfilled.*

Mechanical Damage Summary: *There was a total of 55 damage features noted in the NDE assessment area consisting of 11 gouge/scrape features and 44 scabs or scab-like features. These features were all located in the base metal and were not associated with any other feature. No cracking was associated with any of these features. All damage features were successfully removed within the grind limits outlined in the Enbridge Gas Remediation Report for this site. All grind repairs were found acceptable by Enbridge Gas Engineering, site to be coated and backfilled.*

Additional Comments: *All grind repairs were found acceptable by Enbridge Gas Engineering, no further repairs were required.*

The above reports chronicle a series of inspections that occurred over almost 20 years. We would like to understand how these series of reports have resulted in a conclusion of replacing the NPS 42 pipe in 2022.

12) Please confirm that each inspection resulted in some amount of pipe treatment and concluded that no further repairs were required.

Pg. 439 March 14, 2021 ***Executive Summary***: *Note that the previous ECDA surveys completed in 2005 showed that while the coating on the 26" and 34" lines appeared to be in fair to poor condition with little to no corrosion on the surface of the pipe, the 42" pipe showed areas of Polyken disbondment with minor to moderate pitting corrosion with up to 16% wall loss (Trapped water under coating had a pH of 7). It was also predicted that further pitting would not exceed another 10 mils (for a total of 80mils). until year 2025.*

Pg. 449 March 14, 2021 ***Conclusions and Recommendations:*** *It is important to note that the previous ECDA conducted in 2005 recorded 16% wall loss under disbonded Polyken (trapped water pH of 7) for the 42" Line. Therefore, the prior history of corrosion for the 42" Line is set to Moderate. Finally, it is recommended to set the reassessment interval to ten (10) years. Note, this interval may be modified with respect to results obtained in Steps 3 and 4 of the ECDA process.*

13) Please provide a specific reference and page number in the evidence that provides the determination of 16% wall loss.
    a) Please confirm that the prediction in 2005 was for 20 more years of service life.
    b) After the 2019 repairs, using the same prediction methodology and proper maintenance, how many more years of service life would be predicted.

Pg. 469 NET PRESENT VALUE ASSESSMENT OF ALTERNATIVES

14) Please file the entire report that contains the cost analysis of Options A and B.
    a) If not included in the report, please provide the timing assumed for EMAT LI in the subject analysis.

REF: Exhibit B, Tab 2, Sch. 2, Appendix B

Preamble: EGI evidence states: *As early as 2018, the Company (Union Gas Limited at the time) identified a number of integrity, safety, reliability, maintenance and operational concerns that supported a rebuild of the Station...*

...inability to inability *of the existing Station to support the long term demands of the London market beyond 2022.*

15) Please file the 2018 report identifying the concerns.
    a) Please provide the demand required from each station feed and its relative capacity in:
        i) 2018
        ii) 2022
        iii) 2027

Preamble: Table 1 provides the Estimated Project Costs. We would like to understand better the process of securing third party contractors and the impact on resulting costs relative to estimates.

16) Please confirm that the construction work was awarded through RFP.
   a) If not, why not?
   b) If so, how many pre-qualified contractors bid on this work?
   c) Please provide the range of contractor labour costs bid and the comparison with the Class 1 and Class 5 contractor labour estimates.
   d) From recent replacement projects (e.g., Windsor Line, London Lines) what is the range of bids relative to the applied for estimates for labour?
      i) Please provide the specific range for each.
      ii) Please provide the estimated actual labour that is known or projected at this time.
         (1) Please clarify changes to scope (e.g., Windsor Line running line revisions).

REF: Exhibit B, Tab 2, Sch. 2, Appendix C

Preamble: EGI evidence states: *The current system includes two lines, the Existing Line that is in scope for replacement, and a second NPS 8 Kirkland Lake Loop pipeline that runs in parallel to the Existing Line for the majority of the distance from the TransCanada Pipelines ("TCPL") supply station…*

… The Existing Line and parallel NPS 8 pipeline were determined to be primarily medium risk on the Enbridge Operational Risk Matrix…

Considering forecast customer demand and peak loading, a loss of containment leak and repair on the Existing Line may result in customer outages, as the NPS 8 Kirkland Lake Loop may not have sufficient capacity to support the Municipality of Kirkland Lake (Residential and Commercial customers), the Kirkland Lake Generating Station and Macassa Mines…

… The Project is a like for like replacement. The rationale for the decision is to provide replacement capacity for the current Kirkland Lake Lateral pipeline while also providing reliability of supply for emergency and operational scenarios in summer and shoulder month conditions.

We would like to understand better the risk assessment and alternatives considered.

17) Is the NPS 8 also a risk?
   a) If so, why is EGI only replacing one pipeline?
      i) Is the NPS 8 currently in the EGI Asset Management plan for scheduled replacement?
         (1) If so, why not replace both with one pipeline?

b) If not, could EGI increase the pressure in the NPS 8 pipe to maintain flow without needing the NPS 4 pipe?
    i) What is the highest HDD that would allow the NPS 8 to serve firm load?
        (1) Please provide the inlet and outlet pressures of:
            (a) The pipes currently in a peak day scenario
            (b) The NPS 8 under the highest HDD scenario.
                (i) In the single NPS 8 HDD scenario, could the station(s) be modified to allow a lower inlet to maintain firm customers in a peak day scenario
c) In the last excerpt from EGI evidence stating that the reason to replace the NPS 4 pipe is to have a second feed for emergency or planned operational scenarios (i.e., not peak winter day design).
d) Please explain the answers above fully.

REF: Exhibit B, Tab 2, Sch. 2, Appendix C, Exhibit C, Tab 2, Sch 1 EGI AMP 2021-25 Appendix Inv Codes 102128 & 49607
And EB-2020-0192 Exhibit I.FRPO.6 and FRPO.7

Preamble: We are interested in understanding the output reports by using two replacement projects in the AMP (Kirkland Lake Lateral and London Lines) and factors associated with prioritization.

18) For the Kirkland Lake Lateral, please provide a description of each of the Value Function Measures and provide its numerical determination.
    a) How is Value in Percentage utilized?
        i) Please describe how the absolute value of cost, avoided costs and total investment costs are summed to provide a denominator for the purposes of a percentage.
        ii) What is the utility of the percentage and how is that metric used?

19) For the London Lines, please provide a description of each of the Value Function Measures and provide its numerical determination.
    a) Specifically given the relatively low Operational and Financial Risks and very high negative Total, how and why was this project prioritized to 2021.

REF: Exhibit B, Tab 2, Sch. 3, pg. 8

Preamble: ***Panhandle Regional Expansion Project (PREP) Strategy Development:...*** *As part of the project plan, EGI will complete a supply-side IRP assessment in addition to a binding reverse open season. In this way, EGI will minimize the facilities required to serve incremental demand while optimizing any unwanted existing capacity.*

We are interested in understanding better the process undertaken to use supply-side IRP to mitigate the need for funding of long-term assets.

20) Please file the Ojibway to Dawn Firm Exchange Service with Call Option – 2023 published September 16, 2021.
   a) Please provide the number of respondents to the RFP.
   b) Please provide the timeline associated with evaluation of Panhandle demand, proposal evaluation and Leave to Construct application, if still needed.

Preamble: **Dawn to Corunna Strategy Assessment**

To mitigate the risks at this facility 20km of NPS 36 pipeline will be installed from Dawn to Corunna Compressor Station. The investment includes the retirement of 7 compressor units. This project replaces the equivalent design day storage capacity of 1.4PJ/d provided by the 7 compressors and will re-utilize horsepower at Dawn to eplace the capacity. The in-service date is targeted for November 1, 2023.

We would like to understand more about the analysis that resulted in applying for an NPS 36 pipeline versus upgrading/replacing compressors and foundations.

21) Please file the study(ies) that drove the change to build the proposed pipeline instead of replacing the compressors and/or reinforcing the units with problem foundations.

REF: Exhibit C, Tab 2, Sch. 1, pg. 18

Preamble: EGI evidence states: *"A notable change that occurred in December 2019 was that the LUG delivery areas moved from monthly meter reading to bi-monthly meter reading, to align with the LEGD practice. This change did not impact the methodology for estimating un-billed consumption but rather only increased the amount of billed volumes that were based on estimated consumption. It should be noted that the change from monthly to bi-monthly meter reading does not contribute to incremental UFG; however, it could contribute to increased volatility in the short-term.*

We understand that UFG matters are out of scope. However, one of the integration activities that EGI has undertaken in the rebasing period is harmonization of meter readings cycles and integration of the billing systems. We have come to understand that the "notable change" is causing substantial customer billing issues which can transfer costs to the customer as some meters, especially in LUG, are not being read for months. We, and we trust the Board, want to understand the scope of the current challenge and what EGI is doing to correct the issues.

22) For LUG in 2021, please provide the percentage of meters with no read for:
   a) 4 months
   b) 6 months
   c) 9 months
   d) 12 months

23) For LUG in 2021, what percent of accounts received a zero consumption bill:
   a) From January to June
   b) From July to November

24) What criteria is used to determine if a customer is billed an estimate or billed for zero consumption for a month for which the meter is not read.
   a) If the bill is estimated, does classification (actual vs. estimate) appear in the consumption data (e.g., the Invoice Rate Ready data) for direct purchase pools.
   b) If not, what would be the cost to add this field to the data provided?

25) If a direct purchase customer whose year-end contract balance is impacted by estimated or zero consumption readings, will EGI commit to reversing the charges to the customer caused by the estimated or zero consumption billings.

26) If a group of general service rate customers are aggregated into a direct purchase group, what avenues do these customers have to seek adjustments to their accounts?
   a) Is there an Account Executive or similar type role.

27) What is the average wait time to get to a live account representative using the customer billing enquiry number 1-877-362-7434 and what is the abandonment rate:
   a) From January to June of 2021?
   b) From July to November of 2021?

28) Please provide the amount invested in the meter read, billing and customer accounting for EGI:
   a) Using 2020 actual costs
   b) Using 2021 actual costs for 9 months and forecast costs for the final 3 months