ENBRIDGE GAS INC. 2024 REBASING APPLICATION

EB-2022-0200

ONTARIO ENERGY BOARD STAFF INTERROGATORIES

1.Staff-1

Ref: Exhibit 1

Following publication of the Notice of Application, the Ontario Energy Board (OEB) received several letters of comment. Sections 2.1.6 of the Filing Requirements state that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment.

Please file a response to the matters raised in the letters of comment that were also copied to Enbridge Gas Inc. (Enbridge Gas). Going forward, please ensure that responses to any matters raised in subsequent comments or letters that the applicant receives are filed in this proceeding. Please ensure that name and contact information is redacted for public filings. All responses must be filed before the argument (submission) phase of this proceeding.

1.2-Staff-2

Ref: Exhibit 1, Tab 2, Schedule 1, pp. 13 and 19; Exhibit 1, Tab 8, Schedule 1, Attachment 10, p. 77; Exhibit 1, Tab 10, Schedule 4, p. 16

The Government of Canada has committed to reducing greenhouse gas (GHG) emissions by 40% below 2005 levels by 2030 and the Government of Ontario has committed to reducing GHG emissions by 30% below 2005 levels by 2030.

Enbridge Gas states that energy transition poses a significant increase to the risks faced by natural gas utilities. Enbridge Gas considered alternatives to respond to these increasing risks, including changes to the expected service life of assets and changes to its deemed equity ratio to address increased business risk.

For each of the following categories of community and system expansion projects, please respond to the questions that follow: (i) Natural Gas Expansion Program (NGEP) funded expansion projects; (ii) non-NGEP funded expansion projects that require the use of Contributions in Aid of Construction (CIAC), System Expansion Surcharges (SES), Temporary Connection Surcharges (TCS) or Hourly Allocation Factors; and (iii) other expansion projects that do not require any of the funding sources mentioned in categories (i) and (ii).

a) Please provide the number of projects that will be constructed by the end of 2028 in each category.
b) Please provide the total capital costs across all projects for each category.
c) If available, please provide the average capital cost per residential customer across all projects in each category.
a) Please provide the average amortization period, in years, across all projects in each category.
b) Given Enbridge Gas's statements regarding stranded asset risk that it is facing and considering that federal and provincial commitments to reducing GHGs are likely nearer term than the amortization period for the projects in these categories, please explain further what Enbridge Gas has done or is considering doing to manage the risk of stranded assets in each category.

1.2-Staff-3

Ref: Exhibit 1, Tab 2, Schedule 1, pp. 13 and 19

The Government of Canada has committed to reducing GHG emissions by 40% below 2005 levels by 2030, and to net-zero emissions by 2050, and the Government of Ontario has committed to reducing GHG emissions by 30% below 2005 levels by 2030.

The forecast capital expenditure for the 2024 Test Year is $1,491.7 million and includes supporting the demand for customer and system growth.

a) Is Enbridge Gas planning to construct by 2028 any non-NGEP supported community expansion projects that will require the use of CIAC, SES, TCS or Hourly Allocation Factors? If so, how many, where are they located, and in what years might they go into service?
b) For any projects identified in part (a), please:
    i. Comment on their feasibility
    ii. Explain how Enbridge Gas is assessing electrification as an alternative to natural gas (whether conventional, renewable, or hydrogen blended natural gas)
    iii. Comment on (and quantify, if possible) their overall average capital cost per residential customer (i.e., do not provide an updated average capital cost per residential customer for each project)
    iv. Confirm that their amortization period is 40 years; if not, please explain
    v. Explain what Enbridge Gas is doing to manage the risk of stranded assets considering that federal and provincial commitments to reducing GHGs are nearer term than the amortization period for these projects.

c) Is Enbridge Gas planning to construct by 2028 any non-NGEP supported community expansion projects that will not require the use of CIAC, SES, TCS or Hourly Allocation Factors? If so, how many, where are they located, and in what years might they go into service?
d) For any projects identified in part (c), please:
    i. Comment on their feasibility
    ii. Explain how Enbridge Gas is assessing electrification as an alternative to natural gas (whether conventional, renewable, or hydrogen blended natural gas)
    iii. Comment on (and quantify, if possible) their overall average capital cost per residential customer (i.e., do not provide an updated average capital cost per residential customer for each project)
    iv. Confirm that their amortization period is 40 years; if not, please explain
    v. Explain what Enbridge Gas is doing to manage the risk of stranded assets considering that federal and provincial commitments to reducing GHGs are nearer term than the amortization period for these projects.

1.6-Staff-4

Ref: Exhibit 1, Tab 6, Schedule 1

Enbridge Gas conducted a customer engagement process through 2021 and early 2022 to understand customer needs and preferences to inform its business planning process. Enbridge Gas explored customer perceptions of key planning trade-offs, overall rate impacts of its draft plan, and rate design issues.

Acknowledging that Enbridge Gas's last customer engagement survey used different survey instruments and methodologies, to the extent possible, please identify any differences or similarities in customer preferences from the last survey.

1.6-Staff-5

Ref: Exhibit 1, Tab 6, Schedule 1, p. 14

Enbridge Gas noted that customers participating in the customer engagement survey were given the option to receive follow-up information from Enbridge Gas (after the conclusion of Phase Three) about how customer feedback was used and the overall outcomes of the customer engagement.

a) Please provide a copy of the follow-up information provided by Enbridge Gas to participants following the conclusion of Phase Three.
b) Please confirm if participants had an opportunity to provide feedback on the follow-up information provided by Enbridge Gas. If not, please explain why. If feedback was provided, please provide a summary of the feedback received including any issues and concerns raised and how they were addressed by Enbridge Gas in this application. Also, please explain whether and how any feedback has impacted Enbridge Gas's business and capital planning.

1.6-Staff-6

Ref: Exhibit 1, Tab 6, Schedule 1, Attachment 1, pp. 137 & 280; Exhibit 8, Tab 3, Schedule 1, p. 12;

Enbridge Gas is proposing an extra length charge of $122 per metre in excess of the 20-metre service length threshold.

When engaged on the topic of Enbridge Gas's Infill Policy, the Phase Two results found that 38% of residential participants either did not have an opinion or indicated "don't know".

The Phase Three results found that 32% of participants indicated a preference for 15 metres at no cost and $75 per metre for the remainder, 22% indicated a preference for 20 metres at no cost and $100 per metre for the remainder, 13% indicated a preference 25 metres at no cost and $140 per metre for the remainder, and 32% either did not have an opinion or indicated "don't know".

a) Did Enbridge Gas probe the results further to understand why 38% of participants in Phase Two, and 32% of participants in Phase Three, did not have an opinion or indicated "don't know"?
b) Please explain why the option in Phase Three for 20 metres at no cost and $100 per metre for the remainder did not more accurately reflect Enbridge Gas's request to charge $122 per metre in excess of the 20-metre service length in this application.
c) Please explain why Enbridge Gas did not consider offering 15 metres at no cost with a lower cost per metre for the remainder considering participants generally preferred this option.

1.6-Staff-7

Ref: Exhibit 1, Tab 6, Schedule 1, Attachment 1, pp. 20 & 25

When engaged on the topic of investing in an Innovation and Technology fund, the Phase Two results found that 37% of residential participants, 48% of small business participants and 52% of medium-large business participants were not willing to pay anything extra towards a technology fund.

When engaged on the same topic in Phase Three, the results found that over half of the participants in all customer segments were willing to pay additional amounts towards a technology fund.

a) Please reconcile the two results and explain the inconsistency.
b) Please confirm if Enbridge Gas undertook further research or analysis to understand the inconsistent results.
c) Please explain how Enbridge Gas considers the above noted results to be valid.

1.6-Staff-8

Ref: Exhibit 1, Tab 6, Schedule 1, Attachment 2, p. 26

Enbridge Gas undertook a customer engagement process with Rate M13 customers using a workbook-style survey. A total of seven M13 customers participated in the survey.

c) How many Ontario conventional natural gas producers are Rate M13 customers of Enbridge Gas?
d) How many of the seven participants were Ontario conventional natural gas producers?
e) How many of the seven participants are Rate M13 customers of Enbridge Gas?

1.6-Staff-9

Ref: Exhibit 1, Tab 6, Schedule 1, Attachment 1, p. 32

When engaged on the topic of Renewable Natural Gas (RNG), the Phase Three results found that the majority of residential and business customers were willing to pay more to increase the amount of RNG in the system. However, the two most popular choices were to increase the amount of RNG to only 2% (22% of residential participants, 25% of business participants) or not add any at all (25% of residential participants, 23% of business participants).

Did Enbridge Gas probe the results further to understand why 25% of residential participants and 23% of residential participants indicated a preference not to add any RNG to the gas supply?

1.7-Staff-10

Ref: Exhibit 1, Tab 7, Schedule 1, pp. 12 & 20

Enbridge Gas stated that the attrition rate for meter reading personnel in 2022 is 20% and the level of absenteeism is 17%, the highest that Enbridge Gas has experienced, which has contributed to the challenge of achieving staffing levels required to meet the MRPM.

Part of Enbridge Gas's mitigation plan to meet the MRPM includes working with meter reading vendors to hire additional readers and engaging and providing assistance to customers to submit meter reads.

a) Please expand on Enbridge Gas's plans to increase staffing levels required to meet the MRPM.
b) How does Enbridge Gas plan to accommodate the additional time and resources required to onboard new staff? Has Enbridge Gas implemented initiatives to reduce the attrition rate of meter reading personnel?
c) What is the percentage of customer meter submissions rejected by Enbridge Gas?
d) Please expand on Enbridge Gas's plans to engage and provide assistance to customers to provide their own meter reads. Does Enbridge Gas have plans to increase customer training on meter reads (through videos on its website) in order to reduce the number of rejected meter submissions?
e) Please confirm if a customer has to be on e-billing in order to submit a meter read (by phone or online).

1.7-Staff-11

Ref: Exhibit 1, Tab 7, Schedule 1, p. 14

Enbridge Gas is requesting partial exemption under Section 1.5.1 of the Gas Distribution Access Rule (GDAR) related to certain service quality requirements (SQR) performance measures beginning in 2024 for the rebasing period or until the OEB orders otherwise, specifically: Call Answering Service Level (CASL), Time to Reschedule a Missed Appointment (TRMA) and Meter Reading Performance Measurement (MRPM). Enbridge Gas requested the following modified measures:

- CASL – achieve 65% of calls reaching the general inquiry number answered within 30 seconds;
- TRMA – attempt to contact customers requiring a rescheduled appointment within one business day of the original appointment window 98% of the time; and
- MRPM – achieve no more than 2% of meters with consecutive estimates for four months or more.

a) Please confirm if Enbridge Gas is also requesting an exemption of these SQR performance metrics for 2022 and 2023. If so, please confirm if Enbridge Gas's requested modified performance measures for 2022 and 2023 are the same as those requested for 2024.
b) Please describe the customer impact of Enbridge Gas's proposed modifications to the CASL, TRMA and MRPM measures.

1.7-Staff-12

Ref: Exhibit 1, Tab 7, Schedule 1, p. 14; EB-2022-0188 Enbridge Gas Assurance of Voluntary Compliance, dated September 12, 2022

The CASL performance standard as set out in GDAR is 75% of calls reaching the general inquiry number answered within 30 seconds. Aside from 2021 where Enbridge Gas achieved 64.3% in this performance measure, Enbridge Gas has historically achieved the target. Enbridge Gas requested to modify its CASL performance measure from 75% to 65%.

In September 2022, Enbridge Gas provided the OEB with an Assurance of Voluntary Compliance in which it committed to mitigation plans that aim to achieve 75% for the CASL performance measure for 2022.

Please explain the basis for modifying the CASL measure from 75% to 65% given that aside from 2021, Enbridge Gas has historically achieved the metric and has committed to mitigation plans to achieve the 75% CASL measure for 2022.

1.7-Staff-13

Ref: Exhibit 1, Tab 7, Schedule 1, Attachments 2-4

Enbridge Gas's mitigation plans for 2022 were provided to the OEB as part of the Assurance of Voluntary Compliance dated September 2022; the mitigation plans for the 2023 reporting year were provided in Enbridge Gas's 2023 GDAR Exemption Request Application (EB-2022-0276); and the mitigation plans for 2024 and beyond were filed as part of the current application.

Please provide an update on the implementation of Enbridge Gas's mitigation plans to date. Describe what mitigation plan(s) have been implemented, its outcome(s), and how it has impacted Enbridge Gas's performance metric(s) for 2022.

1.8-Staff-14

Ref: Exhibit 1, Tab 8, Schedule 1, Attachment 1
Exhibit 1, Tab 8, Schedule 1, Attachment 2
Exhibit 1, Tab 8, Schedule 1, Attachment 9
Exhibit 1, Tab 8, Schedule 1, Attachment 11
Exhibit 1, Tab 8, Schedule 1, Attachment 12

Enbridge Gas has provided the following:

- Consolidated financial statements for 2020 and 2021.
- Pro-forma statement of utility income for 2023 bridge year.
- Rating reports from DBRS Morningstar (September 27, 2022) and S&P Global Ratings (February 1, 2022).

a) As Concentric has compared Enbridge Gas's risk profile in 2022 to Enbridge Gas Distribution (EGD) and Union Gas Limited's (Union Gas) risk profile in 2012, please provide the following information starting from 2012 (all information to be provided for Enbridge Gas):
   i. Audited financial statements for 2019, including income statement, balance sheet and cash flow statement in MS Excel format.
   ii. Audited financial statements, if available, or draft financial statements for 2022, including income statement, balance sheet and cash flow statement in MS Excel format.
   iii. Pro-forma financial statements, prepared in the same manner as Enbridge Gas's audited financial statements, for 2023, 2024, 2025, 2026, 2027 and

2028 (including income statement, balance sheet and cash flow statement in MS Excel format).
    iv. All relevant credit rating reports from DBRS Morningstar and S&P Global Ratings from 2019 to 2022.

b) As Concentric has compared Enbridge Gas's risk profile in 2022 to EGD and Union Gas's risk profile in 2012, please provide the following information starting from 2012 (all information to be provided separately for EGD and Union Gas):
    i. Audited financial statements for 2012, 2013, 2014, 2015, 2016, 2017 and 2018 (including income statement, balance sheet and cash flow statement in MS Excel format).
    ii. All relevant credit rating reports from DBRS Morningstar and S&P Global Ratings from 2012 to 2018.

1.8-Staff-15

Ref: Exhibit 1, Tab 8, Schedule 1, Attachment 2 – 2021 Audited Financial Statement

Under Note 2 Push-Down Accounting of the audited financial statements (AFS), it states that push-down accounting with respect to the accounts of Union Gas was applied. The carrying values of certain assets and liabilities of Union Gas transferred to EGD have been adjusted to reflect Enbridge Inc.'s (Enbridge) historical cost as at February 27, 2017, the date upon which Enbridge acquired common control of EGD and Union Gas.

Furthermore, under Note 7 Property, Plant & Equipment, it states that depreciation expense is $22M in incremental depreciation resulting from push-down accounting for the year ended December 31, 2021.

a) Please discuss how the accounting of Union Gas's assets and liabilities have been treated for regulatory purposes upon acquisition of EGD and Union Gas.
b) Please confirm that the historical costs for Union Gas's capital assets were adopted for regulatory purposes. If not confirmed, please discuss and explain why the implications of this are not reflected in the Accounting Policy Change Deferral Account.

1.8-Staff-16

Ref: Exhibit 1, Tab 8, Schedule 1, Attachment 2 – 2021 Audited Financial Statement

Under Note 2 Asset Retirement Obligations (ARO) of the AFS, it states that currently for the majority of assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

Under Note 19 Environmental, it states that to the extent that Enbridge Gas is unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, it will be responsible for payment of liabilities arising from environmental incidents associated with our operating activities.

a) Please clarify whether Enbridge Gas has AROs recorded in its financial statements.
   i. If yes, please explain how it is treated for regulatory purposes, where it is included in the application, and quantify the amount(s).
b) Please clarify whether Enbridge Gas has environmental liabilities recorded in its financial statements.
   i. If yes, please explain how it is treated for regulatory purposes, where it is included in the application, and quantify the amount(s).

1.8-Staff-17

Ref 1: Exhibit 1, Tab 8, Schedule 1, Attachment 2 – 2021 Audited Financial Statement (AFS)
Ref 2: EB-2012-0459, Decision with Reasons, July 17, 2014

In the 2021 AFSs, Note 5 shows long-term regulatory liabilities for the future removal and site restoration reserves of $1,543 million for 2021. Footnote 9 states that the amount consists of amounts collected from customers, with the approval of the OEB, to fund future costs of removal and site restoration relating to property, plant and equipment. These costs are collected as part of the depreciation expense charged on property, plant and equipment that is reflected in rates.

In the OEB's Decision for EGD's 2014-2018 Custom IR proceeding noted in Reference 2, the OEB approved the Constant Dollar Net Salvage (CDNS) method for site restoration costs (SRC). In that proceeding, EGD proposed to refund $259.8 million in excess SRC to ratepayers. The OEB decided that the refund would be increased by an additional $120 million and the SRC provision for 2014 to 2018 would be reduced by $85 million.

a) Please confirm that the $1,543 million of future removal and site restoration reserves shown in the 2021 AFS represents the amount that has been recovered from customers in rates as at December 31, 2021. If not confirmed, please explain what the amount represents.
b) Please provide the approximate amount of site restoration costs that have been recovered to date.
    i. Please confirm that this amount would be equal to the SRC provision in accumulated depreciation. If not confirmed, please explain why not.
c) On page 60 of Reference 2, it was estimated that EGD would require over $3 billion in the future to remove and replace assets at the end of their useful lives. Please provide the most current update on the estimated total future removal and replacement costs.
d) Please confirm that when SRC are incurred, actual SRC costs draw down the accumulated SRC reserve in accumulated depreciation. If not confirmed, please explain how SRC are recorded for regulatory purposes when incurred and confirm that there is no double counting of recovery of SRC.
e) In EGD's 2014 to 2018 Custom IR proceeding, the OEB required the SRC refund to be increased by an additional $120 million and the SRC provision for 2014 to 2018 to be reduced by $85 million. Please explain the implications of the OEB's decision to the SRC reserve and annual SRC provision in its 2021 AFS and for 2024 to 2028.
f) Please quantify the annual SRC provision from 2024 to 2028.
    i. Please explain whether the annual SRC provision is equal to the SRC forecasted to be incurred from 2024 to 2028.
    ii. If the annual SRC provision is not equal to the SRC forecasted to be incurred from 2024 to 2028 are not equal, please provide the annual SRC forecasted to be incurred from 2024 to 2028.
g) When EGD was approved to transition from the Traditional method of accounting for SRC to the CDNS method in EGD's 2014 to 2018 Custom IR proceeding, the accumulated depreciation requirement (i.e. SRC reserve) was less than the requirement using the Traditional method. The difference between the two was approved to be returned to ratepayers. In the current rate application, Enbridge Gas is proposing that Union Gas transition from the Traditional Method to the CDNS method. For Union Gas, please quantify the SRC reserve under the Traditional method and the SRC reserve under the CDNS method.
    i. If there is no difference in the SRC reserve between the two methods, please explain why and how it is different from EGD's circumstances when EGD transitioned from the Traditional method to the CDNS method.

ii. If there is a difference in the SRC reserve between the two methods, please explain the difference and Enbridge Gas's proposed treatment for the difference.

1.8-Staff-18

Ref 1: Exhibit 1, Tab 8, Schedule 2, p.3
Ref 2: January 27, 2023, Evidence Corrections and Updates

Regarding reporting under USGAAP, Enbridge Gas stated that the Ontario Securities Commission and the Alberta Security Commission decided that Enbridge Gas can continue to use USGAAP for financial reporting purposes until January 1, 2027.

a) Please explain Enbridge Gas's views on adopting International Financial Reporting Standards (IFRS) for regulatory purposes if it is required to adopt IFRS for financial reporting purposes.
b) Please explain whether Enbridge Gas has assessed the implications of adopting IFRS. If yes, please discuss.
c) If Enbridge Gas is required to adopt IFRS during its IRM term, please discuss how Enbridge Gas will address this change for regulatory purposes (e.g. establishment of a DVA).

1.8-Staff-19

Ref: Exhibit 1, Tab 8, Schedule 2, p.5
Ref 2: Exhibit 1, Tab 9, Schedule 1, Attachment 1
Ref 3: Exhibit 2, Tab 6, Schedule 1, p.35

In Table 1, Enbridge Gas listed accounting standard updates that had no impact or an immaterial impact on its revenue requirement. Enbridge Gas indicated that the update for ASU 2017-07 Improving the Presentation of Net Periodic Benefit Cost related to Defined Benefit Plans improves the income statement presentation of the components of net periodic pension cost and net periodic post-retirement benefit cost for an entity's sponsored defined benefit pension and other postretirement plans. OEB staff notes that the update also allows only the service cost component to be eligible for capitalization, when applicable.

Enbridge Gas also indicated that for ASU 2018-15 relating to cloud computing arrangements, the ASU specifies that an entity would apply Accounting Standards Codification 350-40, internal-use software, to determine which implementation costs related to a hosting arrangement that is a service contract should be capitalized and which should be expensed. Ref 2 shows capital expenditure integration project for the CIS Integration HANA cloud application of $11.8 million as at December 31, 2023.

a) Regarding ASU 2017-07, please confirm that the update relating to capitalization also did not have a material impact on Enbridge Gas's revenue requirement.
   i. If not confirmed, please quantify and explain the impact on the treatment of capitalization of pensions and Other Post Employment Benefits (OPEB) since the implementation of ASU 2017-07.
b) With regards to cloud computing, please explain Enbridge Gas's regulatory treatment for cloud computing and whether these costs are capitalized or expensed.
   i. Please provide a schedule showing all costs related to cloud computing as at December 31, 2023 broken down by project/category as applicable, and indicate whether each of these costs have been expensed or capitalized.
   ii. Reference 3 states that Enbridge Gas has adopted cloud computing services, and that the transition to cloud computing services results in higher O&M costs (lower capital costs) as spending shifts away from capital. Please indicate which costs in response to part "b" above would have been historically treated as capital.

1.8 Staff-20

Ref: Exhibit 1, Tab 8, Schedule 1, Attachment 4, p1

In the above reference noted, there is an adjustment to corporate income to derive utility income. Specifically, there is an adjustment of $4.4 million to gas sales and distribution, and gas costs as well as an adjustment of $0.4 million to transportation revenues. These adjustments relate to accelerated CCA.

Please elaborate further on the $4.4 Million and $0.4 Million accelerated CCA adjustments and explain why they would impact the revenues and costs of the utility.

1.9-Staff-21

Ref: Exhibit 1, Tab 9, Schedule 1, p. 16

The OEB approved the amalgamation of EGD and Union Gas in EB-2017-0306/0307. As part of its decision on the amalgamation, the OEB also approved a ratemaking framework and a deferred rebasing period of 5 years. In order to deliver the integration benefits and the savings to be passed on to customers at rebasing, O&M costs associated with integration were tracked separately over the deferred rebasing term. Enbridge Gas has noted that these costs will no longer be required beyond 2023 and were not reflected in rates during the deferred rebasing term, and as such were borne by the utility. Also included are severance costs associated with any full-time equivalent (FTE) reductions brought about by restructuring.

a) Please confirm that integration costs incurred by Enbridge Gas or forecast to be incurred are not included in the 2024 OM&A costs.
b) Please confirm if Enbridge Gas has included any severance costs associated with FTE reductions brought about by restructuring in 2024 O&M costs or in the 2024 revenue requirement. Also, please provide any severance costs included in 2024 rates.

1.9-Staff-22

Ref: Exhibit 1, Tab 9, Schedule 1, p. 20

Over the deferred rebasing term (2019 to 2023), Enbridge Gas expects to incur approximately $252.2 million in capital expenditures related to integration efforts. Enbridge Gas has noted that the revenue requirement to support these investments was not included in base rates, and as such was borne by the shareholder.

a) Please confirm that investments (revenue requirement borne by the shareholder) on all capital expenditures (with the exception of recoveries related to approved Incremental Capital Module funding) and not just capital expenditures related to integration efforts are not included in base rates during the deferred rebasing term.
b) Please confirm that Enbridge Gas has requested that the net book value of integration-related capital spending incurred during the deferred rebasing term be added to the 2024 rate base.

1.10-Staff-23

Ref: Exhibit 1, Tab 10, Schedules 1-8

Enbridge Gas has submitted a detailed energy transition plan in this application. It has also sought approval for an Energy Transition Technology Fund (“ETTF”) of $5 million per year, totaling $25 million over the 2024 to 2028 period to “advance and accelerate research, development, and commercialization of low-carbon technologies.”

Please elaborate on how the energy transition plan and the ETTF (if approved) would help to mitigate the risks from energy transition faced by Enbridge Gas, specifically for the 2024-2028 period.

1.10-Staff-24

Ref: Exhibit 1, Tab 10, Schedule 3, pp. 4-12; Exhibit 1, Tab 10, Schedule 4, pp. 2-3, Exhibit 1, Tab 10, Schedule 6, pp. 1-8.

Enbridge Gas describes current provincial and federal climate policies impacting Enbridge Gas (federal - methane regulations, carbon pricing, Clean Fuel Regulation; provincial - Emissions Performance Standards). Enbridge Gas provides its energy transition forecasts for number of customers and average use, and notes that historically, it has only considered climate policies that have been implemented and that in this application it is accounting for known energy transition factors and will incorporate changes as policy signals become more certain. Enbridge Gas describes emerging federal, provincial, and municipal energy transition and climate change policies.

a) Have any of the policies described as “emerging” in Exh. 1, Tab 10, Schedule 6 been directly incorporated into Enbridge Gas’s forecasts for number of customers and average use? If so, please describe.
b) Please provide a description of the approach Enbridge Gas plans to take during the rebasing term to adapt its investments and expenditures as a result of these emerging policies.

1.10-Staff-25

Ref: Exhibit 1, Tab 10, Schedule 4, pp.3-4; Exhibit 3, Tab 2, Schedule 5, p.9

Enbridge Gas describes its Energy Transition assumptions for average use. Enbridge Gas notes that its average use forecast includes adjustments for carbon pricing. Enbridge Gas notes that, as a result of the energy transition adjustment to the customer forecast, the 2024 Test Year general service annual volume forecast is approximately 2,899,408 cubic meters per year lower than would otherwise be the case. However, (Exhibit 3) Enbridge Gas also notes that natural gas price was not statistically significant in the residential average use forecasting model, thus was excluded as a forecasting variable.

a) Do the Energy Transition assumptions for average use described in this section (i.e., the inclusion of carbon pricing, but no inclusion of other potential factors such as future energy efficiency of codes and standards) in this section apply to both the 2024 Test Year forecast and the longer-term demand forecast through 2032 that is used to develop Enbridge Gas's Asset Management Plan (AMP)? If there are differences in the assumptions regarding average use in the longer-term forecast, please describe.
b) Please confirm that the forecasting adjustments described for carbon pricing are only used for the average use forecast for non-residential customers, i.e. the assumption is that residential average use is not affected by cost of natural gas, including the rising carbon price.

1.10-Staff-26

Ref: Exhibit 1, Tab 10, Schedule 4, p. 4; Exhibit 2, Tab 6, Schedule 2, Table 5.1.10-1 and Appendices A and B; Exhibit 4, Tab 2, Schedule 6, p. 18

In exhibits 1.10.4 and 4.2.6, Enbridge Gas proposes to conduct a Hydrogen Blending Grid Study for a total of $12 million.

In Exhibit 2.6.2, Table 5.1.10-1, Enbridge Gas proposes to conduct a Hydrogen Feasibility Study for a total of $15.5 million. In Appendix A of this exhibit, Enbridge Gas proposes to conduct a Hydrogen Feasibility Study for a total of $12 million. In Appendix B of this exhibit, Enbridge Gas proposes to conduct a Hydrogen Feasibility Study for a total of $15.5 million.

a) Please confirm that "Hydrogen Blending Grid Study" and "Hydrogen Feasibility Study" are different names for the same study. If not, please explain the differences between these two studies.
b) If question (a) is confirmed, please reconcile the cost estimates of $12 million and $15.5 million.

1.10-Staff-27

Ref: Exhibit 1, Tab 10, Schedule 4, pp.5-7; Exhibit 3, Tab 2, Schedule 5, p. 7; Exhibit 3, Tab 2, Schedule 6, pp. 4, 9; EB-2021-0002 Decision and Order, p.3; Enbridge Gas Home Efficiency Rebate Plus website (https://www.enbridgegas.com/residential/rebates-energy-conservation/home-efficiency-rebate-plus)

Enbridge Gas discusses the energy transition assumptions embedded in its customer additions forecast (Table 2). Enbridge Gas notes that based on market trends, Enbridge Gas assumed that on a voluntary basis, a portion of new buildings would not be serviced by natural gas, and a portion of existing natural gas customers would choose to replace heating equipment reaching end of life with non-gas alternatives.

a) Please provide more detail on the market trends that informed Enbridge Gas's energy transition assumptions in Table 2.
b) Please provide a copy of the 2020 Residential: Single Family Natural Gas End Use Study used to inform the assumption that 94% and 82% of customers were likely to replace their equipment with natural gas space and water heating equipment, respectively.
c) How much emphasis is Enbridge Gas placing on these study results in developing its energy transition assumptions in Table 2, given that certain key variables, such as the cost of natural gas including the carbon price, were different in 2020 than they are in 2023 and will be at the end of this rebasing period?
d) Please describe how Enbridge Gas has considered the rising carbon price in its consideration of forecasts as they relate to customer additions.
e) Has Enbridge Gas considered the likely impact of building code changes (including the new Canadian Energy model code discussed in Exhibit 3) on its assumptions for the portion of new buildings that would be serviced by natural gas?
f) Why does Enbridge Gas assume that the rate of customer additions for replacement customers (existing homes and businesses who switch from other energy sources to natural gas) does not begin to decline until 2030?
g) The Home Efficiency Rebate Plus program (a modified version of the Government of Canada's Greener Homes Grant program that is delivered by Enbridge Gas in Ontario and is available to Enbridge Gas customers and non-Enbridge Gas customers) provides significant incentives for existing buildings to install electric space heating systems (ground source and air source heat pumps) intended to service the entire home. Per the OEB's EB-2021-0002 decision, Enbridge Gas customers are not required to remain an Enbridge Gas customer after participating in this program. What assumptions regarding the impact of the Home Efficiency Rebate Plus program are included in Enbridge Gas's customer additions forecast for replacement customers (existing homes and businesses who switch from other energy sources to natural gas) and its forecast for shrinkage of existing Enbridge Gas customers?
h) Has Enbridge Gas performed any sensitivity analysis regarding how its forecast of year-over-year change to average number of customers (customer additions minus shrinkage customers) would impact its forecast spending in the 2023-2032

AMP?, e.g. what would be the impact on capital requirements in the AMP of a 25%, 50%, or 100% reduction in net new customers, relative to the forecast?

1.10-Staff-28

Ref: Exhibit 1, Tab 10, Schedule 4, pp.7-8

Enbridge Gas describes its Energy Transition assumptions in the volume forecast. Enbridge Gas notes that, as a result of the energy transition adjustment to the customer forecast, the 2024 Test Year general service annual volume forecast is approximately 2,899,408 cubic meters per year lower than would otherwise be the case.

a) Does the reduction in 2024 Test Year annual volume of 2,899,408 cubic meters per year in the general service annual volume forecast in the 2024 Test Year forecast derive only from the changes in number of customers, or does the volume reduction also incorporate the impact of the carbon pricing assumptions on average annual use?
b) Please provide the annual volume forecast for each year through 2032 for general service customers that is used in the longer-term demand forecast used to develop Enbridge Gas's AMP, and the change in annual volumes in these years due to Energy Transition assumptions.
c) Please provide the annual greenhouse gas emissions associated with the annual volume forecast for general service customers for each year through 2032, first assuming these volumes are 100% conventional natural gas, and second, incorporating Enbridge Gas's assumptions as to what percentage of volumes may come from lower-carbon supply sources (please provide the rationale for these assumptions).

1.10-Staff-29

Ref: Exhibit 1, Tab 10, Schedule 4, pp.7-8; Exhibit 3, Tab 2, Schedule 7, pp. 3-4; EB-2021-0002, Decision and Order (DSM Decision), November 15, 2022; 2021 Natural Gas Demand Side Management Annual Verification Report, November 1, 2022, p.4 & p.6.

Enbridge Gas discusses adjustments to its volume forecast to adjust for future demand side management (DSM) Plan activities.

a) Please discuss why Enbridge Gas's 2024 Test Year DSM volumes are lower than the verified first year natural gas savings from 2021 DSM programs in the 2021 Annual Verification Report (93,890,052 m^3).

b) Please discuss how the proposed 2023 Bridge Year and 2024 DSM Test Year forecast volumes reconcile with the recently approved DSM plan that includes materially increased DSM budgets and correspondingly higher natural gas savings targets beginning in 2023 and increasing in 2024 and 2025.
c) Please discuss what updates or assumptions, if any, Enbridge Gas has made or is proposing to its load forecasting methodology (including the longer-term demand forecast through 2032 used to develop Enbridge Gas's AMP) in response to the OEB's DSM Decision that includes expectations from the OEB that DSM programs result in more meaningful reductions in overall natural gas sales volumes, and that approved DSM programs show progress in reducing overall natural gas usage while delivering benefits to ratepayers, including
    - The establishment of an End-of-Term Natural Gas Reduction Incentive (p. 3 of DSM Decision) during the current DSM plan term that runs to the end of 2025;
    - The expectation that "the next DSM Plan will result in meaningful natural gas savings each year between 2026 and 2030 … the OEB expects that, at a minimum, the level of natural gas savings from DSM programs during the next multi-year term will be the equivalent of at least 0.6% of sales in 2026, 0.8% of sales in 2027 and 1.0% of sales in each year from 2028 through to the end of 2030, relative to the prior year on a weather normalized basis." (p. 4 of the DSM Decision).

1.10-Staff-30

Ref: Exhibit 1, Tab 10, Schedule 4, p.8

Enbridge Gas notes that it did not make any additional energy transition-related adjustments in the distribution contract market forecast and that energy transition impacts are inherent and specific to customers in the proposed forecast methodology.

a) Please confirm that the methodology used to develop customer and volume forecasts for the distribution contract market extends beyond the 2024 test year to cover the length of the AMP (through 2032).
b) Please provide the annual volume forecast for each year through 2032 for distribution contract customers that is used in the longer-term demand forecast used to develop Enbridge Gas's AMP.
c) Please provide the annual greenhouse gas emissions associated with these volumes, first assuming these volumes are 100% conventional natural gas, and second, incorporating Enbridge Gas's assumptions as to what percentage of

volumes may come from lower-carbon supply sources (please provide the rationale for these assumptions).

d) For the power generation sector specifically, what are the annual volume forecasts for each year through 2032? Has Enbridge Gas considered how provincial or federal energy transition policy (e.g, the federal government's commitment that Canada's electricity generation would be net zero by 2035) are likely to impact these volumes?

1.10-Staff-31

Ref: Exhibit 1, Tab 10, Schedule 4, p. 8 and Exhibit 3, Tab 2, Schedule 6, p. 8

The 2024 customer additions forecast reflects an adjustment of 321 fewer general service customer additions as a result of energy transition assumptions. As a result of the energy transition adjustment to the customer forecast, the 2024 Test Year general service annual volume forecast is approximately 2,899,408 cubic metres per year lower than would otherwise be the case.

Please state the assumptions and explain the methodology used to reflect an adjustment of 321 fewer general customer additions in the 2024 customer forecast and the resulting reduction of approximately 2.9 million cubic metres in the 2024 general service annual volume forecast.

1.10-Staff-32

Ref: Exhibit 1, Tab 10, Schedule 4, pp.8-11

Enbridge Gas describes energy transition assumptions used for design hour and design day.

a) Please provide more details or cross-references as to how the peak hour trends from the ETSA Reference Case Scenario were used to develop the design hour adjustment factors in Table 3, and how these factors incorporate impacts from future DSM programing, carbon pricing and natural gas commodity pricing, building performance and appliance efficiency improvements for existing customers.
b) Please confirm that these adjustments were applied only to the forecasts of design hour and design day demand, not the annual volume forecasts.

1.10-Staff-33

Ref: Exhibit 1, Tab 10, Schedule 4, pp.13-14

Enbridge Gas notes that changes to its design hour process and inclusion of energy transition factors resulted in reduced system needs and fewer reinforcements, resulting in a reduction of approximately $66 million excluding overheads, to the Distribution Reinforcement Capital forecast in the current AMP relative to the previously filed AMP.

Please provide more details on these reductions; e.g., which potential projects were avoided, deferred, or downsized, and how did the changes to the design hour process and inclusion of energy transition factors specifically contribute to these changes in the AMP?

1.10-Staff-34

Ref: Exhibit 1, Tab 10, Schedule 4, p. 13-14, 18-19, Exhibit 1, Tab 15, Schedule 1, p. 1

Enbridge Gas discusses how the AMP, including the growth asset class incorporates energy transition assumptions. Enbridge Gas notes the increased risk of stranded assets from energy transition and has proposed changes to its deemed capital structure. Enbridge Gas further requests approval of its harmonized customer connection policies.

a) Please describe how Enbridge Gas has considered and attempted to mitigate the risks of stranded assets associated with the proposed capital expenditures identified in its AMP (particularly growth-related capital expenditures including customer connections and distribution/transmission system reinforcement/expansion projects, but also considering system renewal expenditures to extend the service life of assets), related to uncertainty in future volumes or number of customers arising from the energy transition.
b) In Enbridge Gas's opinion, should ratepayers bear 100% of the cost recoveries related to stranded assets?
c) Has Enbridge Gas considered whether the proposal to increase Enbridge Gas's equity ratio may work at cross-purposes to the intent of managing energy transition risk, by increasing rates and potentially increasing the risk of customers exiting the natural gas system?
d) Has Enbridge Gas given consideration to adjustments to its customer connection policies to mitigate the risk of stranded assets associated with new customer connections who may leave the natural gas system before Enbridge's investment is recovered, e.g., by reducing the customer revenue horizon, requiring greater

upfront customer contributions, eliminating the free service allowance for residential infills, introducing exit fees for new customers, etc.? If so, please provide details.

1.10-Staff-35

Ref: reference: Exhibit 1, Tab 10, Schedule 5, Attachment 1

Ref: 2019 Achievable Potential Study, APS (https://www.ieso.ca/2019-conservation-achievable-potential-study)

Ref: Federal Clean Building Strategy Discussion Paper: https://www.nrcan.gc.ca/sites/nrcan/files/engagements/green-building-strategy/CGBS%20Discussion%20Paper%20-%20EN.pdf

The Posterity Group study provided by Enbridge Gas (p. 42, Reference Scenario) includes assumptions related to the Greenhouse Gas Pollution Pricing Act schedule as \$20/tonne CO2e in 2019 rising to \$58.58/tonne C02e in 2023. The study also includes assumptions related to the Natural Gas Commodity Price being 11.75¢/m^3 in 2019 rising to 15.90 ¢/m^3 by 2038 as well as the DSM Budget of \$132 million being held constant. The Posterity Group Reference Case follows the volume and account forecast provided by Enbridge Gas, which reflects 2019 enforced codes and standards.

a) Please provide rationale for each of the above noted assumptions in the Reference Case, given established DSM budgets for 2023 onwards, regular updates to the building code, significantly higher commodity costs since 2019, and established increases to the federal carbon prices after 2023. If the reference case was not meant to reflect established understanding related to DSM budgets for 2023 onwards, regular updates to the building code, significantly higher commodity costs since 2019, and established increases to the federal carbon prices after 2023 of current reality, please explain why it was included in this study.
b) Please describe how the impacts of existing and announced federal and municipal policy and programs, including promotion of electrification and energy efficiency, such as the Federal Canadian green building strategy, have been considered in the reference case. If they have not been considered, please explain why not.

1.10-Staff-36

Ref: reference: Exhibit 1, Tab 10, Schedule 5, Attachment 1

The Posterity Group study provided by Enbridge Gas (p. 19-20, Price Elasticity) includes an explanation that price elasticity is only used to adjust consumption of natural gas in response to price changes of natural gas and carbon price, but that price elasticity considerations did not influence demand for Renewable Natural Gas (RNG), hydrogen or carbon capture and storage (CCS). Prices of RNG, hydrogen and natural gas with carbon capture were not used as factors that change consumption of these fuels.

a) Please provide rationale for use of elasticity of natural gas demand for each sector based on these historical studies, including one study dating back to 1997, given commodity and carbon costs context being significantly different today.
b) Please explain whether any sensitivity analysis was conducted on these elasticity assumptions. If yes, provide and describe the results. If not, please explain why not and please provide a qualitative explanation of the impact of significantly different elasticity rates than used in this study.
c) Please explain the rationale for not considering consumer price elasticity for RNG, hydrogen, and CCS in any scenario, given that the prices of these options are likely to impact adoption by customers.

1.10-Staff-37

Ref: reference: Exhibit 1, Tab 10, Schedule 5, Attachment 1

Ref: 2019 Achievable Potential Study, APS (https://www.ieso.ca/2019-conservation-achievable-potential-study)

The Posterity Group study provided by Enbridge Gas includes the following

- Customer account assumptions for all scenarios (p. 42 of study) in which the Reference Case is calibrated to Enbridge Gas' account forecast which provides growth rates by rate class which are mapped to the sectors in the model as follows: Residential: ~1% annual growth; Commercial: 0.1-0.4% annual growth; and Industrial: decline by 0.7% from 2019-2021 and hold constant from 2022-2038.

- Assumptions around fuel-switching in Electricity-Centric Model (p. 43 of study) as follows: Policy driven fuel switching for Residential/Commercial sectors: New residential and commercials will not connect to the gas grid starting in 2026 and water/space heating in existing buildings will be replaced at equipment turnover rate; space and water heating will be served by Air-source heat pump (ASHP) without gas back-up; and Non-mandated electrification of some industrial end-uses in some sectors as equipment will be replaced.

- In the Electricity Centric scenario (p. 69), annual volume decreases by 22% by 2030 and by 52% by 2038 relative to 2019. Increased electrification of space and water heating, high stringency codes and standards, high carbon pricing, and high DSM spending all lower volumes of gaseous fuels.

a) The 2019 APS found that 62% of natural gas use was in commercial and residential buildings in 2019 (page 12 of 2019 APS). Please explain why the estimated decline in natural gas use is 52% in 2038, given all scenarios anticipate growth in the number of residential and commercial customers, but a declining number of industrial customers.
b) Given heat pumps provide both heating and cooling, was consideration given to replacement of air conditioners with heat pumps, which could also reduce natural gas consumption if those heat pumps are used for heating (i.e. hybrid heating)? If yes, how? If not, why not?
c) Were cold climate heat pumps assumed to be required for all space and water heating? If yes, why? If not, in what circumstances would they be installed?

1.10-Staff-38

Ref: reference: Exhibit 1, Tab 10, Schedule 5, Attachment 1

Ref: OEB Marginal Abatement Cost Curve: https://www.oeb.ca/industry/policy-initiatives-and-consultations/consultation-develop-regulatory-framework-natural-gas, p. 47

The Posterity Group study provided by Enbridge Gas includes the following:

- Customer account assumptions for all scenarios (p. 42 of study) in which the Reference Case is calibrated to Enbridge Gas's account forecast which provides growth rates by rate class which are mapped to the sectors in the model as follows: Residential: ~1% annual growth; Commercial: 0.1-0.4% annual growth; and Industrial: decline by 0.7% from 2019-2021 and hold constant from 2022-2038.

- Assumptions around fuel-switching in Electricity-Centric Model (p. 43 of study) as follows: Policy-driven fuel switching for residential/commercial sectors includes assumptions that these sectors will not connect to the gas grid starting in 2026, and water/space heating in existing buildings will be replaced at the existing equipment turnover rate; Space and water heating will be served by ASHP without gas back-up; and Non-mandated electrification of some industrial end-uses in some sectors as equipment is replaced

- In the Electricity Centric scenario (p. 69), annual volume decreases by 22% by 2030 and by 52% by 2038 relative to 2019. Increased electrification of space and water heating, high stringency codes and standards, high carbon pricing, and high DSM spending all lower volumes of gaseous fuels.
- Information related to RNG, Hydrogen and carbon capture, utilization and sequestration (CCUS) - p. 26, including
    - Renewable Natural Gas: Max: Mandated use of RNG requires about three billion cubic meters per year by 2038, which is 11% of reference case demand in 2038
    - Hydrogen (H2): Max: Hydrogen blending begins in 2025, consumption reaches 12 billion cubic meters per year in 2038, or about 14% of Reference Case demand in 2038, based on mandated hydrogen targets.
    - CCUS: Carbon capture is used for all process heating and power generation in refineries, chemicals, nonmetallic minerals, primary metals, and utilities in the former Union South, phased-in between 2028 and 2037
    - High: Renewable content policies build demand for RNG and H2; H2 strategy overcomes equipment H2 barriers and carbon capture and sequestration (CCS) deployed for industrial end uses/ sectors not using H2

a) The OEB's Marginal Abatement Cost Curve identified the potential for RNG production in Ontario to be 627 million m^3, and in Canada, 2.4 billion m^3. Please provide rationale for assuming 3 billion m^3 of RNG to be available to meet Ontario natural gas demand by 2038.
b) Please provide rationale for assuming 12 billion m^3 of hydrogen to be available to meet Ontario natural gas demand by 2038.
c) Please provide rationale for assuming widespread adoption of hydrogen-fueled space and water heating equipment when it can be assumed that all buildings have access to electricity and would therefore have the choice between hydrogen and electric space and water heating equipment.

d) Please provide rationale for assuming widespread adoption of CCS by 2037 given current level of technical feasibility.
e) For RNG, hydrogen, and CCS assumptions in all scenarios, please explain how uncertainty related to technical feasibility has been accounted for in comparison to decarbonization options that are currently technically feasible (e.g. electric heat pumps, energy efficiency).

1.10-Staff-39

Ref: Exhibit 1, Tab 10, Schedule 6, pp. 13-14

Enbridge Gas describes the objectives of its Energy Transition Plan and also describes how it considers an action to be a 'safe bet' action.

Please describe whether and how Enbridge Gas considered the risk of asset stranding in its objectives for its Energy Transition Plan and also describe how Enbridge Gas considered the risk of asset stranding in considering whether an action is a 'safe bet'.

1.10-Staff-40

Ref: Exhibit 1, Tab 10, Schedule 6, p. 26

CCUS refers to the capture of carbon dioxide (CO2) emissions from facilities or directly from the air, which are then compressed and transported to be permanently stored in geological formations underground or to be used to create products. Enbridge Gas considers CCUS to be a "safe bet" as it is required to significantly reduce Ontario's GHG emissions. Enbridge Gas says that studies show Ontario's unique geology is well suited to store carbon. Enbridge Gas is not requesting OEB approval for any costs or activities related to CCUS in the current application. Enbridge Gas is completing studies to further evaluate potential subsurface CO2 storage regions in Ontario.

Will the studies being completed by Enbridge Gas compare the financial benefits for shareholders and ratepayers of CCUS to the financial benefits of conventional natural gas storage? If not, would Enbridge Gas add this comparison to the scope if its studies?

1.13-Staff-41

Ref: Exhibit 1, Tab 13, Schedule 3, pp. 1-7

Enbridge Gas has requested approval of a new deferral account as part of this application for the enhanced Distribution Integrity Management Program (DIMP), to record general administrative costs, as well as operating and maintenance and ongoing integrity inspection-related costs incurred to implement and execute the enhanced DIMP. Enbridge Gas noted that the program will enable Enbridge Gas to assess the condition of certain distribution assets that are approaching end of life, which allows for appropriate action to be taken, whether that is maintenance work or replacement of the pipe. The enhanced DIMP responds to the OEB's Decision in the St. Laurent Ottawa North Replacement Project (EB-2020-0293) and is above and beyond the requirements set out in code as well as industry best practices. As such, the costs for enhanced DIMP are all incremental to the amounts included in the revenue requirement for the 2024 Test Year forecast. Enbridge Gas anticipates the costs of the program to be $10 million on an annual basis.

a) Please explain why an incremental cost of $10 million for the enhanced DIMP cannot be accommodated within the OM&A budget.
b) Please confirm if an Integrity Management Program for distribution assets is part of the AMP. Please also provide the estimated annual budget for the Integrity Management Program.
c) Enbridge Gas has noted that enhanced DIMP initiatives are above and beyond the requirements set out in code as well as industry best practices and therefore the costs are incremental to the amounts included in the 2024 revenue requirement. Please provide any expenditures (capital or operating) that is included in the 2024 revenue requirement or the AMP and is for initiatives that go beyond codes or industry best practices.

1.14-Staff-42

Ref: Exhibit 1, Tab 14, Schedule 2, pp. 1-9

Enbridge Gas has requested approval to continue the Natural Gas Vehicle (NGV) program as a utility activity and expand the current NGV program for the EGD rate zone to all Enbridge Gas franchise areas. In its evidence, Enbridge Gas notes that although the NGV market has been in place and active for many years, the market has been slow to develop.

a) Please provide Enbridge Gas's view on recent innovation in electric vehicles and battery technology for medium and heavy-duty commercial vehicles.
b) Does Enbridge Gas see a diminishing role of NGV in the next five years due to electrification of commercial and fleet vehicles?

1.14-Staff-43

Ref: Exhibit 1, Tab 14, Schedule 2, pp. 10-13

In the current application, Enbridge Gas has requested approval to modify the current regulatory treatment of the NGV Program to remove the need for revenue imputation, such that the program is funded solely by the monthly service rates charged to participating customers over the life of the program. Under the current NGV program, if the program's annual rate of return (RoR) does not meet or exceed the RoR, revenue is imputed to bring the program's RoR up to the required level. In order to ensure that there is no subsidy from ratepayers, Enbridge Gas has proposed that the final NGV service charge included in the NGV customer's contract will be on a fully allocated basis and will be updated at the time the project is completed. Enbridge Gas further noted that it will file a report as part of its next rebasing proceeding.

a) Please confirm that if the program is unable to meet the RoR, Enbridge Gas's non-participating customers will subsidize the NGV program under Enbridge Gas's proposal.
b) Please explain why the NGV program should be considered a utility activity.
c) Please clarify if an NGV customer has the option to exit the contract before term and whether the term of the contract is set in a manner to recover the entire cost of the project.
d) Enbridge Gas has proposed to file a NGV report as part of its next rebasing application. If Enbridge Gas's rate framework proposal is approved, the next rebasing application will be for 2029 rates. Would Enbridge Gas consider filing a NGV report mid-term (in 2026) in order to assess the performance of the NGV program under the proposed framework?

1.15-Staff-44

Ref: Exhibit 1, Tab 15, Schedule 1, Attachment 1

Enbridge Gas filed its proposed harmonized customer connection policies. The harmonized policies replace the OEB-approved connection policies for the EGD and Union rate zones.

a) Please file the current OEB-approved connection policies for the EGD and Union rate zones.
b) Please provide a summary of the changes to the proposed harmonized customer connection policies from the current EDG and Union rate zone connection policies and explain the basis of these changes.
c) Aside from Enbridge Gas's Infill policy, did Enbridge Gas undertake customer engagement on any other topics related to key changes to its Customer Connection Policy (i.e. CIAC allocation and collection)? If not, please explain why. If yes, please provide a summary of the engagement results.
d) Please outline Enbridge Gas's plans for communicating changes to its customer connection policies to customers.

1.15-Staff-45

Ref: Exhibit 1, Tab 15, Schedule 1, Attachment 1, p.3, Enbridge Gas reply argument in EB-2020-0091, p.69

Enbridge Gas's customer connection policies include a method for calculating normalized system reinforcements costs. In the IRP proceeding (EB-2020-0091), OEB staff submitted that Enbridge Gas should review its economic feasibility policies associated with system expansion to ensure that system reinforcement costs are based on a forward-looking approach that accounts for system needs/constraints identified in the AMP and submit the revised policies in the rebasing case. Enbridge Gas indicated that it would consider including this update into its economic feasibility policies to be presented for approval at rebasing.

Has Enbridge Gas given further consideration to this approach, e.g., varying system reinforcement costs for new customers by geographic area to link to the identified system reinforcement projects and project costs for different geographic areas identified in its 2023-2032 AMP in this application? If yes, please elaborate, and if not, please explain Enbridge Gas's rationale for not proposing to adopt such an approach.

1.15-Staff-46

Ref: Exhibit 1, Tab 15, Schedule 1, Attachment 1, p. 12

Enbridge Gas's customer connection policies state that projects that do not achieve a PI of 1.0 after factoring in the maximum term of 40 years of the SES or TCS, cannot use CIAC in conjunction with the SES or TCS to bridge any economic shortfall. The policies also state that small volume customers (SVC) on a project that are designated for SES or TCS, do not have the option of paying a CIAC in lieu of the SES or the TCS. The policies also state that large volume customers (LVCs) have the option of paying an upfront CIAC in lieu of the SES or the TCS or a combination of both.

Please confirm that LVCs, unlike SVC, have the option of paying a CIAC, a SES or TCS, or a combination of a CIAC and a SES or TCS.

2.1-Staff-47

Ref 1: Exhibit 2, Tab 2, Schedule 1, pp.3-4

Ref 2: Exhibit 1, Tab 8, Schedule 1, Attachment 2 – 2021 Audited Financial Statement (AFS)

In Tables 1 and 2 of Ref 1, the 2021 net book value of PP&E is $14,095 million. The net book value of PP&E in Notes 7 and 8 of the 2021 AFSs is $16,438 million. The differences are shown below. Please explain and reconcile the differences.

2021	**Ref 2 AFS($M)**	**Ref 1 Exhibit 2 ($M)**	**Difference Calculated by OEB Staff ($M)**
Regulated Gross PP&E	20,725		
Gross Intangibles	515		
Total Gross PP&E	21,240	22,221	- 981
Accumulated Depreciation PP&E	- 4,464		
Accumulated Depreciation Intangibles	- 338		
Total Accumulated Depreciation	- 4,802	- 8,127	3,325
Net PP&E	**16,438**	**14,094**	**2,344**

2.3-Staff-48

Ref: Exhibit 2, Tab 3, Schedule 1, p. 4

In order to align the treatment of materials and supplies inventory in Enbridge Gas's 2024 Test Year allowance for working capital, the company proposes to adopt the former Union Gas approach and allocate a portion of total Enbridge Gas materials and supplies to unregulated storage operations and exclude this portion from Enbridge Gas's utility allowance for working capital. Materials and supplies are allocated to unregulated storage operations using a composite rate, based on the proportion of the company's unregulated operating and maintenance (O&M) expenses relative to total O&M expenses.

a) Please identify the typical items included in materials and supplies
b) Please provide the composite rate used to allocate a portion of total Enbridge Gas materials and supplies to unregulated storage operations and also provide the quantum of the costs.

2.3-Staff-49

Ref: Exhibit 2, Tab 3, Schedule 1, p. 13

Enbridge Gas has noted that the average balance of materials and supply inventory has continuously increased over the 2019 to 2021 years and this trend is expected to continue through the remainder of the deferred rebasing term. Enbridge Gas planned for larger lead times of inventory purchases resulting from supply shortages experienced in 2020 to 2022. For the forecast years 2022 to 2024, Enbridge Gas is expecting an approximate 5% annual increase in average costs as there continues to be an expectation that prices will continue to rise with inflation and the company continues to plan for supply shortages.

a) Please confirm if supply shortages related to materials and inventory have eased in 2022 compared to the 2019 to 2021 period.
b) Does Enbridge Gas expect supply shortages to continue in 2024 and beyond? If yes, please provide the basis for this expectation.

2.3-Staff-50

Ref: Exhibit 2, Tab 3, Schedule 2, pp. 2-5

Enbridge Gas has harmonized its lead-lag approach to calculate the Working Cash Allowance requirements. The O&M lead has been set at 44.6 days which is between the previous of 60.9 days for the former EGD and 20.8 days for Union Gas.

Please explain the reasons for the significant different between the O&M lead for EGD and the former Union Gas.

2.4-Staff-51

Ref: Exhibit 2, Tab 4, Schedule 1, pp.6-7

Prior to amalgamation, EGD capitalized interest on all capital projects involving the construction of assets using the weighted average cost of debt instead of the OEB's Construction Work in Progress (CWIP) rate. Union Gas capitalized interest only on capital projects involving construction that exceeded the spend and duration of $1 million and 12 months using the OEB's prescribed CWIP rate. Post amalgamation, Enbridge Gas adopted the OEB's prescribed CWIP rate effective January 1, 2019 and capitalized interest on all capital projects that involve the construction of capital assets in accordance with USGAAP.

Please quantify the annual interest capitalized during the 2024 to 2028 period for capital projects involving construction that does not exceed the spend of $1 million or 12 months.

2.4-Staff-52

Ref 1: Exhibit 2, Tab 4, Schedule 1, pp.3-6
Ref 2: Exhibit 9, Tab 2, Schedule 1, pp.7-8

It states that after the amalgamation, Enbridge Gas identified differences in the historical capitalization treatment for certain costs between EGD and Union Gas due to how EGD and Union Gas applied USGAAP to specific costs. USGAAP Accounting Standard Codification (ASC) 360 – Property, Plant, and Equipment requires these costs to be expensed as incurred, while ASC 980 – Regulated Operations allows the programs and costs to be capitalized if approved by a regulator. The costs Enbridge Gas identified with different capitalization treatments were capitalized by EGD in accordance with ASC 980 and expensed as incurred by Union Gas in accordance with ASC 360.

a) Please explain whether there were costs Union Gas capitalized in accordance with ASC 980, but would have been expensed in accordance with ASC 360 if ASC 980 were not applied.
    i. If yes, please identify and explain the types of these costs, and quantify the annual revenue requirement impact for each type of cost from January 1, 2019, to December 31, 2023.
b) Please also explain whether there were costs EGD capitalized in accordance with ASC 980, but would have been expensed in accordance with ASC 360 if

ASC 980 were not applied, beyond those already identified in the Accounting Policy Changes Deferral Account resulting from harmonization.

   i. If yes, please identify and explain the types of these costs, and quantify the annual revenue requirement impact for each type of cost from January 1, 2019, to December 31, 2023.

c) Please explain whether Enbridge Gas has proposed to capitalize any costs that would be expensed in accordance with ASC 360 if ASC 980 is not applied.

   i. If yes, please identify and explain the types of these costs, and quantify the annual revenue requirement for each type of cost from 2024 to 2028.

2.4-Staff-53

Ref: Exhibit 2, Tab 4, Schedule 2, p.7

It states that a new harmonized overhead capital policy was implemented on January 1, 2020.

a) Please confirm that the harmonized policy was implemented on January 1, 2020 prospectively and not applied retroactively to January 1, 2019. If confirmed,

   i. please explain whether Enbridge Gas had the option of applying the policy changes retroactively. If yes, please explain the rationale for Enbridge Gas's selected implementation date.

   ii. Please explain whether Enbridge Gas is able to quantify the approximate revenue requirement impact of the harmonized policy being implemented on January 1, 2019 instead of January 1, 2020? If yes, please quantify.

b) If not confirmed, please explain why the 2019 impact from the harmonized policy is not reflected in the Accounting Policy Changes Deferral Account.

2.4-Staff-54

Ref: Exhibit 2, Tab 4, Schedule 2, pp.13-14, 21

Enbridge Gas noted that the inputs to the harmonized methodology are updated annually to ensure that the overhead capitalization rates closely reflect the underlying capital activity.

Furthermore, Enbridge Gas intends to eliminate the use of regulatory overhead asset accounts for Union Gas and adopt the EGD approach of presenting capitalized overheads within PPE asset classes.

a) Please explain if Enbridge Gas performs any year-end review or analysis to determine if the capitalized overhead amounts are appropriate. If yes, please describe the review or analysis, and the results of the most recent review or analysis.
b) It states that overhead capitalization rates for 2024 is based on 2021 actuals and is identical to those used for the 2023 budget. Please explain whether Enbridge Gas considered using an average of prior year actuals instead of only using 2021 actuals, and explain Enbridge Gas's rationale for only using 2021 actuals.
    i. Please quantify the capitalized amount if capitalization amounts were based on an average of 2020, 2021 and 2022 actual rates and compare this capitalized amount with the proposed one.
c) With regards to eliminating the use of regulatory overhead asset accounts, please explain whether Enbridge Gas will still be able to quantify the total amount of overhead capitalized if required.
    i. If no, please explain why Enbridge Gas does not feel that this information is necessary.

2.4-Staff-55

Ref 1: Exhibit 2, Tab 4, Schedule 2, pp.15-19
Ref 2: EB-2018-0305, Exhibit JT 1.7, May 8, 2019

Table 2 in Reference 1 shows how cost categories from the prior EGD and Union Gas methodologies align with the harmonized cost categories. Table 3 in the noted reference provides the capitalized amount and capitalization rate under the historical method and harmonized method for 2024. Table 4 provides the O&M/capital expenditure amounts using the historical and harmonized overhead capitalization methodologies for 2020 to 2023.

a) Please indicate whether there are cost categories that were not included in EGD and Union Gas's capitalization of indirect overheads but are proposed to be included in the harmonized capitalization policy.
    i. If yes, please list the cost categories, quantify the costs capitalized and explain why these costs are included for capitalization.
b) Please indicate whether there were cost categories included in EGD and Union Gas's capitalization of indirect overhead that are proposed to be excluded in the harmonized capitalization policy.
    i. If yes, please list the cost categories, quantify the costs no longer capitalized and explain why these costs should not be included for capitalization.

c) Please provide Table 3 annually for 2020 to 2024, with the historical capitalized amount and capitalization rate broken down for each of EGD and Union Gas. If there are material changes to the 2024 amounts presented in Table 3 as a result of finalizing the 2022 financial results, please provide updated 2024 amounts.
d) Table 3 shows the combined historical capitalization rate for EGD and Union Gas using the historical method. The total combined historical capitalization rate is 22.7%. In Reference 2, it states that EGD and Union Gas allocated indirect overheads on a percentage basis to all capital projects. Union Gas's allocation rate for the noted ICMs was 14.8% and EGD's allocation rate for the noted ICM was 36.4%. Please reconcile these rates to the rates shown in Table 3 or the response to Part c) above.

2.4-Staff-56

Ref: Exhibit 2, Tab 4, Schedule 2, p 17 and Table 4, p. 19

Enbridge Gas's harmonized methodology results in total overhead capitalization of $310.5 million for the 2024 Test Year, which represents an overhead capitalization rate of 23.8%.

a) Please provide the capitalization overhead amount, capitalization rate and actual O&M expenses for 2021 and 2022. Also, please provide the total O&M expenses that were actually incurred for 2021 and 2022, irrespective of whether they were capitalized or not.
b) Enbridge Gas has provided the impact of the harmonized methodology for the years 2020 to 2023 and the amount recorded in the Accounting Policy Changes Deferral Account. Please confirm that the amounts recorded for the years 2020 to 2023 are based on the harmonized methodology submitted in this proceeding. If not, please provide a detailed explanation of the methodology used to calculate overhead capitalization for the 2020 to 2023 period.

2.4-Staff-57

Ref: Exhibit 2, Tab 4, Schedule 2, p.20

The Union Gas approach of allocating capitalized overheads based on forecasted capital additions by asset class was adopted for both the legacy EGD and Union Gas rate zones. The approach was implemented in 2021 for the EGD rate zone and resulted in a $1 million increase in depreciation expense. The amount was not recorded in the

Accounting Policy Changes Deferral Account as it was a change in estimate and not a change in policy.

a) Please further explain how the change in allocation approach is a change in estimate and not a change in policy.
b) Please indicate if there are other changes in accounting where Enbridge Gas assessed whether the change represented a change in policy or estimate and Enbridge Gas concluded that it was a change in estimate. If such circumstances existed, please list and explain each of the changes and provide the rationale on why these changes were changes in estimates and not changes in policies.

2.4-Staff-58

Ref 1: Exhibit 2, Tab 4, Schedule 2, p.12
Ref 2: Exhibit 2, Tab 4, Schedule 2, Attachment 1 - EY Report

It states that for Shared Services Costs, a single overhead capitalization rate was calculated by taking a weighted average of Operations Costs and Business Costs rates and non-capitalizable costs (groups that do not support capital activity).

a) Please explain why non-capitalizable costs are included in the calculation of the overhead capitalization rate for Shared Services Costs.
b) Please provide the capitalization rate for Shared Services costs from 2019 to 2024.
c) Please confirm that the 2020 capitalization rate for Shared Services cost per Appendix II of the EY Report is 19.5%. If not confirmed, please provide the 2020 capitalization rate for Shared Services in the EY Report.

2.4-Staff-59

Ref: Exhibit 2, Tab 4, Schedule 2, Attachment 1, Overhead Capitalization Study

Enbridge Gas retained EY to assist management in its determination of the company's harmonized capitalization methodology. As part of the overhead capitalization study, EY reviewed best practices with peers in the study.

a) Please provide the Terms of Reference included in the Request for Proposal.
b) The study notes that EY reviewed best practices. Please provide more information on the peers researched as part of the study without identifying the individual companies. Were any of the peers regulated utilities? How did their

overhead capitalization rate compare to what Enbridge Gas has requested in this application?

c) Did Enbridge Gas incorporate all the best practices that have been outlined in pages 17-18 of the study? If not, please identify the deviations.

2.4-Staff-60

Ref 1: Exhibit 2, Tab 4, Schedule 2, Attachment 1 - EY Report
Ref 2: Exhibit 1, Tab 8, Schedule 2, p.3
Ref 3: Exhibit 2, Tab 4, Schedule 1, Attachment 1 - Enterprise Wide Policy, p.23
Ref 4: Exhibit 2, Tab 4, Schedule 2, pp.11, 17

As noted in the EY Report, EY used a combined approach of relying on accounting guidance, cost causation linkage, discussion with Enbridge Gas personnel, and understanding industry best practices. Page 11 of the EY Report indicates that EY provided alternatives and best practices within the industry.

a) Please discuss the alternatives EY provided and explain the rationale for the overhead capitalization methodology Enbridge Gas adopted.
b) Please indicate whether Enbridge Gas has compared its overhead capitalization methodology and rates with industry peers. If yes, please discuss the results of this comparison.
c) On page 17 of Reference 4, Table 3 shows that compared with the capitalized amounts of $295.1 million from using the historical method, the capitalized amounts of $310.5 million from using the harmonized method has increased by $15.4 million. Please provide the revenue requirement impact of the increase in $15.4 million capitalized amount, considering the impact to OM&A and depreciation.
d) In Reference 2, Enbridge Gas indicated that it believes that it is appropriate to continue to use USGAAP for ratemaking purposes in this application and for the next IR term. One of the differences between USGAAP and IFRS is that IFRS does not allow for administration and other general overheads to be capitalized while USGAAP does. Please indicate which of Enbridge Gas's four cost categories (e.g. Shared Services cost) administration and other general overheads would be capitalized.
    i. Please approximate the amount of administration and other general overheads included in 2024 that would not be eligible for capitalization under IFRS?
e) In the Enterprise Wide Capitalization Policy in Reference 3, Appendix 3 indicates that general and administrative costs which are not directly attributable to capital

projects are expensed as incurred. This would include items such as office support services, human resources, IT, accounting, legal, and executive costs which are not chargeable to a capital project. On page 4 of Reference 4, it defines Shared Services Cost as services from Finance, Legal, Real Estate and Workplace Services, Technology and Information Services. A single capitalization rate was calculated for Shared Services Cost. Please reconcile the capitalization of Shared Services Costs with the Enterprise Wide Capitalization policy which requires costs that are not directly attributable to projects be expensed.

f) Please explain whether Enbridge Gas has incurred incremental costs to implement the harmonized capitalization policy. If yes, please quantify and explain how these incremental costs are treated for regulatory purposes. If it is included in this application for recovery, please provide the reference to this.

2.4-Staff-61

Ref: Exhibit 2, Tab 4, Schedule 2, Attachment 1, Overhead Capitalization Study, Appendix II

In the Appendix, EY has summarized the capitalization rates. For the “Director Group”, please explain the higher capitalization rate for Eastern Region (66.0%) and Toronto Region operations (70%) as compared to the Northern (44.4%), Southeast (45.2%) and Southwest (40.4%) operations.

2.4-Staff-62

Ref 1: Exhibit 2, Tab 4, Schedule 3, pp.6-8
Ref 2: Exhibit 2, Tab 4, Schedule 2, p.14

In Reference 1, it states that the average burden rate is the sum of the incentive, benefits and pension burden rates. Table 1 in Reference 1 provides the burden rate for 2019 to 2022. Table 1 in Reference 2 shows the weighted average burden rate for Pension and Benefit Costs for 2024 to be 41.7%.

a) Please provide a breakdown of the burden rates in Table 2 of Reference 1 to separate out the Pension and Benefit Costs burden rate from 2019 to 2022.
b) Please provide the annual weighted average burden rate for Pension and Benefit Costs from 2019 to 2024.

2.5-Staff-63

Ref: Exhibit 2, Tab 5, Schedule 1, pp. 5-6

Enbridge Gas has indicated that 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 noted that the constraint of $1.2 billion is required to safely operate and maintain the natural gas system, respond to demand growth, invest in low-carbon solutions and ensure on-going reliability and service to customers.

a) Enbridge Gas noted that a constraint of $1.2 billion along with a 2% escalation factor was recommended. Please identify who recommended the constraint.
b) The determination of the constraint seems to be a subjective determination. Please describe any quantitative or econometric analysis that is conducted to support the determination of the constraint on total in-service capital spend.

2.5-Staff-64

Ref: Exhibit 2, Tab 5, Schedule 2, p. 2, Table 1

In Table 1, Enbridge Gas provided a list of Utility Capital Expenditures by Asset Class for the period 2024 to 2028.

One of the spending categories is classified as “Other” with $41.1 million spend in 2024. Please identify the type of spending that is included in this category.

2.5-Staff-65

Ref: Exhibit 2, Tab 5, Schedule 3, pp. 6-7

The GTA Reinforcement project involved the construction of two segments of underground pipeline and associated facilities. 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.

a) Please provide clarification regarding escalation of the construction bid price. Did the bid price escalate after the contract was awarded? If yes, please provide reasons for escalation of the bid price.

b) Please provide a breakdown of the cost components that exceeded the initial budget and explain the variance.

2.5-Staff-66

Ref: Exhibit 2, Tab 5, Schedule 3, Table 5, p. 11

In Table 5, Enbridge Gas provided a list of capital pass-through projects for the period 2013 to 2018 for the former Union Gas.

One of the capital pass-through projects included the Parkway West Reliability Project. The project with an actual spend of $228.4 million exceeded the overall budget by $25.3 million.

a) Please provide reasons for the significant variance between the budgeted and actual spend.
b) Please confirm the contingency amount that was budgeted for the project and explain how it was accounted for in the overall spend.

2.5-Staff-67

Ref: Exhibit 2, Tab 5, Schedule 3, Table 10, p. 29

Table 5 provides a comparison of utility capital expenditures for 2022 and 2023.

Please update the table including providing actual capital expenditures for 2022. Please also update the explanation of any variances that have not been provided in the evidence.

2.5-Staff-68

Ref: Exhibit 2, Tab 5, Schedule 3, p. 35

Enbridge Gas has provided a description of some integration projects. The GTA West Site project will dispose of the Brampton Colony Court, Burlington Mainway and Milton facilities and construct a new asset with an estimated in-service of 2023. The GTA East Site project will dispose of the Coburg and Peterborough site and construct a new consolidated facility with an estimated in-service of 2023. The facility projects are being implemented to efficiently combine the operations teams.

a) Please identify any other realignment projects that have the potential of consolidating existing facilities within the Enbridge Gas franchise area.
b) Please provide the estimated savings in annual operating costs as a result of the consolidation projects noted above.

2.6-Staff-69

Ref: Exhibit 2, Tab 6, Schedule 1, p.4, EB-2020-0091 decision, July 22, 2021 (chapter 10)

Enbridge Gas proposes to file an AMP every two years, and an update or addendum to the AMP in the intervening years, in the annual rates case or as directed by the Integrated Resource Planning (IRP) Framework. Enbridge Gas indicates that it will not be requesting any approvals of the AMP (or AMP update/addendum).

a) For system needs identified in the AMP that do not require OEB approval in the form of a Leave to Construct application (should a facility solution be chosen), or an IRP Plan (should an IRP alternative be chosen), please confirm that Enbridge Gas would make a final determination on the preferred approach to meeting this system need on its own, taking account of updated information in its IRP assessment as appropriate.
b) Please provide an update on Enbridge Gas's implementation of the broader Stakeholder Engagement Process (chapter 10 of the IRP decision) to gather more information prior to making a determination on the preferred approach to meeting system needs in the AMP, particularly the intent to use Stakeholder Days to discuss needs/constraints identified in the AMP and the plans to address such items through IRP, and the use of an IRP website to facilitate the broad sharing of information on IRP stakeholdering efforts.
c) Please confirm that the updated AMP information filed on an annual basis would include the most recent results of Enbridge Gas's IRP Assessment Process for system needs, including reporting on those system needs where a negative binary screening or technical/economic evaluation resulted in no further assessment of IRPAs, as required by the IRP Decision.

2.6-Staff-70

Ref: Exhibit 2, Tab 6, Schedule 1, pp. 35-48, Tables 4, 5 and 6

Enbridge Gas's projected spend totals \$6.9 billion from 2024 to 2028 and \$13.8 billion from 2023 to 2032.

a) In Tables 4, 5 and 6, Enbridge Gas has provided a list of several large projects such as Dawn C Compression, Hamilton Industrial Reinforcement, Dawn to Parkway Expansion, Looping to Comber Transmission and Panhandle Line Replacement. Please confirm that the cost of these projects will be recovered from Enbridge Gas customers over the next 40 to 50 years.
b) Does Enbridge Gas expect to see a significant reduction in the consumption of natural gas in Ontario within the next 20 years? If yes, please describe the steps that Enbridge Gas has taken or intends to take to ensure that ratepayers are not burdened with cost recovery related to stranded assets.
c) Please explain how these projects would be considered essential and prudent considering Canada's carbon reduction goals.

2.6-Staff-71

Ref: Exhibit 2, Tab 6, Schedule 1, pp. 39-48, Tables 4, 5 and 6

Based on the 2023 to 2032 capital expenditure forecast, Enbridge Gas does not anticipate seeking Incremental Capital Module (ICM) recovery for these projects.

Please confirm that Enbridge Gas does not intend to seek ICM recovery (if the OEB approves an IRM framework that includes ICM eligibility) for any of the projects listed in Tables 4, 5 and 6 (Tab 6, Schedule 1).

2.6-Staff-72

Ref: Exhibit 2, Tab 6, Schedule 2, Asset Management Plan (AMP), pp. 66-75

The 2022-2032 customer connections capital expenditure was informed by the 2022 Long Range Plan (LRP) forecast without Energy Transition assumptions. When the 2022 LRP including Energy Transition forecast was produced, Enbridge Gas compared it to the 2022 LRP forecast without Energy Transition assumptions. The comparison showed that the Energy Transition assumptions reduced the capital expenditure forecast by $60,000 in 2024 and by $44 million over the 2024-2028 rebasing period. Enbridge Gas clarified that the AMP capital expenditures have not been revised to reflect the forecast with Energy Transition assumptions as the impact was minimal.

a) Please confirm that Enbridge Gas has not reflected the impact of Energy Transition in the proposed capital expenditures over the 2024 to 2028 period or in the proposed rate base for the 2024 Test Year. Please discuss your response.

b) Please provide the basis for the reduction of $44 million in capital expenditures over the 2024 to 2028 period to reflect Energy Transition assumptions.

2.6-Staff-73

Ref: Exhibit 2, Tab 6, Schedule 2, AMP, pp.68-69

Enbridge Gas discusses its distribution system reinforcement investments and forecasting methodology. Enbridge Gas notes that it creates a reinforcement plan to sustain the 10-year customer growth forecast.

Does the same 10-year planning horizon typically apply for transmission system reinforcement projects? Has Enbridge Gas considered using a shorter planning horizon for sizing reinforcement projects given uncertainties in future demand arising from energy transition?

2.6-Staff-74

Ref: Exhibit 2, Tab 6, Schedule 2, AMP, section 5.1.9.3, p. 73

In 2020, Enbridge Gas submitted several project proposals seeking funding under Phase 2 of the Government of Ontario's Natural Gas Expansion Program. In 2021, the Government of Ontario awarded Enbridge Gas approximately $214 million to support 27 Phase 2 projects. At the time it filed its project proposals, the total estimated capital cost of the 27 projects was approximately $335 million. As a result, Enbridge Gas's net capital investment at that time was estimated to be approximately $121 million.

Capital expenditures associated with the 27 Community Expansion projects are not included in Enbridge Gas's AMP capital expenditures.

The Community Expansion projects are subject to a 10-year rate stability period.

Based on correspondence (General EB-2022-0001, OEB letter to Enbridge Gas regarding East Perth/Brunner) and leave to construct applications (Haldimand Shores EB-2022-0088, Bobcaygeon EB-2022-0111, Mohawks of the Bay of Quinte EB-2022-0248) filed with the OEB, OEB staff observes that the estimated capital costs of several of Enbridge Gas's projects have changed since the original estimates were made in 2020.

In the case of the Hamilton Airport Expansion Project (EB-2022-0001, Enbridge Gas letter to the OEB regarding the Hamilton Airport Expansion Project), the current estimated net capital cost is lower than the original estimate. Based on a letter filed regarding its Hamilton Airport Expansion Project (EB-2022-0001, Enbridge Gas letter to the OEB responding to questions about the Hamilton Airport Expansion Project), Enbridge Gas appears to propose to include in rate base the original net capital cost associated with any Community Expansion projects that will be in-service prior to the end of 2024.

a) Please confirm that Enbridge Gas proposes to include in rate base the original net capital cost associated with each of the 27 Community Expansion projects that will be in-service prior to the end of 2024. Also, please provide a list of the community expansion projects that will be in-service prior to the end of 2024.
b) Please provide the original estimated net capital cost and most up-to-date estimated net capital cost for the 27 Community Expansion projects.
c) For projects where the current estimated net capital cost is lower than the original net capital cost estimate, please confirm that Enbridge Gas intends to include a capital cost in rate base that it does not believe will be incurred on an actual basis (i.e., the incremental net capital cost set out in the original estimate relative to the latest estimate).
d) Based on information currently available to Enbridge Gas, please comment on how many of the 27 Community Expansion projects are likely to have updated net capital costs that are lower than originally estimated and the magnitude of the variances.

2.6-Staff-75

Ref: Exhibit 2, Tab 6, Schedule 2, AMP, pp. 86-111 and p. 119

The steel main reliability model forecasts the number of annual leaks will increase steadily over the next 20 years. By 2040, Enbridge Gas predicts that the number of leaks will have increased by approximately 10-fold. The significant increase in corrosion leaks is forecast to take place as a portion of the mains population approaches 100 years of age. This occurs between 2037 and 2057.

Enbridge Gas has developed a Proactive Vintage Steel Replacement Program to mitigate the predicted future risk that results from some of Enbridge Gas's oldest steel mains reaching the end of their useful life and beginning to fail. The goal of the Proactive Vintage Steel Replacement Program is to avoid the risk that these aging assets pose by renewing them. Enbridge Gas's selection process identifies approximately 5,100 km of the 17,423 km of Vintage Steel mains for renewal based on their predicted future risk. The Proactive Vintage Steel Replacement Program proposes renewing these targeted mains over a 20-year term.

a) Please provide the total costs associated with the Proactive Vintage Steel Replacement Program for the year 2023-2032.
b) Please provide the estimated cost of replacing the 5,100 km of Vintage Steel mains over the 20-year term.
c) Please indicate if Enbridge Gas intends to replace all vintage steel mains over an extended period or if some pipelines will be abandoned?
d) Considering the government's carbon reduction programs and the goal to significantly reduce greenhouse gas emissions, has Enbridge Gas assessed the possibility of abandoning some of the Vintage Steel Mains under a low carbon environment and meeting the needs through electrification or other alternatives? If not, please explain why.
e) Please indicate if Enbridge Gas has conducted any simulation or analysis to assess the impact on its distribution system if some of the Vintage Steel Mains identified for replacement are abandoned. If no such analysis has been done, please indicate if Enbridge Gas intends to do so.
f) If the vintage steel mains are replaced, does Enbridge Gas expect the assets to be used and useful for the next 40 years?

2.6-Staff-76

Ref: Exhibit 2, Tab 6, Schedule 2, AMP, p. 185

Enbridge Gas has stated that several compressors may become exposed to obsolescence risk over the next 10 years. With 15 compressor units exceeding 50 years of age within the next 10 years, the risk of declining reliability and parts availability is increasing.

a) Please confirm if Enbridge Gas intends to replace all 15 compressors over the next 10 years. If yes, what is the estimated cost of replacing the 15 compressors?
b) Considering the Government of Canada's commitment to reducing GHG emissions by 40% below 2005 levels by 2030, how has Enbridge Gas determined that all old compressors need to be replaced under a declining load scenario?
c) Please confirm that if volumes decline by 10% in 2030, all 15 compressors would still need to be replaced. Please explain your response.

2.6-Staff-77

Ref: Exhibit 2, Tab 6, Schedule 2, AMP, pp. 211-218

In its AMP, Enbridge Gas noted that it has a total of 92 properties as part of its real estate inventory. The facility assessment results in Section 5.4.5.4 indicate that a number of facilities have been categorized as obsolete and scheduled for renovation or new build.

a) Considering the amalgamation of EGD and Union Gas, and the flexible work environment post COVID, does Enbridge Gas see any opportunities for disposing of or consolidating the obsolete facilities? Please provide a detailed response.
b) Has Enbridge Gas done any cost-benefit analysis of operating with fewer facilities? If no, why not?

2.6-Staff-78

Ref: Exhibit 2, Tab 6, Schedule 2, AMP, pp. 240-248

The Technology and Information Services assets include a number of key applications that provide critical functionality to Enbridge Gas employees and customers. Packaged applications include commercial off the shelf software. Developed applications are custom built solutions by Enbridge Gas to meet business requirements.

Please provide a list of all software and applications that have been discontinued as a result of replacement, but their net book value is being included into rate base. Also, please provide the reasons for their replacement.

2.6-Staff-79

Ref: Exhibit 2, Tab 6, Schedule 2, AMP, p. 256

The capital plan was optimized from 2023 to 2032 using the Optimize Portfolio of Solutions step in the Asset Management Process (outlined in section 4.3.3). The optimized result and significant projects (Net Base Capex > $10M) were reviewed with all asset managers and business stakeholders. The evidence notes that Enbridge Gas removed an average of $100 million per year of capital spend over the 10-year plan. This reduction was achieved through using optimization to assign timing to investments in order to maximize the value of the portfolio and through reductions Enbridge Gas made in consultation with internal stakeholders.

a) Please provide a list of all projects (Net Base Capex > $10M) that were removed for 2023 and 2024.
b) Please clarify whether the projects removed during the 10-year plan have been deferred or cancelled. For projects that have been cancelled, please provide a list of such projects for the 2023 to 2032 timeframe.

2.6-Staff-80

Ref: Exhibit 2, Tab 6, Schedule 2, AMP, p. 271

The total average capital spend for the Distribution Pipe asset class is forecast to be $361 million over the 10-year capital plan. Enbridge Gas provided a figure (6.2-5) that shows 4 years of historical spend and the projected 10-year spend profile. The 2022 forecast data was produced before Enbridge Gas's 2023-2032 capital plan was created and before the OEB's St. Laurent Leave to Construct Decision (EB-2020-0293) was received.

Please provide an updated figure and table with the amounts that reflects 2022 actuals and the OEB's St. Laurent Leave to Construct Decision.

2.6-Staff-81

Ref: Exhibit 2, Tab 6, Schedule 2, p.280, 284, Appendix B; Exhibit 7, Tab 1, Schedule 2, pp.6-7; EB-2020-0091 decision, July 22, 2021, p. 35

Enbridge Gas discusses its IRP assessment results and technical evaluation project review.

a) Please provide more details on Enbridge Gas's current procedure as to how Enbridge Gas evaluates the technical viability of potential Integrated Resource Planning Alternatives (IRPAs) to reduce peak demand to the degree required to meet the identified system need. Specifically, please describe: which investment categories Enbridge Gas considers to be driven in part or in full by peak demand (and thus not automatic failures in the technical evaluation); how Enbridge Gas determines the level of peak demand reduction required to meet a system need; how Enbridge Gas assesses the technical potential of geotargeted energy efficiency to meet a system need; how Enbridge Gas assesses the technical potential of other types of IRPAs (e.g., demand response, supply-side alternatives) to meet a system need.

b) Do the investment categories considered to be driven by peak demand for the purposes of the IRP assessment align with Enbridge Gas's cost allocation methodology (Exhibit 7), which categorizes functionalized assets and operating costs as demand, commodity, and customer? Please describe and explain the rationale for any differences – i.e., if there are assets that are categorized (in part or in full) as demand costs (capacity-related costs) for the purposes of cost allocation, but not considered to be driven by peak demand for the purposes of the IRP assessment.
c) Appendix B shows the status of IRP assessments for all system needs that are direct customer connections as "planned" but notes the concern that "EGI (Enbridge Gas) is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers." Does Enbridge Gas expect that these system needs will therefore be an automatic failure in the technical evaluation? What is Enbridge Gas's approach to receiving connection requests, regarding informing customers of options to use energy sources other than natural gas, and how, if at all, is Enbridge Gas implementing the optional approach noted in the IRP decision that "Enbridge Gas can also seek opportunities to work with the IESO or local electricity distributors to facilitate electricity-based energy solutions to address a system need/constraint, as an alternative to IRPAs or facility projects undertaken by Enbridge Gas"?

2.6-Staff-82

Ref: Exhibit 2, Tab 6, Schedule 2, p.285

Enbridge Gas indicates that a technical evaluation has not yet been completed for all system needs in the AMP, and that it will provide an updated version of Appendix B in 2023 to document the progress of IRP evaluations for system needs.

a) Please clarify when this update will be provided, in relation to the schedule for this proceeding.
b) Please confirm that, for all projects in the 2023-2032 AMP that passed the binary IRP screening, Enbridge Gas would complete a technical evaluation of IRPAs, prior to implementing a solution (whether the default facility solution in the AMP or an IRPA). If not confirmed, please provide additional details as to the circumstances under which Enbridge Gas might implement the default facility solution without a technical evaluation of IRPAs, and the number/cost of projects that might be affected.
c) With reference to Appendix B, please provide a list of the projects that would fall into the indicated focus areas used to prioritize technical evaluations

(investments with in-service dates of 2028 and prior, with highest costs and/or geographic areas with the highest forecast growth).

2.6-Staff-83

Ref: Exhibit 2, Tab 6, Schedule 2, Appendix B; Exhibit 4, Tab 2, Schedule 6, p. 14

In Exhibit 2.6.2, Appendix B, the estimated capital cost of the Hydrogen Blending Phase 2 project (investment code 736974) is given as $9.05 million. In Exhibit 4-2-6 the estimated capital cost of the Hydrogen Blending Phase 2 project is given as $7 million.

Please provide the current estimated capital cost of the Hydrogen Blending Phase 2 project.

3.2-Staff-84

Ref: Exhibit 3, Tab 2, Schedule 2, p. 4

Enbridge Gas engaged Guidehouse Canada Ltd. (Guidehouse), to undertake a comparative review of natural gas volume forecast approaches. The study compared Enbridge Gas's approved gas volume forecast methods to that of comparable utilities in North America. The study reviewed the following areas:

- Heating Degree Day Forecasting
- Weather Normalization
- General Service Customer Count Forecast
- General Service Average Use per Customer Forecast
- General Service Volume Forecast
- Contract Market Volume Forecast
- Revenue Stability & Deferral Accounts

a) Please indicate if Guidehouse reviewed the accuracy of the methodologies across the comparable utilities. If no, why not?
b) Please confirm if the study ranked the methodologies of Enbridge Gas and the comparator utilities across certain metrics (accuracy, data selection, applicability, duration etc.). If not, please explain why the study was limited to only describing and comparing methodologies.

3.2-Staff-85

Ref: Exhibit 3, Tab 2, Schedule 2, p. 20

The Guidehouse report notes that none of the comparator utilities' including Enbridge Gas's forecast methodologies considered more recent trends (electrification, renewable natural gas etc.) as part of their core forecasts.

a) Please confirm if Enbridge Gas has considered emerging trends (use of electricity to replace natural gas, use of heat pumps, hydrogen blending, renewable natural gas etc.) in their forecasting methodologies. If no, please provide reasons and the drawbacks of not using these factors in developing volume forecasts.
b) Please indicate if Enbridge Gas intends to consider these emerging trends in future forecasting methodologies.

3.2-Staff-86

Ref: Exhibit 3, Tab 2, Schedule 2, p. 26

The Guidehouse study discusses revenue stabilization approaches used by utilities to reduce weather risk. One of the utilities uses a dead-band for managing revenue risks from weather and a recovery or refund is applied when the threshold has been met. Revenue deficiency recovery amounts are capped such that any recovery charges cannot result in the utility earning a rate of return on common equity in excess of its approved percentage.

a) Has Enbridge Gas considered using a dead-band in its average consumption deferral accounts or the Volume Variance Account as a Revenue Stability Mechanism? If no, why not?
b) Would Enbridge Gas consider foregoing recovery related to lower average consumption if its earnings are over the OEB-approved return on common equity? If yes, at what earnings over and above the OEB-approved return on common equity would Enbridge Gas consider foregoing recovery related to weather risks?

3.2-Staff-87

Ref: Exhibit 3, Tab 2, Schedule 3, pp. 3-11

In its evidence on load forecast methodologies, Enbridge Gas discussed the different approaches to forecast heating degree days. For the East weather zone, Enbridge considered two methodologies: the 10-year moving average and Energy Probe method. Based on the overall ranking, Enbridge Gas has proposed to use the 10-year moving average methodology for forecasting degree days for the East weather zone.

a) In Table 3 (p. 11), Enbridge Gas provided the results of the different methodologies and shown how the results compare to the actual degree days. For the year 2016, the Energy Probe method has an outcome of 3,935. Please confirm that the output is accurate and if possible, please redo the calculations and provide the outcome.
b) Please provide the degree days for 2024, if Enbridge Gas were to select the Energy Probe method for forecasting degree days for the East weather zone.

3.2-Staff-88

Ref: Exhibit 3, Tab 2, Schedule 3, p. 16

In its evidence on load forecast methodologies, Enbridge proposed to use the 10-Year moving average for forecasting degree days for the West weather zone.

Figure 3 in the evidence shows the West Weather Zone Actual vs. Fitted/Forecast Heating Degree Days (HDD) which illustrates the accuracy of the different methodologies. Please provide a revised figure that also shows the Energy Probe results.

3.2-Staff-89

Ref: Exhibit 3, Tab 2, Schedule 5, Attachment 1, pp. 3-5

Enbridge Gas has proposed to use 15°C in the calculation of its HDD starting in 2024. The 2024 Test Year HDD forecast for base temperature of 15°C were determined by converting the daily HDD forecast calculated based on 18°C and summing these daily values over the year. Enbridge Gas provided the 2024 annual HDD forecast based on 18°C and 15°C. OEB staff has reproduced the table below showing the difference and percentage decline over 18°C.

Weather Zone	Methodology	HDD Forecast - 18°C	HDD Forecast - 15°C	Difference	% Decline
Central	50/50 Hybrid	3,560	2,764	796	22.4%
East	10-Yr MA	4,338	3,479	859	19.8%
West	10-Yr MA	3,398	2,605	793	23.3%
South	10-Yr MA	3,781	2,941	840	22.2%
North	10-Yr MA	4,673	3,746	927	19.8%

a) Please confirm that the numbers and calculations shown in the above table are accurate.
b) Please confirm that the volume forecast underpinning the proposed 2024 rates uses HDD values resulting from using a base temperature of 15°C.
c) The 2024 Test Year HDD forecast for base temperature of 15°C were determined by converting the daily HDD forecast calculated based on 18°C and summing these daily values over the year. Please describe in detail how HDD values using a base temperature of 15°C were determined by converting the daily HDD forecast that was based on a temperature of 18°C.
d) Enbridge Gas notes that heating starts at a temperature below 15°C for about 98% of consumption observations. Please reconcile this observation with the calculations provided in the table above that shows an approximate 20% decline in the average HDDs as a result of using 15°C as the base temperature.

3.2-Staff-90

Ref: Exhibit 3, Tab 2, Schedule 5, Attachment 4

Enbridge Gas has provided the weather coefficients by month derived from the regression equations to determine weather normalized actual average use. For some of the regression equations, Enbridge Gas has added an autoregressive term (AR) to improve regression results.

For the Central and West weather zones, the p-value of the AR used to improve the regression results is more than 0.05.

a) Please provide an interpretation of the results considering the high p-value.
b) Please run the regression excluding the AR term and provide the results for the two weather zones.

3.2-Staff-91

Ref: Exhibit 3, Tab 2, Schedule 6, pp. 7-8

Enbridge Gas notes that housing starts increased dramatically in 2021, reaching levels unseen since the mid-1970s. Builders are expected to boost completions in 2022 and 2023. As a result, housing activity is expected to remain strong until 2024. Even though the housing starts forecast remains strong, Enbridge Gas expects customer additions to remain flat until 2024 due to economic uncertainties, specifically the increase in interest rates. Accordingly, Enbridge Gas has forecasted 41,648 new customers for the 2024 Test Year.

a) Please update Attachment 1 in Exhibit 3, Tab 2, Schedule 6 to show actual customer additions for 2022. If required, please provide comments for any variance from the estimate included in the original evidence.
b) Enbridge Gas notes that housing activity is expected to remain strong until 2024. Please explain why Enbridge Gas expects customer additions to remain flat in 2024. Does Enbridge Gas expect that construction projects will not be completed as planned in 2023 and 2024 or whether some proportion of new construction will remain unsold?
c) Please provide the estimated impact of rising interest rates on the customer additions forecast for 2023 and 2024.

3.2-Staff-92

Ref: Exhibit 3, Tab 2, Schedule 7, pp. 3-4

The general service volume forecast is adjusted for future DSM plan activities. DSM volumes used to adjust the base volume forecast are provided in Table 1 (page 4 of Schedule 7).

Please explain why the 2023 DSM volumes are significantly lower than volumes for 2024.

3.2-Staff-93

Ref: Exhibit 3, Tab 2, Schedule 8, p. 4 and Exhibit 1, Tab 2, Schedule 1, p. 13

The Government of Canada has committed to reducing GHG emissions by 40% below 2005 levels by 2030 and provincial climate policy development and implementation is under way, with some policies already in place. Enbridge Gas has proposed to develop the customer and volume forecast for all customers in the distribution contract market through customer specific bottom-up forecasts for existing and forecasted new customers.

Please confirm if accounts managers have had discussions with contract customers regarding their long-term volume forecasts considering the GHG reduction goals of the government. If such discussions have not taken place, please provide reasons and explain why such information is not relevant to develop the 10-year AMP.

3.2-Staff-94

Ref: Exhibit 3, Tab 2, Schedule 8, Attachment 2, p. 2

The Table in Attachment 2 shows the average customers in the contract market for the years 2019 to 2024.

a) Please provide a revised table that shows the actual numbers for 2022.
b) The number of customers in Rate 25 (Union rate zone) shows a significant decline from 65 customers in 2022 to 25 customers in 2023 and 2024. Please provide reasons for the significant decline in the forecasted number of Rate 25 customers in 2023 and 2024.

3.3-Staff-95

Ref: Exhibit 3, Tab 3, Schedule 1, pp. 3-9

Enbridge Gas has provided the normalized throughput volumes on a historical and forecast basis for the general service and contract market in Tables 1 and 2. The normalized gas supply and delivery revenues on a historical and forecast basis for the general service and contract market have been provided in Tables 3 and 4.

a) Please update the above referenced tables with 2022 actuals.
b) The total normalized general services volumes have declined over the 2019 to 2024 forecast period, from 15.86 million 10^3m^3 in 2019 to 15.69 million 10^3m^3 in

2024. Please explain why the 2024 normalized throughout is forecasted to decline from 2019.

3.5-Staff-96

Ref: Exhibit 3, Tab 5, Schedule 1, Attachment 1, pp. 3-4

Enbridge Gas has provided comparisons of Other Revenues for the historic and forecast years.

Please provide the relevant revised tables that show 2022 actuals.

3.6-Staff-97

Ref: Exhibit 3, Tab 6, Schedule 1, pp. 1-7

In its application, Enbridge Gas proposed harmonization of its heat value methodology. For the Annual Heat Value (AHV) calculation, Enbridge Gas has proposed to move from three to two AHVs called the Enbridge Gas North heat value and Enbridge Gas South heat value.

a) In Figure 1 on page 7, Enbridge Gas has provided a graphical representation of the heating values of the Enbridge Central Delivery Area, Enbridge Eastern Delivery Area (EEDA) and Union rate zones (North & South) over the 2016 to 2021 period. Please explain the increase in heating value from 2016 to 2021 for the EEDA and Union North rate zone.
b) What is the impact of Enbridge Gas's proposal regarding harmonization of annual heating values on 2024 rates?

4.2-Staff-98

Ref: Exhibit 4, Tab 2, Schedule 1, pp. 14-15

Enbridge Gas holds third-party transportation contracts that are used to meet in-franchise demands on the distribution system for both sales service and DP customers. Enbridge Gas proposes to allocate the costs of these transportation contracts to in-franchise rate classes for recovery in delivery rates consistent with the purpose of the contracts. This proposal is consistent with the former Union Gas's approach for the cost of the two St. Clair Pipeline LP contracts that are recovered in in franchise delivery rates. In Table 3, Enbridge Gas has provided a list of these third-party contracts. One of these contracts is the Dawn to Union ECDA contract required by TransCanada to maintain flow into Enbridge Gas's system in Burlington.

a) Please explain why a contract that is required by TransCanada to maintain flow into Enbridge Gas's system should be recovered in in-franchise delivery rates.
b) Please confirm that volumes flowing as a result of the Dawn to Union ECDA contract is used to meet in-franchise demands on the distribution system.

4.2-Staff-99

Ref: Exhibit 4, Tab 2, Schedule 3, pp. 1-2

Enbridge Gas as the provider of last resort, endeavours to size its pipeline systems to minimize the risk of failure in its ability to deliver gas to its customers. Customers are inherently risk averse and expect to be able to heat their homes and operate their businesses on the coldest day.

Please indicate the number of times that Enbridge Gas (former EGD and Union Gas) has had a major outage in the past 20 years during cold days, the cause of the outage and the number of customers impacted.

4.2-Staff-100

Ref: Exhibit 4, Tab 2, Schedule 3, pp. 3-4 and p. 33

EGD used a probabilistic method with one in five-year recurrence level to determine the design day. The EGD method was specifically designed for gas supply planning functions, which was to support contracting for space on upstream transportation systems. Enbridge Gas has proposed to adopt the method used by the former Union Gas with certain modifications, to determine the design criteria. Enbridge Gas has proposed that the design criteria be determined using the coldest day on record, as measured by heating degree days for a specified timeframe, adjusted for wind speed (set temperature method). The proposed harmonized method increases the design day demand by 0.4% or 34 TJ/day and includes an increase of 113 TJ/day in the EGD CDA offset by decreases in the EGD EDA, Union North and Union South rate zones of 17 TJ/day, 17 TJ/day and 44 TJ/day respectively. As a result of the proposal to use the Union Gas 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.

a) Please confirm if EGD was unable to deliver natural gas to its customers on a cold day within the former EGD CDA at any time in the past 20 years. If yes, please provide details and the cause of disruption.
b) If Enbridge Gas has been able to meet its requirements within the former EGD CDA, why is an increase in the design day demand of 113 TJ/day reasonable?
c) Enbridge Gas has noted that the net increase of 34 TJ/day will not require incremental transmission or storage facilities. Please explain how the additional design day demand of 34 TJ/day will be met.
d) Enbridge Gas has noted that harmonization of the design day methodology will lead to a decrease in the design day demand in the EGD EDA, Union North and Union South. Please explain if Enbridge Gas proposes to de-contract for transportation capacity within certain delivery areas to account for the decrease in design day demands.
e) Please outline the impact on the Enbridge Gas distribution system if the existing design day demand methodology is continued.

4.2-Staff-101

Ref: Exhibit 4, Tab 2, Schedule 3, pp. 21-22

In Figure 1 on page 21, Enbridge Gas illustrated the hourly demand change over the design day. Enbridge Gas notes that customers typically consume gas in a diurnal pattern, low at night when people are sleeping and higher during the day when people are active. As the morning hour approaches, gas use increases to heat buildings and gas burning appliances such as hot water heaters. This usage peaks around 8 a.m. along with a secondary smaller increase in the late afternoon and early evening.

a) Please confirm if the above trend has shifted post COVID with work from home and flexible work arrangements. Is there a softening of the Design Hour Demand during the peak period?
b) Please provide a figure that shows the hourly demand change over the design day in 2020 and 2021 (coldest day in 2020 and 2021).

4.2-Staff-102

Ref: Exhibit 4, Tab 2, Schedule 3, Attachment 1, pp. 11-14

Enbridge Gas engaged Guidehouse to conduct a comparative analysis of utility common practices for design day demand modelling, used for Gas Supply Planning in upstream contract sizing. One of the utilities that Guidehouse discussed was National

Grid. National Grid uses the probabilistic approach to Design Day for its gas utilities serving Boston and Rhode Island, where the Design Day standard is based on once-in-35 years probability of occurrence of extreme weather conditions in Boston and once in 58.92 years in Rhode Island. In the Boston Gas and Rhode Island service territories, National Grid conducts a cost-benefit analysis that considers cost and risk of an outage compared to levels of investment in infrastructure and other solutions as part of its gas supply planning process.

To confirm its Design Day selection, National Grid Boston Gas uses the following approach:

1. Perform a statistical analysis of the coldest days recorded over a historical period.
2. Conduct a cost-benefit analysis to evaluate the cost of maintaining the resources necessary to meet Design Day demand versus the cost to customers of experiencing service curtailments.
3. Identify a design day standard that would maintain reliability at the lowest cost.

a) Please provide Enbridge Gas's opinion on the approach to Design Day used by National Grid Boston Gas.
b) Did Boston Gas need to curtail supply as a result of its approach to Design Day on a very cold day within the last 30 years? If yes, please provide details.
c) Has Enbridge Gas conducted a cost-benefit analysis to evaluate the cost of maintaining the resources necessary to meet Design Day demand versus the cost to customers of experiencing service curtailments, at least, as it pertains to interruptible customers?

4.2-Staff-103

Ref: Exhibit 4, Tab 2, Schedule 6; EB-2019-0294, Exhibit B, Tab 1, Schedule 1, p. 17

In its decision on Enbridge Gas's Low Carbon Energy Project application, the OEB approved the request for a rate rider to compensate customers in the blended gas area for the additional extra costs associated with the increased volumetric requirements for blended gas as compared to conventional natural gas. As part of its request, Enbridge Gas stated that it would absorb the costs associated with the rate rider during the deferred rebasing period.

Consistent with the decision in Enbridge Gas's Voluntary RNG Program,[5] the OEB approved the costs for the rate rider to flow through the Earnings Sharing Mechanism (ESM) calculation. The OEB stated that it understands that there is a possibility that all customers will bear a portion of these costs if Enbridge Gas's earnings reach a level that require them to be shared with customers.

Please explain how Enbridge Gas proposes to manage the costs of the rider after rebasing. In particular, does Enbridge Gas propose to continue to absorb the costs associated with the rate rider after rebasing?

4.2-Staff-104

Ref: Exhibit 4, Tab 2, Schedule 6

Enbridge Gas provides information on its near-term plans related to hydrogen and highlights are provided from the Canada's Hydrogen Strategy and Ontario's Low-Carbon Hydrogen Strategy.

In terms of hydrogen that is suitable for Enbridge Gas to distribute to its customers:

a) Please provide a forecast of hydrogen production and demand in (i) Ontario, (ii) Canada and (iii) North America.
b) Please provide a forecast of the market price for hydrogen in (i) Ontario, (ii) Canada and (iii) North America.

4.2-Staff-105

Ref: Exhibit 4, Tab 2, Schedule 6, Pages 9 and 10; Exhibit 4, Tab 3, Schedule 1, Page 1; Exhibit 4, Tab 3, Schedule 1, Attachment 3, Page 2

Enbridge Gas states that studies indicate that the current distribution system may be suitable for up to 5% hydrogen by volume with relatively minimal changes. Minimal changes could include enhanced leak management practices, recalibration of existing equipment and prioritized repair or proactive replacement of identified assets in order to mitigate the potential for future leaks. Based on current knowledge, Enbridge Gas's systems may require substantial changes above 20% hydrogen by volume.

In its evidence, Enbridge Gas has defined unaccounted for gas (UFG) to describe the loss of gas from distribution, transmission, and storage. The main sources of UFG included retail meter variations, gate station meter variations, leaks, fugitive emissions, third-party theft, company use and accounting adjustments.

a) Please discuss and quantify the permeability of steel and plastic pipeline systems to hydrogen relative to conventional natural gas.

b) Does the permeability of hydrogen referred to in part (a) change depending on the concentration of hydrogen that is blended with the conventional natural gas? Please explain.
c) Please discuss and quantify the impact of hydrogen blending on UFG.
d) Please comment on (and quantify, if possible) the impact of UFG on a typical residential customer's annual bill in the EGD rate zone resulting from a 20% hydrogen blend

4.2-Staff-106

Ref: Exhibit 4, Tab 2, Schedule 6, p. 12

Enbridge Gas provides an update on Phase 1 of its Low Carbon Energy Program.

a) What volume of hydrogen has been delivered to date to customers located within the blended gas area?
b) What would the volume of hydrogen have been if Enbridge Gas had used 5% hydrogen by volume?
c) What would the volume of hydrogen have been if Enbridge Gas had used 20% hydrogen by volume?

4.2-Staff-107

Ref: Exhibit 4, Tab 3, Schedule 1, pp. 7-9

Based on its analysis, Enbridge Gas has noted that the 3-year simple average methodology results in the smallest forecast error. It is therefore the most accurate forecast when using the last five years of actual Unaccounted for Gas (UFG) data (historical UAF volumes for the EGD rate zone and historical UFG volumes for the Union rate zone). In this application, Enbridge Gas has recommended a 3-year simple average methodology for the determination of the forecast for UFG volumes for the amalgamated utility starting in 2024.

a) Please confirm that in case of an outlier year of UFG volumes, a 5-year or 7-year average would provide a better forecast for UFG volumes as compared to a 3-year average.
b) Please indicate if Enbridge Gas examined a longer period to determine the average volumes for UFG such as a 7-year average.

c) Please use an example where there was a large variation in a specific year and use that year to derive a 3-year, 5-year and 7-year average. Please provide the results and an analysis.
d) The 2024 Test Year forecast for UFG is $56.1 million based on the proposed harmonized 3-year simple average forecasting methodology. Please provide the 2024 Test Year forecast amount related to UFG using a 5-year and 7-year simple average forecasting methodology.

4.2-Staff-108

Ref: Exhibit 4, Tab 3, Schedule 1, pp. 19-20

Enbridge Gas has provided a list of measures as noted in the UFG Progress Report and the Supplemental UFG Progress Report.

Please confirm if Enbridge Gas has implemented these measures. For measures that have not been implemented, please provide a status update.

4.2-Staff-109

Ref: Exhibit 4, Tab 3, Schedule 1, Attachment 3, pp. 3-9

UFG is broadly defined as the difference between gas receipts and gas deliveries. UFG also includes various accounting adjustments including unbilled sales adjustments, billing adjustments, line pack and other accounting related adjustments.

a) Please provide the UFG volumes and percentage of throughput for the years 2019 to 2022 that excludes unbilled sales and billing adjustments.
b) Has Enbridge Gas considered excluding unbilled sales adjustments and billing adjustments from the UFG calculation and capturing these adjustments through other approaches? Please explain your response.

4.4-Staff-110

Ref: Exhibit 4, Tab 4, Schedule 2, p. 6

At the above reference when explaining anticipated increases in OM&A, it is stated that:

> In 2023, bad debt and Technology and Information Systems (TIS) costs related to migration to ‘as a service’ models to enhance technology reliability and training, change management and sustainment associated with harmonized systems will be a key driver along with drivers mentioned for 2022.

a) Please explain the differences between ‘as a service’ models and those models presently used by Enbridge Gas and how the use of these models will enhance technology reliability and training.
b) Please state how Enbridge Gas determined that the increased costs of these models justified the incremental benefits expected from them relative to the current models being used.
c) Please state why sustainment associated with harmonized systems would increase costs and to what extent the harmonization of the affected systems would produce offsetting cost reductions.

4.4-Staff-111

Ref: Exhibit 4, Tab 4, Schedule 2, p. 8

At the above reference, it is stated that:

> Synergies are defined as cost savings that were delivered through integration initiatives under conditions made possible by amalgamation. These synergies include the 2019 initial Enbridge Gas organization restructuring and role rationalization and the 2020 Voluntary Workforce Options (VWO) Program which incentivized employees to retire early, take leave, pursue part-time or job-sharing arrangements, or voluntarily exit. While VWO was an Enbridge initiative in response to COVID-19, its implementation in 2020 led to swifter role rationalization by advancing resourcing reductions that were expected over the amalgamation period leading up to rebasing.

a) Please state the criteria used by Enbridge Gas to distinguish a saving arising from amalgamation to one arising from COVID-19 impacts.
b) Please state the extent to which the VWO impacted the calculated merger savings.

4.4-Staff-112

Ref: Exhibit 4, Tab 4, Schedule 2, p. 8

At the above reference, it is stated that in addition to synergies, other initiatives which did not require integration resulted in productivity savings and that productivity savings have been achieved across all operating areas during the deferred rebasing term.

Please state the criteria used by Enbridge Gas to distinguish a productivity saving from normal prudent business practice.

4.4-Staff-113

Ref: Exhibit 4, Tab 4, Schedule 2, pp. 8-9

At the above reference, Table 2 “Integration Synergies and Productivity Savings” is provided and includes information for the period 2019 to 2024. For the 2024 Test year, $35.2 million of productivity savings are shown.

In explaining these savings, it is stated that:

> Gross O&M reductions of $20.7 million ($13.9 million net O&M) and $28.5 million ($18.1 million net O&M) have been included in the 2023 Bridge Year and 2024 Test Year, respectively. The net O&M embedded productivity for the 2023 Bridge Year and the 2024 Test Year is included in each year’s productivity savings in Table 2. The 2024 Test Year contains a reduction in salaries & wages of $7 million and other cost categories of $21.5 million, primarily factored into the forecasts for Operations and Engineering & STO. The cost component and departmental breakdown of the embedded productivity amounts are preliminary estimates as the Company has not conclusively identified the additional productivity opportunities.

a) Please state how and when these savings will be identified and whether or not Enbridge Gas will file an update to the application to reflect them.
b) In the explanation provided above, it is stated that the 2024 Test Year contains a reduction in salaries and wages of $7 million and other cost categories of $21.5 million:
    i. Please reconcile these two numbers, which add up to $28.5 million with the $35.2 million shown in Table 2
    ii. Please provide a breakdown of the other cost categories of $21.5 million.

4.4-Staff-114

Ref: Exhibit 4, Tab 4, Schedule 2, p. 9

At the above reference, it is stated that at this time, while opportunities for additional productivity savings have not been identified, productivity savings have been embedded to reflect committed savings which the Company will strive to manage. It is further stated that these embedded productivity savings allow the Company to maintain O&M below the level of inflation for the 2024 Test Year.

Please provide the productivity savings referred to above, that have been embedded in the OM&A costs and explain how the company will achieve these savings.

4.4-Staff-115

Ref: Exhibit 4, Tab 4, Schedule 2, p. 13,
Exhibit 4, Tab 4, Schedule 2, p. 15-16
Exhibit 9, Tab 1, Schedule 4, p. 2, p. 6 and p. 25

At the first reference, it is stated when discussing Business Development & Regulatory (BD&R) costs that:

> Significant O&M reductions due to synergies resulting from restructuring and lower spend due to the impact of COVID-19 in 2019 and 2020 were later offset by the resumption of activity from the easing of COVID-19 restrictions starting in 2021 and carrying into 2022 as well as impacts due to significant inflationary pressures. In addition, the Test Year includes costs recovered in deferral accounts in 2023 and earlier in the amount of $7.1 million.

At the second reference, it is stated when discussing BD&R costs for the 2024 Test Year versus 2023 Bridge Year that:

> The $4.3 million increase in salaries & wages includes $1.8 million in FTE additions for IRP and $1.4 million for administrative staff related to compliance with federal and provincial GHG emission regulations previously recovered through the IRP Operating Costs Deferral Account (IRPOCDA) and the GHG Emissions Administration Deferral Account (GHGEADA). The remaining increase in salaries & wages is due to merit. Contract services is forecast to increase by $3 million which includes $3.9 million for OEB costs previously recovered through the OEB Cost Assessment Variance Account (OEBCAVA) partially offset by the elimination of $1.5 million in rebasing hearing and intervenor costs from 2023.

At the third reference, it is stated that Enbridge Gas is not proposing changes to the IRPOCDA and the GHGEADA, beyond account number changes and harmonization. In relation to OEBCAVA, it is stated that the OEB directed regulated entities to cease recording amounts in these accounts when their rates are rebased, incorporating any updated forecast of cost assessments.

a) Please confirm that the first reference to COVID-19 impacting the 2019 and 2020 spending levels only applies to 2020, or if not, please explain.
b) In relation to IRPOCDA and GHGEDA, please explain why costs are being recovered as O&M expenses given that Enbridge Gas is proposing to continue the respective deferral and variance accounts.

4.4-Staff-116

Ref: Exhibit 4, Tab 4, Schedule 2, p. 15

At the above reference, it is stated when discussing BD&R costs for the 2022 estimate versus 2021 actuals that one aspect contributing to the increase was:

> Increases in contract services and other O&M spend is primarily due to investigative costs relating to potential capital projects and the resumption of travel, employee training, and normal levels of marketing and public affairs activities.

a) Please explain the investigative costs relating to potential capital projects, in particular, the criteria used to determine these costs. Please also provide the actual 2022 costs and explain any variance from forecast.
b) Please state whether Enbridge Gas's travel costs are expected to return to pre pandemic levels, or whether Enbridge would anticipate that these costs would be permanently lower as a result of new practices developed during the pandemic such as increased use of virtual meetings. If the costs would be expected to be lower, please state the extent of the reductions, if not, please explain why not.

4.4-Staff-117

Ref: Exhibit 4, Tab 4, Schedule 2, pp. 15-16

At the above reference, it is stated when discussing BD&R costs for the 2024 Test Year versus the 2023 Bridge Year that a couple of elements of the increase were:

> The remaining increase in salaries & wages is due to merit. Contract services is forecast to increase by $3 million which includes $3.9 million for OEB costs previously recovered through the OEBCAVA partially offset by the elimination of $1.5 million in rebasing hearing and intervenor costs from 2023.

a) Please elaborate on what is meant by the remaining increase in salaries and wages is due to merit. In particular, please provide the amount of this increase that is included in the 2024 Test Year.
b) Please provide the amount that is incorporated in the 2024 Test Year for OEB and other regulatory costs and provide a breakdown of these costs. Please state whether or not Enbridge Gas would expect these costs to decline in the 2025 to 2028 period and if not, why not.

4.4-Staff-118

Ref: Exhibit 4, Tab 4, Schedule 2, pp. 22

At the above reference, it is stated when discussing Customer Care costs for the 2023 Bridge Year versus the 2022 Estimate that:

> The other O&M decrease of $2.8 million is primarily driven by unapplied customer payments where the Company has exhausted efforts to identify customers and refund payments.

Please state how Enbridge Gas determines when it has exhausted efforts to identify customers and refund payments and what the time frame is for making this determination.

4.4-Staff-119

Ref: Exhibit 4, Tab 4, Schedule 2, pp. 22 and Table 4, p.18

At the first reference above, it is stated when discussing Customer Care costs for the 2024 Test Year versus the 2023 Bridge Year that a couple of elements of the increase were:

> 2024 Test Year costs are forecast to be $11.2 million higher than 2023 Estimate. The main driver is an increase in bad debt due to higher arrears as a result of the prolonged effect of higher commodity prices, economic conditions, and inflation in addition to higher consumer indebtedness.

At the second reference above, actual bad debt costs are shown as $10.6 million, $9.0 million, $10.7 million and $13.2 million for the years 2018 to 2021, while the 2024 Test Year level is shown as $21.5 million, which is a very substantial increase over the levels in these years. It is also a substantial increase over the 2023 Bridge Year level of $17.5 million, representing about a 14% year over year increase.

Please state whether or not Enbridge Gas undertook any studies to determine that the proposed 2024 Test Year level of Bad Debt expense was appropriate and if so, please provide such studies. If not, please state how this proposed expense level was calculated, including methodology and inputs. Please also explain how the expense level for Bad Debt was determined to be appropriate.

4.4-Staff-120

Ref: Exhibit 4, Tab 4, Schedule 2, p. 25 and p. 15

At the first above reference, it is stated when discussing the Operations Group's functions that:

> Major Projects manages and executes capital projects for Enbridge Gas, providing functions such as engineering, construction planning, project management and project governance. Since this group is dedicated to capital projects, associated O&M costs are fully capitalized resulting in no impact on utility O&M.

At the second reference above, it is stated when discussing increases in BD&R group costs that:

> Increases in contract services and other O&M spend is primarily due to investigative costs relating to potential capital projects and the resumption of travel, employee training, and normal levels of marketing and public affairs activities.

Please state why investigative costs related to potential capital projects are not also capitalized.

4.4-Staff-121

Ref: Exhibit 4, Tab 4, Schedule 2, p. 27

At the above reference, it is stated when discussing Operations costs increases for 2019 Actuals versus 2018 Actuals that:

> Contract services was also impacted by the cancellation of the Company’s aviation contract resulting in a termination fee of $3.5 million which ultimately resulted in future annual savings of $2.5 million starting in 2020.

a) Please explain the purpose of the aviation contract and the service provided under this contract. Why did the company cancel the aviation contract?
b) Please explain how the $2.5 million annual future savings were derived?

4.4-Staff-122

Ref: Exhibit 4, Tab 4, Schedule 2, p. 33

At the above reference, it is stated when discussing Operations costs increases for the 2022 Estimate versus 2021 Actuals that:

> Further pressure on the cost of locates is driven by the introduction of Bill 93 which was passed into law on April 14, 2022. The new regulations mandate absolute liability compliance for 5 day and 10 day locate deliveries depending on the scope of the excavation project.

Please provide Enbridge Gas’s forecasts of the cost impacts of Bill 93 for the 2023 to 2024 period.

4.4-Staff-123

Ref: Exhibit 4, Tab 4, Schedule 2, p. 34

At the above reference, it is stated when discussing Operations costs increases for the 2022 Estimate versus 2021 Actuals that:

> The increase in other O&M is driven by multiple cost pressures along with offsetting decreases. The primary driver of the increase is due to an accounting presentation change that reflects damage recoveries as other revenue instead of as an offset to O&M expense. Although there is no net impact to utility earnings, this adjustment causes a $6.2 million increase to other O&M

a) Please state why this change was made.
b) Please provide the amounts of damages recoveries by year for the 2018 to 2024 period.

4.4-Staff-124

Ref: Exhibit 4, Tab 4, Schedule 2, p. 37

At the above reference, it is stated when discussing Operations costs increases for the 2024 Test Year versus the 2023 Bridge Year that:

> The new regulations under Bill 93 are expected to cause significant changes to locate delivery services in Ontario. 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. The changes to be implemented under Bill 93 are currently in development given how recently the legislation was implemented. Enbridge Gas expects the external costs for locate delivery services to materially increase from the amounts included in the 2024 Test Year Forecast as a result of the mandate of absolute liability compliance for five-day and ten-day locate deliveries depending on the scope of the excavation project.

a) The 2024 Test Year forecast includes $45 million of operating and maintenance costs for external services to be incurred by Enbridge Gas to provide locate delivery services to customers and for receiving locate delivery services from other third-party providers and other utilities required for Enbridge Gas's own operations. Please explain how the $45 million in additional costs was calculated.
b) Will Enbridge Gas require to hire additional FTEs or contractors to respond to changes in providing locate delivery services as a result of Bill 93? If yes, please provide details including the number of FTEs/contractors that will be required.

4.4-Staff-125

Ref: Exhibit 4, Tab 4, Schedule 2, p. 49

At the above reference, it is stated when discussing Engineering and Storage & Transmission Operations (STO) costs increases for the 2022 Estimate versus the 2021 Actual that:

> The 2022 Estimate is expected to be $34.5 million higher than the 2021 actual. The primary driver of the increase is higher contract services of $21.8 million to address the backlog of work created by COVID-19's impact as well as higher planned IMP inspections as a result of risk modelling enhancements.

a) Please provide the amounts related to higher planned IMP inspections as a result of risk modelling enhancements for the 2019 to 2022 period.
b) Please explain the results of the risk modelling and the reasons for the increase in the risk profile.
c) Please also comment on the outlook for IMP spending beyond 2023 and the potential for costs to remain at higher than historic levels.

4.4-Staff-126

Ref: Exhibit 4, Tab 4, Schedule 2, p. 51

At the above reference, it is stated when discussing Engineering and STO costs increases for the 2024 Test Year versus the 2023 Bridge Year that:

> The $4.5 million increase in salaries & wages is driven by merit and FTE increases to support the maximum operating pressure (MOP) verification Program.[14] The program's scope will be expanded to include the former Union Gas pipelines with the goal of demonstrating and understanding pipeline operating stresses in order to inform the Integrity program and facilitate the assessment of the Company's overall risk profile for higher stress pipeline assets.

Footnote 14 states as follows:

> The MOP verification program supports an industry best practice that ensures pipeline operating limits are verified through assessments. This best practice was developed as a result of severe industry incidents and has been implemented to ensure asset records are traceable, verifiable, complete and that operating limits of pipelines are understood by the operators.

a) Please state whether the MOP verification program is already in place in the former EGD business segment and is now being introduced in the former Union Gas business segment. If not, please explain.
b) If this program was already in place in the former EGD business segment, please state when it was adopted by EGD.
c) Please provide a breakdown of the $4.5 million increase in salaries and wages related to the expansion of the MOP verification program in 2024. Please state the number of additional FTEs related to this program and why existing staff were not able to undertake the additional tasks.

4.4-Staff-127

Ref: Exhibit 4, Tab 4, Schedule 2, p. 51

At the above reference, it is stated when discussing Central Functions (CF) that:

> Both EGD and Union Gas historically received corporate cost allocations from their respective corporate parents. In 2018, following the merger of Enbridge and Spectra, Enbridge established CFs that provide typical shared services to its affiliate companies and implemented an internally developed Central Functions Cost Allocation Methodology (CFCAM) to allocate the CF costs amongst the service recipients.

a) Please state whether or not there are any differences between the current CFCAM and the historic methodologies used previously by EGD and Union that have had material impacts on how costs are allocated to the regulated entities currently, as compared to how they were allocated prior to the merger.
b) If there were any material impacts, please identify the specific impacts and provide their magnitude.

4.4-Staff-128

Ref: Exhibit 4, Tab 4, Schedule 2, p. 52 and Exhibit 1, Tab 9, Schedule 1, p. 21

At the first reference above, it is stated when discussing Central Functions (CF) that:

> Beyond 2021 there are a few key factors impacting CF costs. First, TIS costs increase as a result of technology industry shifts to an ‘as a service’ model driving costs from capital to O&M. Technology modernization has resulted in a shift from capital intensive traditional on-site physical data centres to O&M intensive infrastructure and software ‘as a service’ models, leading to higher O&M related to the implementation and sustainment of solutions in an ‘as a service’ model.

At the second reference above, it is stated when discussing integration capital expenditures that:

> Over the deferred rebasing term, Enbridge Gas expects to incur approximately $252.2 million in capital expenditures related to integration efforts (Table 6). The revenue requirement to support these investments was not included in base

> rates, and as such was borne by the shareholder. The largest capital expenditures were in pillar technologies: one Customer Information System (CIS), one Asset and Work Management (AWS) system and buildings to effectively align areas with geographic proximity supporting field operations.

Please reconcile the statement in the second quote that over the deferred rebasing term "The largest capital expenditures were in pillar technologies: one Customer Information System (CIS), one Asset and Work Management (AWS) system and buildings to effectively align areas with geographic proximity supporting field operations" with the statement in the first quote that "Technology modernization has resulted in a shift from capital intensive traditional on-site physical data centres to O&M intensive infrastructure and software 'as a service' models, leading to higher O&M related to the implementation and sustainment of solutions in an 'as a service' model."

4.4-Staff-129

Ref: Exhibit 4, Tab 4, Schedule 2, p. 54

Table 9 at the above reference provides Enbridge Gas's business unit benefits costs (BU Benefits). This shows a drop in these costs from $143.3 million in 2021 to $87.0 in the 2024 Test Year.

In explaining the differences in BU Benefits in the 2018 to 2021 period, it is stated that:

> Contributing to the decline in 2021 is the change in identification of BU and CF benefits from improvements in CFCAM (please see paragraph 116). The BU benefits amount represents a lower portion of the overall benefits amount than estimated in prior years.

Please state whether this change resulted in any offsetting increases in CF costs to Enbridge Gas and if so, please provide these amounts for the 2021 to 2024 period. If not, please explain why not.

4.4-Staff-130

Ref: Exhibit 4, Tab 4, Schedule 2, p. 55

At the above reference, it is stated that:

> In 2022 Estimate, BU benefit costs are forecast to decline by $39.6 million as

> compared to 2021. Pension and OPEB are the primary driver of the year-over-year decline due to a $26 million reduction from Mercer's actuarial valuation.

Please provide an explanation for the above-referenced $26 million reduction.

4.4-Staff-131

Ref: Exhibit 4, Tab 4, Schedule 2, p. 56

Table 10 at the above reference provides EGI integration severance costs of $41.5 million for 2019 and $77.7 million for 2020.

Please provide the FTE reductions in 2019 and 2020 that resulted from the payment of these severance costs.

4.4-Staff-132

Ref 1: Exhibit 4, Tab 4, Schedule 3, p.8
Ref 2: Exhibit 9, Tab 2, Schedule 1, Attachment 9.
Ref 3: January 27, 2023 Evidence Correction and Updates, Attachments 1

Table 2 in Reference 1 provides total compensation expense broken down by salary & wages, as well as total benefits and incentive pay for 2024 and Table 1 in Reference 3 provides updated pension and Other Post-Employment Benefit (OPEBs) amounts.

a) For the total benefits and incentive pay, please provide a breakdown of the amounts for pension and OPEBs for 2024.
b) For the period from the last rebasing to 2024 for EGD, Union Gas and Enbridge Gas, as applicable, please provide the following annual pension as well as annual OPEB amounts:
    i. included in rates
    ii. actual/forecasted accrual amounts
    iii. actual/forecasted cash contributions made
c) For the annual pension and annual OPEB amounts included in rates and actual/forecasted accrual amounts provided in response to part b above, please provide an annual breakdown of the amounts included in OM&A versus the amounts included in capital.
d) Please indicate if Enbridge Gas, EGD or Union Gas was eligible for a pension contribution holiday from the last rebasing to 2024. If yes, please provide further details.

e) On page 2 of Reference 2, it states that from EGD RPP's inception to 2011, all DC contributions had been drawn from the DB provision's surplus. Starting in 2012, DC contributions were remitted from cash rather than the DB provision surplus. Please explain the rationale for the change in contribution treatment in 2012.
    i. Please explain the implications to pension and OPEBs when DC contributions are drawn from the DB provision's surplus (e.g. impact to obligation)
    ii. For the actual/forecasted cash contributions made from last rebasing to 2024 as provided in response to part b(iii) above, please indicate the portion of cash contributions that could have been drawn from the DB provisions' surplus.

4.4-Staff-133

Ref 1: Exhibit 4, Tab 4, Schedule 3, p.8
Ref 2: Exhibit 9, Tab 2, Schedule 1, pp.17-19
Ref 3: Exhibit 9, Tab 2, Schedule 1, Attachment 8 - Mercer Letter
Ref 4: Exhibit 4, Tab 4, Schedule 2, Attachment 1 - Actuarial Report
Ref 5: January 27, 2023 Evidence Correction and Updates, Attachment 1

Table 2 of Reference 1 provides total compensation expense broken down by salary & wages, and total benefits and incentive pay for 2024

In Reference 2, it states that the balance in the Accounting Policy Changes Deferral Account (APCDA) reflects the unamortized accumulated actuarial gains/losses and past service costs incurred by Union Gas. The amortization of this amount and the corresponding drawdown of APCDA over the deferred rebasing term is recognized as a component of accrual-based pension expenses which are included in O&M and recovered in rates. The amortized amount from 2017 to 2023 is $56 million. The remaining balance in the APCDA is $155.2 million.

Reference 3 provides the projected balance sheet and accumulated other comprehensive income (AOCI) on the "local" books" basis for the fiscal years ending 2021 to 2023. It states that "local" books is prepared from the perspective that the Legacy Spectra Plans continued as going concerns, without taking into account the February 27, 2017 merger with Enbridge. The purpose of these projections is to estimate the difference between the unamortized actual gain (or loss) as at December 31, 2023 determined on the local books basis and the corporate books basis.

a) For the period from the last rebasing to 2024 for EGD, Union Gas and Enbridge Gas, as applicable, please provide the annual pension and annual OPEB actual/forecasted actuarial gains/losses.
b) Please confirm that actuarial gains/losses are being amortized over the expected average remaining service life (i.e. EARSL) of the active employee and included in rates in 2024. If not confirmed, please explain.
c) Regarding the unamortized accumulated actuarial gains and losses and past service costs incurred by Union Gas and recorded in the APCDA, please confirm that no amortization of the APCDA is reflected in the 2024 O&M and no further amortization of APCDA is expected to be included in O&M going forward. If not confirmed, please explain.
    i. In Reference 5, pension and OPEB costs were updated. Please explain whether the update impacts the balance in the APCDA and the amortized amount. If yes, please provide updated amounts.
    ii. Please provide a breakdown of the $56 million (or updated amount per part ci above) amortized amount and the remaining $155.2 million (or updated amount per part c-i above) in the APCDA by the amount relating to unamortized actuarial gains/losses and the amount relating to past service costs.
    iii. Please explain whether the amount amortized in the APCDA was amortized on the same basis as the actuarial gains/losses that was included in rates (i.e. EARSL).
    iv. Please confirm that the difference in the projections shown in Appendix A and B of the Mercer letter in Reference 3 and that shown in the Actuarial Report in Reference 4 only pertains to the actuarial gains and losses in AOCI, where the Mercer letter quantifies the Union Gas actuarial gains and losses for the period pre-2017 and the Actuarial Report quantifies actuarial gains and losses for Enbridge Gas, excluding the portion relating to pre-2017 Union Gas. If not confirmed, please explain.
d) Please discuss Enbridge Gas's views on excluding all actuarial gains and losses from revenue requirement (if material), and instead capturing those impacts in a deferral and variance account.

4.4-Staff-134

Ref 1: Exhibit 4, Tab 4, Schedule 2, Attachment 1 – Actuarial Report
Ref 2: January 27, 2023 Evidence Correction and Updates, Attachment 3 – Updated Actuarial Report

The Actuarial Report for Enbridge Gas was provided in Reference 1 and updated in Reference 2. The Actuarial Report includes net periodic benefit costs and minimum cash requirements for Enbridge Gas as well as its affiliates.

a) Please provide a reconciliation of the accrual expense and cash contributions provided in 4.4.3-Staff-132 and the updated Actuarial Report for 2022 to 2024.
b) Page 6 of the Actuarial Report states "The EI RPP, EGD RPP, Pension Choices Plan, and Legacy Spectra Closed Plans are funded by contributions from the Company unless it elects to use a funding excess to meet annual contribution requirements." Please explain what the funding excess is, and when Enbridge Gas would elect to use the funding excess.
c) Page 6 of the Actuarial Report states "In 2022, Enbridge Inc. decided to merge all past service benefits from the Legacy Spectra Closed Plans into the EI RPP". The amendment and related asset transfer are subject to regulatory approval and have not been reflected in the results of the report. Please explain what the expected implications would be if the amendment and asset transfer are approved. Please also include a discussion on any regulatory impacts.
d) Please provide Enbridge Gas's most recent actuarial valuation. Please explain whether Enbridge Gas anticipates an actuarial valuation report in 2023. If so, when will the report will be available.
e) In the updated Actuarial Report in Reference 2, it states that Mercer has projected the results of the December 31, 2021/January 1, 2022 actuarial valulations of the plans for the financial reporting and funding purposes forward to each year ending 2023 through 2024. Please explain how the recent changes in general economic conditions have impacted the actuarial valulation and resulting pension and OPEB costs.

4.4-Staff-135

Ref 1: Exhibit 4, Tab 4, Schedule 2, Attachment 1– Actuarial Report
Ref 2: Exhibit 4, Tab 4, Schedule 2, p.53
Ref 3: Exhibit 1, Tab 8, Schedule 1, Attachment 10, p.94 – 2021 Enbridge Inc. Annual Report
Ref 4: OEB letter regarding 2023 Inflation Parameters, October 20, 2022
Ref 5: January 27, 2023 Evidence Correction and Updates, Attachment 3

Page 9 of the Actuarial Report states that the results of the December 31, 2021 / January 1, 2022 actuarial valuations of the plans have been projected forward for financial reporting purposes to each of the years ending 2022 through 2023. The purpose of these projections is to estimate the accounting costs for 2023 through 2024.

The projections are based on the economic environment as at April 30, 2022 and assumptions described in Appendix C.

Reference 2 states that for non-pension and OPEB benefit costs, inflation adjustments and impacts from changes in FTEs were layered onto the 2022 Estimate. Inflation was projected at 2.4% for 2023 and 2.2% for 2024.

In its letter issued on Oct 20, 2022 in Reference 4, the OEB calculated the 2023 inflation factor for electricity distributors to be 3.7%, and for electricity transmitters to be 3.8%.

a) The OEB's prescribed inflation rates issued for the electricity sector are higher than Enbridge Gas's projected inflation rates for 2023 and 2024. Please explain the method used by Enbridge Gas for the projection and whether Enbridge Gas thinks that the projected inflation rates should be updated. If so, please provide the updated inflation rates. If not, please explain why these projected inflation rates should not be updated.
b) Please provide a sensitivity analysis of a 0.5% change in assumptions similar to that shown in the 2021 Enbridge Inc. Annual Report.
c) Page 18 of the Actuarial Report states "The projections and calculations of costs have been prepared in accordance with US accounting standards (US GAAP). They are based on methods, assumptions, and accounting policies selected by Management." Please discuss the discretion management has in selecting methods, assumptions, and accounting policies and the impact it would have on pension and OPEB expenses.
d) In Reference 5, it states the update in pension and OPEB results in an $28.9 million increase in forecasted O&M. Please provide the main drivers for the increase in O&M.

4.4-Staff-136

Ref 1: Exhibit 4, Tab 4, Schedule 2, Attachment 1– Actuarial Report
Ref 2: January 27, 2023 Evidence Correction and Updates, Attachment 1

In Reference 2, Enbridge Gas proposes to establish the Post-Retirement True-Up Variance Account (PTUVA) to record the difference between the revenue requirement impact of actual pension and OPEB costs and the revenue requirement impact of pension and OPEB costs included in rates. Please confirm that the revenue requirement impact of pension and OPEB costs will include the portion of costs in OM&A and the portion of costs in capital. If not confirmed, please explain.

4.4-Staff-137

Ref: Exhibit 4, Tab 4, Schedule 3, p. 4

At the above reference, it is stated that:

> As integration activities reach completion, 2023 will see a reduction of approximately 115 FTEs dedicated to integration with the remaining 70 FTEs being eliminated in 2024.

Please state whether these FTEs will be eliminated from the total headcount of Enbridge Gas on a permanent basis or will be eliminated from the integration activities but reassigned to other projects.

4.4-Staff-138

Ref: Exhibit 4, Tab 4, Schedule 3, pp. 4-5

At the above reference, it is stated that:

> Several of the key trends and drivers provided at Exhibit 4, Tab 4, Schedule 2, will require incremental FTE additions beginning in 2022, continuing into 2023 and sustained for 2024. While all business unit departments have FTE additions, Distribution Operations and Engineering and Storage & Transmission Operations account for most of the growth occurring between the 2021 actual FTEs of 3,013 (2,928 excluding integration FTEs noted in the preceding paragraph) and the 2024 Test Year FTEs of 3,470.

OEB staff also notes in this context that at the same reference, Enbridge Gas discusses the staff reduction programs that took place in the 2018 to 2020 period as a result of the restructuring and the VWO program.

a) Please state whether at the time these staff reductions were made, Enbridge Gas was anticipating the need for the staff increases that are currently forecast for the 2022 to 2024 period.
b) If Enbridge Gas was not anticipating these increases at that time, please explain why this was the case.
c) If Enbridge Gas was anticipating these increases, please explain why it made the noted staff reductions when it was aware that additional staff would be needed beginning in 2022. In responding, please discuss whether Enbridge Gas assessed how the termination costs involved in the VWO program would compare to the costs of retaining the staff until 2022 when the increased

staffing requirements were anticipated to begin. Please provide any analysis that was undertaken related to this matter, or if none was undertaken, please explain why this was the case.

4.4-Staff-139

Ref: Exhibit 4, Tab 4, Schedule 3, p. 8, Table 2

Note 3 at the bottom of the above referenced table states as follows:

> Costs for employees that are part of CFs have been excluded from Enbridge Gas compensation amounts starting in 2018 following the Enbridge Spectra merger as costs are allocated through the Central Function Cost Allocation Methodology

Table 2 shows total compensation decreasing from $541 million in 2017 to $444 million in 2018, a drop of $97 million.

Please state whether the allocation of these costs through the Central Function Cost Allocation Methodology beginning in 2018 resulted in any changes to these costs or was just a reclassification of them. If there were any changes, please state the amount of the changes.

4.4-Staff-140

Ref: Exhibit 4, Tab 4, Schedule 3, p. 19

At the above reference, it is stated that:

> Enbridge implemented CFs beginning in 2018 and provides the associated services to affiliates, including Enbridge Gas, rather than the provision of those services by Enbridge Gas itself. Prior to the merger in 2017, these services were provided by utility-based employees and augmented by additional services provided by the respective corporate parent.

a) Please provide the amount of any costs related to the switch over to the CF system in 2018 that were allocated to Enbridge Gas.
b) Please state whether the switch to the CF system increased or decreased the costs allocated to Enbridge Gas.

4.4-Staff-141

Ref: Exhibit 4, Tab 4, Schedule 3, p. 31

At the above reference, it is stated with respect to the Guidehouse Conclusion, Adjustments and Observations that:

> The 2022 budget proposed adjustments, provided at Attachment 3, Table 6-3, were accepted by Enbridge Gas and manually reflected in the 2022 Estimate and 2024 Test Year, provided at Attachment 3, Table 9-1.

Please explain Enbridge Gas's statement that these adjustments were manually reflected in the 2022 Estimate and 2024 Test Year.

4.4-Staff-142

Ref: Exhibit 4, Tab 4, Schedule 3, p. 32, Table 3

At the above reference, TIS costs are shown to increase from $66 million in 2020 to $139.7 million in 2024 and Benefits costs are shown to increase from $26.6 million in 2020 to $61.4 million in 2024.

a) Please provide an itemized breakdown of the increase in TIS costs between 2020 and 2024. For any category, with average annual cost increases greater than 5 percent, please provide an explanation for the cost increases.
b) Please provide an itemized breakdown of the increase in Benefits costs between 2020 and 2024.

4.4-Staff-143

Ref: Exhibit 4, Tab 4, Schedule 3, p. 32, Table 3
Exhibit 4, Tab 4, Schedule 3, p. 34-35

At the first reference, Finance costs are shown to increase from $25 million in 2020 to $36.7 million in 2024.

At the second reference, it is stated that:

> Finance costs have increased as a result of inflation and benefits alignment in addition to the creation of the Finance Sustained Business Organization (SBO) and Finance Strategic (FSS) groups, partially offset by synergies related to

restructuring and VWO. Utility consolidation synergies are provided at Exhibit 1, Tab 9, Schedule 1. SBO and FSS provide new services to Enbridge Gas and were created to explore and drive out new productivity initiatives to identify potential cost savings, cost avoidance and revenue generation for Enbridge and its affiliates, including Enbridge Gas. SBO supports collaboration and connections across the company to maximize improvements and delivers a capability building program focused on empowering individuals including Enbridge Gas employees with new mindsets and behaviours to drive innovation and unlock value for the organization (lean, agile, design thinking, etc.). FSS supports Enbridge Gas in enabling business process efficiencies and optimizations. This has included the deployment of 66 BOTs through Robotics Process Automation, eliminating 3,500+ productivity hours previously performed by employees and allowing for work redistribution to higher value activities.

a) Please provide an itemized breakdown of the increase in finance costs between 2020 and 2024. As part of the itemized breakdown, please also indicate whether costs are “Directly Attributable Costs” or “Indirect Costs” or “Direct Charge Costs”.
b) Please provide any cost/benefit assessments of SBO and FSS undertaken by Enbridge Gas.
c) Please explain why SBO and FSS costs have been categorized as finance related rather than as human resources or technology-related costs.

4.4-Staff-144

Ref: Exhibit 4, Tab 4, Schedule 3, p. 34

At the above reference, it is stated in relation to Enterprise Asset and Work Management (EAWM) that:

> EAWM is a new enterprise function providing services to Enbridge Gas as of 2020. EAWM provides expertise in the development and implementation of work management capabilities.

a) Please state whether EAWM is an entirely new function. If so, please explain how asset and work management was facilitated in the absence of the EAWM enterprise function.
b) Please state whether EAWM has resulted in any cost reductions in other components of the OM&A.
c) Please provide any cost/benefit assessments of EAWM undertaken by Enbridge Gas.

4.4-Staff-145

Ref: Exhibit 4, Tab 4, Schedule 3, p. 35

At the above reference, it is stated that:

> Legal costs have increased as a result of inflation and benefits alignment in addition to the centralization of legal services within the CF groups with corresponding decreases in CF costs for various CFs, including Finance.

a) Please provide an itemized breakdown of the increase in legal costs between 2020 and 2024. As part of the itemized breakdown, please also indicate whether costs are “Directly Attributable Costs” or “Indirect Costs” or “Direct Charge Costs”.
b) Please state whether centralization of legal services has resulted in an increase in legal costs. If so, please provide reasons.

4.4-Staff-146

Ref: Exhibit 4, Tab 4, Schedule 3, p. 35 - 36

At the above reference, it is stated that:

> PAC costs have remained fairly consistent aside from increases due to inflation and benefits alignment and the Indigenous Lifecycle Engagement and the Brand Reputation programs. The Indigenous Lifecycle Engagement Program is a relatively new area of focus which seeks to build positive long-term relationships with Indigenous nations and groups, including those in Enbridge Gas’s franchise area. The Brand Reputation program highlights the role Enbridge's assets, including those of Enbridge Gas, can play in reducing emissions over time in a cost effective and reliable manner.

a) Please provide the forecasted 2024 costs associated with the Indigenous Lifecycle Engagement Program and the Brand Reputation program.
b) Please provide any cost/benefit assessments of the Brand Reputation program undertaken by Enbridge Gas.

4.4-Staff-147

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 1

a) Please provide a list of all compensation benchmarking reviews and similar studies that Mercer Canada Limited (Mercer) or other organizations have undertaken for Enbridge Gas and its predecessor companies that have been filed with the OEB and the case numbers under which they were filed.
b) Please state whether or not the approaches used by Mercer in its study filed in this proceeding are consistent with those which were used in these prior studies and, if not, please identify the substantive changes and provide a brief explanation as to why they were made.

4.4-Staff-148

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 1
Exhibit 4, Tab 4, Schedule 3, p. 3, Table 1

At the second reference above, Table 1 “Employees – Full Time Equivalents” provides in column c “Business Unit” employees which are described as “EGI employees that provide core services to the utility,” while column d is “Central Functions” employees, which are described as “EGI employees that provide shared services to the utility. Their costs have been excluded from EGI Compensation amounts starting in 2018 following the Enbridge-Spectra merger as costs are allocated through the Central Functions Cost Allocation Methodology.”

Please state how Mercer took into account the exclusion of the costs related to the Central Functions employees in undertaking its study.

4.4-Staff-149

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 1, p. 2

At the above reference, it is stated that:

> In conducting the compensation analysis, Mercer worked with Enbridge Gas to identify benchmark positions that represent a statistically reliable sample of Enbridge Gas’s functions and levels. Specifically, the review includes 354 non-union positions representing 82% of the non-union population, and 31 union positions representing 75% of the union population.

Please discuss the reasons for the significant difference between the number of benchmark jobs used in the study between non-union and union positions including whether the percentages of the union and non-union populations represented in the Enbridge Gas study would be typical of what Mercer would expect for studies of this kind. If these percentages are not typical, please discuss any impacts this would have had on the study.

4.4-Staff-150

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 1, p. 3

At the above reference, it is stated with respect to the Ontario Comparator Group for Non-Union positions that:

> ─ This comparator group reflects talent markets in Ontario that Enbridge would source talent from, and lose talent to, as most corporate positions do not require industry experience.
>
> ─ The data is sourced from the 2021 Mercer Benchmark Database and comprises of large (>$3 billion in revenue) private sector organizations, with significant Ontario presence. Only data for Ontario-based employees is considered from this robust sample of large, general industry companies

a) Please state whether or not Mercer undertook any assessments as to the extent Enbridge Gas would source talent from, or lose talent to, organizations other than the referenced large private sector organizations with significant Ontario presence. If not, please explain why not, and if so please state the extent to which Enbridge Gas sources talent from, or loses talent to, organizations other than the chosen comparator group.
b) Please state why only data for Ontario-based employees is considered from the chosen sample and if this would be a restriction Mercer would typically incorporate in undertaking this type of study.

4.4-Staff-151

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 1, p. 3

At the above reference, it is stated with respect to the Ontario Comparator Group for Non-Union positions that:

─ Where there is insufficient market data from the ideal comparator group, the scope was expanded until there is sufficient data to report in the following order: (1) All Ontario Public and Private Sector (25 positions), (2) All Ontario (2 positions), and (3) National All Industry (3 positions).

─ Market data is not reported for 75 positions that are energy-specific (e.g. Pipeline Scheduling).

a) With respect to the discussion above of there being insufficient data from the ideal comparator group and the expansion of the scope until there was sufficient data, please explain how it was determined that the amount of data was sufficient.
b) Please state whether the non-reporting of market data for 75 positions would be typical for a study of this kind.

4.4-Staff-152

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 1, p. 3

At the above reference, it is stated with respect to the Energy Comparator Group for Non-Union positions that:

─This group reflects companies most similar in nature to Enbridge Gas, that have similar compensation considerations in terms of administering pay and maintaining internal equity for a workforce across multiple provinces. This data set provides valuable perspective for positions that require energy industry experience.

Please explain how the analysis considered whether (and the extent to which) the companies in the Energy Comparator Group made use of services provided by affiliates, as is the case with Enbridge Gas.

4.4-Staff-153

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 1, p. 4

At the above reference, it is stated with respect to the Energy Comparator Group for Union positions that:

─ This group captures the Ontario market and collective bargaining job rates.

─ The data is sourced from 2021 collective agreements at energy organizations in Ontario with a unionized population.

Please explain why Mercer used only Ontario organizations for the assessment of Union Positions, while also using groups outside of Ontario for non-Union positions.

4.4-Staff-154

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 1, p. 4

At the above reference, it is stated that:

> For non-union positions, market comparisons are made to a blend of large, private sector general industry organizations in Ontario (67% weighting) and large, national energy sector organizations (33% weighting). The weightings were selected to recognize the local Ontario market where Enbridge Gas competes for talent for these roles while also considering the energy industry in which Enbridge Gas operates. The weightings are reversed for director level roles to reflect the fact that talent is sourced nationally and that energy sector experience is more important for these senior positions.

a) Please provide additional discussion as to the reasoning for the reversing of the weighting for director level roles.
b) Please discuss the impact of this reversal on the results of Mercer's study.
c) Please state whether this reversal is something that Mercer has done in other similar studies or is specific to the current study.

4.4-Staff-155

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 1, p. 4

At the above reference, it is stated that:

> For single incumbent director positions, a premium of 10% was applied to the market data to reflect the broader scope of responsibility for these positions.

a) Please provide further explanation as to why this adjustment was made and how a 10% premium was determined to be a reasonable adjustment.

b) Please state whether this adjustment is something that Mercer has done in other similar studies or is specific to the current study.

4.4-Staff-156

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 1, p. 5

At the above reference, it is stated that:

> Overall, Enbridge Gas non-union positions are within the competitive range. Management positions are positioned more competitively than non-management, but are generally within the market competitive range.

OEB staff notes that the table provided at the same reference shows that the overall -1% Target Total Direct compensation for non-union positions breaks down to +9% for management and -5% for non-management.

a) Please state whether Mercer would consider this breakdown typical for this type of study when compared to those which it has undertaken for other Canadian utilities.
b) Please explain the rationale for management positions being compensated at higher levels than the market competitive range.

4.4-Staff-157

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 2

a) Please provide a list of all compensation benchmarking reviews and similar studies that Towers Watson Canada Inc. (WTW) has undertaken for Enbridge Gas and its predecessor companies that have been filed with the OEB and the case numbers under which they were filed.
b) Please state whether or not the approaches used by WTW in its study filed in this proceeding are consistent with those which it used in these prior studies and, if not, please state what any such substantive changes would be and provide a brief explanation as to why they were made.

4.4-Staff-158

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 2, p. 5

At the above reference, a list of the benefit programs included in the WTW competitive benchmarking review of the pension, savings and benefits programs offered to Enbridge Gas's unionized and non-unionized employees (WTW study) is provided.

Please state whether or not any of Enbridge Gas's programs of this kind were excluded and, if so, identify the programs and explain why they were excluded.

4.4-Staff-159

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 2, p. 6

At the above reference, it is stated that:

> BenVal establishes a controlled environment where differences in value among employer plans are exclusively a function of the differences in plan provisions. A BenVal analysis is not intended to compare actual benefit costs. Each organization's actual benefits costs are affected by its benefit program design, but also by other factors which are not captured in a BenVal analysis such as funding decisions, plan experience and demographics. Each plan is valued under the same actuarial valuation method using a consistent set of actuarial assumptions and employee population.

a) Please further explain how Benval quantifies differences in value among employer plans as exclusively a function of the differences in plan provisions.
b) Given that a Benval analysis is not intended to compare actual benefit costs, please state what the appropriate comparative perspective for assessing the results of this analysis would be.

4.4-Staff-160

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 2, p. 7

At the above reference, it is stated that:

> When a plan offers the possibility to switch between a defined contribution pension plan and a defined benefit pension plan, employees are deemed to participate in the defined contribution pension plan if they are younger than age

46 as of the valuation date. If they are age 46 or older as of the valuation date, they are deemed to participate in the defined benefit pension plan. For the purpose of valuing the defined benefit plan, the Projected Unit Credit benefit is prorated over credited service after age 46. If the decision made at plan entry is irrevocable, employees who join the plan prior to age 36 are deemed to participate in the defined contribution pension plan while the others are deemed to participate in the defined benefit pension plan.

Please state whether or not the above assumptions are what would usually be used in studies of this kind or are specific to the WTW study. If they are specific to the WTW study, please further discuss the basis for these assumptions.

4.4-Staff-161

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 2, pp. 8-9

At the above reference, the approaches to determining valuation for health and dental care, disability, death benefit and flexible benefit (other than pension) plans are outlined.

Please state whether or not the above approaches are what would usually be used in studies of this kind or are specific to the WTW study. If any are specific to the WTW study, please further discuss the basis for these assumptions.

4.4-Staff-162

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 2, p. 9

At the above reference, it is stated that “Enbridge selected the peer group for the purposes of this review.”

Please state whether it is WTW’s normal practice when undertaking a study of this kind to have the entity being assessed select the peer group for the purposes of the study.

4.4-Staff-163

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 2, p. 10

At the above reference, the 14 organizations in the peer group selected for this review are listed.

Please state why WTW believes that the Canadian Imperial Bank of Commerce, Labatt Brewing Company Limited and Sun Life Financial are appropriate comparators to Enbridge.

4.4-Staff-164

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 2, p. 15

At the above reference, it is stated that “The employer-provided value of Enbridge combined pension, savings and benefits programs is competitive and ranks them 6.3% above the peer group median.”

Please provide WTW’s views on the implications if the employer-provided value of the Enbridge Gas programs referenced above was at the peer group median, rather than 6.3% above it. Please include a discussion as to whether or not WTW believes this would be an appropriate level for Enbridge Gas to target going-forward and if not, why not.

4.4-Staff-165

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 3, p. 17

At the above reference, it is stated that the Massachusetts Formula (or 3FF) and the Modified Massachusetts Formula have been accepted as cost allocation methodologies by utility regulatory commissions across the United States. It is further stated that 3FF has also been implemented by other utilities within Canada (footnote 12 notes the utilities to be ATCO, EPCOR, Fortis BC, Hydro One, AltaGas, SEMCO Energy and Pacific Northern Gas). It is also stated that in the case of Enbridge Gas a modified 3FF has been used.

a) Please state whether the Canadian utilities listed by Enbridge Gas have implemented the 3FF approach or the modified-3FF approach.
b) Please explain why the modified 3FF approach is appropriate for Enbridge Gas to use, relative to the other allocation options.

4.4-Staff-166

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 3, p. 38, Table 9-2
Exhibit 4, Tab 4, Schedule 3, Attachment 3, p. 39, Table 9-3

At the first reference, in relation to the 2022 Forecast Comparative Analysis, it is shown that Enbridge Gas's normalized TIS costs are about 40% higher than the average comparative utility.

At the second reference, in relation to the 2024 Forecast Comparative Analysis, it is shown that Enbridge Gas's normalized TIS costs are about 46% higher than the average comparative utility.

a) In both cases, please outline how many comparative utilities within the sample set analyzed had normalized TIS costs greater than Enbridge Gas.
b) Please explain why Enbridge Gas's normalized TIS costs are significantly higher than the average comparative utility.

4.4-Staff-167

Ref: Exhibit 4, Tab 4, Schedule 3, Attachment 3, p. 47

At the above reference it is stated that:

> 3FF is an appropriate Cost Driver for Corporate Secretarial, TIS, SCM Legal Services as well as Ethics, Compliance, Privacy & Security as these services benefit the entire organization.

Please explain why 3FF is an appropriate proxy for causation of legal services. What steps have been taken to ensure that Enbridge Gas has not been allocated legal costs in relation to its sister companies that may have more litigious operations?

4.5-Staff-168

Ref 1: Exhibit 4, Tab 5, Schedule 1, p.7
Ref 2: EB-2012-0459, Decision with Reasons, July 17, 2014, pp. 61, 62

Concentric recommended the use of a credit adjusted risk-free (CARF) rate as an appropriate discount rate to calculate net salvage under the CDNS method on the basis that the CARF is consistent with discount rates mandated by accounting standards for asset retirement obligations for financial statement disclosures and estimating the discount. In the OEB's Decision for EGD's 2014 to 2018 Custom IR proceeding, the utility's weighted cost of debt, and the discount rate for pension funds were noted as other possible discount rates to use.

a) Please provide Enbridge Gas's proposed 2024 weighted cost of debt and the discount rate used for pension funds and the resulting SRC reserve using these rates.
b) Please explain whether these rates were considered as the discount to calculate SRC reserve. If yes, please explain why they were not selected.

4.5-Staff-169

Ref 1: Exhibit 4, Tab 5, Schedule 1, pp.17-18
Ref 2: EB-2020-0290, Exhibit C2, Tab 1, Schedule 1, p.8

It states that Enbridge Gas is collecting amounts for future abandonment within the net salvage component of the depreciation rates for the EGD and Union rate zones. These amounts are included in accumulated depreciation which results in a reduction to the PP&E component of the rate base. The amounts collected are used to fund working capital requirements, which in turn reduces the need for financing and therefore has a favourable impact for customers in the form of lower rates, all else being equal. It also states that Enbridge Gas has not identified any precedents in which a utility has voluntarily set up a segregated fund for Site Restoration Costs (SRC).

a) Does Enbridge Gas plan to recover future abandonment costs if the amount of these costs are less than the amount of the net salvage component already recovered as a part of depreciation expense?
b) If yes, please explain whether there is double recovery for future abandonment costs.
c) Has Enbridge Gas identified any precedents where a utility has involuntarily set up a segregated fund for SRC? If yes, please list these utilities.
d) As noted in Reference 2, Ontario Power Generation established segregated funds for the purpose of future expenditures related to its asset retirement obligation for nuclear liabilities. Please explain whether Enbridge Gas views these segregated funds as comparable to segregated funds that could be established for Enbridge Gas's SRC.

4.5-Staff-170

Ref 1: Exhibit 4, Tab 5, Schedule 1, Attachment 1 – Depreciation Study
Ref 2: Exhibit 4, Tab 5, Schedule 1, Attachment 2

Page 16 of the Depreciation Study states that EGD historically used the Average Life Group (ALG) procedure, and Union Gas historically used Generation Arrangement Procedure. Furthermore, page 16 states that as Equal Life Group (ELG) more accurately reflects the actual life of the assets used, Concentric is recommending the movement to ELG at this time.

Page 7 of the Depreciation Study also states that ELG procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America.

a) A comparison of the depreciation using the proposed and existing depreciation methodologies is provided in Attachment 2. Please quantify the 2024 depreciation expense using the ALG method of depreciation and compare it to the proposed depreciation expense, in the same format as Attachment 2.
b) If there are material updates to the depreciation expense for 2024 resulting from 2022 financial results being finalized, please provide updated depreciation expense for 2024 in the format of Attachment 3.
c) Please explain Enbridge Gas's views on whether the use of ELG and ALG would be allowed under IFRS.

4.5-Staff-171

Ref 1: Exhibit 4, Tab 5, Schedule 1, Attachment 1 – Depreciation Study

Concentric's recommendations reflect retirement and net salvage analyses in Sections 6 and 7 of the study. As well, pages 2-3 of the Depreciation Study discuss information provided by Enbridge Gas to Concentric.

a) Please provide the following information and data used by Concentric to prepare and support the Depreciation Study:
    i. Current balances by vintage year for each account (aged balances) through December 31, 2021 in a readable Excel format that provide the amount of investment sorted by installation year.

ii. Retirement transactions for all accounts from 1948 through December 31, 2021 in a readable Excel format, which include information regarding the transaction year of the retirement, the installation year of the asset being retired, and the original cost of the asset being retired.
iii. Cost of removal and gross salvage transactions for all accounts requiring the recovery of net salvage through December 31, 2021 in a readable Excel format, which include information regarding the transaction year of the retirement, the costs associated with the retirement, and any gross salvage proceeds from the sale or reuse of the property.
iv. For each account, provide the output of all life/curve combinations that were considered as part of the study from the retirement rate analysis. Please include the residual measures for each life/curve combination presented.
v. Discussion/interview notes with EGD's operational and management staff with respect to historical life and future expectations for asset accounts that Concentric relied upon as explained in Section 3 of the Depreciation Study.

4.5-Staff-172

Ref 1: Exhibit 4, Tab 5, Schedule 1, pp. 2-3

In Schedule 1, Enbridge Gas discusses depreciation studies and rates prior to and after amalgamation of EGD and Union.

a) Please confirm that the last public depreciation study for EGD was as filed in the EGD 2013 Cost of Service proceeding EB-2011-0354. Please provide an explanation if not confirmed.
b) Please indicate if EGD had any subsequent depreciation studies or analysis initiated (internally, or studies by consultants, reviewing any of depreciation lives, rates or salvage costs) since the 2013 EGD Cost of Service, and if so please provide the dates and circumstances for the studies and provide a copy.
c) Please confirm that the last public depreciation study for Union Gas was as filed in the Union Gas's 2013 Cost of Service proceeding EB-2011-0210. Please provide an explanation if not confirmed.
d) Please indicate if Union Gas had any subsequent depreciation studies or analysis initiated (internally, or studies by consultants, reviewing any of depreciation lives, rates or salvage costs) since the 2013 Union Gas Cost of Service, and if so please provide the dates and circumstances for the studies and provide a copy.

4.5-Staff-173

Ref 1: Exhibit 4, Tab 5, Schedule 1, pp. 3-4
Ref 2: Exhibit 4, Tab 5, Schedule 1, Attachment 1 – Depreciation Study

In Schedule 1 Enbridge Gas discusses depreciation methods and procedures used in the Depreciation Study.

a) Please confirm that the proposed methodology uses the ELG procedure (other than accounts that use amortization accounting), with a Remaining Life technique.
b) Please confirm that the depreciation study has generally adopted EGD's depreciation methodologies generally (straight-line method, group procedures, remaining life technique, CDNS net salvage) but with two exceptions: First, the ELG procedure rather than the Average Life Group/Average Service Life (ALG/ASL) procedure. Second, the use of amortization accounting for some groups of assets. If not confirmed, please provide a detailed explanation as to why this is not confirmed.
c) EGD previously used the ALG method, and other Ontario utilities (e.g. Ontario Power Generation in EB-2020-0290 and Hydro One Networks Inc. in EB-2021-0110) use the ALG method of depreciation. Please provide a detailed rationale for the adoption of the ELG procedure rather than the ALG procedure. Please include an explanation on whether there are circumstances specific to Enbridge Gas that renders the ALG method of depreciation less appropriate, or the ELG method more appropriate.
d) Please provide examples, if Enbridge Gas or Concentric are aware, of utilities that use the ELG method, the ALG method, or the Generation Arrangement method, in North America, specifically noting which use a Whole Life technique and which use a Remaining Life technique.
e) Please provide a version of the Concentric Depreciation Study's Table 1 (Concentric Depreciation Study page 5-2) and Section 8 for each of the following:
    i. Using the ALG procedure
    ii. Using the ELG procedure with a Whole Life technique
    iii. Using the ELG Procedure with a Whole Life technique, with remaining lives calculated on the basis the ALG procedure.

4.5-Staff-174

Ref 1: Exhibit 4, Tab 5, Schedule 1, pp. 3-5

Enbridge Gas outlines differences in accounting policies related to depreciation at paragraphs 7-12

a) Please indicate any material differences between the Union Gas, EGD and Enbridge Gas capitalization policies for the following matters:
    i. Overhauls and major inspections
    ii. Capitalization spending thresholds
    iii. Definition of minor repairs which are not capitalized
    iv. Site preparation costs
    v. Costs incurred to remove previous utility assets when completing interim retirements/replacements
    vi. Treatment of retirements for assets replaced under insurance or warranties
    vii. Treatment of retirements for costs incurred for asset removal or relocation under cost-sharing arrangements (such as highway or civic-driven projects which may be funded in whole or in part by local or provincial governments)
    viii. Treatment of retirements for major natural disasters (e.g., floods, fires, etc.) or other extraordinary retirements
b) For each of the items in (a) please have Concentric identify if and how any changes were incorporated into the assessment of depreciation lives, dispersion and net salvage in the Depreciation Study.

4.5-Staff-175

Ref 1: Exhibit 4, Tab 5, Schedule 1, pp. 6-7

Enbridge Gas indicates that there is significant accumulated amortization variance related to computer assets prior to December 1, 2023, which is proposed to be amortized over the Remaining Life.

a) Please confirm if the amortization period is the ELG remaining life, the ALG remaining life, or the remaining life calculated based on the newly adopted amortized lives.
b) Enbridge Gas indicates that "once the last asset is retired for the pools in these pre-existing accounts, depreciation expense will cease on these accounts". Please indicate the treatment of any residual accumulated depreciation variance

at the time of the disposal of the last asset for each pool. For example, if the last asset retires earlier than expected, what will happen to the unamortized variance at that time?

4.5-Staff-176

Ref 1: Exhibit 4, Tab 5, Schedule 1, Attachment 1 – Depreciation Study

In Section 3.3.2 of the Depreciation Study, Concentric outlines four approaches to addressing costs of net salvage indicating the proposed CDNS approach including: "Methodology relies on more estimates of future inflation and future cost of capital and that are harder to predict and subject to debate."

a) Please provide a detailed description of the use of inflation estimates in CDNS as proposed by Enbridge Gas, including whether the discount rates are real or nominal, how the estimated future costs are established (including on a real or nominal basis), and the impact over time if inflation is different (e.g., higher) than assumed in the preparation of CDNS estimates.
b) Please explain the meaning of "customer equity" in the quote: "Attempts to have more customer equity by passing on the benefit of any return of capital" at page 3-10 of the Depreciation Study.
c) If costs of removal are estimated via the ratio between nominal dollars spent to remove an item, divided by nominal dollars spent (in the past) to build the item, as is the case in the Depreciation Study's Section 7, why is it necessary to additionally inflate these values as described in the Depreciation Study, page 3-11?
d) For account 456, on page 3-13, Concentric notes: "At this time, Concentric recommends that a negative ten percent net salvage estimate continue to be used to form the basis of the CDNS calculations for this account. When the CDNS method is used, the net salvage rate is adjusted to negative six percent for the purposes of depreciation calculations." Please provide a detailed calculation of the revision from negative 10% to negative 6% for this account.

4.5-Staff-177

Ref 1: Exhibit 4, Tab 5, Schedule 1, Attachment 1 – Depreciation Study, Section 6

Concentric provides proposed Life and Dispersion curves for each asset group, based on account experience. Please provide the following alternative life and dispersion curves. In each case, please include the calculated Residual Measure, and exclude vintages with exposures below 1% of total exposures.

a) Please provide Account 452 using a 45-R2.5 curve
b) Please provide Account 456 using a 44-R4 curve
c) Please provide Account 457 using a 40-R2.5 curve
d) Please provide Account 465 using a 70-R4 curve
e) Please provide Account 472 using a 45-S0.5 curve
f) Please provide Account 475.30 using a 60-L2, a 65-R3 and a 60-R4 curve.
g) Please provide Account 477 using a 45-R2 curve

4.5-Staff-178

Ref 1: Exhibit 4, Tab 5, Schedule 1, Attachment 1 – Depreciation Study, Section 6
Ref 2: EB-2011-0210, Exhibit D2, Foster and Associates – 2011 Depreciation Study

Concentric provides proposed Life and Dispersion curves for each asset group, based on account experience.

a) Please provide a description of the full range of assets in account 455 and indicate why the retirement experience on this account departs notably from the proposed 55-R3 life and dispersion curve.
b) Union Gas's depreciation study (Foster and Associates – 2011 Depreciation Study) indicates at page 7 that Union Gas had aged data and plant transactions for all post-1997 activity. Please explain why Account 466 relies on an experience band only from 2010-2021.
c) Please provide any additional retirement experience data for Account 466 transmission for periods from 1997 to 2010, including in Excel format.
d) Please provide a description of the assets in account 456 and indicate why the retirement experience on this account departs notably from the proposed 30-R4 life and dispersion curve.
e) As both peers (35-37 years) and the experienced retirement data (Concentric Depreciation Study, page 6-38) are suggestive of a much longer life for Account 466 Transmission Compressors, please provide a detailed reasoning for adopting the 30-R4 life at this time.
f) For Account 473.01, per Concentric Depreciation Study page 3-17, the existing EGD life and dispersion of 45-L1.5 appears to be a better fit to the data than the proposed 45-S1. Please provide a copy of the retirement rate analysis limiting exposures to 1% of total exposures and illustrate and calculate RM values for 45-L1.5 and 45-S1.

g) For Account 475.21, per Concentric Depreciation Study page 3-19, the existing EGD life and dispersion of 61-R3 appears to be a better fit to the data than the proposed 55-R3. Please provide a copy of the retirement rate analysis limiting exposures to 1% of total exposures, and illustrate and calculate RM values for 55-R3 and 61-R3.
h) As both peers (55-80 years) and the experienced retirement data (Concentric Depreciation Study, page 6-83) are suggestive of a much longer life for Account 475.21 Distribution Mains - Coated and Wrapped, please provide a detailed reasoning for shortening to a 55-R3 life at this time.
i) Please provide the range of peers (with references) for Account 477.
j) As both peers (15-25 years) and the experienced retirement data (Concentric Depreciation Study, page 6-100) are suggestive of a much longer life for Account 478 Meters than the 15-S2.5 proposed, please provide a detailed reasoning for shortening to a 15-S2.5 at this time.

4.6-Staff-179

Ref: Exhibit 4, Tab 6, Schedule 2, pp. 3-4

The opening base 2022 property tax forecast is based on the annual property taxes paid in the prior year adjusted for growth, inflation and special/major projects for the 2022 estimate, 2023 Bridge Year and 2024 Test Year.

a) In Table 2, Enbridge Gas has provided the property tax forecast for 2022, 2023 and 2024. Please provide a revised table that shows the actual numbers for 2022.
b) Please confirm if property taxes related to the Dawn to Corunna Replacement Project are included in the property tax forecast.

4.4-Staff-180

Ref: Exhibit 4, Tab 6, Schedule 2, p. 5

At the above reference, it is stated when discussing the property tax forecasts contained in the application that:

> An inflation escalation rate of 1% was used for the 2022 Estimate. This escalation rate was based on an internal analysis of pipeline tax impacts for the 2016 to 2020 taxation years. The 2021 taxation year was excluded due to the

business education tax reductions implemented by the Ministry of Finance in 2021….

The 2023 and 2024 utility property tax forecast has been adjusted for the inflation rate of 2.4% and 2.2% respectively for the Bridge Year and Test Year as provided in the Economic and Financial Assumptions provided at Exhibit 3, Tab 2, Schedule 4.

Please state why different methodologies were used to determine the inflation escalation rate for the 2022 estimate and the 2023 and 2024 utility property tax forecast.

4.6-Staff-181

Ref 1: Exhibit 4, Tab 6, Schedule 1, Attachment 2, pp 4-6
Ref 2: Exhibit 2, Tab 2, Schedule 1, Plus Attachment, p3

OEB staff has compiled the following table based on the information provided in Ref 1 & 2:

	($ Millions)	**2022 Estimate**	**2023 Bridge Year**	**2024 Test Year**
Ref 2	Opening Balance of Gross Property, Plant and Equipment Adjustments	10.4	(69.6)	(317.5)
	In-Service Additions	1,442.3	1,541.9	1,504.3
Ref 1	Capital Additions	1,283.9	1,387.7	1,360.9
	Variance	158.4	154.2	143.4

a) Please reconcile the difference in the above table and provide a fixed asset continuity schedule by CCA class for 2022 to 2024.
b) Please elaborate further on the Opening Balance Adjustments in the above table.

4.6-Staff-182

Ref 1: Exhibit 4, Tab 6, Schedule 1, Attachment 2, Actuals/Summary of Capital Cost Allowance (CCA)

Ref 2: Exhibit 1, Tab 8, Schedule 1, Attachment 14, p 70, 2021 T2 Corporation Income Tax Return/Capital Cost Allowance (CCA)

a) OEB staff has compiled the following table based on the information provided in Ref 1 & 2:

($000s)	Ref 1, p.3	Ref 2	Variance
2021 Capital Cost Allowance	829,932.6	857,929.3	27,996.7
Ending Undepreciated Capital Cost	9,757,141.6	9,764,697.9	7,556.3

Please reconcile the difference in the above table.

i. Please confirm that the capital assets by class in Reference 1 are 100% related to Enbridge Gas's regulated business. If not confirmed, please explain.
ii. If the capital assets by class in Reference 1 are not 100% related to Enbridge Gas's regulated business, please provide the breakdown between the regulated business and unregulated business for Enbridge Gas and please also explain why unregulated business was not excluded for regulatory purpose?

b) In Reference 1, the 2019 to 2022 CCA schedules show a column for "True-up from Filing to Tax Return" and the 2023 CCA schedule shows a column for "Opening Balance Adjustments". Please explain what these columns represent, why it is a different amount each year, and why it is needed.
c) In Reference 1, the 2024 CCA schedules show a column for "Asset Harmonization Adjustment". Please explain what this column represents and why it is needed.

4.6-Staff-183

Ref 1: Exhibit 4, Tab 6, Schedule 1, Attachment 1, p 6 – 2024 Test year Calculation of Utility Taxable Income and Income Tax Expense

Ref 2: Exhibit 1, Tab 8, Schedule 1, Attachment 14, pp 47, 48, 87 - 2021 T2 Corporation Income Tax Return

a) The following tax additions: "scientific research expenditures deducted per financial statements" and "reserves from financial statements – balance at the end of the year" are in Reference 2 p.47. These types of adjustments do not appear to be in Reference 1. Please confirm this or identify where it is included in Reference 1.

    i. If confirmed, please explain why these adjustments are not included for regulatory taxes in Reference 1 and revise regulatory taxes as applicable.

b) The following tax deductions: "SR&ED expenditures claimed in the year" and "reserves from financial statements – balance at the beginning of the year" are in Reference 2 p.47. These types of adjustments do not appear to be in Reference 1. Please confirm this or identify where it is included in Reference 1.
    i. If confirmed, please explain why these adjustments are not included for regulatory taxes in Reference 1 and revise regulatory taxes as applicable.
c) In Reference 2 p.87, Enbridge Gas had "investment tax credits on SR&ED expenditures". Please explain whether Enbridge Gas typically qualifies for SR&ED Income Tax Credits (ITC) and whether these amounts are material. If material, please provide the SR&ED ITCs from 2013 to 2021.
    i. Tax credits do not appear in the calculation of regulatory taxes in Reference 1. Please confirm.
    ii. If confirmed, please explain why they are not included in the calculation of regulatory taxes.
    iii. If not confirmed, please indicate where it is included in the calculation of regulatory taxes and the amounts of the tax credits.

4.6-Staff-184

Ref 1: Exhibit 4, Tab 6, Schedule 1, p.6

Ref 2: Exhibit 4, Tab 6, Schedule 1, Attachment 1, p. 6 – 2024 Test year Calculation of Utility Taxable Income and Income Tax Expense

Reference 1 states for Union Gas's determination of utility income subject to tax, a deduction for interest during construction (IDC) was included, consistent with how corporate income taxes are calculated for tax filing purposes, along with interest determined through utility capital structure. The Union Gas approach has been adopted for Enbridge Gas.

The calculation of utility taxable income and income tax expense for 2024 is provided in Reference 2.

a) Please confirm that for tax purposes, Enbridge Gas deducts interest expense equal to deemed interest plus IDC. If not confirmed, please clarify.
b) Please indicate where the IDC deduction is included in the calculation of regulatory taxes in Reference 2 and provide the amount.

c) Please explain and quantify the impact on the 2024 utility income tax calculation if the EGD approach for IDC is adoped.
d) The calculation of regulatory taxes includes a calculation for the tax shield on interest expense. Please explain what the tax shield on interest expense represents, including a discussion on why it is appropriate for regulatory purposes.
    i. Please explain whether this calculation is associated with or impacted by the IDC. If yes, please explain.

4.6-Staff-185

Ref: Exhibit 4, Tab 6, Schedule 1, Attachment 1, p. 6 – 2024 Test year Calculation of Utility Taxable Income and Income Tax Expense

Please explain Enbridge Gas's treatments of capital contributions for tax purposes and for regulatory tax purposes respectively (e.g. whether an election is made for capital contributions to include it in undepreciated capital property) and explain the regulatory impact of any difference in the treatment.

4.7-Staff-186

Ref: Exhibit 4, Tab 7, Schedule 1, pp. 2-5

As part of Union Gas's 2014 rates proceeding (EB-2013-0365), parties reached an agreement to reduce the Parkway Delivery Obligation (PDO) and payment of a Parkway Delivery Commitment Incentive (PDCI) through the PDO Settlement Framework with an end date of December 31, 2018. The mechanism was subsequently extended through Enbridge Gas's 2019 to 2023 deferred rebasing term. The intent of the PDO Settlement Framework was to address the inequity in which the delivery of gas required by the utility at Parkway was achieved. Certain direct purchase (DP) customers of the former Union Gas were contractually required to deliver some or all of their daily contract quantity (DCQ) at Parkway, at their own expense. Essentially, DP customers with a PDO conferred a benefit on all users of the Dawn Parkway system because the system capacity was less than would otherwise be required. As part of the settlement agreement in EB-2013-0365 parties agreed that the PDO should be permanently reduced by shifting customers' obligated DCQ from Parkway to Dawn and the payment of a PDCI should be made for any continuing obligated DCQ deliveries at Parkway.

In this application, Enbridge Gas has proposed to expand the PDO and PDCI offering to customers located in the EGD rate zone who are contractually obligated to deliver gas at the Enbridge CDA.

Please clarify if customers located in the EGD rate zone have requested a reduction to their obligated deliveries to the Enbridge CDA.

4.7-Staff-187

Ref: Exhibit 4, Tab 7, Schedule 1, pp. 14-16

In Enbridge Gas's MAADs proceeding (EB-2017-0305/0306), certain parties claimed that ratepayers were paying twice for the same Dawn Parkway system capacity. At the time of Union Gas's 2013 Cost of Service proceeding (EB-2011-0210), 210 TJ/day 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. Enbridge Gas has noted that if the company adjusts for the excess capacity incorporated in base rates during Union Gas's 2014 to 2018 IRM term and/or Enbridge Gas's 2019 to 2023 deferred rebasing term as part of the current application, the company will not be kept whole as agreed to by parties in the PDO Settlement Framework and subsequently approved by the OEB. The PDO Settlement Framework will instead reduce the utility's earnings during the IRM term(s), as the excess capacity would have otherwise been available to sell. Enbridge Gas believes that adjusting for the excess capacity as part of this application would be contrary to the guiding principles of the PDO Settlement Framework.

a) Please confirm if Enbridge Gas recovered the cost of 210 TJ/day of excess Dawn Parkway capacity in rates.
b) Enbridge Gas notes that in the absence of the PDO Settlement Framework, the excess capacity would have been available to sell. If the excess capacity had been sold, how would the revenues have been accounted for in rates?

5.1-Staff-188

Ref: Exhibit 5, Tab 1, Schedule 1, Table 3
Exhibit 5, Tab 2, Schedule 1, Table 1
OEB letter announcing 2023 Cost of Capital Parameters, issued October 20, 2022

On October 20, 2022, the OEB issued is letter announcing the 2023 cost of capital parameters for rates effective in the 2023 rate year. In light of current macroeconomic conditions, the 2023 parameters are based on more current socioeconomic data and are likely more representative of what the parameters may be for 2024, for Enbridge Gas's rebased rates.

a) Please update Table 3 of Exhibit 5/Tab 1/Schedule 1 to reflect the OEB-issued return on equity (ROE) of 9.36% for 2023, for the 2024 test year.
b) Please update Table 1 of Exhibit 5/Tab 2/Schedule 1 to reflect the OEB-issued 2023 ROE of 9.36% for the 2024 test year.

5.1-Staff-189

Ref: Exhibit 5, Tab 1, Schedule 1, Page 4 of 5

Assuming a capital structure comprising 38% common equity and an ROE of 8.66%, Enbridge Gas has requested the OEB to approve a cost of capital compensation of $950.7 million for the 2024 test year. The OEB has approved an ROE of 9.36% for rates effective from January 1, 2023.[1] The ROE effective from January 1, 2024 is expected to be closer to the 2023 approved ROE of 9.36% than to the 2022 ROE of 8.66%, based on current and forecasted macroeconomic indicators for inflation and interest rates. Assuming a capital structure comprising the currently approved 36% common equity and an ROE of 9.36%, the cost of capital compensation works out to approximately $977 million for the 2024 test year, which is higher than the cost of capital increase being sought by Enbridge Gas.[2]

As the approved ROE already leads to higher than forecasted cost of capital compensation (in $) relative to what has been requested in the application, please explain further why OEB should consider increasing Enbridge Gas's equity thickness.

5.2-Staff-190

Ref: Exhibit 5, Tab 2, Schedule 1, page 4
Exhibit 5, Tab 1, Schedule 1, page 4, Table 3
Exhibit 5, Tab 2, Schedule 1, page 3, Table 1

[1] OEB. Cost of Capital Parameter Updates. Last revised: October 20, 2022.
[2] Assumptions used to calculate revised cost of capital compensation for 2024: capital structure of 36% common equity, 63.96% long-term debt and 0.04% short-term debt; cost of long-term debt – 4.17% (same as Enbridge Gas' assumption), cost of short-term debt – 3.00% (same as Enbridge Gas's assumption) and ROE of 9.36%.

Investment Industry Regulatory Organization of Canada (IIROC) Canadian Bankers' Acceptance Rates (https://www.iiroc.ca/markets/canadian-bankers-acceptance-rates)

On page 4 of Exhibit 5, Tab 2, Schedule 1, Enbridge Gas documents its methodology for forecasting its short-term debt rate, stating:

> The cost of short-term debt used in the cost of capital calculation reflects the projected Canadian Dealer Offered Rate (CDOR) which represents the 3-month bankers' acceptances plus a spread of 0.10% (based on historical trends and current market trading levels).

In Table 3 of Exhibit 5, Tab 1, Schedule 1 and Table 1 of Exhibit 5, Tab 2, Schedule 1, it is seen that Enbridge Gas is forecasting a short-term debt rate of 3.0% for 2024. However, the calculation of this rate, or the data on which is based, are not provided.

1-month and 3-month Canadian Bankers' Acceptance Rates are published by IIROC on a business daily basis up to the most recent actuals.

a) Can Enbridge Gas provide the data on which the proposed rate is based, and the date or time period of the data used?
b) Does Enbridge Gas consider that its proposed short-term rate of 3.0% is reasonable in light of current economic conditions and forecasts of economic conditions this year and in 2024? Please explain your response.
c) Is Enbridge Gas proposing to update the short-term debt rate during the proceeding, up to and including at the Draft Rate Order (DRO) stage? If so, please provide further explanation of when and how Enbridge Gas proposes to do any update.

5.2-Staff-191

Ref: Exhibit 5, Tab 2, Schedule 1, page 1
Exhibit 5, Tab 3, Schedule 1, page 2
Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 5, 19-28 of 164

Enbridge Gas is proposing an increase in its deemed equity thickness from 36% currently to 42%, to be phased in over the five year period from 2024 to 2025. Enbridge Gas's proposal is supported by the evidence of Concentric Energy Advisors, Inc. (Concentric), and is entitled *Enbridge Gas Inc. - Common Equity Ratio Study*, dated October 17, 2022 (Concentric Report). Enbridge Gas also has documented Energy Transition as an issue affecting its business environment and operations, and Concentric in its report, discusses energy transition as the most important factor:

> In our [Concentric's] assessment, Enbridge Gas' risk profile has increased significantly as compared to its risk profile at the time of EB-2011-0354 and EB-2011-0210. The most material factor contributing to the increase is the Energy Transition – a broad-scale transformation from a primary reliance on fossil fuels to a primary reliance on more renewable fuel sources.

Can Enbridge Gas or Concentric quantify the increase in risk, and the commensurate increase in the deemed equity thickness that would be solely attributable to energy transition as faced by Enbridge Gas? If so, please provide, with supporting discussion and analysis.

5.2-Staff-192

Ref: Exhibit 5, Tab 2, Schedule 1, page 9, Table 3

Enbridge Gas provides forecasts for 2022, 2023 bridge and 2024 test years for its Fixed Financing Charges.

Please provide an update of Table 3 also showing actuals for each year from 2019 to 2022.

5.2-Staff-193

Ref: Exhibit 5, Tab 2, Schedule 1, Plus Attachments, Page 11 of 11

Enbridge Gas has provided details of forecast issuances of medium-term notes from 2022 to 2024 in Table 4.

a) Please provide the methodology and assumptions used to estimate the coupon rate (including the details of benchmark Bank of Canada bond used for estimation of coupon rate).
b) Please provide details of all medium term and long term bond issuances forecasted from 2022 to 2028, including the principal amount, coupon rate, issue date, maturity date and bond term (in MS Excel format).
c) Please provide details of all medium term and long term bonds outstanding as on December 31, 2021, including the original principal amount, principal amount outstanding, coupon rate, issue date, maturity date and bond term (in MS Excel format).

5.3-Staff-194

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, pp. 2-7
Exhibit 10, Tab 1, Schedule 1, pages 4 and 13
EB-2006-0088/-0089, *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, December 20, 2006, pages 22,43-44[3]

On pages 2 through 4 of Exhibit 5, Tab 3, Schedule 1, Enbridge Gas proposes that its deemed equity thickness be increased from 36% (currently) to 38% with 2024 rebased rates, and then increased by one percentage point per year during the price cap plan from 2025-2028, thus achieving a deemed 42% equity thickness by 2028.

In para. 11 on page 6 of this exhibit, Enbridge Gas states:

> In order to implement the proposed 1% increase in equity thickness in each year of the IR term (2025 to 2028), the Company proposes an annual base rate adjustment of $13.6 million. The annual base rate adjustment of $13.6 million is calculated as the incremental 2024 revenue requirement between an equity thickness of 42% and 38%, or $54.5 million, divided by the remaining four years of the IR term. In the derivation of annual rates, the Company proposes to include the annual base rate adjustment to the revenue requirement for rate-setting following the escalation of the previous year's rates.

OEB staff notes that Enbridge Gas does not mention in any detail the adjustment for the increased equity thickness as part of the proposed price cap plan mechanism in Exhibit 10, Tab 1, Schedule 1, other than mentioning it on pages 4 and 13 the proposal documented in Exhibit 5, Tab 3, Schedule 1. Further, the price cap plan operates on Enbridge Gas's rates and not on its revenue requirement. OEB staff also observes that Enbridge Gas's expert, Black & Veatch, does not discuss this in its evidence.[4]

OEB staff also notes that Enbridge Gas has only provided a customer and load forecast for the 2024 rebasing test year and has not provided any customer and load forecasts for the years of the price cap plan 2025-2028.

It is not clear what is the "revenue requirement for rate-setting" that Enbridge Gas is proposing to use for the 2025-2028 of the price cap term.

[3] https://www.oeb.ca/documents/cases/EB-2006-0088/report_of_the_board_201206.pdf
[4] Exhibit 10, Tab 1, Schedule 1, Attachment 1

Normally, under incentive mechanisms such as price or revenue caps, changes to the cost of capital, including changes in the deemed capital structure, for rate-setting purposes, are not allowed. However, OEB staff notes that, for the 2nd Generation IRM for electricity distributors, the OEB implemented an approach to migrate electricity distributors from different deemed capital structures to the current common 40% equity/56% long term debt/4% short-term debt. This was phased in by up to three years from 2008 to 2010, with some adjustments made at the time of a cost of service application to rebase rates and during years of price cap adjustments by a k-factor in the price cap formula. This is discussed on pages 21 and 43-44 of the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*.

a) Please provide further details on the definition and derivation of the "base rate adjustment" and the "revenue requirement for rate-setting" as discussed in para. 11 of Exhibit 5, Tab 3, Schedule by which Enbridge Gas proposes to implement incremental increases in the equity thickness during the price cap term.

b) Did Enbridge Gas consider an approach for implementing the change through a factor in the price cap formula itself, akin to the k-factor adopted by the OEB for 2nd Generation IRM for electricity distributors? If so, why did Enbridge Gas adopt its proposed method?

c) Does Enbridge Gas's proposed "base rate adjustment" or "revenue requirement for rate-setting" take into account changes in customers or load during the 2025-2028 years? Please explain your response.

d) Was Black & Veatch asked to review the phase-in of the deemed equity thickness increase as part of its work, or was it made aware of this proposal? If so, why is it not discussed in Black & Veatch's report? If not, please explain why this was omitted from Black & Veatch's analysis of Enbridge Gas's price cap plan proposal.

5.3-Staff-195

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 5 of 164

Concentric Energy Advisors, Inc. ("Concentric") has stated the following:

> … our analysis compares the Company's risk profile today to the Company's risk profile in 2012, which is the approximate period in which EB-2011-0354 (i.e., the OEB's most recent equity thickness evaluation for EGD) and EB-2011-0210 (i.e., the OEB's most recent equity thickness evaluation for Union Gas) occurred.

Enbridge Gas proposed a common equity ratio of 36% in its application for amalgamation of EGD and Union Gas, which was accepted by the OEB in 2018.[5] This implies that Enbridge Gas and the OEB agreed that the risk profile of Enbridge Gas had not changed materially from 2012 to 2018.

Please provide justification for comparing Enbridge Gas's risk profile in 2022 to EGD and Union Gas's risk profile in 2012 instead of comparing to their risk profiles in 2018.

5.3-Staff-196

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, page 6 of 164/Table 1

Exhibit 5/Tab 3/Schedule 1/Attachment 1 is the evidence of Concentric Energy Advisors, Inc. (Concentric), and is entitled *Enbridge Gas Inc. - Common Equity Ratio Study*, dated October 17, 2022 (Concentric Report). Table 1 of the Concentric Report, on page 6 of 164, is a "Risk Analysis Summary" of Concentric's assessment of EGD's / Enbridge Gas's business, operational, financial, volumetric and regulatory risk since 2012, when the OEB last made a determination of EGD's risk based on evidence in front of it in a rate application for the utility.[6]

OEB staff notes that Concentric does not identify the formation of Enbridge Gas Inc. as a result of an acquisition and amalgamation of Union Gas and EGD approved by the OEB in a joint MAADs and multi-year rate plan application,[7] as a major factor in any change in the risk since 2012.

a) All else being equal, would not investors and lenders consider that the amalgamation of EGD and Union Gas, and creating a larger utility with service areas (in the more populous area of southern Ontario) largely contiguous and thus offering opportunities for economies of scale and other synergies, as lowering the risk of Enbridge Gas relative to that of EGD as assessed in 2012?
b) Please explain why Concentric does not consider the amalgamation of EGD and Union Gas, upon acquisition of the latter, to form Enbridge Gas, a major change affecting Enbridge Gas's business risk relative to that of EGD in 2012.

[5] OEB. EB-2017-0306 and EB-2017-0307. Decision and Order. Enbridge Gas Distribution Inc. and Union Gas Limited Application for Amalgamation and Rate-Setting Mechanism. August 30, 2018.
[6] EB-2011-0354 and EB-2011-0210
[7] EB-2017-0306/-0307

5.3-Staff-197

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 17-18 of 164

On pages 17-18 of 164 of its evidence, Concentric summarizes its assessment of how Enbridge Gas's risk has increased relative to the last case when it was reviewed in 2012. The second bullet of the list, at the bottom of page 17 and continuing on page 18 relates to volumetric risk. The concluding sentence in that bullet states: "Regulatory mechanisms provide short-term insulation, but do not change the long-term challenges facing the Company [Enbridge Gas]."

a) Please identify the regulatory mechanisms that Concentric is referring to.
b) Please explain why Concentric believes that, even if these regulatory mechanisms provide "short-term insulation" for Enbridge Gas, they do not address the longer-term challenges faced by the utility.
c) Can Concentric quantify, to the best of its ability, what it is meaning by "short-term" versus "long-term", as used in this sentence.
d) Concentric has also assessed a sample of U.S. natural gas utilities in its evidence.
    i. Based on its assessment of the U.S. natural gas utilities in its sample, does Concentric view that the volumetric risk also exists elsewhere on the natural gas sector in North America? Is the volumetric risk higher, lower, or the same for Enbridge Gas compared with the natural gas sector generally?
    ii. Are there the same, or analogous, regulatory mechanisms in place for the sampled U.S. utilities as there are for Enbridge Gas in Ontario. Please explain your response.

5.3-Staff-198

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, page 21 of 164/Figure 3

On page 21 of 164 of its evidence, Concentric notes that 48 Ontario municipalities have declared "climate emergencies". Figure 3 lists the municipalities that Concentric identified as having declared climate emergencies.

a) On what basis has Concentric concluded that municipal council "climate emergency" declarations are representative of Energy Transition actualization and that indicate that Enbridge Gas's business risk has materially increased?
b) Of the Ontario municipalities listed in Figure 3:

i. How many are currently serviced by Enbridge Gas, in all of part of the municipality?
ii. In how many of the municipalities serviced by Enbridge Gas has it increased its service in the municipality since early 2019, either by addition of customers and/or by increasing or reinforcing pipeline capacity to service the municipality?
iii. In how many of the municipalities listed in Figure 3 has Enbridge Gas been denied a franchise agreement or an application to connect customers or increase capacity, since early 2019?

5.3-Staff-199

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 23-25 of 164

On pages 24-25 of 162 of its evidence, Concentric notes that, while it is unaware of any specific bans on natural gas expansion in Ontario, 48 municipalities in Ontario have declared "climate emergencies". Concentric also references the City of Toronto targets, and quotes from speeches from the current Minister of Energy.

Please provide any analysis Concentric has done to corroborate the quotes that it has taken from The Brattle Group presentations or Government announcements being actualized so as to constitute a real energy transition risk to Enbridge Gas at this point in time.

5.3-Staff-200

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 25 of 164

Concentric states the following on the referenced page: "S&P [Standard & Poor's] and Moody's have incorporated ESG criteria into their credit rating analyses…".

a) Please provide examples (with detailed references) of a company's credit rating being affected by ESG criteria (examples may include credit rating reports from any major credit rating agency).
b) Has this addition of ESG criteria into credit rating agencies' rating methodologies affected Enbridge Gas's credit rating? If yes, please provide references and/or any relevant credit reports.

5.3-Staff-201

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 25 of 164

Concentric states the following on the referenced page:

> Six of Canada's largest banks, including the Bank of Montreal, the Canadian Imperial Bank of Commerce, the National Bank of Canada, the Royal Bank of Canada, Scotiabank, and Toronto-Dominion Bank, recently signed on to the Net-Zero Banking Alliance, thereby committing to establishing a variety of sustainability-linked emissions targets.[footnote omitted] These banks are the primary debt capital providers for EGI.

How has signing on to the Net-Zero Banking Alliance impacted, in real or practical terms, debt market access to Enbridge Gas to date? What are the practical implications, if any, expected on Enbridge Gas's access to debt financing over the 2024-2028 period from this arrangement of major Canadian banks aligning with the Net-Zero Banking Alliance? Please elaborate in your response.

5.3-Staff-202

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 26 of 164

Concentric has presented a chart on "S&P Estimated North American Energy New Issues Yield Curve: 2019-2021" in Figure 6 on this page.

Please provide underlying data for this chart (in MS Excel format), updated to December 2022.

5.3-Staff-203

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 31 of 164

Concentric states the following on the referenced page:

> …the OEB is not bound by the findings of utility regulators in Massachusetts, Colorado, California, or New York. However, these proceedings illuminate the degree to which the operating environment for gas distribution utilities has changed.

In light of these developments, how have approved common equity ratios and allowed ROEs changed for gas distribution utilities in these jurisdictions? Please explain, and provide references, as necessary.

5.3-Staff-204

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 32 of 164

Concentric states the following on the referenced page:

> "While Enbridge benefits from the estimated 5-basis point "greenium," the SLB issuance also includes a 50-basis point penalty if Enbridge fails to meet the GHG emission reduction milestones."

a) Please provide the source document for this statement.
b) Please provide the methodology used for the estimation of the "greenium" (5 basis points) and the penalty (50 basis points").

5.3-Staff-205

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

Concentric has provided the following quote from Standard & Poor's:

> "S&P Global Ratings believes hydrogen can push the energy transition forward, but this would require coordinated policy, lower hydrogen production costs, and massive growth of renewables. Energy transitions typically take decades…"

Can Enbridge Gas or Concentric elaborate and quantify the projected financial impacts from hydrogen-related energy transition risks and initiatives on Enbridge Gas during the 2024-2028 period.

5.3-Staff-206

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 37 of 164, Exhibit 1, Tab 10, Schedule 6, Page 21 of 40

Concentric has stated the following:

> These preliminary studies regarding the viability of RNG do not necessarily mean that RNG is not a viable long-term solution. However, from an investor's perspective, pursuing such an uncertain pathway intrinsically carries risk. Further, as with the hydrogen discussion above, it is a risk that was not as meaningful at the time of the Company's previous equity thickness proceedings (i.e., 2012).

Elsewhere in its evidence, Enbridge Gas describes its plans to increase RNG in the gas supply as a "safe bet" for the energy transition. Please reconcile with Concentric's statement that this is an uncertain pathway carrying risk.

5.3-Staff-207

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 37 of 164

Concentric has state the following on the referenced page:

> "The Energy Transition substantially affects nearly every aspect of the Company's business, from its growth prospects, to the capital projects it pursues, to its fundamental ability to offer investors the opportunity to earn a fair return on, and of, invested capital. Even though the Energy Transition will play out over many decades, it is now underway and it is materially increasing the Company's risk profile because of the long expected lives of most natural gas utility investments."

a) Does Concentric distinguish between the risk of recovery of investment on existing rate base and the change in growth opportunities due to the energy transition?
b) Please quantify the "material increase in risk profile" mentioned here for Enbridge Gas for the 2024-2028 period.

5.3-Staff-208

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Pages 38, 51, 57-59 of 164

Concentric has stated the following on the referenced page:

> The Company has deferral and variance accounts that provide a degree of short-term insulation from this risk (insulation that will improve if the Company's SFV rate design proposal is adopted). However, in the long-term, investors are

concerned that increasing costs recovered over declining volumes may create a "death spiral" scenario.

a) Please clarify what is meant by "short-term" versus "long-term" in this statement. Is the 2024-2028 period considered "short-term"?
b) Please provide evidence of investors showing concern regarding the "death spiral" scenario that Concentric describes for Enbridge Gas.

5.3-Staff-209

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, pp. 38-39, 51, 57-59 of 164

On pages 38-39 of 164 of its report, Concentric discusses volumetric risk as a factor increasing Enbridge Gas's business risk. Concentric discusses this by pointing to opposition to natural gas expansion in light of energy transition.

a) Concentric notes that Enbridge Gas's Residential customers accounted for 57% of revenues in 2020 but just 32% of sales volumes.
   i. Does Concentric consider that the difference between revenues (to recover the costs of serving) and sales volumes is unique to Enbridge Gas, or to natural gas distributors, relative to other network-based service providers, such as electricity distributors or telecommunications providers? Please explain your response.
   ii. Has Concentric satisfied itself that the difference observed in 2020 is typical, and not due, at least in part to the lockdown restrictions due to the COVID-19 pandemic declared in mid-March of that year?

5.3-Staff-210

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 39 of 164

Concentric has stated the following on the referenced page:

> Increasing opposition to natural gas makes it more difficult, costly, and time-intensive for natural gas distribution utilities such as the Company to construct and permit new facilities. Depending on the extent of this opposition, shareholders may bear increasing amounts of operational risks or cost overruns as critical infrastructure projects are delayed.

a) Please provide Ontario specific examples of time/cost over-runs from recent periods, due to operational risk as defined here.

b) Are there specific quantifiable project development and executions risks that Enbridge Gas has faced in the last 10 years or expects to face over the 2024-2028 period? Please provide details.

5.3-Staff-211

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 42-44 of 164
Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 77-79 of 164

At the bottom of page 42 of 164 of its evidence, Concentric notes that Enbridge Gas has not been immune to increased "operational risk" from increased scrutiny of proposed replacement and addition of pipeline infrastructure investment. Concentric then documents several recent Leave to Construct (LtC) applications, and notes that several were denied by the OEB. However, there are a few (EB-2021-0205, EB-2022-0088, EB-2022-0157) for which Concentric does not discuss the OEB's decisions on those LtC applications.

In addition to LtC applications, Enbridge Gas has also applied for funding for capital projects under the OEB's Capital Funding Options policies[8] (i.e., Incremental Capital Module (ICM) and Advanced Capital Module (ACM)) since the amalgamation of EGD and Union Gas. Enbridge Gas has been approved for some but not all ICM applications that it has filed since amalgamation. Concentric does not discuss the availability of ICMs/ACMs under Enbridge Gas's regulatory framework (on pages 77 to 79 of 164 of its evidence); nor does Concentric address these as complements or alternatives to LtCs under operational risks on pages 42 to 44 of 164.

a) Can Concentric confirm that the OEB's decisions on EB-2021-0205 and EB-2022-0088 did approve the LtC applications.
b) Can Concentric identify what factors were the primary drivers of the "increased scrutiny of proposed replacement and addition of pipeline infrastructure investment". For example, is the increased scrutiny of pipeline infrastructure investment due specifically to Energy Transition or to increasing environmental awareness, or to other factors?
c) Please explain why Concentric has not considered the availability of Capital Funding Options, and of Enbridge Gas's filing of ICM applications in the current Price Cap IR plan since amalgamation (2019-2023) in consideration of (or assessing) Enbridge Gas regulatory risk or operational risk.

[8] EB-2014-0219, *Report of the Board on New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014, and *Report of the OEB on New Policy Options for the Funding of Capital Investments: Supplemental Report*, January 22, 2016

d) Does Concentric consider that Enbridge Gas faces less, the same, or more operational risk compared to U.S. natural gas utilities, given Enbridge Gas's recent experiences in seeking approval for system expansion, reinforcement and replacement through LtC and ICM applications since the merger and similar applications by the U.S. utilities? Please explain your response.

5.3-Staff-212

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 45-47 of 164
State of Rhode Island Division of Public Utilities and Carriers, Docket D-21-09, Report and Order, issued February 23, 2022

On pages 45-47 of 194 of its evidence, Concentric discusses increased operational risk due to "going concern".

Concentric goes on to discuss the application concerning the sale of The Narragansett Electric Company, as considered by the State of Rhode Island Division Of Public Utilities and Carriers (the Division). Concentric quotes from the evidence of witnesses of the Attorney General of Rhode Island in that docket.

OEB staff notes that the Division issued its Report and Order in Docket D-21-09 on February 23, 2022.[9] OEB staff also notes the Division's finding with respect to environmental matters and recommendations on pages 328 to 331 of the Report and Order.

a) Can Concentric confirm that the Division was satisfied with evidence and commitments on environmental and Energy Transition matters of The Narragansett Electric Company, PPL Corporation and PPL Rhode Island Holdings, LLC as conditions of approval of the sale?
b) Can Concentric confirm that the Division approved the sale of The Narragansett Electric Company?
c) Can Concentric quantify the "going concern" risk as it relates to Enbridge Gas, and how much this has increased since 2012?
d) Can Concentric identify the time horizon applicable for this increased "going concern" risk as it specifically relates to Enbridge Gas?

[9] https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/D_21_09_Order.pdf

5.3-Staff-213

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 46 of 164

Concentric has stated the following on the referenced page: "Another risk of the Energy Transition is that a significant portion of the Company's gas plant investments could become stranded."

Please provide specific examples of the OEB failing to provide cost recovery for stranded assets in the last 10 years.

5.3-Staff-214

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 46 of 164

Concentric has stated the following on the referenced page: "… the Energy Transition creates both risks and opportunities for gas utilities such as Enbridge Gas."

Can Concentric please describe all of the opportunities that arise as a result of Energy Transition for gas utilities such as Enbridge Gas that Concentric is aware of.

5.3-Staff-215

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 51 of 164

Concentric has stated the following on the referenced page:

> Figure 9 presents the normalized average use of natural gas by the Company's residential customers from 2006 to 2021. This figure shows that normalized residential average use has declined even further from 2012 levels. In fact, for the period 2006 to 2012, the average annual growth rate in residential average use was -0.30%. For the period 2013 to 2021, the average annual growth rate decreased to -0.57%.

a) As Concentric has compared Enbridge Gas's risk profile in 2022 to EGD and Union Gas's risk profile in 2012, please provide the following information starting from 2012 (in MS Excel format):
    i. Actual annual load/sales and consumer data from 2012 to 2022 (segregated by consumer category). Please ensure that the data is provided separately for EGD and Union Gas from 2012 to 2018.

ii. Forecasted annual load/sales and consumer data from 2023 to 2028 (segregated by consumer category).

5.20-Staff-216

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 52-53 of 164

On page 52 of 164, Concentric states that:

> Considering the Energy Transition risks discussed above, we conclude that the Company's growth prospects today are weaker than they were at the time of the Company's previous equity thickness proceeding (i.e., 2012). Further, Figure 10 compares a variety of long-term economic growth projections from 2012 to comparable projections today. As shown, long-term economic growth prospects in Ontario, Canada overall, and the U.S. are weaker today than they were in 2012, diminishing the Company's growth prospects relative to 2012 even absent Energy Transition risks.

On page 10, Concentric provides Table 10, summarizing various economic forecasted statistics for certain key Canadian and U.S. statistics from sources such as The Conference Board of Canada, *Consensus Forecasts*, and Blue Chip Forecasts.

For all of the measures documented in Table 10 on Canadian and U.S. GDP growth, Concentric concludes that, even ignoring Energy Transition, it considers Enbridge Gas's growth prospects as diminished relative to when the last time that Enbridge Gas's business risk and commensurate equity thickness was reviewed.

OEB staff has prepared a table, set out in the excel sheet provided separately, based on Canadian GDP growth statistics, and certain other measures, such as the OEB's issued ROE, and actual and forecasted 10-year Government of Canada bond yields, corresponding to the timeframes of the October 2012 and April 2022 Consensus Forecasts used by Concentric. OEB staff has also added the 10-year long range forecasts for GDP growth from *Consensus Forecasts* October 10, 2022 publication, as this was known prior to Enbridge Gas filing the current application.

a) Please confirm or correct the data provided in OEB staff's table.
b) For the Consensus Forecasts of GDP growth, Concentric has only provided the years 3,4, 5 and 6-10 from the semi-annual 10-year forecast included as a supplement in the April and October *Consensus Forecast*s

publications, while Concentric has omitted the forecasts for years 1 and 2. Please explain why Concentric omitted the forecasts for the first two years as provided in the *Consensus Forecasts* publications for October 2012 and April 2022.

c) In focusing on GDP growth forecasts, doesn't the consideration of reduced growth in GDP impact on the growth for firms in the economy generally? In other words, while there are some firms and sectors that may buck the trend, due to emerging or growing technologies, or due to better management or favorable business conditions, that may sustain higher growth, most firms and sectors would exhibit lower growth potential now due to socioeconomic changes in the past 10 years?
d) Is not the important consideration whether or not Enbridge Gas's growth prospects have, regardless of energy transition, changed (declined or improved) relative to economic growth generally?

5.3-Staff-217

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 64 of 164

Concentric has provided details of 'EGD/EGI Financial Metrics' in Figure 17.

Please expand the table in this figure and provide ratios for all years between 2012 and 2022, (in MS Excel format), and showing the calculations for the financial metrics, as appropriate.

5.3-Staff-218

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 66 of 164

Concentric has provided details of its "Comparison of Enbridge Gas' Credit Metrics to the Proxy Companies" in Figure 19, shown on the referenced page.

a) OEB staff understands that this data is for 2021, as the numbers match the 2021 metrics shown in Figure 18 on page 65 of 164 of Concentric's report. Please confirm or correct this.
b) Please provide backup data and underlying calculations for this table, and provide a similar table for each year between 2012 and 2022, including underlying calculations (including for combining EGD and Union Gas data pre-amalgamation, in MS Excel format).

c) Please expand this table to provide 2023, 2024, 2025, 2026, 2027, 2028 forecasts, showing estimates for these credit metrics assuming: (i) no change in capital structure; and (ii) change in capital structure as proposed by Enbridge Gas. Please provide underlying calculations for the entire expanded table, in MS Excel format.

5.3-Staff-219

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 69-72 of 164

On pages 69 to 72 of 194 of its evidence, Concentric discusses the issue of the effects of climate change and severe weather risk on the operational risk of natural gas utilities generally.

a) Can Concentric quantify the increase in operational risk related to climate change and severe weather risk as it pertains to:
    i. North American natural gas utilities generally
    ii. Enbridge Gas?
b) Can Concentric quantify the time horizon for the increased operational risk due to climate change and severe weather risk as discussed in this section of its evidence?
c) Can Concentric provide specific instances associated with climate change that have directly affected Enbridge Gas or, pre-amalgamation, EGD or Union Gas from 2012 to 2022, and which involved costs that Enbridge Gas, EGD or Union Gas were unable to recover. If so, please identify and describe.

5.3-Staff-220

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 69-72 of 164

On pages 69-72 of 164 of its report, Concentric discusses the issue of the "Effect of Climate Change and Severe Weather Risk" on Enbridge Gas's operational risk. Concentric concludes:

> In summary, the risks associated with changing climate parameters and severe weather events have increased for EGI since 2012, at the asset, industry, distribution system and macroeconomic levels. Investors are keenly focused on how such risks are being managed by organizations. While we expect that the risks will continue to manifest over time, current trends point to a greater and potentially more urgent likelihood of

incremental expenditures and operational impacts over the upcoming rate setting period.

a) In the discussion provided in this section, Concentric does not point to any incidents or discussions from market analysts, government agencies or experts specifically about Enbridge Gas. Please explain Concentric's reasoning for concluding that Enbridge Gas's risk has increased since 2012 with respect to climate change and weather risk. Please provide analysis done or references that Concentric has used in reaching its conclusion.

b) If possible, please provide a quantification of the increase in Enbridge Gas's risk due to climate change and severe weather since 2012. In the alternative, please explain how Concentric has reached its conclusion, and whether, and on what basis, it considers the increase in risk is material or not.

5.3-Staff-221

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 72 of 164

Concentric has stated the following on the referenced page: "Higher insurance costs are a risk to the extent they are not recovered in base rates."

OEB staff notes that insurance expense is a standard part of OM&A expense that goes into the determination of the revenue requirement. Hence, approved budgeted insurance expense is recovered through rates and, under formulaic inflation-less-productivity adjustment under IRM plans, there is an escalation annually, while the utility has flexibility in its expenditures but is also expected to manage its costs during the multi-year IRM period.

Can Concentric identify specific instances where Enbridge Gas has not been able to recover its insurance expense through customer rates to date? If so, please identify and describe such instances.

5.3-Staff-222

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 74-75 of 164

On page 75, Concentric presents is conclusion, stating that it views Enbridge Gas's operational risk is increased relative to what it was in 2012 due to its review of factors such as climate changes and severe weather risk, insurance costs, etc.

a) Can Concentric provide a quantification of the increase in operational risk and the relative importance of the factors that it identified and discussed in this section (Section 4-d) of its evidence?
b) Concentric's evidence, under "Engineering Regulations and Operational Complexity" on pages 74 and 75 of 164, states that "EGI operational personnel have indicated …", and the section talks about internal Enbridge Gas operations and views. No references to sources are provided.
    i. Is what is documented in this section the views of Enbridge Gas or of Concentric?
    ii. If these are the views of Enbridge Gas, how has Concentric satisfied itself with what Enbridge Gas personnel discussed with it are factual and material such that Concentric has satisfied itself to reach a conclusion that these factors "increase the uncertainty and risk of operating the gas distribution system as compared to the situation in 2012"?

5.3-Staff-223

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 77-79 of 164

On pages 77 to 79 of 164 of its evidence Concentric discusses its assessment of the regulatory framework under which Enbridge Gas, and the predecessor utilities of EGD and Union Gas, have operated. At the bottom of page 78 of 164, and continuing on page 79, Concentric notes that both EGD and Union rebased rates for 2013 through cost of service applications, and subsequently were under formulaic rate adjustment mechanisms. Concentric references the inherent increased risk often noted by credit rating analysts with respect to performance-based forms of rate regulation.

a) OEB staff observes that Concentric has not gone further back in the regulatory history of EGD and Union.
    i. Can Concentric confirm that EGD rebased its rates 2008 (EB-2007-0617) and that its rates were annually adjusted under a revenue per customer formula plan for 2009 through 2012?

ii. Can Concentric confirm that Union Gas has also operated under a number of PBR/IRM frameworks, with periodic cost of service reviews to rebase rates through much of the 2000s and 2010s up until rebasing?
iii. Can Concentric confirm that EGD has operated under formulaic rate adjustment mechanisms as approved by the OEB, with periodic cost of service reviews to rebase rates and set the parameters for subsequent performance-based regulation/incentive regulatory mechanism (PBR/IRM) plans, going back to the late 1990s?
iv. Given the long history PBR/IRM in Ontario, and specifically for gas distribution regulation, why does Concentric consider that Enbridge Gas's regulatory risk has increased from that of EGD in 2012, if factors such as IRPAs and the proposed SFV rate design are ignored?

5.3-Staff-224

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 81 of 164

Concentric has provided "Comparison of Market Risk Indicators" in Figure 22 on the referenced page.

Please expand this table to provide data for all years from 2011 to 2022.

5.3-Staff-225

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 84 of 164

On the referenced page, Concentric has provided 'Summary of Comparative Analysis Results (Mean)' and 'Summary of Comparative Analysis Results (Median)' in Figures 23 24 respectively.

Please provide backup data and calculations, in MS Excel format, for the data shown in Figures 23 and 24.

5.3-Staff-226

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 84 of 164

Concentric has stated the following on the referenced page:

> Taken together [Figures 23 and 24], the analyses support an equity ratio in the range of 40% to 45% for Enbridge Gas. Within that range, Concentric specifically recommends an equity ratio of no less than 42% for Enbridge Gas for the reasons discussed later in this report.

Can Concentric please elaborate on the specific numbers in Figures 23 and 24 that Concentric used, and those that it gave less consideration to in determining its recommended equity ratio range of 40%-45% for Enbridge Gas.

5.3-Staff-227

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, page 75 of 164
Exhibit 1, Tab 4, Schedule 1, page 1
Exhibit 1, Tab 4, Schedule 1, Attachment 1

Concentric discusses the impact of the amalgamation of EGD and Union Gas, resulting in the current Enbridge Gas, the applicant utility. Concentric concludes that "the amalgamation of EGD and Union Gas did not reduce the operating risk profile of the resulting EGI as compared to EGD in 2012", stating earlier in that section that "... S&P [Standard & Poor's] observes that the amalgamation with Union Gas did not increase the geographic, economic, or regulatory diversification of EGI".

Under "Conclusion", Concentric states: "While the Company has grown in size due to the amalgamation of EGD and Union Gas, this did not reduce the operating risk profile of the resulting EGI".

On page 1 of Exhibit 1, Tab 4, Schedule 1, Enbridge Gas describes its seven operating regions, and the map provided in Exhibit 1, Tab 4, Schedule 1, Attachment 1 shows these areas, comprising the amalgamation of EGD and Union Gas, along with a service area expansions since amalgamation five years ago. OEB staff observes that there is a fairly contiguous service area for Enbridge Gas as a result of the amalgamation.

a) Please provide the Standard & Poor's report that Concentric refers to in this section.
b) In addition to the larger customer base and larger service area of Enbridge Gas as a result of the amalgamation of EGD and Union Gas, would the largely contiguous nature of the former EGD and Union Gas service areas not provide more opportunities for economies of scale, greater asset and labour utilization, and hence should result in lower operational risk for Enbridge Gas compared to EGD in 2012, all else being equal?

c) Noting that the discussion under Amalgamation of EGD and Union Gas only references the Standard & Poor's report, what analysis did Concentric conduct itself regarding the impacts of the amalgamation on Enbridge Gas's operation risk compared to that of EGD in 2012. Please provide any analysis conducted by Concentric on this issue.

5.3-Staff-228

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, page 77-79 of 164
Exhibit 10, Tab 1, Schedule 1, pages 10-11
Handbook for Utility Rate Applications, October 13, 2016
EB-2014-0219, *Report of the Board on New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014
EB-2014-0219*, Report of the Board on New Policy Options for the Funding of Capital Investments: Supplemental Report*, January 22, 2016

On pages 77-79, Concentric documents its understanding of Enbridge Gas's regulatory framework under the OEB and considers that there is no material change in the relative regulatory risk since 2012. Concentric discusses the availability of the Z-factor for cost recovery for material events outside of the utilities ability to predict and control, and to deferral and variance accounts (DVAs) for cost pass-through. Concentric also points to the straight fixed variable (SFV) rate design proposal that Enbridge Gas is seeking approval for in this application.

However, OEB staff notes that Concentric makes no reference to the following:

- The Handbook for Utility Rate Applications (Rate Handbook), issued by the OEB on October 13, 2016. The Rate Handbook provided a higher level rate-setting policy for better alignment of rate-setting approaches and options across all energy sectors, including natural gas distribution.
- The OEB's policies for capital funding options as updated in the 2014-2016 period with the following two Reports of the Board:
    - EB-2014-0219, *Report of the Board on New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014
    - EB-2014-0219, *Report of the Board on New Policy Options for the Funding of Capital Investments: Supplemental Report*, January 22, 2016

> These rate regulatory policies were not in existence when EGD's and Union Gas's cost of capital were last reviewed. Enbridge Gas has availed itself to the Incremental Capital Module in several rate applications since amalgamation, and, while it has not identified specific capital projects, in its system plan in the application, for which it is seeking Advanced Capital Module or Incremental Capital Module cost recovery, the utility is requesting the availability of the Incremental Capital Module as part of the price cap proposal for 2025-2028,

Please explain why Concentric did not address the Rate Handbook or the OEB's capital funding options in assessing changes in Enbridge Gas's regulatory framework that were not available to EGD and Union Gas in 2012.

5.3-Staff-229

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 87-88 of 164
EGI_Rebasing Appl_Concentric Equity Thickness Supporting Schedules_20221101.xlsx

Figure 25, on page 87 of 164, lists the Canadian operating companies (opcos) in one of Concentric's proxy groups. Figure 26 on page 88 of 164, list the Canadian holding companies in a second proxy group used by Concentric. In the spreadsheet EGI_Rebasing Appl_Concentric Equity Thickness Supporting Schedules_20221101.xlsx, on Sheet "Sch 4 – Op. Company Auth", these Canadian opcos and holdcos are provided, along with the authorized equity thicknesses for natural gas service opcos for the Canadian holdcos. Further data on the Canadian opcos and holdcos is provided on sheet "Schedule 2 – analysis", including the gross plant and accumulated depreciation of many, but not all, of the sampled companies; from this can be calculated the net book value (NBV) of in-service assets.

a) Analysis of the data in sheet "Schedule 2 – analysis" would indicate that Enbridge Gas, with a gross book value of $21,744M and accumulated depreciation of ($4,905M) or a NBV of $16,839M, is more than three times as large as the next largest in the list (FortisBC, with 2021 GBV of $7,823M, accumulated depreciation of ($2,335M) and an NBV of $5,488M. Other Canadian opcos appear to be smaller still, and an examination of several of those for which data is listed as "NA" (not available) would indicate that they are smaller still. How has Concentric taken into account differences in the sizes of the Canadian opcos relative to Enbridge Gas in its analysis?

b) How has Concentric factored Hydro One Inc., which has no gas operations in any operating subsidiaries into its analysis at the opco or holdco level?

c) In calculating the authorized equity thickness of the holdco, as shown in sheet "Sch 4 – Op. Company Auth", Concentric has used the simple arithmetic average of the authorized equity thickness of subsidiary opcos for which data is available. No account is taken of differences in sizes of the opcos. Also, in calculating the average of the holdco proxy group, Concentric has again just taken the simple average.

   i. Why does Concentric consider that the simple average, at both holdco and holdco proxy group level, to be adequate for its analysis, without taking into account differences in sizes?

   ii. For Algonquin Power & Utilities, OEB staff observes that only Liberty Gas New Brunswick (for which opco data is NA) operates in Canada, while all of the other subsidiary opcos listed for Algonquin Power & Utilities operate in the U.S. Further, OEB staff observes that the listed subsidiary gas opcos for AltaGas Inc. and Emera Inc. all operate in the U.S. Please explain why Concentric considers its Canadian holdco proxy group to be representative given the mix of data based on both Canadian and U.S. subsidiary opcos.

d) Concentric uses the authorized ROE and the deemed equity thickness in its analysis, but does not appear to use any data on actual ROEs in its analysis. Please explain why Concentric does not use actual ROEs in its analysis.

5.3-Staff-230

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 91-92 of 164

Concentric documents how it has assessed the risk of the Canadian and U.S. operating companies (opcos) and holding companies (holdcos), relative to Enbridge Gas, on several dimensions, including:

- Energy Transition
- Size
- Regulatory framework.

With respect to Energy Transition, Concentric states:

> The Energy Transition places gas distribution utilities' long-term ability to earn a return of invested capital at risk as increasing costs must be

collected from declining volumes. Accordingly, as a general matter, companies whose assets have more remaining book life and lower depreciation rates have more exposure to Energy Transition risks than companies whose assets have less remaining book life and higher depreciation rates. **All else equal, relatively higher remaining book lives and/or relatively lower depreciation rates indicate that it will take longer for an investor to recover the return of invested capital, therefore increasing exposure to Energy Transition risks** such as stranded asset risk and volumetric risk. [Emphasis added]

Concentric then discusses means available to Enbridge Gas and other gas utilities to mitigate some of these risks.

a) As shown in Figure 29, Concentric notes that the average total life and the average remaining life of Enbridge Gas's assets is higher than that for the Canadian opco and holdco samples. and the percentage depreciation of assets is lower than for any of the Canadian and U.S. opco and holdco samples.
   i. Has Concentric examined, and if so, taken into account the reasons, why Enbridge Gas's assets have longer remaining lives than other Canadian gas utilities or why Enbridge Gas's accumulated depreciation, in percentage terms relative to the Gross Book Value of assets is below that of all samples? For example, are there differences in growth/expansion for Enbridge Gas, including as a result of the amalgamation five years ago, relative to that of other Canadian and U.S. utilities in Concentric's sample.
   ii. Are there other factors (business operating conditions), such as climate, terrain, residential and commercial mix of customers, that differ amongst the utilities in Concentric's samples and need to be accounted for in assessing the energy transition risk? In other words, does Concentric believe that "all else being equal" qualifier is satisfied in its assessment of energy transition risk in this section. Please explain your response.

5.3-Staff-231

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 94-96, 115 of 164
S&P Global Ratings, *Updates And Insights On Regulatory Jurisdictions*

Shaping Policies For North American Utilities --November 2020, November 9, 2020

On page 115 of 164 of its report, Concentric provides a map of the U.S. and Canada, showing the ranking of all states and provinces, by UBS Global Research report “North American Power & Utilities: Mind the Gap(s): 2021 Utility Outlook,” December 14, 2020.

OEB staff notes that S&P Global Ratings provides similar maps, separately for the U.S. and for Canada, on pages 3-4 of its report, “Updates And Insights On Regulatory Jurisdictions Shaping Policies For North American Utilities - November 2020”, issued November 9, 2020. This is shown in chart form on page 2 of the report.

Chart 1

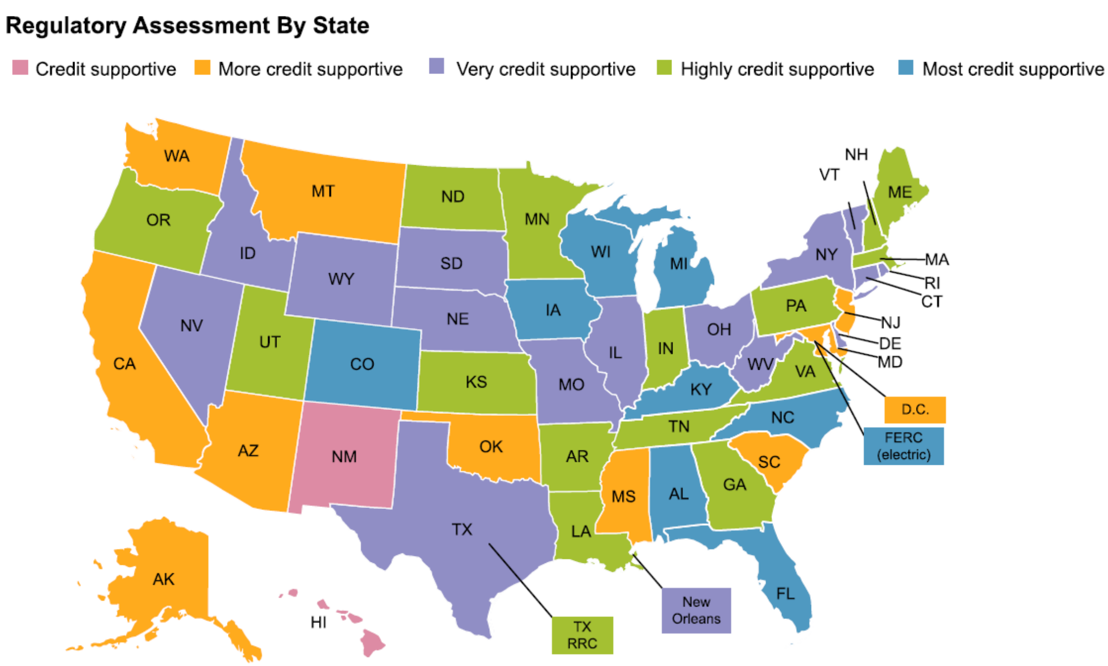
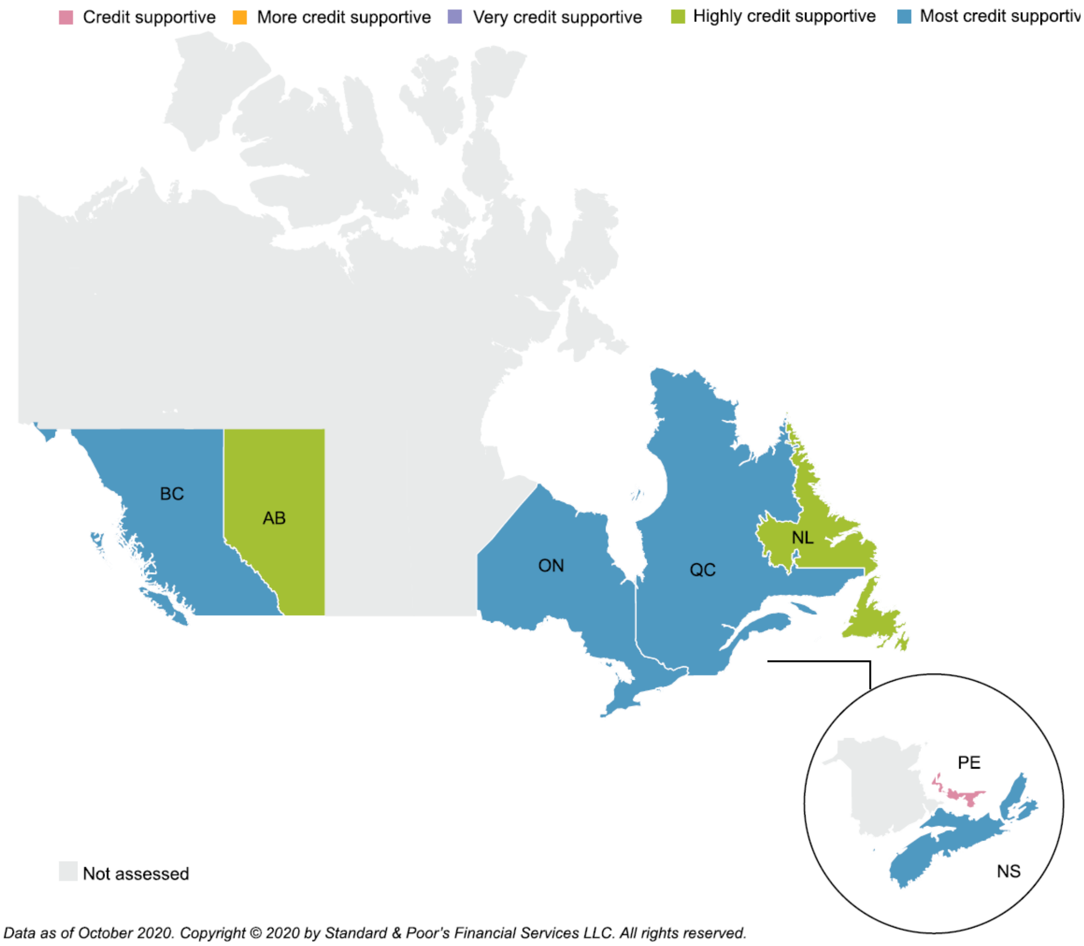


Chart 2

Regulatory Assessment By Canadian Province/Territory



Data as of October 2020. Copyright © 2020 by Standard & Poor's Financial Services LLC. All rights reserved.

Source: S&P Global Ratings, "Updates And Insights On Regulatory Jurisdictions Shaping Policies For North American Utilities - November 2020", issued November 9, 2020, pp. 3-4

a) Please provide a copy of the UBS Global Research report identified in footnote 211 on page 95 of 164: UBS Global Research, "North American Power & Utilities: Mind the Gap(s): 2021 Utility Outlook," December 14, 2020.

b) Concentric has noted that UBS and Standard & Poor's have different rankings of state and provincial regulatory jurisdictions. In particular, UBS ranks Ontario (the OEB) in the third category out of five, while Standard & Poor's ranks Ontario in the top (most credit favorable) category out of its five categories.

   i. OEB staff observes that the regulatory jurisdiction that a firm operates in does not factor into the regulated firm's base credit rating. However, the ranking of the regulatory jurisdiction could, along with other factors, result in a raising or lowering of the firm's credit rating by one notch (e.g. a base credit rating of A could end up as A- or A+).[10] Does Concentric not consider the differences in UBS' and Standard & Poor's rankings of North American regulatory jurisdictions as a concern?

ii. What, based on Concentric's knowledge, are the reasons for the differences in UBS' and Standard & Poor's rankings of North American regulatory jurisdictions?

5.3-Staff-232

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, page 97 of 164

On page 97 of 164 of its report, Concentric provides Figure 37, documenting its summary of the regulatory mechanisms for Enbridge Gas and for the Canadian and U.S. opco and holdco samples.

In interrogatory 5.20-Staff-13, OEB staff noted that lengthy history going back as far as the late 1990s of formulaic rate adjustment plans under PBR/IRM in Ontario for the rate regulation of EGD, Union and, since amalgamation, Enbridge Gas. PBR/IRM has also been used extensively for rate regulation in the electricity distribution sector in Ontario, and has also been, more recently used for electricity transmission and distribution.

a) In the left column, Concentric has a label for "Formula-Based Ratemaking or Multi-Year Rate Plans"
    i. What is the definition of Formula-Based Ratemaking plans that Concentric has used?
    ii. What is the definition of Multi-Year plans that Concentric has used?
    iii. Why does Concentric consider Formula-Based Ratemaking plans and Multi-Year plans to be equivalent or interchangeable in terms of assessing the comparability of Enbridge Gas to each of the samples?
b) Given the long experience of PBR/IRM rate adjustment plans, including for rate regulation of natural gas distributors in Ontario, does Concentric consider that Ontario is, less, or equally, as risky as that of other jurisdictions in Canada and the U.S. that have Formula-Based Ratemaking frameworks in place? Please explain your response.

[10] Standard & Poor's, **Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry**, November 19, 2013 (as updated)

5.3-Staff-233

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 109 of 164

Concentric has provided the table for “Bloomberg Beta Coefficients” in Figure 40.

Please expand on this table to show the data from 2012 to 2021 for each of the proxy groups.

5.3-Staff-234

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 116-118 of 164

On pages 116-118 of its report, Concentric discusses “Credit Rating Agency Perspectives” on the regulatory environments of Canadian and U.S. utilities. In particular, on page 117 of 162, Concentric documents five quotations from a Moody’s Investors Service’s report, “Proposed Refinements to the Regulated Utilities Rating Methodology and Our Evolving View of US Utility Regulation”, issued September 23, 2013. Concentric then goes on to state, on the same page:

> To our knowledge, S&P has not opined on the relative risks of the Canadian and U.S. regulatory environments as directly as Moody’s. However, as noted previously, S&P does assess the credit supportiveness of regulatory jurisdictions in the U.S. and Canadian provinces, ranking them all credit supportive (on a scale from “credit supportive” to “most credit supportive”).[footnote omitted] In this ranking system, S&P categorizes Ontario as “most credit supportive.” S&P indicates, however, that all regulation is credit supportive, and that its rankings between jurisdictions are only a matter of degree.

OEB staff observes that the Moody’s report, dated in September 2013, is from the same period as when EGD’s cost of capital, including the deemed equity thickness was last reviewed.

a) Given that the Moody’s report dates from about the same time period as when Enbridge Gas Distribution’s equity thickness was last reviewed, and in light of the more recent reports from UBS Investors Services and Standard & Poor’s, both from November 2020, what meaningful information is being conveyed in the quotations from the September 2013

Moody's report regarding similarities and differences of regulatory environments for Canadian and U.S. utilities since the last review in 2013?

b) Please provide Concentric's understanding of "credit supportive" as used by Standard & Poor's in its regulatory jurisdictional analyses and as used in conducting credit rating assessments of regulated utilities.
c) Does Concentric consider that being credit supportive is expected and even required of regulators in Canada and the U.S., in order to satisfy the Fair Return Standard, essentially the same in both countries, as established by key Supreme Court Decisions[11] in the 1920s to 1940s period, and upheld in court decisions since? Please explain your response.
d) While Standard and Poor's does state that the degree of credit supportiveness of North American regulatory jurisdictions may be "a matter of degree", Standard and Poor's report on its methodology for assessing country, regulatory, and other operational environmental factors pertinent to regulated utilities, indicates that these are considered and used for adjusting the final credit ratings of regulated utilities.[12] OEB staff thus views that differences between regulatory jurisdictions in North America are <u>not</u> immaterial, and can have real impacts on the cost of debt and equity financing for regulated firms operating in their jurisdictions. Concentric, earlier in its report, notes differences in state and provincial regulatory jurisdictions as assessed by UBS Investor Services and by Standard & Poor's. Please provide, with explanation, Concentric's views on the materiality of regulatory jurisdictional differences in North America as they impact on the credit rating of Canadian and U.S. regulated utilities.

5.3-Staff-235

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 120 of 164

Concentric has stated the following on the referenced page:

---

[11] *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia et. al.* 262 U.S. 679 (1923), *Northwestern Utilities Limited v. City of Edmonton*, [1929] S.C.R. 186, *Federal Power Commission v. Hope Natural Gas* 320 U.S. 591 (1944). See EB-2009-0084, *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, December 11, 2009, pp. 16-17

[12] Standard & Poor's, **<u>Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry</u>**, November 19, 2013 (as updated)

…our analysis shows that Canadian utilities are choosing to invest in U.S. where higher returns are available than in Canada. This is direct market evidence of better potential reward for taking on a similar level of risk.

a) Please explain and elaborate upon the assertion associated with "similar level of risk" in this statement. Is Concentric of the view that every Canadian utility (holdco) M&A transaction in the US involved a higher reward for relatively the same or lower risk? Please explain your response and identify specific examples that Concentric is aware of.
b) Isn't it possible that lack of available investment opportunities, and the desire for portfolio diversification are greater drivers of expansion outside of Canada? Please elaborate on why Concentric agrees or disagrees with this statement.

5.3-Staff-236

Ref: Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 121 of 164

Concentric has provided the US/Canada comparison table for "Country Risk Ratings" in Figure 44.

Other than Sovereign risk rating (where Canada is rated A and US is rated AA), Canada has the same or higher rating across all risk categories, and higher in both political and banking sector risk ratings (which one may argue are relatively more relevant for investors in Enbridge Gas). As such, would Concentric agree that investment risk in Canada remains lower than in the US? If not, please explain.

7.0-Staff-237

Ref: Exhibit 7, Tab 0, p. 3

Enbridge Gas has proposed to harmonize the former EGD and Union rate zones into one rate zone. Enbridge Gas prepared the 2024 cost allocation study based on one rate zone for all costs and rate classes with the exception of transportation service options that provide regional transportation service.

a) Please provide the total cross-subsidy from Union South and EGD rate zone customers to Union North customers resulting from the proposed cost allocation study.
b) Please provide a revised 2024 cost allocation study and resulting rate design implications and bill impacts based on two rate zones: North (the former Union

North rate zones) and South (Union South and EGD rate zone). Please also provide the assumptions underpinning the revised cost allocation study.

7.1-Staff-238

Ref: Exhibit 7, Tab 1, Schedule 1, pp. 5-6
Exhibit 8, Tab 2, Schedule 1, p. 9

The 2024 Cost Allocation Study is prepared based on one rate zone for all costs and rate classes with the exception of transportation service options that provide regional transportation service, such as ex-franchise transportation service options and transportation services for semi-unbundled and unbundled customers. The proposed allocation of costs to rate classes is based on the average embedded costs of the company's integrated system of gas supply, storage, transportation and distribution facilities to deliver gas to customers in different geographical regions of Ontario. This approach is consistent with the Cost Allocation Study of the legacy EGD rate zone, which used a unform system of rates throughout its franchise area.

a) Considering that the legacy Union rate zone is significantly larger and varies in customer density as compared to the former EGD rate zone, please explain how a single rate zone results in just and reasonable rates.
b) Considering that the costs to serve customers in the North are different from the costs to serve customers in the South, please explain how the proposed single rate zone aligns with the cost causation principle as noted in Exhibit 8, Tab 2, Schedule 1, para 20.

7.1-Staff-239

Ref: Exhibit 7, Tab 1, Schedule 2, p. 9

The 2024 Test Year revenue requirement includes the cost of regulated storage and excludes unregulated storage costs. Costs associated with land rights and wells and lines are incurred to provide both deliverability from storage on design day and to provide capacity to store gas. These costs are classified as 50% deliverability and 50% space. The storage space costs are further classified between storage space and operational contingency as Enbridge Gas manages the operational contingency storage space and its associated inventory to support the reliability and resilience of the Enbridge Gas system.

Please provide the basis for 50% allocation between deliverability and storage space. Please provide any calculations used to derive the allocation factor.

7.1-Staff-240

Ref: Exhibit 7, Tab 1, Schedule 3, Attachment 1, p. 6

The functional classification of “Distribution Customer-Services” is allocated to in-franchise rate classes in proportion to the average number of customers.

Please explain why the proposed allocation of “Distribution Customer-Services” is different from the allocation methodology of the former EGD, Union North and Union South zone.

7.1-Staff-241

Ref: Exhibit 7, Tab 1, Schedule 4, pp. 18-20 & Attachment 1; EB-2021-0002, Decision and Order, November 15, 2022, Schedule A

Enbridge Gas is proposing to update the DSM budget allocation methodology for the current rate classes from the 2024 DSM budget allocation provided in the 2022 to 2027 DSM Plan proceeding.

a) Please confirm the DSM-related rate class impacts in Attachment 1 are fully aligned with approved 2024 DSM budget in Schedule A of the EB-2021-0002 decision. If not confirmed, please update Attachment 1 to align.
b) Please discuss the reasons for DSM-related changes to rate class impacts noted in Attachment 1 relative to the DSM budget allocation provided in the DSM Plan, particularly for those rate classes where costs have changed greater than +/- $250,000.

8.2-Staff-242

Ref: Exhibit 8, Tab 2, Schedule 1, pp. 15-21

As part of assessing a proposal for rate harmonization, Enbridge Gas identified eight possible rate zone alternatives for gas supply costs, including gas supply commodity, transportation and load balancing, and transmission costs. The alternatives for gas supply and transportation costs include one alternative based on the existing rate zones, the proposed alternative for one rate zone and six different combinations of grouping the four service areas (Central, North, East and South).

In its discussion of the rate zone alternatives, Enbridge Gas has only discussed the disadvantages of all alternatives with the exception of the one rate zone. At the same time, while discussing the one rate zone, only the benefits have been discussed. Please discuss some of the possible advantages of other options (excluding single rate zone) and any possible disadvantages of the one rate zone.

8.2-Staff-243

Ref: Exhibit 8, Tab 2, Schedule 5, p. 16

Enbridge Gas has proposed a new fixed RNG sampling charge of $10,000 per sample as part of the Rate M13 rate design to recover the incremental costs incurred by the company to sample and test the quality of gas for producers of RNG. The RNG sampling charge is set based on the incremental cost for each occurrence of RNG sampling activity which is forecast at $10,000.

a) Please confirm if local producers who are not providers of RNG but inject natural gas into the distribution system under Rate M13 will be subject to the sampling charge. If yes, please provide reasons.
b) Please confirm if the $10,000 charge represents the actual costs that will be incurred by Enbridge Gas to undertake the RNG sampling activity.

8.2-Staff-244

Ref: Exhibit 8, Tab 2, Schedule 6, pp. 2-14

In its application, Enbridge Gas has noted that its cost allocation and rate design proposal results in a total bill impact greater than 10% and/or volatile rate changes during the transition to the harmonized rate classes. Accordingly, Enbridge Gas has proposed rate mitigation measures. The rate mitigation plan has lowered the 2024 total bill impact for 740 out of 985 in-franchise contract customers and has reduced the frequency of bill impacts exceeding 10% from 56 to 4 customers for in-franchise contract rate classes.

Please indicate if Enbridge Gas considered other rate design proposals that did not result in large bill impacts or volatility. If yes, please provide details.

8.3-Staff-245

Ref: Exhibit 8, Tab 3, Schedule 1

Enbridge Gas has proposed a change to a number of miscellaneous service charges. Among them, notable increases are for Construction Heat Activation ($120), Safety Inspection ($120), Meter Unlock ($120), Meter Dispute Test ($195), Field Locate Delivery ($160), Emergency Cost Response ($290), Damage Investigation ($550) and Regular & Overtime Labour Charges ($178 & $223).

Please describe how the increase in these costs impact Other Revenues. Please provide a table showing the impact on other revenues as a result of the increase in the miscellaneous service charges.

8.4-Staff-246

Ref: Exhibit 8, Tab 4, Schedule 2, pp. 22-23

Enbridge Gas has proposed to eliminate consolidated billing. Of the 3.8 million general service customers only 1,300 meters benefit from consolidated billing arrangements. Based on the current 1,300 accounts, there is approximately $1.0 million in incremental revenue generated by eliminating the consolidated billing option.

a) Please confirm that the $1.0 million in incremental revenue is on an annual basis.
b) Please provide the rate classes that the 1,300 accounts belong to and the quantum (and percentage) of the bill impact for 2024 on these customers.

8.4-Staff-247

Ref: Exhibit 8, Tab 4, Schedule 7, p. 20

In its application, Enbridge Gas has proposed to include the ability to charge negotiated interruptible rates that are below the posted rate in an effort to incent adoption of interruptible services to support IRP. Non-compliance with a notice of interruption results in charges being applied to customers bills and the potential for the interruptible service to be withdrawn. Enbridge Gas has proposed a non-compliance charge of $60/GJ to ensure that customers comply with a notice of interruption.

a) Please provide the number of non-compliance occurrences before Enbridge Gas provides notice to a customer of interruptible service being withdrawn.

b) Enbridge Gas has proposed a non-compliance charge of $60/GJ. Please indicate if Enbridge Gas considered a higher non-compliance charge to ensure that customers comply with a notice of interruption.

9.1-Staff-248

Ref: Exhibit 9, Tab 1, Schedule 1, p.14; Exhibit 9, Tab 1, Schedule 2, p.2, EB-2020-0091 decision, July 22, 2021, p. 81

The definition of the existing IRP Operating Costs and IRP Capital Costs deferral accounts is described. Enbridge Gas indicates that it is proposing to continue these deferral accounts through the IR term, as they are still required to support IRP.

a) The IRP Decision approved these accounts only for the 2021 to 2023 period. Please clarify Enbridge Gas's rationale as to the continuing need for these accounts, and why IRP-related costs should not be considered exclusively as part of Enbridge Gas's base revenue requirement.
b) The IRP Decision indicated that "Whether there will be amendments to these deferral accounts after rebasing will be determined in the rebasing application, taking into consideration what IRP costs have been included in base rates". Did Enbridge Gas give consideration to whether any changes are needed to the purpose of these accounts, to handle the issue of incrementality of IRP Plans that address system needs which are already budgeted for in the AMP and associated capital constraint for the rebasing term?

9.1-Staff-249

Ref: Exhibit 9, Tab 1, Schedule 1, p.14; Exhibit 4, Tab 4, Schedule 3, p.6; Exhibit 4, Tab 4, Schedule 2, p. 15

The IRP Operating Costs Deferral Account records incremental IRP general administrative costs, as well as incremental operating and maintenance costs and ongoing evaluation costs for approved IRP Plans. Enbridge Gas notes a $1.8 million increase in salaries and wages in 2024 due to FTE additions for IRP.

a) How many of the 23 proposed FTE additions in the Business Development & Regulatory Group are associated with IRP? Please describe their responsibilities, and how this work differs from that done by the Integrity and Asset Management group.

b) Please confirm that the incremental nature of IRP general administrative costs would be assessed against the base O&M costs of $1.8 million for the integrated resource planning FTEs described in part (a).

9.1-Staff-250

Ref: Exhibit 9, Tab 1, Schedule 2, p.2

Enbridge Gas indicates that the DSM-related deferral and variance accounts are subject to OEB approval as part of the 2023 to 2027 DSM Plan (EB-2021-0002).

Please confirm that, now that the OEB has issued a decision on the 2023 to 2027 DSM Plan, no OEB approval for the DSM-related deferral and variance accounts is required as part of the current Application.

9.1-Staff-251

Reference: Exhibit 9, Tab 1, Schedule 2, p.25; Exhibit 4, Tab 4, Schedule 2, p.10, 15; Exhibit 4, Tab 4, Schedule 3, p.6.

Enbridge Gas proposes to consolidate the two greenhouse gas emissions administration deferral accounts into a single account and change its purpose from a deferral account to a variance account, and indicates that this account (Greenhouse Gas Emissions Administration Variance Account) would record incremental administration costs associated with new or changing climate policies, while administrative costs associated with current federal and provincial regulations related to greenhouse gas emissions requirements would be recovered through 2024 base rates.

Enbridge Gas also notes (Exhibit 4) that 23 FTE additions are proposed for the Business Development & Regulatory department, related in part to compliance with federal and provincial GHG emission regulations previously accounted for under the GHG Emissions Administration Deferral Account. Enbridge Gas notes a $1.4 million increase in salaries and wages in 2024 for administrative staff related to compliance with federal and provincial GHG emission regulations.

Enbridge Gas also notes that the energy transition planning group (within the Business Development & Regulatory department) “leads the development of the energy transition plan and oversees the coordination of its associated goals and objectives. This includes leading Enbridge Gas’s emissions reduction strategy, leading and coordinating the implementation of IRP, providing insight on climate policies to other departments in the Company and implements carbon pricing policies."

a) Please provide more detail on the nature of the administrative costs and the specific activities "associated with current federal and provincial regulations related to greenhouse gas emissions requirements" that would be recovered through 2024 base rates (i.e. the base activities against which incrementality would be assessed for the purposes of the Greenhouse Gas Emissions Administration Variance Account), and how these would be distinguished from Enbridge Gas's other energy transition planning activities.
b) How many of the 23 proposed FTE additions in the Business Development & Regulatory Group are associated with current federal and provincial regulations related to greenhouse gas emissions requirements?
c) Please confirm that the incremental nature of administrative costs associated with new or changing climate policies would be assessed against the base O&M costs of $1.4 million for the FTEs described in part (b).
d) Similar to part (a), how does Enbridge Gas intend to distinguish "incremental administration costs associated with new or changing climate policies" (and thus eligible for recovery in the Greenhouse Gas Emissions Administration Variance Account) from other energy transition planning activities?
e) Did Enbridge Gas consider eliminating the GHG Emissions Administration Deferral Account, or reducing the scope of this account to only bad debt related to carbon charges?

9.1-Staff-252

Ref: Exhibit 9, Tab 1, Schedule 2, pp. 26-27

Enbridge Gas has proposed to establish one variance account for Enbridge Gas to record the revenue impact, exclusive of gas costs, of the volumetric forecast variance resulting from actual average use per customer and weather experienced during the year for the general service rate classes. The proposed Volume Variance Account would be symmetric and revenue neutral for both customers and Enbridge Gas.

Please confirm that the proposed Volume Variance Account would eliminate weather risk over and above the approved revenue requirement. Please explain your response.

9.1-Staff-253

Ref: Exhibit 9, Tab 1, Schedule 3, pp. 2-3

In its application, Enbridge Gas has proposed to establish the Energy Transition Technology Fund (ETTF) Variance Account as a tracking account to support research, development and commercialization of low carbon technologies. Enbridge Gas has proposed to collect $5 million forecasted annually over the IR term, which will accumulate in the proposed ETTF Variance Account. As ETTF expenses are incurred, the accumulated balance in the variance account will be drawn down.

a) Please explain why Enbridge Gas needs additional funding for exploring and developing low carbon technologies and why such initiatives cannot be funded through the OM&A and/or capital budget?
b) How did Enbridge Gas arrive at the $5 million forecast for this program?

9.1-Staff-254

Ref: Exhibit 9, Tab 1, Schedule 3, p.4

Enbridge Gas is proposing the establishment of the Rate Harmonization Variance Account (RHVA) to record material differences to forecast revenues that are attributable to customers switching rate classes as a result of the implementation of the rate harmonization plan. It states that the proposed account will record the material differences (in excess of $1 million in aggregate) to forecast revenue due to the implementation of the rate harmonization plan.

a) Please confirm that Enbridge Gas will track the annual differences in forecast revenues that are attributable to customers switching rate classes, and will only record a balance in the account if it exceeds $1 million at the end of 2028. If not confirmed, please explain.
b) Why does Enbridge Gas propose to record in the RHVA the total revenue variance that exceeds the threshold on a cumulative basis versus recording on an annual basis?
c) Will Enbridge Gas bring forward the annual balance in the RHVA for disposition in Deferral and Variance Account proceedings during the IR period? If no, why not?

9.1-Staff-255

Ref: Exhibit 9, Tab 1, Schedule 3, pp. 6-7

Enbridge Gas has proposed to establish the Dawn Parkway Surplus Capacity Deferral Account (DPSCDA) to record actual revenue generated from the sale of all or a portion of the 89 TJ/day Dawn Parkway System surplus capacity forecast for the winter 2023/2024. The full cost of the Dawn Parkway system is included in the 2024 Test Year revenue requirement. Enbridge Gas has proposed to refund through the DPSCDA any revenue generated from the sale of the surplus capacity up to 89 TJ/day per year. As part of Union Gas's 2017 Dawn Parkway project, there was forecast surplus capacity of 30,393 GJ/day following construction of the project. Parties to the settlement proposal agreed that the legacy Union Gas would include revenue associated with the sale of the surplus capacity in the associated deferral account (EB-2015-0200).

Please confirm that the 89 TJ/day of surplus capacity is in addition to the 30,393 GJ/day surplus capacity forecasted for the Dawn Parkway project. If not, please explain.

9.2-Staff-256

Ref: Exhibit 9, Tab 2, Schedule 1, pp. 25-26

In the 2022 Rates proceeding (EB-2021-0148), the OEB approved $126.7 million in capital ICM funding for the Cherry to Bathurst Replacement project, with an expected in-service date of October 2022. There is a $2 million debit balance in the ICM deferral account for the EGD rate zone related to this project. Enbridge Gas has indicated that the Cherry to Bathurst Replacement project has not gone into service.

a) Please confirm if the Cherry to Bathurst Replacement project has gone into service.
b) Please provide a revised balance in the ICM deferral account related to the Cherry to Bathurst Replacement project.

9.2-Staff-257

Ref: Exhibit 9, Tab 2, Schedule 1, pp. 33-35

Enbridge Gas has proposed to clear the outstanding forecast balance in the Transition Impact of Accounting Changes Deferral Account (TIACDA) of $39.9 million, with no interest applied. All parties to the settlement proposal in EGD's 2013 cost of service proceeding (EB-2011-0354) agreed that EGD could recover OPEB costs evenly over a

20-year period, commencing in 2013. The final amount to be disposed of at the end of 2012 was $88.7 million, resulting in $4.436 million annual recovery over the 20-year period. At the end of 2023, $48.8 million will have been recovered from ratepayers in the EGD rate zone. Enbridge Gas has proposed to clear the remaining $39.9 million balance in the 2024 calendar year to all ratepayers.

Please confirm if Enbridge Gas proposes to recover the balance from legacy EGD customers or from all ratepayers (including former Union Gas customers). If yes, please explain why legacy Union Gas customers should contribute to the recovery.

9.2-Staff-258

Ref: Exhibit 9, Tab 2, Schedule 1, p.36-37

Enbridge Gas is proposing to dispose an outstanding credit for the Transitional Pension Balance of $254.6 million, which represents the life-to-date cash vs. accrual expense up to December 31, 2012. It states that from a cost-recovery perspective, if EGD had recovered costs based on an accrual basis, the cumulative costs that would have been reflected in rates from inception would have been less by $254.6 million. Furthermore, it states that the credit balance does not represent cash amounts retained by Enbridge Gas. The cash collected was used to fund pension plans, and as such Enbridge Gas was not in receipt of excess cash. Therefore, no carrying charges have been accrued.

a) Please clarify whether the $254.6 million is a balance in an established account or an amount that Enbridge Gas has tracked since EGD's 2013 rebasing application.
    i. If the amount is in an account, please provide the reference to the accounting order.
b) Please quantify the total carrying charges on the account balance, if carrying charges were to apply at the OEB's prescribed rate.

9.2-Staff-259

Ref 1: Exhibit 9, Tab 2, Schedule 1, Attachment 3
Ref 2: Exhibit 2, Tab 4, Schedule 2, p.19

Reference 1 provides the calculation of the revenue requirement for the impact from the change in overhead capitalization. Reference 2 provides the O&M and capital expenditure impact from the change in overhead capitalization.

a) OEB staff compared the O&M amounts in Reference 2 to the O&M shown in the revenue requirement calculation in Reference 1 and noted the differences below. Please reconcile the differences.

References ($Million)	2020	2021	2022	2023	Total
E2/T4/S2/p.19 Table 4	-5.6	-6.2	-8.9	-16.6	-37.3
E9/T2/S1/Att 3 Line 5 (EGD + Union OH Capitalization Changes)	-5.6	-5.4	-9.2	-18.3	-38.5
	0	-0.8	0.3	1.7	1.2

b) In the calculation of the revenue requirement impact in Reference 1, please explain how the O&M amounts (line 5) correlate to the rate base amounts (line 1) for the column Capitalization vs. Expense and the column Overhead Capitalization. For example, in the 2023 Overhead Capitalization revenue requirement calculation for Union Gas, O&M decreased by $26.6 million while the rate base increased by $41.9 million.

c) The calculation of the revenue requirement impact in Reference 1 includes “income taxes on earnings” and “taxes on deficiency/sufficiency”. Please explain the tax methodology used.
   i. Please explain what the “taxes on deficiency/sufficiency represents”, why it is needed in the calculation, and how it is calculated.
   ii. The income taxes on earnings are broken down by “excluding tax shield” and “tax shield provided by interest expense”. Please explain what the “tax shield provided by interest expense” represents, why it is needed in the calculation and how it is calculated.
   iii. Please explain whether tax amounts are grossed up. If not, please explain why a gross-up is not necessary.

9.2-Staff-260

Ref 1: Exhibit 9, Tab 2, Schedule 1, pp. 31-32, Impacts Arising from the COVID-19 Emergency Deferral Account (COVID-19DA) (Account No. 179-384)
Ref 2: EB-2020-0133, Regulatory Treatment of Impacts Arising from the COVID-19 Emergency, p. 20

In Reference 1, Enbridge Gas has requested approval to dispose the cumulative forecast debit balance in the COVID-19DA of $1.4 million plus interest as at December

31, 2023, of $0.1 million, for a total of $1.5 million. It has further noted that “these costs are fully recoverable because Enbridge Gas meets the means test, in that utility earnings have not exceeded 300 basis points above the annual approved ROE in any year.”

Reference 2 states that “This Exceptional Pool of costs will be eligible for recoveries up to 100% provided they are prudently incurred and material, and subject to an ROE plus 300 bps limitation, as outlined in the Staff Proposal.”

a) Please provide evidence to demonstrate how Enbridge Gas meets the means test.
b) Please discuss how this exceptional pool of costs are prudently incurred.

9.2-Staff-261

Ref 1: Exhibit 9, Tab 2, Schedule 1, pp 21-23, Integration-Related Capital Additions – Tax Variance Deferral Account (TVDA) Balances
Ref 2: Exhibit 2, Tab 5, Schedule 3, p 13, Utility Capital Expenditures by Asset Class 2019 Actual -2024 Test Year
Ref 3: Exhibit 9, Tab 2, Schedule 1, Attachment 5, pp 1-4, TVDA- Calculation of the Bill C-97 Accelerated CCA Impact for Integration-Related Capital Additions
Ref 4: EB-2021-0149, Decision and Order, p10

Reference 1 states that “As Enbridge Gas is proposing to include the revenue requirement of integration/amalgamation capital, as well as any ongoing savings, in the determination of its 2024 revenue requirement, it believes it’s appropriate to credit to ratepayers the 2023 ending TVDA balance as part of the combined balance proposed for disposition in this evidence.”

In Reference 4, the OEB “directs Enbridge Gas to record the $3.7 million in the 2020 TVDA. The OEB finds it appropriate to record the balance in question in the TVDA pending a full review of integration/amalgamation capital projects in Enbridge Gas’s 2024 rebasing application”.

OEB staff has compiled the following table based on the information provided in References 2 & 3:

Integration Capital - 2019 Actual -2024 Test Year

	$ Millions	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
Ref 2	Integration Capital	21.7	39.8	87.5	41.6	43.6	-
	Integration Capital Additions / (Deductions)	-	18.1	47.7	(45.9)	2.0	(43.6)
Ref 3	Integration Capital Additions	-	18.9	69.9	48.8	52.8	-
	Variance	-	0.1	22.2	94.7	50.8	-

a) Please reconcile the variances in the above table.
b) The 2023 ending TVDA balance includes the $3.7 million noted in Reference 4. Please confirm that a full discussion of integration/amalgamation capital projects is incorporated in EGI's 2024 rebasing application. If not, please provide an explanation.
c) Please identify the specific projects categorized as amalgamation/integration spending and the accelerated CCA amount associated with each project. Please also provide the reasons for classifying these projects as amalgamation/ Integration-related capital spending.

9.2-Staff-262

Ref: Exhibit 9, Tab 2, Schedule 1, Attachment 6

Attachment 6 provides the balances in the ICM deferral accounts for the deferred rebasing period (2019 to 2023).

Please provide a revised table with 2022 actual costs.