Robin Stevenson
Technical Manager
Strategic Applications – Rate Rebasing

tel 416-495-5499
EGIRegulatoryProceedings@enbridge.com

Enbridge Gas Inc.
P. O. Box 2001
50 Keil Drive North
Chatham, ON N7M 5M1

August 1, 2025

VIA RESS AND EMAIL

Ritchie Murray
Acting Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ritchie Murray:

Re: Enbridge Gas Inc. (Enbridge Gas, or the Company)
EB-2025-0064 - 2024 Rebasing – Phase 3 Technical Conference Undertaking Responses

Enbridge Gas filed Phase 3 of its 2024 Rebasing Application on February 28, 2025. As part of the Phase 3 proceeding, Enbridge Gas is requesting approval for several items, related primarily to harmonization of cost allocation, rates, services, and gas supply variance accounts.

The OEB held a Technical Conference on July 16, 2025, and July 17, 2025, and in Procedural Order No. 2, ordered the Company to file its undertaking responses from the Technical Conference by August 1, 2025. In accordance with Procedural Order No. 2, please find enclosed the undertaking responses of Enbridge Gas. Enbridge Gas will post the responses on its website at www.enbridgegas.com/about-enbridge-gas/regulatory. Enbridge Gas will send a copy of this letter, and a link to the website page, to all parties in the proceeding.

Enbridge Gas notes in responding to undertakings, it identified a calculation error in the current approved bill for the average Rate M2 profile filed at Phase 3 Exhibit 8, Tab 2, Schedules 9 to 14, Attachment 10, lines 22-28. As a result of this error the bill impacts for Rate M2 were overstated. The corrected calculation reduces the Rate M2 average bill impact from 6.1% to 2.3% for the proposed one rate zone, which impacts the proposed rate mitigation and Rider R adjustment for this rate class. Please see Table 1 and Exhibit JT1.53 for more details, including the updated bill impacts and rate mitigation.

Table 1
Summary of General Service Rider R Bill Impacts

Line No.	Total Bill Impacts	Excluding Rider R Adjustment	Including Rider R Adjustment
		(a)	(b)
1	Rate 1	0.7%	1.7%
2	Rate 6	(13.6%)	(12.4%)
3	Rate 01 - NW	(5.0%)	(4.1%)
4	Rate 01 - NE	(19.5%)	(18.8%)
5	Rate 10 - NW	(3.4%)	(2.0%)
6	Rate 10 - NE	(24.1%)	(23.0%)
7	Rate M1	6.4%	2.8%
8	Rate M2	2.3%	3.3%

Should you have any questions, please let us know.

Sincerely,

Robin Stevenson

Robin Stevenson
Technical Manager, Strategic Applications – Rate Rebasing

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking:

Tr: 5

To provide a written response to Exhibit KT1.1, Question 1.

Exhibit I.8.2-ED-12 (rate design, demand charges): The figure below is pasted from this interrogatory response. It shows that a customer with electric heating will pay slightly more with SFVD. An example of this would be a customer who has electrified their heating but still has a gas stove or a gas stove and gas water heater. We would have expected this customer to have lower rates under SFVD, all other things equal, because their peak winter demand will be so much lower. Please (a) explain why this is not the case, (b) provide the underlying calculations for the electric heat row in the table, and (c) ask Christensen if changes could be made to the model to better reflect the benefits of peak demand reductions arising from customers with electrified heating.

Table 1. Illustrative bill impacts for hybrid heating and no gas heating scenarios

	Annual Bill ($)		
Scenario	2024 Rates	Harmonized SFVD	Bill Index vs. Current
Conventional Gas Heat	919.97	924.65	1.005
Hybrid System, 0C Crossover	697.73	781.19	1.120
Hybrid System, 10C Crossover	512.58	661.94	1.291
Electric Heat, Other Gas Uses	458.57	461.49	1.006

Response:

The following response was provided by Christensen Associates Energy Consulting:

In responding to this undertaking, CA Energy Consulting identified an error at Exhibit I.8.2-ED-12, Table 1: the third scenario, originally labeled ‘Heating System, 10C Crossover,’ should instead read ‘Hybrid System, -10C Crossover.’

a) Please note that the SFVD bill impact shown combines effects of both the change in rate design and rate harmonization and is for the total bill including distribution and commodity charges. Compared to the conventional gas heating scenario, the monthly customer charges are unchanged in the electric heat scenario, while distribution and commodity charges that are volumetric and demand-based decline in proportion to consumption and demand (respectively), as applicable.

   As shown in Attachment 1 to Exhibit I.8.2-ED-12, worksheet “R1,” under 2024 rates, distribution charges excluding the monthly charge are $211.59 for the gas heating scenario and $58.16 under the electric heating scenario. Compare worksheet R1, cells K30-K33 and K72-K75. Commodity charges decline from $411.74 (cell L34) to $103.77 (cell L76). Both declines are due to the 75 percent decline in gas consumption in the scenarios, from 2,399 to 605 cubic metres. The average volumetric distribution charge is higher in the electric heating scenario as the consumption is concentrated in higher-priced blocks.

   For the SFVD scenario, distribution charges excluding the monthly charge decline from $176.72 in the gas heating scenario (cells S29-S33) to $12.32 (cells S71-S75) with electric heating, here reflecting the reduction in design day demand from 24.21 to 1.66 cubic metres. The reduction in commodity charges (cells T34 and T76) is slightly smaller than under current rates, though qualitatively similar to the change under current rates; the level of harmonized commodity charges in the SFVD case is slightly lower than 2024 rates in both the gas and electric heating scenarios.

   Additionally, under the SFVD rates, monthly customer charges increase from $296.64 (cell K70) to $349.17 (cell S70), more than offsetting the $45.84 reduction in other distribution charges in SFVD compared to 2024 rates. The net effect is an increase of $2.92 for the electric heating scenario under SFVD, resulting in the 1.006 bill index versus 2024 rates.

b) The underlying calculations were provided in Attachment 1 to Exhibit I.8.2-ED-12, worksheet “R1,” rows 65-78.

c) Insofar as demand-related costs are recovered from the SFVD demand charge and the monthly customer charge recovers costs that are unrelated to customers’ design day demands (and gas consumption), the SFVD design appropriately reflects the benefits of the peak demand reduction for customers with electric heating.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking:

Tr: 5

To provide a written response to Exhibit KT1.1, Question 2.

Exhibit I.8.2-ED-13 (rate design, demand charges): This interrogatory was intended to explore how quickly and appropriately the proposed demand estimation model will account for reduced peak demand due to DSM measures, such as weatherization or electrification of heat. The interrogatory response provides a helpful narrative indicating that there will be a lag but does not provide the quantification originally requested. We therefore request the following:

a) Enbridge indicates that there will inevitably be a lag in reflecting peak demand reductions arising from DSM in a customer's bill. Please discuss potential solutions to reduce that lag, including the option for customers to trigger a review of their peak demand arising from DSM measures. Please indicate which solutions Enbridge commits to implement if SFVD is approved.

b) Please confirm that a lag in reflecting peak demand reductions will mean that customers who are impacted by that lag will likely have demand charges that are temporarily higher than they would otherwise be (i.e. they will be temporarily overcharged). Please describe potential mechanisms to allow customers to be reimbursed for these excess demand charges. Please indicate which solutions Enbridge supports.

c) Please estimate the average duration of the time lag discussed above.

d) Please estimate the longest duration of the time lag that will be possible (with assumptions as necessary, such as an assumption that Enridge updates its peak demand estimate calculations in Q2 of each year).

e) Please provide the quantitative example requested in Exhibit I.8.2-ED-13.

Response:

The following response was provided by Enbridge Gas Inc.:

a-b) The Company would like to highlight that providing an option for customers to trigger a review of their peak day demand arising from adoption of DSM measures would necessitate creation of associated processes and administration. In its SFVD implementation plan Enbridge Gas will endeavor to strike an appropriate balance between costs/ benefits and providing a seamless experience for customers.

Considering the above, the Company notes that common DSM measures, such as building envelope improvements, could result in peak day demand reductions in the range of 1 to 3 cubic metres of demand. For example, please see response at Exhibit I.8.2-ED-17, Attachment 1, page 11, Figure 5. Such a level of reduction in peak day demand would result in a lower demand charge of approximately $7 to $21 per year, which will be fully reflected on the customer bill, based on the customer's actual consumption characteristics, within one to two years from the time the customer adopts DSM measures. Note that the inverse lag considerations apply to customers who would increase their peak day demands, such as adding footprint to their homes or adding baseload or space heating equipment.

In Enbridge Gas's view, it is appropriate for the Company to change the billing determinant for an existing customer in response to demonstrated demand reductions, which would be automatically captured through an annual update process and would eliminate the need for a review process.

As part of the SFVD rate design implementation plan, an approach could be investigated where customers who take part in DSM programs be flagged in the billing system, so that the Company would anticipate seeing changes in their peak day demands approximately one year after implementation and not potentially treat them as exceptions (i.e. year-over-year change in demand exceeding a threshold).

Enbridge Gas plans and operates its gas distribution system on an annual prospective basis. Rates are also designed and approved on an annual prospective basis. Therefore, any changes to customers' demand levels would only be billed once new demand values are derived through the annual update / refresh cycle.

The following response was provided by Christensen Associates Energy Consulting:

c-d) The likely range of time lags as discussed above is approximately 1-2 years, assuming that the design day demand calculation is updated late in Q2 of each year for implementation the following January 1. As discussed in Exhibit I.8.2-ED-13, page 2, actions taken close to the update may not have generated sufficient data to be captured in the update process. There must be a minimum of one period between actual reads (i.e., approximately two months) after a DSM project is placed into service to provide any data on the effects of the measures taken. Thus, it is technically possible that a project placed into service as late as Q1 of the update year could be at least partly reflected in the subsequent Q2 demand update. The extent of any such partial effects will depend on factors including the magnitude of the demand change and the customer's historical data, and it is not possible to quantify those effects reliably.

Projects undertaken before the heating season preceding an update would be expected to have their demand effects reflected in the one-year regression results from the update. By extension, a project installed in Q1 of a given year would be in place for at least a full year as of the second demand update (implemented approximately two years after the project completion).

We are not aware of data on typical installation timing to determine an "average" lag. As discussed above and in Exhibit I.8.2-ED-13, projects completed outside the heating season will tend to have lags in the middle of the 1-2 year range.

e) The example in Exhibit I.8.2-ED-13 concerned a 24-month period with the project placed into service at the middle of the period. If the lag is at least one year, then the customer would be expected to be billed on the pre-installation DDD in Exhibit I.8.2-ED-13, Table 1, for the entire period, while the post-installation DDD would be the true DDD for the post-installation period. The customer would be expected to be billed on the post-installation demand once the project was reflected in a demand update, most likely in the subsequent 12 months. Table 1, below, shows the actual DDD, billed DDD, and demand charge using the scenarios presented in Exhibit I.8.2-ED-13.

Table 1
Examples of Time Lag Effects for Demand Updates

	12 Months Pre Installation	12 Months Post Installation	After Demand Update
Electric Heating			
Actual DDD	24.2	1.7	1.7
Billed DDD	24.2	24.2	1.7
Demand Charge	14.87	14.87	1.02
Hybrid Heat			
Actual DDD	24.2	24.2	24.2
Billed DDD	24.2	24.2	24.2
Demand Charge	14.87	14.87	14.87
Envelope Improvement			
Actual DDD	24.2	18.6	18.6
Billed DDD	24.2	24.2	18.6
Demand Charge	14.87	14.87	11.40

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking:

Tr: 5

To provide a written response to Exhibit KT1.1, Question 3.

Exhibit I.7-ED-10 (rate design, demand charges): This interrogatory response describes how the proposed SFVD rate design will impact the customer cost-effectiveness calculations for DSM. These calculations will become complicated, making it harder for customers and efficiency/HVAC contractors to estimate the savings from DSM measures. If SFVD is approved, would Enbridge commit to developing an online tool to help customers and contractors calculate the bill savings from various different kinds of DSM measures?

Response:

The Company expects to file a more detailed implementation plan in its 2027 Rates Application, as described at Phase 3 Exhibit 8, Tab 2, Schedule 1. As part of this process, the Company will assess options and tools to assist with customer understanding.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking:

Tr: 6

To provide a written response to Exhibit KT1.1, Question 4.

Exhibit I.2-ED-9 (capital reductions, issue 13b): This interrogatory reads as follows: "Enbridge spent less on connections than forecast. Please provide a breakdown of the decline in spending between the causes of the decline, including the proportion that are caused by fewer customer requests versus factors that Enbridge controls." The response pointed us to Exhibit I.2.5-STAFF-7, but that response did not discuss or quantify the decline in connections spending due to factors that Enbridge controls. Please discuss the ways in which Enbridge can manage connection costs (if any) and quantify the approximate percentage of connections cost reductions that are due to factors Enbridge controls.

Response:

Factors that Enbridge Gas controls were not changed and therefore did not contribute to any material reduction to the customer connections capital in 2024. As stated in response at Exhibit I.2.5-STAFF-7, the decline in customer connections spending was directly attributed to the decline in housing starts as seen in the *"Canada Mortgage and Housing Corporation housing starts, under construction and completions, all areas, annual"* [1],which shows a 16.5% decline from 2023 to 2024 which is consistent with the reduction in customer connection capital.

[1] Government of Canada. (2025-01-17) Canada Mortgage and Housing Corporation, housing starts, under construction and completions, all areas, annual.
https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=3410012601&pickMembers%5B0%5D=1.7&cubeTimeFrame.startYear=2020&cubeTimeFrame.endYear=2024&referencePeriods=20200101%2C20240101

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking:

Tr: 6

To provide a written response to Exhibit KT1.1, Question 5.

Exhibit I.2-ED-8 (capital reductions, issue 13b): Table 1 in this interrogatory response provided the reductions in spending on the corrosion prevention program versus the 2024 capital update. The response also listed a number of other maintenance programs. Please provide the same details for those other programs as well (i.e. update table 1 to include the rows for each of the maintenance programs listed in part (b) of the interrogatory response).

Response:

The programs listed in response at Exhibit I.2-ED-8, part b) were provided to show examples of maintenance programs, activities and standards Enbridge Gas employs to maintain and prolong the life of its distribution pipe assets. The spending in these programs, unlike the Cathodic Prevention Program, is O&M based and thus not within the scope of Issue 13(b) which relates to the Company's report on steps taken to implement the capital reduction from the Phase 1 Decision[1].

[1] EB-2022-0200, Decision and Order, December 21, 2023.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking:

Tr: 6

To provide a written response to Exhibit KT1.1, Question 6.

Exhibit I.1.16-ED-7 (annual energy cost comparison information): This interrogatory asked for Enbridge to add a column for all-electric heat pump heating to the annual heating bill comparison chart that it previously provided to customers (shown in the IR). Enbridge declined to do so but did not indicate that this request was irrelevant or not feasible. It is relevant to a contention by Environmental Defence that Enbridge has not abided by its obligations regarding annual heating cost comparisons (which we understand Enbridge to dispute). It is feasible to produce (and simple to produce) as Enbridge's DSM group already has detailed information relating to heat pump electricity consumption. We ask that the figure be provided.

Response:

In the Phase 2 Settlement Agreement[1] Enbridge Gas agreed to not include statements, including cost comparison charts, related to the relative cost-effectiveness of natural gas heating or to savings that can be achieved with natural gas heating in written marketing materials, or reference materials aimed at customers, potential customers, HVAC contractors, or builders that the Company distributes unless it includes a comparison with the relative cost-effectiveness of heating with electric cold climate heat pumps.

Enbridge Gas did not commit to producing energy cost comparisons with heat pumps or agree to requiring prior approval to do so. Should Enbridge Gas decide to produce energy comparisons with heat pumps for the purpose of marketing materials, the materials will be filed with the OEB at that time.

Enbridge Gas has taken appropriate actions and has met all the commitments outlined in the Phase 2 Settlement Agreement[2], removing all the energy comparison information from its marketing materials. Therefore, Enbridge Gas declines to provide the information requested as it is not relevant to the Issues List in this Application.

[1] EB-2024-0111, Settlement Agreement, November 29, 2024.
[2] Ibid.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking:

Tr: 6

To provide a written response to Exhibit KT1.1, Question 7.

Exhibit I.1.13-ED-1 (interruptible service & IRP): Enbridge indicates that it gauges interest in interruptible service (and other non-pipeline solutions) via questionnaires sent out via a Non-Binding EOI / ROS process. Table 1 in this interrogatory response indicates that the response rate for these questionnaires is extremely low. Please (a) provide the average response rate over the most recent 5 questionnaires (show in table 1) and (b) discuss other mechanisms that could be used to explore whether customers may be willing to move, at least partially, to interruptible service and to participate in non-pipeline solutions, which are in addition to mechanisms in place today. Please also provide (c) an anonymized spreadsheet for large volume customers showing their contract demand amount and the number of hours that they were using that contract amount or more. If it is not feasible to complete this for all large volume customers, please do so for a sample that is chosen randomly.

Response:

a) As provided in response at Exhibit I.1.13-ED-1, Account Managers typically follow up with potential contract rate bidders after notifying them about the EOI/ROS process to confirm their interest. Enbridge Gas also sends reminders regarding the EOI/ROS as a follow-up. Bidders may or may not respond, and Enbridge Gas does not track every interaction since these are routine communications. Outreach to general service customers can include unreturned cold calls or brief inquiries, which are not recorded. Therefore, the average response rate provided in Table 1 is approximate.

Table 1
Approximate Average EOI Questionnaire Response Rate

Line No.	Project	Average Response Rate	Notes
1	Oakville to Mississauga Area	17-25%	This project is before the OEB (EB-2025-0073)
2	Wheatley Area	7-10%	Discussions with bidders are ongoing
3	Wendover-Hawkesbury-Alexandria-Lancaster Area	23-30%	Bidders no longer wish to proceed, the EOI is closed
4	Stratford-Palmerston-Goderich-Teeswater Area	28-40%	Some bidders have indicated they no longer wish to proceed. Discussions continue with other bidders
5	Sarnia Transmission Market Area	40-45%	Outreach and follow-up in progress

b) The EOI/ROS process is most effective for potential facility builds, as it directly targets customers in the affected area. Customers can also annually review their contracted services with an account manager to discuss any adjustments. As noted in the Interruptible Rate Study provided at Phase 3 Exhibit 8, Tab 4, Schedule 7, the proposed changes to the IT rates will ensure a consistent price spread between firm and interruptible rates, making IT rates more appealing. Additionally, allowing negotiated interruptible rates from an IRP perspective below the posted rate further encourages customers to shift from firm to interruptible service, either fully or partially.

c) Enbridge Gas declines to provide the information requested as it is not relevant to the Phase 3 Issues List. The contract demand amount for large volume customers and the number of hours that these customers were using that contract amount is not relevant to the customer's consideration in pursuing firm or interruptible service. Moreover, providing data for all contract customers (or a representative sample) does not relate to the particular circumstances where interruptible rates could be used as an IRPA relative to a particular system constraint/potential facility project. Contract rate customers contract for capacity based on their gas equipment installed and their operation's peak hour needs. They make a business decision to contract for firm or interruptible service based on their risk tolerance for an interruption to their gas service and the impact that would have on their business. There may be days where a customer is not using their peak hour/day needs, but the customer reserves the capacity, pays for the reserved capacity in their firm service rates and counts on the firm service being available to meet their operational needs, whether they are consuming gas or not, to provide assurance to access at all times.

ENBRIDGE GAS INC.

Answer to Undertaking from
London Property Management Association (LPMA)

Undertaking:

Tr: 6

To provide a written response to Exhibit KT1.2, Question 1.

Reference:

Ex. I.8.2-CCC-23
Ph. 3 Ex. 8, Tab 2, Sch. 2, Att. 1
Ph. 3 Ex. 8, Tab 2, Sch. 5, pg. 3
Ph. 3 Ex. 8, Tab 2, Sch. 6, pgs. 8-9
Ex. I.8.2-VECC-11

The response to the CCC interrogatory shows an $8.6 million base rate reduction in costs recovered from rate E62. Attachment 1 of Exhibit 8, Tab 2, Schedule 2 shows that this cost is recovered primarily from rates E01, E02 and E10.

a) Please confirm the above.

b) Please confirm that the reduction of $8.6 million in costs recovered from rate E62 results in decreases in the increase in rates for Rate 200 from 13.9% to 0.5% and for Rate M9 from 26.6% to 3.1% as shown in Table 2 on page 8 of Exhibit 8, Tab 2, Schedule 6. If not confirmed, what is driving the decreases shown in Table 2.

c) Please confirm that in addition to the reduction of the $8.6 million there is a further adjustment proposed for customers within Rate E62 through Rider R and that this involves the phasing in of credits and debits over a 5 year period between the existing Rate 200 and M9 customers. If not confirmed, please explain.

d) Please confirm that the reduction of $8.6 million base rate reduction in costs is not included in Rider R and is a permanent reduction in costs recovered from rate E62, at least until the next cost allocation and rate design exercise is undertaken. If not confirmed, please explain.

e) As noted, Table 2 on page the impact including adjustment for Rate M9 under the proposed one rate zone is an increase of 3.1%. Please explain the difference between this figure and the 3.5% shown in column b on line 2 of Table 1 in Exhibit

I.8.2-VECC-11.

f) Please confirm that the average total bill impacts for Rate E62 customer shown in Table 1 of Exhibit I.8.2-VECC-11 includes the reduction of $8.6 million costs recovered for Rate E62 as proposed by EGI. If not confirmed, please explain.

g) For the other lines in Table 1 of Exhibit I.8.2-VECC-11, please add a column to show the dollar reduction in the costs recovered from Rate E62 based on the other scenarios shown in the table.

h) Please explain how a gas distributor located in another province can be considered an infranchise customer (Ex. I.8.2-VECC-11) while another gas distributor located within the province is served under rates that EGI labels as ex-franchise (M17 and proposed E60 & E70 (Exhibit 8, Tab 2, Schedule 5, Table 1).

<u>Response</u>:

a) Confirmed. The base rate reduction for Rate E62 is recovered on a common unit rate basis from customers in Rate E01, Rate E02, Rate E10, Rate E30 and Rate E34.

b) Confirmed.

c) Confirmed.

d) Confirmed.

e) The figures referenced in the question both represent total bill impacts for the four distributors in Rate M9. The 3.4% impact provided in response at Exhibit I.8.2-VECC-11, part c), Table 1, column (b), line 2 is based on the weighted average of total bill impacts for Rate M9. The 3.1% impact at Phase 3 Exhibit 8, Tab 2, Schedule 6, p. 8, Table 2, column (b), line 2 is based on the average of each individual customer's total bill impact with equal weighting.

f) Confirmed.

g) Please see Table 1. The revenue recovery from Rate E62 is less than the revenue requirement from the Cost Allocation Study for all rate zone alternatives due to the allocation of S&T margin and the base rate adjustment under the proposed one rate zone alternative. Enbridge Gas has not prepared a rate mitigation plan for the other rate zone alternatives due to the level of time and effort required. Additional mitigation measures may be required if the OEB approves a rate zone alternative other than proposed.

Table 1
Average Total Bill Impacts and Rate Design Adjustment for Rate E62

Line No.	Rate Zone Alternative	Rate 200 (1)	Rate M9 (2)	Rate Design Adjustments ($000) S&T Margin (3)	Rate Mitigation (4)	Total
		(a)	(b)	(c)	(d)	(e) = (c + d)
1	Current Rate Zones	(5.4%)	(0.8%)	(197)	-	(197)
2	One Rate Zone - Proposed	0.5%	3.4%	(197)	(8,593)	(8,790)
3	One Rate Zone - No Regional Adjustments	(6.0%)	5.1%	(163)	-	(163)
4	One Rate Zone - As Filed in Phase 1	(4.9%)	6.3%	(173)	-	(173)
5	Two Rate Zones - One Rate Zone Distribution	13.9%	4.7%	(273)	-	(273)
6	Two Rate Zones	7.8%	6.1%	(273)	-	(273)
7	Four Rate Zones - One Rate Zone Distribution	10.3%	(0.8%)	(151)	-	(151)

Notes:
(1) Phase 3 Exhibit 7, Tab 0, Schedule 1, Attachment 3, p. 1, line 8, updated July 4, 2025.
(2) Phase 3 Exhibit 7, Tab 0, Schedule 1, Attachment 3, p. 3, line 41, updated July 4, 2025.
(3) Phase 3 Exhibit 8, Tab 2, Schedules 9 to 15, Attachment 1, column (f).
(4) Phase 3 Exhibit 8, Tab 2, Schedules 9 to 15, Attachment 1, column (g).

h) The applicability of gas distributors as in-franchise or ex-franchise refers to the type of service provided to the gas distributor, not their location as either in-franchise or ex-franchise of the Enbridge Gas franchise area. The applicability of in-franchise and ex-franchise service to gas distributors is based on their ability to access cost-based storage as determined in the NGEIR Decision.[1] Specific to Enbridge Gas Québec (previously Gazifère), the OEB determined the following:

[1] EB-2005-0551 Natural Gas Electricity Interface Review Decision with Reasons, November 7, 2006, pp. 61-66.

> The Board must also consider the application of its findings to Gazifère. Gazifère is a small Quebec distributor, serving 30,000 customers, which is connected to the Enbridge system and is an affiliate of Enbridge. Enbridge proposed to charge market based rates to Gazifère on the basis that it is an ex-franchise customer. Others argued that all customers outside Ontario should pay market-based rates.
>
> As outlined earlier in this section, the Board has found that a decision to refrain from regulating storage rates should not be based on an in-Ontario, ex-Ontario approach, but rather on the competitive position of the customer. The appropriate consideration is whether Gazifère has access to alternatives. The evidence is that it does not; it is connected to the Enbridge system and takes a bundled distribution service. In all respects, Gazifère is similarly situated to the distributors attached to Union's system (namely, Kitchener, NRG, and Six Nations) which each take bundled or semi-unbundled service. The Board finds that it is appropriate for Gazifère to receive regulated cost based service, just as Kitchener, NRG and Six Nations do, because the service they receive is not subject to competition sufficient to protect the public interest.

Subsequent to the NGEIR Decision, Union implemented a new ex-franchise rate class under Rate M17 for new gas distributors, which requires the use of market-based storage for their storage needs. [2] It was determined at that time that any new gas distributors would not be eligible for the existing services offered under Rate M9, Rate T3 or Rate 200, as these rate classes have access to cost-based storage.

[2] EB-2019-0183 Owen Sound Reinforcement Project Leave to Construct and Rate M17, Decision and Order, April 9, 2020.

ENBRIDGE GAS INC.

Answer to Undertaking from
London Property Management Association (LPMA)

Undertaking:

Tr: 6

To provide a written response to Exhibit KT1.2, Question 2.

Reference:

Exhibit I.7.0-FRPO-33, pg. 3
Exhibit I.7.1-CCC-6, pg. 2

The second paragraph in the response part C in FRPO interrogatory indicates that gas supply administration costs are recovered as part of the delivery revenue rather than through gas cost revenue. The response to part C in the CCC interrogatory states that EGI is not allocating sales service-related gas supply administration costs to direct purchase customers and that these costs to provide sales service are allocated in proportion to sales service volumes and recovered from sales service customers only.

The response then goes on to state that EGI classifies the O&M costs for direct purchase and distributor consolidated billing service to the same gas supply admin functional classification which are then offset by other revenue associated with the DP admin charge and the DCB charge.

a) Do the DP admin and DCB charges cover 100% of the associated costs that are included in the gas supply admin? If not what percentage of the associated costs are recovered through these charges?

b) Please explain how the gas supply admin costs associated with providing sales service customers with gas are only recovered from system gas customers if these costs are recovered through delivery rates which are also recovered from direct purchase customers.

Response:

a) The other revenue associated with the DP admin and DCB charges recovers 100% of the associated costs of administering the DPAC and DCB Program.

b) The gas supply administration costs are recovered in the gas supply commodity charge from sales service customers. Enbridge Gas separates the revenue between delivery and gas costs revenue to identify the Enbridge Gas costs separate from gas cost revenue.[1] Please see Phase 3 Exhibit 8, Tab 2, Schedule 2, page 3, Table 1, line 4 for the current approved and proposed gas supply administration charge unit rate included in the gas supply commodity charge.

[1] The gas supply administration costs are considered delivery for the purpose of separating revenue requirement and the revenue sufficiency/deficiency between gas costs and delivery. The gas cost revenue includes gas supply and upstream third-party transportation costs, plus compressor fuel, UFG and company use gas, while delivery revenue includes all other Enbridge Gas costs.

ENBRIDGE GAS INC.

Answer to Undertaking from
London Property Management Association (LPMA)

Undertaking:

Tr: 6

To provide a written response to Exhibit KT1.2, Question 3.

Reference:

Ex. I.8.2-Staff-30

This interrogatory response deals with the potential movement between rates E02, E10 and E20.

EGI has identified more than 800 customers that may have a financial incentive to switch rate classes upon implementation of the rate harmonization plan. Does EGI planning on informing each of these customers of the potential financial benefit of switching from one rate class to another upon the implementation of the rate harmonization plan? If not, why not?

Response:

Enbridge Gas will provide an update on the Rate Harmonization Implementation Plan, including an update on the communication plan, as part of the 2027 Rates application. The potential movement and financial incentive to switch rate classes is dependent on the outcomes of the OEB decision in this Application. As such, Enbridge Gas will develop a comprehensive communication and stakeholder implementation plan to ensure all affected customers are made aware of rate class and customer distribution service changes and available options once the outcomes of Phase 3 are known. Enbridge Gas does not intend to contact each individual customer directly regarding their specific options, as doing so would present an administrative burden and not be effective given the size and diversity of the customer base. Instead, Enbridge Gas expects to proceed as described below.

For customers that map to Rate E10 firm bundled contract service, the communication plan will include webinars and general customer information sessions. If customers are interested in switching to the semi-unbundled contract service, their account managers will be able to answer their questions and assist with the transition.

Rather than contact all Rate E02 general service customers, Enbridge Gas will contact those customers that are identified as best suited for the Rate E10 contract service through a financial determination (e.g. annual bill savings greater than a defined threshold). In general, larger general service customers are more likely to transition to Rate E10 firm bundled contract service due to a stronger financial benefit, but some may prefer the simplicity of general service despite the potential financial benefits.

ENBRIDGE GAS INC.

Answer to Undertaking from
London Property Management Association (LPMA)

Undertaking:

Tr: 7

To provide a written response to Exhibit KT1.2, Question 4.

Reference:

Ex. I.7.1-FRPO-51, Att. 1

a) Are the average cost per metre figures shown on page 1 of the attachment the gross average costs or net average costs (i.e. reflecting accumulated depreciation)?

b) Please explain the factors that result in the average cost per metre of a 0.5 inch pipe diameter being nearly 5 times more than that of a 1.0 inch diameter pipe.

c) Please explain the factors that result in the average cost per metre of the 1.5 and 3 inch pipes being significantly less than the 1.25 and 2 inch pipes, respectively.

d) Please explain why the average cost per metre of the 16 and 20 inch pipes are significantly less than that of 12 and 14 inch diameter pipes.

e) Are the pipe diameters shown as 0.8 and 1.3 actually 0.75 and 1.25 inches, respectively?

f) Please explain why data from December 31, 2021 was used for the average cost per metre and the classification factor.

g) Please update the information on page 1 to reflect data as of the end of December, 2024, or the most recent information available if December, 2024 data is not available.

h) Please update the information on page 2 to reflect data as of the end of December, 2024, or the most recent information available if December, 2024 data is not available.

i) Please confirm that the figure of 1,801,039 shown on line 6 on page 2 is simply the difference between total low pressure distribution mains and distribution low pressure customer mains. If this is not the case, please explain how the 1,801,039 is calculated.

j) If the total customer-related mains cost shown at line 3 on page 2 was reduced by $100 million to $2,828,488 and with a corresponding increase in the demand-related mains, please confirm that this would result in the allocation of more costs to be recovered through demand charges and less costs to be recovered through customer charges. If not, please explain why not.

k) Please confirm that under the above scenario, the impact on individual rate classes would be determined by both the allocation of customer-related costs and demand-related costs to each of the rate classes. If not confirmed, please explain.

l) Based on the above scenario in the proposed one rate zone scenario, please show the change in customer-related costs and in demand-related costs for each rate class.

m) In the regression equation shown in note 1 on page 2, is the intercept value of 44.798 statistically significantly different from zero at a 95% confidence level; at an 80% confidence level?

Response:

a) The average cost per metre shown in response at Exhibit I.7.1-FRPO-51, Attachment 1 is the gross average cost.

b) In Enbridge Gas's fixed asset register, 0.5 inch diameter mains represent a very small subset of the total gross capital costs of mains ($6,675 or 0.0001%) and are not frequently installed as part of pipeline projects. The average cost per metre represents the vintage value of the installations for 0.5 in diameter mains.

c) Similar to part b), mains with diameters of 1.5 and 3.0 inches are not installed frequently and represent the vintage value of these pipeline assets. Comparatively, mains with diameters of 1.25 and 2.0 inches have been installed in recent years, therefore the gross asset average values are more reflective of current installation costs.

d) Enbridge Gas has made significant additions over the last 10 years for pipeline projects with a diameter of 12 inches, therefore the average cost per metre is more representative of recent actual installation costs. There have been far fewer additions related to 16 and 20 inch diameter pipelines, which explains the lower average cost per metre. The 14 inch diameter mains represent only 65 metres of the overall 75 million metres of mains pipeline and the resulting average cost per metre is an outlier.

e) Yes, the pipe diameters shown as 0.8 and 1.3 inches in Exhibit-I.7.1-FRPO-51, Attachment 1, page 1 of 2 are 0.75 and 1.25 inches respectively due to rounding.

f) Enbridge Gas filed its 2024 Rebasing Application[1] in Fall, 2022. Given the timeframe, the 2021 data was the most recent data available to prepare the Cost Allocation Study.

g) Updating the Zero Intercept calculation to the most recent available information would require significant effort, and it is not clear that any benefits from this exercise would justify the effort. In any event Enbridge Gas is unable to complete the request within the timeline for responding to undertakings.

h) Please see response at part g).

i) Confirmed.

j) Confirmed.

k) Confirmed. Under the proposed straight fixed variable rate design, the cost impact on individual rate classes would be affected by both the allocation of customer-related and demand-related mains costs.

l) Please see Table 1 for the revised Zero-Intercept Classification Factor If the total customer-related mains cost was reduced by $100 million to $2,828,488.

[1] EB-2022-0200.

Table 1
Revised Zero-Intercept Classification Factor

Line No.	Particulars	Cost
	Zero-Intercept Classification Factor	
1	Distribution Demand Mains ($000s)	
2	High-Pressure > 4"	1,775,393
3	High-Pressure <= 4"	339,570
4	Low Pressure (2)	1,901,039
5	Distribution Customer Mains ($000s)	2,828,488
6	Total ($000s)	6,844,489
7	Customer-related Mains (line 5/line 6)	41%
8	Demand-related Mains (sum of lines 2-4 / line 6)	59%

Please see Attachment 1 for the change in customer-related costs and demand-related costs for each rate class under the proposed one rate zone alternative.

m) The intercept value of 44.798 has a p-value of 0.209. Consequently, the 95% and 80% confidence intervals will include zero, suggesting that the intercept value is statistically insignificant.

However, when looking at the underlying data points for pipe diameter less than four inches, the resulting regression equation is relatively flat with an intercept value of 40.732 and corresponding p-value of 0.019. Consequently, based on the data for smaller diameter pipelines, the 98% confidence interval does not include zero and includes the proposed intercept value, suggesting that the intercept value is significantly different from zero.

One Rate Zone - Proposed Alternative
Distribution Demand - Mains Revenue Requirement

Line No.	Particulars ($000s)	Demand-Related: Distribution Demand High Pressure > 4" (1)	Demand-Related: Distribution Demand High Pressure <= 4" (2)	Demand-Related: Distribution Demand Low Pressure (3)	Customer-Related: Distribution Customer Mains (4)
		(a)	(b)	(c)	(d)
1	Rate E01	125,363	31,017	167,868	398,294
2	Rate E02	89,093	22,043	119,301	8,836
3	Rate E10	24,276	3,518	14,266	79
4	Rate E20-F	25,425	642	1,984	8
5	Rate E20-I	-	-	233	-
6	Rate E22-F	7,123	215	26	5
7	Rate E22-I	-	-	479	-
8	Rate E24-F	33,768	-	-	1
9	Rate E24-I	-	-	1,168	-
10	Rate E30	2	-	343	5
11	Rate E34	26	4	15	4
12	Rate E38	-	-	-	-
13	Rate E60	314	-	-	-
14	Rate E62	2,417	74	-	1
15	Rate E64	3,600	-	-	0
16	Total	311,407	57,513	305,683	407,234

Notes:
(1) Phase 3 Exhibit 7, Tab 3, Schedule 1, Attachment 8, line 21.
(2) Phase 3 Exhibit 7, Tab 3, Schedule 1, Attachment 8, line 22.
(3) Phase 3 Exhibit 7, Tab 3, Schedule 1, Attachment 8, line 23.
(4) Phase 3 Exhibit 7, Tab 3, Schedule 1, Attachment 8, line 24.

One Rate Zone - Proposed Alternative
Distribution Demand - Mains Revenue Requirement
Shift $100 Million in Costs from Customer Related to Demand Related

Line No.	Particulars ($000s)	Demand-Related Distribution Demand High Pressure > 4" (a)	Demand-Related Distribution Demand High Pressure <= 4" (b)	Demand-Related Distribution Demand Low Pressure (c)	Customer-Related Distribution Customer Mains (d)
1	Rate E01	124,832	30,880	176,333	397,294
2	Rate E02	88,716	21,946	125,316	8,814
3	Rate E10	24,173	3,502	14,986	79
4	Rate E20-F	25,317	639	2,084	8
5	Rate E20-I	-	-	245	-
6	Rate E22-F	7,093	215	28	5
7	Rate E22-I	-	-	503	-
8	Rate E24-F	33,624	-	-	1
9	Rate E24-I	-	-	1,227	-
10	Rate E30	2	2	360	5
11	Rate E34	26	4	16	4
12	Rate E38	-	-	-	-
13	Rate E60	313	-	-	-
14	Rate E62	2,407	74	-	1
15	Rate E64	3,584	-	-	0
16	Total	310,087	57,260	321,093	393,395

One Rate Zone - Proposed Alternative
Change in Revenue Requirement from Shifting $100 Million

Line No.	Particulars ($000s)	Demand-Related: Distribution Demand High Pressure > 4"	Demand-Related: Distribution Demand High Pressure <= 4"	Demand-Related: Distribution Demand Low Pressure	Customer-Related: Distribution Customer Mains
		(a)	(b)	(c)	(d)
1	Rate E01	(531)	(136)	8,465	(1,000)
2	Rate E02	(378)	(97)	6,016	(22)
3	Rate E10	(103)	(15)	719	(0)
4	Rate E20-F	(108)	(3)	100	(0)
5	Rate E20-I	-	-	12	-
6	Rate E22-F	(30)	(1)	1	(0)
7	Rate E22-I	-	-	24	-
8	Rate E24-F	(143)	-	-	(0)
9	Rate E24-I	-	-	59	-
10	Rate E30	(0)	2	17	(0)
11	Rate E34	(0)	(0)	1	(0)
12	Rate E38	-	-	-	-
13	Rate E60	(1)	-	-	-
14	Rate E62	(10)	(0)	-	(0)
15	Rate E64	(15)	-	-	(0)
16	Total	(1,320)	(251)	15,415	(1,022)

ENBRIDGE GAS INC.

Answer to Undertaking from
London Property Management Association (LPMA)

Undertaking:

Tr: 7

To provide a written response to Exhibit KT1.2, Question 5.

Reference:

Ex. I.8.2-LPMA-15
Ph. 3 Ex.8, Tab 2, Sch. 3, Att. 7, pg. 28

a) Please confirm that when the federal carbon charge was included in the calculation, about 63,000 customers or 1.6% of total general service customers would see bill impacts of a 10% or more increase.

b) Please confirm that when the federal carbon charge is removed from the calculation, about 288,000 customers or 7.3% of total general service customers would see bill impacts of a 10% or more increase.

c) Based on the no federal carbon charge calculation, please confirm that only about 42,000 customers or 1.1% of total general service customers would see bill impacts of a 10% or more increase.

d) Did EGI consider a rate design with three parts for general service customers of a fixed charge, a demand charge and a volumetric charge where a portion of the demand-related costs were recovered through a demand charge and the remainder of the demand-related costs were recovered through a volumetric charge as a form of rate mitigation? If not, why not?

Response:

The following response was provided by Christensen Associates Energy Consulting:

a) We confirm that about 63,000 customers in the CA Energy Consulting sample have bill impacts under the SFVD design, in the presence of a carbon charge, in excess of a 10% increase. Since the sample of customers is slightly less than the population total, the percentage of the population with such impacts is slightly greater than LPMA's estimate of 1.6%.

b) We confirm that approximately 288,000 customers in the sample have bill impacts in excess of 10% under the SFVD design after removal of the carbon charge. As with the response to question a), the population share is slightly higher than LPMA's estimate of 7.3%. Note that the *absolute dollar bill impacts* of the introduction of the SFVD design do not change with the removal of the carbon charge. The reduction in bills due to that removal merely increases the absolute *percentage change* of the bill impact. As mentioned in the report, increasing the ceiling to 12% (from 10%) reduces the share of customers above the ceiling from levels of 23% and 11% for Rates M1 and M2, respectively, to 8% and 7%, respectively. (Please see Phase 3 Exhibit 8 Tab 2, Schedule 3, Attachment 7, updated July 4, 2025, p. 28 of 61.)

c) We confirm that about 42,000 customers in the sample have bill impacts in excess of 10% under the volumetric rate alternative after the removal of the carbon charge. (We infer that the question refers to the volumetric alternative.) Again, the question's percentage should be adjusted slightly upward to reflect the difference between the sample size and the population size. The modest upper tail bill impacts reflect the similarity of the volumetric alternative to the current design. As noted previously, this reduction is purchased at the expense of the loss of billing accuracy under the SFVD design that reflects differences in load factor across customers.

d) The General Service Rate Harmonization Project undertaken collaboratively between Enbridge Gas and CA Energy Consulting did not consider a three-part design in which demand-related cost recovery would be split between a demand and a volumetric charge. Given the generally modest levels of bill impacts generated by the SFVD design, the additional complexity of a three-part design is not warranted as a form of rate mitigation (or as an alternative rate design option for general service customers).

ENBRIDGE GAS INC.

Answer to Undertaking from
London Property Management Association (LPMA)

Undertaking:

Tr: 7

To provide a written response to Exhibit KT1.2, Question 6.

Reference:

Ex. I.8.2-LPMA-18
Ph. 3 Ex. 8, Tab 2, Sch. 9, Att. 2, g. 1

In the response to part a of the LPMA interrogatory, EGI states that design day demands are allocated to the harmonized rate classes proportionally by CAEC based on their analysis of individual customers historical consumption, but CAEC states that the sum of the individual 2018 and 2019 demands will not match the general service 2024 total forecast design day demand. For cost allocation and billing demand purposes, EGI has used 1,087,127 103 m3/d for Rate E01 and 772,599 103 m3/d for Rate E02, resulting in delivery demand rates of 61.4250 cents/m3 and 63.5355 cents/m3 respectively.

a) Please confirm that the billing demand figures noted above are not related to the sum of the design day estimates using the CAEC regression methodology based on 2018 an/or 2019 data or any other period.

b) Does EGI and/or CAEC have the aggregate sum of all customers under each of Rate E01 and E02 based on the CAEC regression methodology? If yes, please provide the two figures.

Response:

Please see response at Exhibit JT2.1.

ENBRIDGE GAS INC.

Answer to Undertaking from
London Property Management Association (LPMA)

Undertaking:

Tr: 7

To provide a written response to Exhibit KT1.2, Question 7.

Reference:

Ex. I.8.2-LPMA-18
Ph. 3 Ex. 8, Tab 2, Sch. 9, Att. 2, pg. 1

In the response to part d of the LPMA interrogatory, EGI indicated that it does not plan on requesting a variance account to track the difference in delivery demand charge revenues noting that the annual update is intended to capture changes in demand requirements specific to each customer under design day conditions. However this does not take into account the difference in the design day billing units used to calculate the delivery demand rates which appear to be based on a different methodology that the aggregate of all customers in the rate classes based on the CAEC methodology that will be used for billing purposes beginning in 2027.

a) If the billing units from the CAEC methodology derived from 2018/2019 data or any period prior to the end of 2024 are higher than the figures used to derive the delivery demand rates, will this not result in higher revenues to EGI because the delivery demand rate is higher than it should be based on the lower forecast of delivery demand forecasts?

b) If the billing units from the CAEC methodology derived from 2018/2019 data or any period prior to the end of 2024 are lower than the figures used to derive the delivery demand rates, will this not result in lower revenues to EGI because the delivery demand rate is lower than it should be based on the higher forecast of delivery demand forecasts?

Response:

Please see response at Exhibit JT2.1.

ENBRIDGE GAS INC.

Answer to Undertaking from
London Property Management Association (LPMA)

Undertaking:

Tr: 7

To provide a written response to Exhibit KT1.2, Question 8.

Reference:

Ex. I.8.2-CCC-15

Please calculate the design day demand shown in line 4 of the table on page 2 based on the consumption, days and heating degree days shown in the response to part a, with the following changes to that data:

a) No consumption in July through October in each of 2018 and 2019;
b) If the design day demand increases, please explain why this is reasonable.
c) If the design day demand decreases, please explain why this is reasonable.

Response:

The following response was provided by Christensen Associates Energy Consulting:

a) As shown in Attachment 1 to this response, the illustrative model produces a design day demand of 16.38 cubic metres when the July through October consumption values are modified to zero, as specified in the question. See Attachment 1, worksheet “Data,” cell F29. As may be seen in the chart on worksheet “Chart Negative Intercept,” the modified consumption profile results in a negative intercept (base demand). In this case, the exception arises from the regression’s fit of data for periods with zero consumption and positive HDDs. The negative intercept is considered an exception because actual base demand (i.e., gas demand at zero HDDs in Attachment 1) would be non-negative.

   The “Chart Zero Intercept” worksheet shows the result of addressing the negative intercept exception by setting the regression intercept to zero, which leads to a design day demand of 16.02 cubic metres. Addressing negative intercepts is already part of Enbridge Gas's exception management protocols for estimated billing and not specific to the prospective application of SFVD.

b) In the illustrative regression, reducing the July through October consumption to zero without corresponding reductions of consumption in other months serves to reduce the customer's apparent base demand and, by extension, increase the apparent extent to which consumption in other months is related to heating demand. The effect is to increase the heating factor and reduce the base factor, relative to the original example. The increase in the heating factor has a larger effect on design day demand than the reduction in the base factor in this case, resulting in the increase in design day demand.

c) Not applicable.

This page is intentionally left blank. Due to size, this Attachment has not been included.

Please see Exhibit JT1.15_Attachment 1.xlsx on the OEB's RDS.

ENBRIDGE GAS INC.

Answer to Undertaking from
City of Kitchener (Kitchener)

Undertaking:

Tr: 7

To provide a written response to Exhibit KT1.3, Question 1.

Reference:

Exhibit I.7.0-Kitchener-2

Response mentions about customer engagement process with Kitchener.

i. Considering Kitchener to be only customer in the T3 rate class, please confirm if the engagement was in-person meeting or a virtual meeting to review T3 rate class requirements and discuss revenue impacts in dollars and percentage.

ii. Please confirm if customer engagement took place recently with other rate class customers (after Phase 1) to review rate zone alternatives and rate design information along with rate impacts.

Response:

i.- ii. As described in response at Exhibit I.7.0-Kitchener-2, Enbridge Gas indicated that the formal customer engagement for Contract Rate customers conducted virtually in early 2022 focused specifically on distribution and direct purchase services and did not include any questions about rate zone alternatives and the related rate impacts in the workbook. The work to provide rate design information was not completed until just prior to the initial filing of evidence in November 2022.

Enbridge Gas discussed rate impacts of rate harmonization this year when updated Phase 3 evidence was filed. Enbridge Gas shared rate impact information, at the rate class level, with customers at customer meetings (which Kitchener attended in person). As an intervenor, Kitchener also had the ability to review rate impacts throughout each phase of the proceeding.

At Phase 3 Exhibit 8, Tab 2, Schedule 1, Enbridge Gas has proposed the harmonized services and rates be effective in 2027. This provides Enbridge Gas time to implement changes to internal and customer-facing business applications and to provide notice to customers of the changes in their services. Enbridge Gas expects to have more detailed discussions with customers about customer-specific changes after the OEB issues its Phase 3 Decision. Enbridge Gas also plans to develop a comprehensive customer communication plan explaining the proposed changes prior to implementation of the harmonized rates and services, subject to OEB approval in Phase 3. The Company expects to file a more detailed implementation plan, including a description of the communication plan, in its 2027 Rates Application.

ENBRIDGE GAS INC.

Answer to Undertaking from
City of Kitchener (Kitchener)

Undertaking:

Tr: 7

To provide a written response to Exhibit KT1.3, Question 2.

Reference:

Exhibit I.7.0-Kitchener-3

Response mentions change in total revenue under current rate zone alternative is 2%.

i. Please confirm T3 rate class is a Direct Purchase customer.

ii. Please confirm 2% as shown in Phase 3 Exhibit 7, Tab 0, Schedule 1, Attachment, page 11, column (a), line 54 includes gas commodity cost also which customer provide for itself.

iii. Considering T3 rate customer to be a direct purchase customer, please provide delivery rate impact to T3 rate i.e., without gas commodity cost?

iv. Please provide T3 rate impact based on delivery rates for each alternative in Phase 3 Exhibit 7, Tab 0, Schedule 1, Attachment, page 11, column (a), line 54

1. Current rate zone
2. One rate zone proposed
3. One rate zone = No regional adjustments
4. One rate zone – as filed in Phase 1
5. Two rate zones – One rate zone distribution
6. Two rate zones
7. Four rate zones – one rate zone distribution

Response:

i. Confirmed.

ii. Not confirmed. The 2% change in total revenue for Rate T3 under the current rate zones alternative, as shown at Phase 3 Exhibit 7, Tab 0, Schedule 1, Attachment 2, page 11, column (a), line 54, does not include an assumption for gas supply commodity costs.

The detailed derivation of the total revenue change for Rate T3 under the current rate zones alternative is provided at Phase 3 Exhibit 8, Tab 2, Schedule 15, Attachment 2, page 12, lines 342 to 355.

iii-iv. The direct purchase bill impacts for Rate T3 are provided for each rate zone alternative at Phase 3 Exhibit 7, Tab 0, Schedule 1, Attachment 4, page 3, line 46, updated July 4, 2025.

ENBRIDGE GAS INC.

Answer to Undertaking from
City of Kitchener (Kitchener)

Undertaking:

Tr: 7

To provide a written response to Exhibit KT1.3, Question 3.

Reference:

Exhibit I.7.1-Kitchener-4

Response mentions confirms that T3 is a DP customer and manages all its gas supply requirements and does its own load balancing.

In addition, confirmed that under proposed one rate zone alternatives load balancing transportation costs are not allocated to rate T3.

i. Please provide details of cost included in Stort-Term Storage and Other Balancing Services under account number 179-70.

ii. Please confirm if T3 rate would get cost allocated from account 179-70 under proposed rate zone alternatives.

iii. If yes, please explain the details of cost allocated.

Response:

i. The Short-Term Storage and Other Balancing Services Deferral Account (179-70) includes revenues from C1 Off-Peak Storage, Gas Loans, Supplemental Balancing Services, and C1 Short-Term Firm Peak Storage from the sale of excess utility storage space. The deferral account records the utility portion of revenue for Short-Term Storage and Other Balancing Services less a 10% shareholder incentive to provide these services less the net revenue forecast for these services included in approved rates.

ii.-iii. Enbridge Gas does not expect to record balances in the Short-Term Storage and Other Balancing Services Deferral Account when the proposed rate zone alternative is implemented, subject to OEB approval in Phase 3, as the excess utility storage previously held by Union Gas will be used to serve all in-franchise customers as part of the consolidated Gas Supply Plan.

ENBRIDGE GAS INC.

Answer to Undertaking from
City of Kitchener (Kitchener)

Undertaking:

Tr: 7

To provide a written response to Exhibit KT1.3, Question 4.

Reference:

Exhibit I.7.3-Kitchener-6

Response (b-c) mentions storage parameter for rate T3 is based on 2024 test year forecast.

i. Please provide contracted deliverability for rate T3 from April 1, 2023, to March 2024.

ii. If the contracted deliverability for rate T3 from April 1, 2023 to March 2024 was 49,000 GJ/day, then why the 2024 Test year forecast is using 54,139 GJ/day and not 49,000 GJ/day.

iii. Please provide updated revenue requirement for T3 rate based on contracted deliverability 49,000 GJ/day.

iv. Please confirm if there would be savings to T3 rate if contracted deliverability 49,000 GJ/day is used instead of contracted deliverability 54,139 GJ/day

v. Our understanding in the phase 1 application was that the cost allocation and the related allocation factors used for allocating cost would be discussed and finalized as a part of phase 3 application. Please confirm our understanding and let us know the next application/opportunity during the IR term to fix deliverability allocation factor before the next rebasing application.

Response (g-h) mentions T3 can inject up to 24,139 GJ/ day in incremental supply transactions.

vi. Please confirm if 24,139 GJ/day can be considered as firm incremental injection rights in addition to example of regular DCQ of 30,000 GJ/day.

vii. Please confirm if operational restrictions / lights during the year can impact injection of 24,139 GJ/day of incremental supply on any day of the year.

viii. If yes, please provide rational if the operational lights actually impact deliverability.

Response (i) confirms annual firm injection/withdrawal rights are not balancing transactions.

ix. Please confirm 24,139 GJ/day of incremental supply would be considered as part of the firm injection and not balancing transactions.

x. If annual firm injection is not balancing transactions, then can it be curtailed?

Response:

i. The contracted deliverability for Rate T3 was 49,000 GJ/day for the period April 1, 2023, to March 31, 2024.

ii. The 2024 Test Year Forecast was developed by Enbridge Gas in Q1 & Q2 of 2022. The Rate T3 storage deliverability parameter of 54,139 GJ/day used in the derivation of the proposed cost allocation factor is consistent with the contracted deliverability for Rate T3 at the time the 2024 Test Year Forecast was developed.

iii. The Cost Allocation Study proposed as part of this Application is based on the 2024 Test Year Forecast agreed to by parties and subsequently approved by the OEB as part of the Phase 1 Settlement Agreement[1]. The Cost Allocation Study factors are not recalculated for changes to contract parameters for customers until the next rebasing application. Please see response at part v.

iv. Please see response at part iii. All else being equal, the costs allocated to Rate T3 would be lower if the contracted deliverability used in the derivation of the allocation factor was changed from 54,139 GJ/day to 49,000 GJ/day.

v. The Phase 3 Issues List includes the following issue:

Is the 2024 Cost Allocation Study to allocate costs to harmonized rate classes appropriate, including the methodologies.[2]

The 2024 Cost Allocation Study is based on the 2024 Test Year Forecast, which was agreed to by parties as part of the Phase 1 Settlement Agreement[3] and

[1] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p. 10.
[2] Decision on Issues List and Procedural Order No. 2, May 16, 2025.
[3] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p. 10.

subsequently approved by the OEB in Phase 1. As such, the Cost Allocation Study and the methodologies used to allocate costs to rate classes is in scope for Phase 3, but the underpinning data used for the allocation is based on the approved 2024 Test Year Forecast. One exception to the use of the 2024 Test Year Forecast for cost allocation purposes was agreed to by parties in the Phase 1 Settlement Agreement, as noted in Exhibit JT1.22 part vii. Specifically, parties agreed that the weather station data, as it relates to establishing design day demand for cost allocation purposes is within scope of Phase 3.[4]

Independent of the outcomes in this proceeding, Enbridge Gas will seek approval for a cost allocation study, including updated cost allocation factors for the 2029 Test Year, in the Company's next rebasing application.

vi. Not confirmed. In the example provided in the question, the injection rights can be used to inject the DCQ of 30,000 GJ/day and up to 24,139 GJ of scheduled incremental supply transactions.

vii. Incremental supply transactions are interruptible balancing transactions. Operational restrictions can impact the scheduling of interruptible services, including incremental deliveries into the Enbridge Gas system.

viii. Rate T3 storage deliverability (firm injection and withdrawal rights) is set to meet withdrawal requirements based on firm contract demand less obligated DCQ. The deliverability provides Rate T3 with the ability to supplement the DCQ with withdrawals from storage to meet firm contract demand. The contracted storage deliverability also allows Rate T3 to inject their DCQ and scheduled/allowed incremental supply balancing transactions in excess of the DCQ.

ix. Not confirmed.

x. Please see response at part vii.

[4] EB-2022-0200, Settlement Agreement, p. 46.

ENBRIDGE GAS INC.

Answer to Undertaking from
City of Kitchener (Kitchener)

Undertaking:

Tr: 8

To provide a written response to Exhibit KT1.3, Question 5.

Reference:

Exhibit I.7.3-Kitchener-7

Response mentions that Enbridge will seek approval for a cost allocation study based on annual based on updated allocation factors for 2029 test year in next rebasing applications.

i. Our understanding in the phase 1 application was that the cost allocation and the related allocation factors used for allocating cost would be discussed and finalized as a part of phase 3 application. Please confirm our understanding and let us know the next application/opportunity during the IR term to fix this allocation issue before the next rebasing application.

Response:

Please see response at Exhibit JT1.19, part v.

ENBRIDGE GAS INC.

Answer to Undertaking from
City of Kitchener (Kitchener)

Undertaking:

Tr: 8

To provide a written response to Exhibit KT1.3, Question 6.

Reference:

Exhibit I.7.3-Kitchener-9

Response (b-c) confirms that under Union Gas, T3 rate class did not get any DSM program or administration related cost allocated. In addition, that DSM cost started getting allocated since 2023.

i. Please confirm the allocation of DSM cost to T3 rate is a result of amalgamation i.e., new approach of allocating DSM cost to all rate class started after amalgamation.

   Response (d) provides cost of $106,247 allocated to T3 rate class.

ii. Please provide a table showing annual DSM cost toT3 rate class as shown below from 2024 until 2030 (proposed from 2026-2030).

2023	2024	2025	2026	2027	2028	2029
$106,247						

   Response (g) doesn't explain why Kitchener utilities customers cannot access portion of the DSM fund equivalent to fund provided by T3 rate class.

iii. As Kitchener is a municipality, T3 rate gets embedded inside Kitchener Utilities delivery rates (distribution rates). Hence, Kitchener Utility customers are paying towards portion of Enbridge's DSM fund allocated to T3 rates. Please explain why Kitchener utilities low-income customers cannot access DSM low-income program equivalent to funds provided by T3 rate class.

Response:

i. Confirmed. The approach to the DSM allocation to Rate T3 is a result of the previously implemented alignment of allocation methodology between the Union rate zones and EGD rate zone. The allocation of the low-income DSM budget to Rate T3 was approved as part of the Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027).[1]

ii. Enbridge Gas's proposed 2026-2030 DSM Plan Application[2] (filed November 2024) is no longer applicable. As a result of the Government of Canada's decision to set the Federal Carbon Charge to zero effective April 1, 2025, Enbridge Gas filed a 2026 rollover DSM Application in June 2025 and expects to file an updated multi-year DSM Plan Application for 2027 and beyond in Q4 2025, after the OEB issues its decision on 2026 DSM activities. As a result, Enbridge Gas does not have information for 2027 and beyond at this time. Any variance between the DSM program costs included in rates and the final actual DSM program costs will be trued up through the DSM Variance Account.

Table 1
Annual DSM Budget Cost Allocation to Rate T3

Particulars ($000s)	2024 (1)	2025 (2)	2026 (3)
Rate T3	112	98	101

Notes:
(1) EB-2022-0200, Rate Order, Working Papers, Schedule 22, p.1, column (b), line 27 Updated March 15, 2024.
(2) EB-2024-0111, Rate Order, Working Papers, Schedule 10, p. 1, column (b), line 27.
(3) EB-2025-0163, Exhibit C, Tab 1, Rate Order, Working Papers, Schedule 9, p. 1, column (b), line 27.

iii. The portion of DSM costs allocated to Rate T3 is in alignment with the direction from the OEB that the low-income DSM budget should be funded from all rate classes[3]. This is done according to distribution revenue, consistent with the allocation of LEAP funding.

[1] EB-2021-0002, Decision & Order, March 2, 2023.
[2] EB-2024-0198
[3] EB-2008-0346 Demand Side Management Guidelines for Natural Gas Distributors, June 30, 2011, Section 8.3, p. 26.

The portion of DSM costs allocated to Rate T3 is not meant to provide funding for Kitchener low-income customers, but rather to address the OEB direction on funding noted above.

While numerous other issues would need to be considered, if it was possible for Kitchener's low-income customers to participate in Enbridge Gas's Low-Income programming, Rate T3 would be allocated a much larger proportion of the program costs to recognize the participation of Kitchener's customers.

ENBRIDGE GAS INC.

Answer to Undertaking from
City of Kitchener (Kitchener)

Undertaking:

Tr: 8

To provide a written response to Exhibit KT1.3, Question 7.

Reference:

Exhibit I.7.3-Kitchener-10, Exhibit I.7.3-Kitchener-11, Exhibit I.7.3-Kitchener-12

Response confirms that DAWN_DEMAND and KIRKWALL_DEMAND allocation factor is based on Dawn Parkway design day demand. That new rate zone proposals changes represents higher proportion of the Dawn Parkway based on proposed design day demand for T3 rate.

i. Please confirm using higher design day demand will result in higher allocation factor for calculating DAWN_DEMAND and KIRKWALL_DEMAND

ii. Please list all the allocation factors that use design day demand in addition to the list mentioned below
   1) Storage
      a. OP_CONTINGENCY
   2) Transmission
      a. DAWN_DEMAND
      b. KIRKWALL_DEMAND
      c. D-TRANS
      d. PAN_STCLAIR
   3) DISTRIBUTION
      a. HIGHPRESS>4

iii. Please provide percentage of cost allocated to T3 rate class based on design day demand compared to total delivery revenue from T3 rate class based on all the rate alternatives.

iv. Please confirm if the percentage of cost allocated to rate T3 based on design day demand is higher than 50% of the total delivery revenue.

v. If lower design day demand of 2,545.261 10^3m^3, is used, please provide the summary of revenue requirement under all rate alternatives for T3 rate.

Response Exhibit I.7.3-Kitchener-11 (d) mentions that using a higher temperature with the same consumption data means that it would be warmer on the design day as this would decrease the design day HDDw.

vi. For calculating design day demand, please confirm while using regression analysis, for same consumption and using colder temperature for example minus 40. will result in lower design day demand, compared to using same consumption and warmer (higher temperature) for example minus 35.

Response Exhibit I.7.3-Kitchener-11 (e) refers that the design day demand for Kitchener is determined using the methodology agreed to and approved in the Phase 1 Settlement Agreement.

vii. Our understanding from the Phase 1 settlement agreement was that in phase 3 application we would be looking into which weather centre would be used for calculating design day demand one of the critical allocation factors for T3. Please let us know the next proceeding where this issue would be addressed.

<u>Response</u>:

i. Confirmed. All else being equal, a higher design day demand would result in a higher allocation percentage of the proposed DAWN_DEMAND and KIRKWALL_DEMAND cost allocation factors.

ii. The proposed cost allocation factors, not listed in the question above, that use design day demand in the derivation of the allocation factor include:

- ALBIONTRANS
- HIGHPRESS<=4
- LOAD_BALANCING
- LOWPRESS
- NETFROMSTOR
- PKWY_DEMAND

Enbridge Gas would like to note that not all components of the operational contingency allocation factor (OP_CONTINGENCY) are derived using design day demands.

iii. Please see Attachment 1.

iv. Confirmed. Please see Attachment 1, line 16.

v. Please see response at Exhibit JT1.19 part iii. and part v.

vi. Not confirmed. Using a higher design day temperature (lower design day HDDw) with the same consumption data and actual weather data would mean that it would be warmer on the design day as this would decrease the design day HDDw and the design day demand as the demand would be extrapolated to a lower design degree day. Conversely, using a lower design day temperature (higher design day HDDw) would mean that it would be colder on the design day and would result in a design day demand increase as the demand would be extrapolated to a higher design degree day. Specifically, the London weather station used for analysis of all Union South rate zone customers has an equivalent design day temperature of –25.8 C (40.8 HDDw). Both suggestions of using –40 C (55 HDDw) and –35 C (50 HDDw) will result in an increase in design day demand compared to the –25.8 C (40.8 HDDw) as the same consumption and actual weather data is being extrapolated to a colder design day temperature (55 HDDw or 50 HDDw) than the current design day temperature (40.8 HDDw) at London.

vii. The design day demand used in the 2024 Cost Allocation Study was determined using the methodology agreed to and approved in the Phase 1 Settlement Agreement.[1] The design day demand, used for Cost Allocation and Gas Supply planning, for every customer in the Union South rate zone uses the London weather station. Enbridge Gas does not have sufficient historical hourly temperature data to calculate an accurate design day HDDw for the Waterloo weather station.[2]

The weather station data as it relates to establishing design day demand for cost allocation purposes is within scope of the current Phase 3 Application, as agreed to by parties in the Phase 1 Settlement Agreement.[3]

Independent of the outcomes in this proceeding, Enbridge Gas will seek approval for a cost allocation study based on updated cost allocation factors for the 2029 Test Year in the Company's next rebasing application.

[1] EB-2022-0200, Settlement Agreement, August 17, 2023.
[2] The temperature data at the Waterloo weather station on the design day in January 1993 was read between 06:00 to 14:00 only.
[3] EB-2022-0200, Settlement Agreement, p. 46 of 62.

Percent of Delivery Costs Allocated to Rate E64 (Rate T3) using Design Day Demands of the Total Allocated Delivery Revenue

Line No.	Particulars ($000s)	One Rate Zone Proposed (1)	One Rate Zone - No Regional Adjustments (2)	One Rate Zone - As Filed in Phase 1 (3)	Two Rate Zones - One Rate Zone Distribution (4)	Two Rate Zones (5)	Four Rate Zones - One Rate Zone Distribution (6)	Current Rate Zones (7)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Gas Supply							
1	Load Balancing - Transportation (LOAD_BALANCING)	-	(84)	-	-	-	-	-
2	Load Balancing - Commodity (NETFROMSTOR)	-	-	-	-	-	-	-
	Storage Demand							
3	Deliverability (NETFROMSTOR)	1,019	1,019	1,019	1,019	1,019	1,019	1,019
4	Operational Contingency (OP_CONTINGENCY)	22	21	19	22	22	22	31
	Transmission Demand							
5	Dawn Station (DAWN_DEMAND)	149	104	87	134	134	149	149
6	Kirkwall Station (KIRKWALL_DEMAND)	15	5	9	5	5	15	15
7	Parkway Station (PKWY_DEMAND)	-	283	-	306	306	-	-
8	Dawn Parkway (D-PTRANS)	2,397	2,065	1,397	2,631	2,631	2,397	2,397
9	Albion (ALBIONTRANS)	-	155	-	-	-	-	-
10	Panhandle/St. Clair (PAN_STCLAIR)	-	657	1,603	-	-	-	-
	Distribution Demand							
11	High Pressure > 4" - HIGHPRESS>4	3,476	3,476	3,476	3,476	3,375	3,476	3,201
12	High Pressure <= 4" - HIGHPRESS<=4	-	-	-	-	-	-	-
13	Low Pressure - LOWPRESS	-	-	-	-	-	-	-
14	Total Rate E64 Costs Allocated using Design Day Demands	7,077	7,702	7,609	7,594	7,493	7,077	6,812
15	Total Rate E64 Delivery Revenue	8,083	8,635	8,615	8,597	8,490	8,167	7,668
16	Percent of Delivery Revenue (line 14 / line 15)	87.6%	89.2%	88.3%	88.3%	88.3%	86.7%	88.8%

Notes:
(1) Phase 3 Exhibit 7, Tab 3, Schedule 1, Attachment 9, p.2, column (u).
(2) Phase 3 Exhibit 7, Tab 3, Schedule 2, Attachment 9, p.2, column (u).
(3) Phase 3 Exhibit 7, Tab 3, Schedule 3, Attachment 9, p.2, column (u).
(4) Phase 3 Exhibit 7, Tab 3, Schedule 4, Attachment 9, p.5, column (s) and p.8, column (t), adjusted for correction per Exhibit I.7.3-CCC-7, parts e) and f).
(5) Phase 3 Exhibit 7, Tab 3, Schedule 5, Attachment 9, p.5, column (s), adjusted for correction per Exhibit I.7.3-CCC-7, parts e) and f).
(6) Phase 3 Exhibit 7, Tab 3, Schedule 6, Attachment 9, p.9, column (s) and p.12, column (t).
(7) Phase 3 Exhibit 7, Tab 3, Schedule 7, Attachment 9, p.6, column (s).

ENBRIDGE GAS INC.

Answer to Undertaking from
City of Kitchener (Kitchener)

Undertaking:

Tr: 8

To provide a written response to Exhibit KT1.3, Question 8.

Reference:

Exhibit I.7.1-CCC-7

Response mentions Enbridge Gas has identified the error in the derivation of certain cost allocation factors for transmission and storage demand.

i. Please confirm if T3 rate class also got impacted by the error.
ii. If yes, please provide the impact.

Response:

i. Confirmed.

ii. The correction of the error described in response at Exhibit I.7.3-CCC-7 results in a decrease of $5.065 million to the revenue requirement for Rate E64, as shown in Exhibit I.7.3-CCC-7, Attachment 1, page 2, line 16. This change represents a decrease of approximately 10% of the total bill for Rate E64.[1] Enbridge Gas notes that the correction only applies to the Two Rate Zone – One Distribution rate zone alternative provided at Phase 3 Exhibit 7, Tab 3, Schedule 4.

[1] Total bill for Rate E64 decreases from $52.9 million to $47.8 million for the Two Rate Zone – One Distribution rate zone alternative, as per Phase 3 Exhibit 8, Tab 2, Schedule 12, Attachment 10, p.12, line 134.

ENBRIDGE GAS INC.

Answer to Undertaking from
City of Kitchener (Kitchener)

Undertaking:

Tr: 8

To provide a written response to Exhibit KT1.3, Question 9.

Reference:

Exhibit I.7.3-Kitchener-11 (b-c) and Exhibit I.8.2-STAFF-27

Response mentions that the majority of distribution costs are fixed in nature and capacity costs are driven by the design day demand that a customer imposes on the system. Based on best effort by Enbridge, showed lower design day demand for Kitchener.

i. Please confirm if the actual capacity cost of T3 rate using lower design day demand that T3 rate imposes on the system would be lower, compared to capacity cost of T3 rate using higher design day demand that T3 rate imposes on the system

Response:

Confirmed.

ENBRIDGE GAS INC.

Answer to Undertaking from
City of Kitchener (Kitchener)

Undertaking:

Tr: 8

To provide a written response to Exhibit KT1.3, Question 10.

Reference:

Exhibit I.7.1-SEC-11, Atachment 3, Page 2 of 2, Line 18

Response mentions Enbridge Gas rate E64 (T3), will get cost allocated towards transmission compressor fuel allocation factor from Dawn, Daw-Parkway, and Panhandle.

i. Please explain the rational of allocating Panhandle cost towards rate E64/T3.

Response:

Enbridge Gas has proposed a harmonized 2024 Cost Allocation Study using an integrated approach that reflects the harmonization of cost allocation methodologies. The Cost Allocation Study provides an indication of cost responsibility by rate class at a specific point in time and should not be viewed as a precise measurement of the actual cost to serve a particular rate class or a particular customer.

The proposed cost allocation methodology allocates transmission compressor fuel costs to in-franchise rate classes in proportion to delivery volumes excluding unbundled volumes. The delivery volumes for the Union South rate zone are not split by each specific transmission system and as such, Rate E64 (Rate T3) is allocated a portion of the transmission compressor fuel costs for the Union South rate zone on a combined basis.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ginoogaming First Nation (GFN)

Undertaking:

Tr:8

To provide a written response to Exhibit KT1.4.

EGI undertakes to provide the following information in a manner consistent with its answers to Exhibit I.1.2-TFG/M-1, answers C-F:

1. A complete list of the First Nations communities currently served in the Union North West rate zone;

2. For each community listed in EGI’s answer to #1, the estimated residential bill impact (in dollars and percentage), both before and after the application of Rider R;

3. In the event the information in answer to #2 is not currently available, details explaining whether EGI will compile and publish such data in advance of the proposed rate harmonization implementation;

4. The expected rate implications for customers within Ginoogaming First Nation, should EGI’s proposals be accepted, as well as the available calculations and assumptions behind those numbers.

Response:

1. The First Nations communities currently served in the Union North West rate zone are:
   - Fort William First Nation;
   - Ginoogaming First Nation;
   - Couchiching First Nation;
   - Rainy River First Nation; and
   - Long Lake 58 First Nation.

2-4. Please see Table 1.

Table 1

Typical Residential Bill Impacts for the Union North West Rate Zone

			Excluding Mitigation (Rider R)		Including Mitigation (Rider R) (1)	
Line No.	Rate Class	Annual Consumption (m^3)	Total Bill Impact ($)	Total Bill Impact (%)	Total Bill Impact ($)	Total Bill Impact (%)
			(a)	(b)	(c)	(d)
1	Rate 01 - North West	2,200	($45.11)	(5.0%)	($35.79)	(3.9%)

Note:

(1) Includes first year of implementation.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Home Builders' Association (OHBA)

Undertaking:

Tr: 8

To provide a written response to Exhibit KT1.3, Question 1

Exhibit I.1.3-OHBA-2 – Customer education

EGI notes that it does not have a process or the ability to govern third-party website content and marketing materials.

a) Please confirm that will EGI undertake education efforts to ensure third parties (customers, HVAC contractors, builders, etc.) are as up-to-date as possible on the proposed changes.

Response:

a) Enbridge Gas notes that this Undertaking is in response to KT1.5, Question 1.

   Enbridge Gas confirms that it strives to communicate effectively and keep relevant stakeholders (customers, HVAC contractors and builders etc.) as informed as possible of proposed changes. In line with its approach, should Enbridge Gas update its marketing materials to include cost comparisons, these updated materials will be provided to relevant stakeholders as needed.

   Please see response at JT1.31 regarding the efforts that Enbridge Gas has made to inform its employees and field representatives that interact with customers, HVAC contractors, builders, etc. about the discontinuation of energy comparison information in compliance with the Phase 2 Settlement Agreement[1].

[1] EB-2024-0111, Settlement Agreement, November 29, 2024.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Home Builders' Association (OHBA)

Undertaking:

Tr: 9

To provide a written response to Exhibit KT1.3, Question 2.

Exhibit I.1.16-OHBA-3 – Specific customer engagement on rate harmonization
EGI notes that the proposed rate harmonization enables consistent rates across the franchise, thereby enabling builders and HVAC contractors to recommend energy solutions without regional rate differences.

a) Please provide any supporting documents or analysis on regional rate differences or any further commentary that EGI proposed to use to explain how builders and HVAC contractors will be able to recommend energy solutions without regional rate differences, including the significance of same for EGI's existing customers and prospective customers in new residential developments.

Response:

Enbridge Gas notes that this Undertaking is in response to KT1.5, Question 2.

a) Enbridge Gas expects to file a more detailed implementation plan, including a description of the customer communication plan, in its 2027 Rates Application. The communication plan will address the changes that will result from the implementation of the Rate Harmonization Plan, including the approved rate zone alternative, which may result in different regional rates depending on the location of a customer within the franchise area. Please see Phase 3 Exhibit 7, Tab 0, Schedule 1, page 15, Table 3 for an overview of the rate zone alternatives included in the Application.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Home Builders' Association (OHBA)

Undertaking:

Tr: 9

To provide a written response to Exhibit KT1.3, Question 3.

Exhibit I.8.2-OHBA-9 – RHIP

a) Will the comprehensive customer communication plan specifically address needs and concerns of new residential customers?

b) Will EGI’s bill comparisons specifically address new residential customer bills?

Response:

Enbridge Gas notes that this Undertaking is in response to KT1.5, Question 3.

a) Enbridge Gas has not developed the customer communication plan at this time and is not able to comment on the specifics that will be addressed. The communication plan will explain the proposed changes that result from the implementation of the Rate Harmonization Plan for all impacted customers.

b) Please see response at part a). Enbridge Gas provides bill comparisons for typical sales service and direct purchase customers similar to those provided at Phase 3 Exhibit 8, Tab 2, Schedule 9, Attachment 10 as part of its annual rate application filings.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Home Builders' Association (OHBA)

Undertaking:

Tr: 9

To provide a written response to Exhibit KT1.3, Question 4.

Exhibit I.8.2-OHBA-10 – RHIP

a) It appears that the reference to "Exhibit I.8.2-ED-10" provided in response c) is incorrect. Please provide the correct reference.

Response:

a) Enbridge Gas notes that this Undertaking is in response to KT1.5, Question 4.

   The correct reference is Exhibit I.7-ED-10, part a).

ENBRIDGE GAS INC.

Answer to Undertaking from
Pollution Probe (PP)

Undertaking:

Tr: 19

To review and provide any communication responsive to the question in terms of informing company representatives of the commitment to no longer use cost-comparison information within marketing materials.

Response:

Please see Attachment 1 for the communication issued by the Demand Forecasting and Analysis team, which previously created and distributed the cost comparison information, as well as from the Marketing team, which used this information to develop marketing materials.

This communication was directed at all Enbridge Gas representatives who had previously received the cost comparison information, including those that leveraged it to develop marketing or reference materials, and Enbridge Gas field representatives. The purpose of the communication was to inform them of the commitment made in the Phase 2 Settlement Agreement[1] to no longer use the cost comparison information within marketing and reference materials.

In addition to these written communications, the information was also disseminated and reinforced verbally during various team meetings, that included stakeholder groups that previously used or distributed materials containing cost comparison information.

[1] EB-2024-0111, Settlement Agreement, November 29, 2024.

From:	Residential Energy Comparison
To:	Alison Salehi; Amy Mikhaila; Anton Kacicnik; Ben McIntyre; Bradley Lattanzi; Catherine Ho; Colin Healey; Craig Fernandes; Customer Care Process Team; Darren McIlwraith; Dean Dalpe; Deanna Marley; Desiree Swance; Don Armitage; Elena Chang; Faheem Ahmad; George Hantzis; Gilmer Bashualdo-Hilario; Gina Mancini; Heidi Steinberg Laxton; Hulya Sayyan; Islam Elsayed; Jason Rolfe; Jenna Vanderveen; Jennifer Broeders; Jennifer Murphy; Jessica Maga; Joanne Van Panhuis; Joel Denomy; Kain Allicock; Keith Boulton; Kristin McPhee; Margaret Nuttall; Margarita Suarez; Mark Kitchen; Michelle Vestergaard; Mike Wright; Patricia Squires; Patrick McMahon; Rachel Goodreau; Rob Kennedy; Sam Fallis; Sandee Qian; Sarah Robinson; Scott Bullock; Scott Hines; Shu Wa Chu; Sophear Net; Stuart Murray; Sunny Swatch; Suzanne Shea; Tanya Bruckmueller; Tanya Ferguson; Trevor Esdaile; Yash Patel; Yukiko Nishi; Haris Ginis; Leanne McNaughton; Mark Prociw; Nicole Brunner; Ed Reimer; Susan Cudahy
Cc:	Laura Sheehan; Guri Pannu; Gilmer Bashualdo-Hilario; Vanessa Innis; Priyanka Gupta; Meetpal Chhina
Subject:	IMPORTANT NOTICE: Compliance of Phase 2 Settlement Agreement - Discontinuation of Energy Comparison Information
Date:	Tuesday, December 3, 2024 12:02:17 PM
Attachments:	image001.png
Importance:	High

Good afternoon,

It is imperative that all recipients of the energy comparison information read the following to ensure compliance with the Phase 2 Settlement Agreement.

We are writing to inform you that, in accordance with the Phase 2 settlement agreement, the energy comparison information you received via this email distribution is **no longer permitted to be used in written marketing and reference materials (including emails and presentations etc.) aimed at customers, potential customers, HVAC contractors or builders**. As representatives of the Company, **it is imperative that we comply with the orders of the Settlement Agreement**. If we are not in compliance, we can expect intervenors to notify the OEB about the company's non-compliance.

Please feel free to cascade this email to anyone in your group or team that needs to be aware as it is very critical that everyone within the company comply.

If you have any questions or concerns regarding the implications of this agreement and how it impacts your team's practices, processes, or materials, please reach out to the Regulatory Lead (Laura Sheehan), and/or Legal (Guri Pannu) as well as your Supervisor/Manager.

The energy comparison aspect of the settlement agreement is effective December 19, 2024 (45 days after the filing of the Settlement Agreement on Nov. 4, 2024)

Under the settlement agreement, Enbridge Gas has agreed to the following:

Excerpt from EB-2024-0111, Partial Settlement Proposal, Exhibit N, Tab 1, Schedule 1, Page 34 of 44:

24. Has Enbridge Gas appropriately reviewed the energy comparison information in its informational and marketing materials, and taken appropriate actions based on its review?

Enbridge Gas agrees that beginning 45 days after the filing of this Settlement Proposal, Enbridge Gas shall not include statements, including cost comparison charts, related to the relative cost-effectiveness of natural gas heating or to savings that can be achieved with natural gas heating in written marketing materials, or reference materials aimed at customers, potential customers, HVAC contractors, or builders, that the Company distributes unless it includes a comparison with the relative cost-effectiveness of heating with electric cold climate heat pumps. This includes all such material disseminated in Ontario by Enbridge Gas, or by Enbridge affiliates on behalf of Enbridge Gas, to customers, potential customers, HVAC contractors, and builders.

Enbridge Gas agrees that updated materials shall be filed in Phase 3 of the 2024 rates proceeding, or in a subsequent proceeding if not complete at that time.

Thanks,

The Demand Forecasting & Analysis team

From:	Residential Energy Comparison
To:	Amanda Thoms; Amry Al-Amry; Andrew Smith; Ben McIntyre; Brooke Cranston; Cara-Lynne Wade; Don Armitage; Ed Reimer; Elena Chang; Eric VanRuymbeke; Faheem Ahmad; Gilmer Bashualdo-Hilario; Greg Homewood; Haris Ginis; Hulya Sayyan; Ian Macpherson; Jason Rolfe; Jeff Mantej; Jenna Vanderveen; Joanne Van Panhuis; Joel Denomy; John Eve; Liane Seguin; Liz Disepolo; Margaret Nuttall; Mike Wright; Miranda Pilon; Randy Whitten; Sam Fallis; Sarah Robinson; Sean Kramer; Susan Cudahy; Yash Patel; Yukiko Nishi; Jennifer Murphy; Mark Prociw; Nicole Brunner; Ed Reimer; Susan Cudahy
Cc:	Laura Sheehan; Guri Pannu; Gilmer Bashualdo-Hilario; Vanessa Innis; Priyanka Gupta; Meetpal Chhina
Subject:	IMPORTANT NOTICE: Compliance of Phase 2 Settlement Agreement - Discontinuation of Energy Comparison Information
Date:	Tuesday, December 3, 2024 12:03:19 PM
Attachments:	image001.png
Importance:	High

Good afternoon,

It is imperative that all recipients of the energy comparison information read the following to ensure compliance with the Phase 2 Settlement Agreement.

We are writing to inform you that, in accordance with the Phase 2 settlement agreement, the energy comparison information you received via this email distribution (Community Expansion) is **no longer permitted to be used in written marketing and reference materials (including emails and presentations etc.) aimed at customers, potential customers, HVAC contractors or builders**. **Please note though, this email distribution was specific to Community Expansion comparisons, but the Settlement Agreement is applicable to any and all versions of the energy comparison (main comparisons without SES or Community Expansion comparisons with SES).**

As representatives of the Company, **it is imperative that we comply with the orders of the Settlement Agreement**. If we are not in compliance, we can expect intervenors to notify the OEB about the company's non-compliance.

Please feel free to cascade this email to anyone in your group or team that needs to be aware as it is very critical that everyone within the company comply.

If you have any questions or concerns regarding the implications of this agreement and how it impacts your team's practices, processes, or materials, please reach out to the Regulatory Lead (Laura Sheehan), and/or Legal (Guri Pannu) as well as your Supervisor/Manager.

The energy comparison aspect of the settlement agreement is effective December 19, 2024 (45 days after the filing of the Settlement Agreement on Nov. 4, 2024)

Under the settlement agreement, Enbridge Gas has agreed to the following:

Excerpt from EB-2024-0111, Partial Settlement Proposal, Exhibit N, Tab 1, Schedule 1, Page 34 of 44:

24. Has Enbridge Gas appropriately reviewed the energy comparison information in its informational and marketing materials, and taken appropriate actions based on its review?

Enbridge Gas agrees that beginning 45 days after the filing of this Settlement Proposal, Enbridge Gas shall not include statements, including cost comparison charts, related to the relative cost-effectiveness of natural gas heating or to savings that can be achieved with natural gas heating in written marketing materials, or reference materials aimed at customers, potential customers, HVAC contractors, or builders, that the Company distributes unless it includes a comparison with the relative cost-effectiveness of heating with electric cold climate heat pumps. This includes all such material disseminated in Ontario by Enbridge Gas, or by Enbridge affiliates on behalf of Enbridge Gas, to customers, potential customers, HVAC contractors, and builders.

Enbridge Gas agrees that updated materials shall be filed in Phase 3 of the 2024 rates proceeding, or in a subsequent proceeding if not complete at that time.

Thanks,
Demand Forecasting and Analysis

From: Priyanka Gupta
Sent: Monday, December 2, 2024 4:30 PM
To: ONT ETP&EC MT; Ed Reimer; Mark Prociw; Public Affairs-Direct Reports; Laura Sheehan; Guri Pannu
Cc: Henry Ren; Cara-Lynne Wade; Nicole Brunner; Keith Boulton; Ian Macpherson; Sutha Ariyalingam; Chantal Brundage
Subject: Important Notice - Settlement Agreement re: not using Energy comparison in written marketing and reference materials

Hello Everyone,

Most of you have probably been looped into this already, but just wanted to make sure that if you haven't, that you are aware.

Effective December 19th and in accordance with the Phase 2 settlement agreement, energy comparison information or statements related to relative cost-effectiveness of natural gas heating or savings that can be achieved with natural gas, should no longer be used in written marketing and reference materials (including emails and presentations etc.) aimed at customers, potential customers, HVAC contractors or builders. Under the settlement agreement, Enbridge Gas has agreed to the following:

Excerpt from EB-2024-0111, Exhibit N, Tab 1, Schedule 1, Page 34 of 44:

24. Has Enbridge Gas appropriately reviewed the energy comparison information in its informational and marketing materials, and taken appropriate actions based on its review?

Enbridge Gas agrees that beginning 45 days after the filing of this Settlement Proposal, Enbridge Gas shall not include statements, including cost comparison charts, related to the relative cost-effectiveness of natural gas heating or to savings that can be achieved with natural gas heating in written marketing materials, or reference materials aimed at customers, potential customers, HVAC contractors, or builders, that the Company distributes unless it includes a comparison with the relative cost-effectiveness of heating with electric cold climate heat pumps. This includes all such material disseminated in Ontario by Enbridge Gas, or by Enbridge affiliates on behalf of Enbridge Gas, to customers, potential customers, HVAC contractors, and builders.

Enbridge Gas agrees that updated materials shall be filed in Phase 3 of the 2024 rates proceeding, or in a subsequent proceeding if not complete at that time.

As representatives of the Company, it is imperative that we comply with the orders of the Settlement Agreement. From a marketing perspective, we are already reviewing all marketing materials in accordance with the settlement agreement.

If you have any questions or concerns regarding the implications of this agreement and how it affects your processes or materials, please reach out to the Regulatory Lead (Laura Sheehan), and/or Legal (Guri Pannu/Henry Ren).

Please cascade to your teams and others, as you see appropriate.

Thanks, Priyanka

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking:

Tr: 46

To consider the request in SEC-6 and either provide the information requested or provide an explanation as to why it declines to do so.

Response:

The directive received from the OEB in the Phase 1 Interim Rate Order Decision[1] required Enbridge Gas to file a report on the steps it has taken to achieve the 2024 capital reduction. Forecasted capital expenditure spend is not relevant to that direction, the Phase 3 Issues List or the Approvals sought in this Application.

With all of that being said, and without stipulating to the relevance of the foregoing, Enbridge Gas has sought to be responsive by summarizing, in Table 1, the pertinent data from Tables 6.1-4, 6.2-6, 6.2-15, 6.2-24, 6.3-8, 6.3-9, 6.3-10, 6.4-6, 6.5-5 and 6.6-7 from the 2025 to 2034 Asset Management Plan[2] filed November 8, 2024.

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[1] EB-2022-0200, Decision on Interim Rate Order, April 11, 2024.
[2] EB-2020-0091.

Table 1
Utility Capital Expenditures by Asset Class: 2025-2034 AMP

Line No.	Asset Class	Category	2025	2026	2027	2028
1	Compression Stations	Storage	49	70	95	128
2	Customer Connections	Growth	286	256	230	208
3	Distribution Pipe	Dist Ops	332	348	264	234
4	Distribution Stations	Dist Ops	74	71	71	86
5	Fleet & Equipment	General	38	34	37	35
6	Growth - Distribution System Reinforcement	Growth	36	128	139	18
7	Real Estate & Workplace Services	General	32	19	38	13
8	Technology Information Services	General	74	94	72	54
9	Transmission Pipe and Underground Storage	Storage	114	69	99	254
10	Utilization	Dist Ops	166	162	160	159
11	EA Fixed O/H	Other	40	41	42	43
12	Total		1240	1292	1246	1232

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking:

Tr: 65

To provide end-of-month inventory targets for system gas for 2024.

Response:

Enbridge Gas would like to correct the response provided by Ms. Mikhaila on Day 1 of the Technical Conference[1] regarding the availability of inventory balance information used by the Company for purposes of monitoring storage targets for sales service customers.

Enbridge Gas is not able to provide storage targets for sales service customers as the Company has not produced inventory balances separated by bundled direct purchase (DP) and sales service customers as part of the consolidated 2024 Gas Supply Plan prepared for the Rebasing Application.

Enbridge Gas manages planned load balancing requirements for sales service and bundled DP customers. Accordingly, Enbridge Gas monitors the combined inventory balance against storage targets for both sales service and bundled DP customers. When making gas purchase decisions on behalf of sales service customers to meet storage targets, Enbridge Gas considers any projected Union South DP customer Banked Gas Account (BGA) balance variance recognizing Union South DP customers are responsible for taking action on behalf of a BGA balance shortfall by the end of February.

Table 1 provides a summary of monthly planned inventory balances and specific month storage targets for both sales service and bundled DP customers from the consolidated 2024 Gas Supply Plan prepared for the Rebasing Application.

[1] TC Tr. Vol. July 16, pp. 64-65.

Table 1
2024 Rebasing Consolidated Gas Supply Plan

Line No.	Particulars (TJ)	Month-End Planned Inventory Balance[2]	Month-End Storage Targets
		(a)	(b)
1	October[3]	197,945	197,945
2	November	182,514	-
3	December	159,379	-
4	January	111,498	-
5	February	72,461	66,107[4]
6	March	25,458	10,800[4]
7	April	12,442	-
8	May	32,312	-
9	June	73,151	-
10	July	110,680	-
11	August	140,318	-
12	September	176,920	-

[2] Table 1 reflects total cost-based and market-based end of month planned inventory balance.
[3] The October inventory balance and storage target represent maximum storage capacity of 217.7 PJ, less 15.0 PJ of storage capacity allocated to semi-unbundled customers and 4.8 PJ of storage capacity reserved for operational contingency purposes.
[4] The February and March storage targets represent minimum inventory balance levels.

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking:

Tr: 70

To provide a calculation of the WARP inclusive of TransCanada costs for system supply customers.

Response:

Please see Attachment 1 for the calculation of the weighted average reference price (WARP) inclusive of third-party transportation costs related to sales service customers.

For purposes of this response, Enbridge Gas split third-party transportation demand and fuel costs that are incurred on behalf of sales service and bundled direct purchase proportionally based on the 2024 Test Year Forecast volumes for sales service and bundled direct purchase.

This approach adds additional complexity and is less transparent than the proposed WARP, as cost allocation is required to split transportation costs and related fuel between transportation and load balancing. This would also require additional changes to rate design such as separate gas supply transportation charges between sales service and bundled direct purchase to recover the bundled direct purchase transportation component not included in WARP, resulting in customers delivering to Dawn, Parkway/Enbridge CDA paying a different transportation charge than sales service customers.

In addition, the calculation of cost of gas for UFG, own use, compressor fuel and gas in storage using the proposed harmonized WARP was approved on an interim basis as part of the Phase 1 Interim Rate Order[1]. The inclusion of third-party transportation costs into the determination of the WARP would increase the costs for these common cost components and hence increase the revenue requirement for 2024 that was determined in Phase 1.

[1] EB-2022-0200, Decision on Interim Rate Order, April 11, 2024.

Please see response at Exhibit I.4.2-FRPO-23, part a), sub-parts i-ii. for further discussion on some of the complexities that would exist under such an approach similar to an Ontario landed reference price.

Adjusted EGI Weighted Reference Price include Sales Service Share of Third-Party Transportation Costs

Line No.	Particulars	Volumes (10^3m^3)	Gas Costs ($000s)	Average Costs ($\$/10^3m^3$)	Average Costs $/GJ (1)
		(a)	(b)	(c) = (b / a)	(d)
1	EGI Weighted Reference Price (2)	13,491,062	1,924,012	142.614	3.649
2	Transportation Demand & Fuel Costs - System Gas Porportional Share (3)	13,491,062	109,995	8.153	0.209
3	Adjusted Weighted Reference Price for Sales Service portion of Transportation Demand & Fuel (line 1 + line 2)		2,034,007	150.767	3.858

Notes:

(1) Conversions based on heat value of 39.08 $GJ/10^3m^3$.

(2) Phase 3 Exhibit 4, Tab 2, Schedule 2, Attachment 3, line 19.

(3) Gas Costs per Phase 3 Exhibit 7, Tab 3, Schedule 1, Attachment 10, p. 1, column (a), line 4 + portion of line 5, based on transportation commodity split based on contract annual demand capacity split between Transportation Demand and Load Balancing - Transportation. Total cost allocated between sales service and bundled direct purchase using 2024 test year volumes, of which sales service is approximately 68%. Load Balancing Transportation and fuel are excluded from this calculation.

ENBRIDGE GAS INC.

Answer to Undertaking from Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking:

Tr: 75

To provide a fuller response to FRPO-22.

Response:

Exhibit I.4.2-FRPO-22 asks Enbridge Gas to provide a description of the current methodology used to calculate the load balancing costs for customers in Union North. The following is an expanded answer from what was previously filed.

Enbridge Gas does not classify costs as load balancing in the current approved methodology for Union rate zones as noted in response at Exhibit I.4.2-FRPO-22. The equivalent costs for load balancing in the Union North rate zones are considered storage costs, including storage and the transportation necessary to move gas to and from storage. Please see Attachment 1 for details of the components that underpin Union North storage rates.

Rate 01 and Rate 10 rates recover storage costs through the gas supply storage charges. Rate 20 gas supply demand and commodity transportation charges recover both transportation and storage costs. Enbridge Gas has split the detail of the Rate 20 calculations where possible and included the unit rates associated with transportation components to enable a reconciliation to the approved July 2024 QRAM rates for Rate 20. No detail has been provided for Rate 25 as this is an interruptible rate class that is not allocated any storage costs. There are no customers in the current approved rate design or 2024 Test Year Forecast that take Rate 100 bundled service, therefore the current rates are based on notional costs.

A summary of the information provided in Attachment 1 is provided below:

- Page 1 provides the storage cost components for third-party costs at July 2024 QRAM and utility owned assets based on 2013 cost of service. Details of the third-party costs in rates by contract are provided at page 3.

- Page 2 provides the allocation of those costs between Union North West and Union North East by rate class.

- Pages 4 and 5 provide the derivation of unit rates related to storage including additional adjustments for 2014 to 2023 IRM, the Rebasing Phase 1 deficiency, and July 2024 QRAM.

Union North Storage Cost Allocation
Based on OEB-Approved Methodology and the 2018 Gas Supply Plan at July 2024 QRAM

Line No.	Cost Allocation ($000s)	Total	Rate 01	Rate 10	Rate 20	Rate 100	Rate 25
		(a)	(b)	(c)	(d)	(e)	(f)
	Storage - April 2024 QRAM						
1	Cost of Gas - Storage Demand (1)	29,913	22,150	6,081	1,533	149	-
2	Cost of Gas - Storage Fuel (2)	554	360	127	64	2	-
3	Total Cost of Gas Storage Costs	30,466	22,510	6,208	1,598	151	-
4	July 2024 QRAM Adjustment (3)	71	46	16	8	0	-
5	Total Cost of Gas Storage Costs - July 2024 QRAM	30,537	22,556	6,224	1,606	151	-
	Union North Storage Costs (4)						
6	Storage Deliverability	4,190	3,135	821	219	15	-
7	Storage Space	5,644	4,222	1,105	295	21	-
8	Dawn-Parkway Demand	5,885	4,254	1,217	381	34	-
9	Reclassification to Delivery	(2,461)	(1,836)	(485)	(132)	(9)	-
10	Storage Commodity	1,925	1,346	424	151	5	-
11	Dawn-Parkway Commodity	281	187	67	28	(0)	-
12	Total Union North Storage Costs	15,465	11,308	3,149	942	66	-
13	Total Storage Costs (line 5 + line 12) (5)	46,002	33,864	9,373	2,548	217	-

Notes:
(1) Page 3, column (c), line 9. Rate class level detail provided at EB-2024-0093, Exhibit E, Tab 2, Schedule 2, p.3.
(2) Page 3, column (c), line 20. Rate class level detail provided at EB-2024-0093, Exhibit E, Tab 2, Schedule 2, p.3.
(3) Page 3, column (f), line 21.
(4) EB-2015-0181, Exhibit A, Tab 2, Appendix A, Schedule 2, lines 9 through 15 based on 2013 Cost of Service. Dawn-Parkway Demand and Dawn-Parkway Commodity updated to remove $2.4 million reclassifed to transportation for Union North East as shown at EB-2015-0181, Exhibit A, Tab 2, Appendix A, Schedule 5, p.2, lines 8 - 10.
(5) Excludes 2014-2023 IRM and Rebasing Phase 1 Deficiency Adjustments.

Union North Storage Cost Allocation to the Union North West Zone and Union North East Zone by Rate Class
Based on the 2018 Gas Supply Plan at July 2024 QRAM

Line No.	Particulars	Storage Costs ($000s) Storage Demand (1)	Storage Commodity (2)	Total April 2024 QRAM	July 2024 QRAM Adjustment (3)	Total Storage (4)
		(a)	(b)	(c) = (a + b)	(d)	(e) = (c + d)
	Union North West					
1	Rate 01	2,861	405	3,266	18	3,284
2	Rate 10	649	123	772	5	777
3	Rate 20	206	73	279	3	283
4	Rate 100	-	-	-	-	-
5	Rate 25	-	-	-	-	-
6	Total Union North West	3,716	601	4,318	26	4,344
	Union North East					
7	Rate 01	29,184	1,368	30,552	28	30,580
8	Rate 10	8,052	533	8,585	11	8,596
9	Rate 20	2,018	242	2,260	5	2,265
10	Rate 100	202	15	217	0	217
11	Rate 25	-	-	-	-	-
12	Total Union North East	39,455	2,158	41,614	45	41,658
	Total					
13	Rate 01	32,044	1,774	33,818	46	33,864
14	Rate 10	8,701	655	9,357	16	9,373
15	Rate 20	2,224	316	2,540	8	2,548
16	Rate 100	202	15	217	0	217
17	Rate 25	-	-	-	-	-
18	Total (4)	43,172	2,760	45,931	71	46,002

Notes:
(1) Storage demand costs allocated in proportion to the excess of peak day demands over average day demands, as provided at EB-2015-0181, Exhibit A, Tab 2, Appendix A, Schedule 6, p.2, column (e).
(2) Storage commodity costs allocated in proportion to annual volumes, as provided at EB-2015-0181 Exhibit A, Tab 2, Appendix A, Schedule 6, p.2, column (f).
(3) EB-2024-0166, Exhibit E, Tab 2, Schedule 2, p.3, line 14 & line 29.
(4) Total storage costs per p.1, column (a), line 13.

EB-2024-0166 July 2024 QRAM
Union Rate Zones
Union North Storage Costs 2018 Gas Supply Plan as filed at EB-2015-0181 at July 2024 QRAM

Line No.	Particulars	Annual Volume (1) (TJ)	EB-2022-0200 Effective May 1, 2024 Rates (2) ($/GJ)	EB-2022-0200 Effective May 1, 2024 Costs (2) ($000s)	EB-2024-0166 Effective July 1, 2024 Rates (3) ($/GJ)	EB-2024-0166 Effective July 1, 2024 Costs (3) ($000s)	Cost Variance
		(a)	(b)	(c)	(d)	(e)	(f) = (e - c)
	Storage Costs						
	Union North West Zone Demand Costs						
1	TCPL WDA STS Injection	1,150	21.159	800	21.159	800	-
2	Subtotal			800		800	-
	Union North East Zone Demand Costs						
3	TCPL NDA STS Injection	17,921	12.737	7,505	12.737	7,505	-
4	TCPL EDA STS Withdrawal	9,845	8.883	2,875	8.883	2,875	-
5	TCPL Pkwy to EDA	19,042	8.883	5,561	8.883	5,561	-
6	TCPL Pkwy to EDA EMB	9,125	9.785	2,935	9.785	2,935	-
7	TCPL Pkwy to NDA	24,455	12.733	10,237	12.733	10,237	-
8	Subtotal			29,113		29,113	-
9	Demand Costs in Rates			29,913		29,913	-
	Union North West Zone Fuel Costs						
10	TCPL WDA STS Injection	15	2.754	42	2.758	42	0
11	TCPL SSMDA STS Withdrawal	28	3.160	88	3.600	100	12
12	TCPL WDA STS Withdrawal	31	3.160	98	3.600	112	14
13	Subtotal			228		254	26
	Union North East Zone Fuel Costs						
14	TCPL NCDA STS Injection	2	2.754	5	2.758	5	0
15	TCPL NCDA STS Withdrawal	8	3.160	24	3.600	27	3
16	TCPL Pkwy to EDA	8	3.160	27	3.600	30	4
17	TCPL Pkwy to EDA EMB	16	3.160	51	3.600	58	7
18	TCPL Pkwy to NDA	69	3.160	219	3.600	249	30
19	Subtotal			325		370	45
20	Fuel Costs in Rates			554		624	71
21	Total Storage Costs			30,466		30,537	71

Notes:
(1) EB-2015-0181, Exhibit A, Tab 2, Appendix A, Schedule 1, pp.1-2, column (j).
(2) EB-2024-0093, Exhibit E, Tab 2, Schedule 2, p.2, columns (d) & (e).
(3) EB-2024-0166, Exhibit E, Tab 2, Schedule 2, p.2, columns (d) & (e).

Union North Storage Rate Design by Zone
Based on the 2018 Gas Supply Plan

Line No.	Particulars	Total	Union North West	Union North East
		(a)	(b)	(c)
	Rate 01 - Gas Supply Storage Charge			
1	Annual Volume (10^3m^3) (1)	873,545	252,395	621,150
2	Storage Costs ($000s) (2)	33,818	3,266	30,552
3	2014-2023 Cost Adjustments ($000s) (3)	8,142	2,252	5,890
4	Total Storage Costs ($000s)	41,960	5,518	36,442
5	Total Storage Rate - April 2024 QRAM (cents/m^3) (line 4 / line 1)		2.1863	5.8669
6	Rebasing Phase 1 Rate Adjustment (cents/m^3) (4)		0.0514	0.0638
7	July 2024 QRAM Rate Adjustment (cents/m^3) (5)		0.0064	0.0040
8	Total Storage Rates - July 2024 QRAM (cents/m^3) (line 5 + line 6 + line 7)		2.2441	5.9347
	Rate 10 - Gas Supply Storage Charge			
9	Annual Volume (10^3m^3) (1)	307,120	73,443	233,677
10	Storage Costs ($000s) (2)	9,357	772	8,585
11	2014-2023 Cost Adjustments ($000s) (3)	2,154	496	1,658
12	Total Storage Costs ($000s)	11,511	1,267	10,243
13	Total Storage Rate (cents/m^3) (line 12 / line 9)		1.7258	4.3835
14	Rebasing Phase 1 Rate Adjustment (cents/m^3) (4)		0.0398	0.0489
15	July 2024 QRAM Rate Adjustment (cents/m^3) (5)		0.0069	0.0042
16	Total Storage Rates - July 2024 QRAM (cents/m^3) (line 13 + line 14 + line 15)		1.7725	4.4366
	Rate 20 - Gas Supply Demand			
17	Annual Demand (10^3m^3/d) (1)	6,873	2,962	3,911
18	Gas Supply Demand Costs - Storage Costs ($000s) (2)	1,524	168	1,356
19	2014-2023 Cost Adjustments ($000s) (3)	667	199	468
20	Bundled Storage Cost Adjustment ($000s)	(1,156)	(54)	(1,101)
21	Total Gas Supply Demand Cost - Storage ($000s)	1,036	313	723
22	Gas Supply Demand Rate - Storage - April 2024 QRAM (cents/m^3/d) (line 21 / line 17)		10.5600	18.4802
23	Rebasing Phase 1 Rate Adjustment (cents/m^3) (4)		0.1582	0.1173
24	July 2024 QRAM Rate Adjustment - Storage (cents/m^3) (5)		0.1079	0.0444
25	Gas Supply Demand Rate - Storage - July 2024 QRAM (cents/m^3/d)		10.8261	18.6419
26	Gas Supply Demand Rate - Transportation (cents/m^3/d) (6)		26.6486	24.4686
27	July 2024 QRAM Rate Adjustment - Transportation (cents/m^3) (5)		0.0035	0.0360
28	Gas Supply Optimization Rate (cents/m^3) (7)		(4.1642)	(4.1642)
29	Total Gas Supply Demand Rate - July 2024 QRAM (cents/m^3/d) (line 25 + line 26 + line 27)		33.3140	38.9823

Notes:
(1) Billing units as per EB-2024-0093, Exhibit E, Tab 2, Schedule 2, p.1, column (b).
(2) P.2, column (c).
(3) IRM adjustments as per Union's Annual Rate Applications 2014 - 2023 such as PCI, Capital Pass Through, PDO.
(4) EB-2022-0200, Rate Order, Working Papers, Schedule 20, p.5, column (b).
(5) EB-2025-0166, Exhibit E, Tab 2, Schedule 2, p.1, column (c). Rate 20 unit rates split between Storage and Transportation cost change.
(6) Portion of Rate 20 Gas Supply Demand Charge related to recovery of Transportation Costs at April 2024 QRAM.
(7) EB-2014-0271, Rate Order, Working Papers, Schedule 14, p.2, Note 3.

Union North Storage Rate Design by Zone
Based on the 2018 Gas Supply Plan

Line No.	Particulars	Total		Union North West		Union North East	
		(a)		(b)		(c)	
	Rate 20 - Commodity Transportation						
1	Annual Volume (10^3m^3) (1)	73,456		28,383		45,073	
2	Commodity Transportation Costs - Storage ($000s) (2)	1,016		112		904	
3	2014-2023 Cost Adjustments ($000s) (3)	147		29		118	
4	Bundled Storage Cost Adjustment ($000s)	(770)		(36)		(734)	
5	Total Commodity Transportation Costs - Storage ($000s)	393		105		288	
6	Commodity Transportation Rate - Storage- April 2024 QRAM (cents/m^3) (line 5 / line 1)			0.3684		0.6391	
7	Rebasing Phase 1 Rate Adjustment (cents/m^3) (4)			0.0064		0.0052	
8	July 2024 QRAM Rate Adjustment - Storage Costs (cents/m^3) (5)			0.0058		0.0010	
9	Commodity Transportation Rate - Storage- July 2024 QRAM (cents/m^3)			0.3806		0.6453	
10	Commodity Transportation Rate - Transportation Costs (cents/m^3/d) (6)			1.7795		1.0096	
11	July 2024 QRAM Rate Adjustment - Transportation (cents/m^3) (5)			0.0002		0.0026	
12	Gas Supply Optimization Rate (cents/m^3) (7)			(0.2597)		(0.2597)	
13	Total Commodity Transportation Rate - July 2024 QRAM (cents/m^3) (sum of lines 9 - 12)			1.9006		1.3978	
	Bundled Storage	Rate 20				Rate 100	
		(a)				(c)	
14	Annual Demand (GJ/d) (1)	99,288				15,600	
15	Demand Costs ($000s)	1,782	(8)			280	(9)
16	Demand Rate - April 2024 QRAM ($/GJ/d)	17.948				17.948	
17	Rebasing Phase 1 Rate Adjustment (cents/m^3) (4)	0.213				0.213	
18	July 2024 QRAM Rate Adjustment - Storage Costs (cents/m^3) (5)	-				-	
19	Demand Rate - July 2024 QRAM ($/GJ/d)	18.161				18.161	
20	Annual Commodity (GJ) (1)	639,477				100,000	
21	Commodity Costs ($000s)	144	(8)			23	(9)
22	Commodity Rate ($/GJ)	0.225				0.225	
23	Rebasing Phase 1 Rate Adjustment (cents/m^3) (4)	0.006				0.006	
24	July 2024 QRAM Rate Adjustment - Storage Costs (cents/m^3) (5)	0.003				0.003	
25	Demand Rate - July 2024 QRAM ($/GJ/d)	0.234				0.234	

Notes:
(1) Billing units as per EB-2024-0093, Exhibit E, Tab 2, Schedule 2, p.1, column (b).
(2) P.2, column (c).
(3) IRM adjustments as per Union's Annual Rate Applications 2014 - 2023 such as PCI, Capital Pass Through, PDO.
(4) EB-2022-0200, Rate Order, Working Papers, Schedule 20, p.5, column (b).
(5) EB-2025-0166, Exhibit E, Tab 2, Schedule 2, p.1, column (c). Rate 20 unit rates split between Storage and Transportation cost change.
(6) Portion of Rate 20 Gas Supply Demand Charge related to recovery of Transportation Costs at April 2024 QRAM.
(7) EB-2014-0271, Rate Order, Working Papers, Schedule 14, p.2, Note 3.
(8) P.4, column (a), line 20 + p.5, column (a), line (4) split between Demand and Commodity for Bundled Storage recovery.
(9) P.2, column (c) updated for 2014 - 2023 IRM Adjustments.

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking:

Tr: 77

To provide information as to the five coldest days in 2024 for the information requested in parts 1, 2, and 3.

Response:

Please see Table 1 for information requested from Exhibit I.7.1-FRPO-61, part c) i., ii., and iii.

Table 1
5 Coldest Days of Winter 2024/2025

Date	In-franchise (GJ) UGL	In-franchise (GJ) EGD	Ex-franchise (GJ)	C1 < 1 yr (GJ)	Exchanges (GJ)	Parkway Suction (kPa)	Parkway Suction Min-Design (kPa)	Flow through Parkway (PJ) To EGI	Flow through Parkway (PJ) To TCPL	Flow through Parkway (PJ) Total
Jan 21 2025	2,076,317	2,637,110	1,664,610	487,394	113,877	3,727	3,562	1.7	2.5	4.2
Jan 20 2025	1,994,606	2,595,050	1,597,281	511,832	65,746	4,030	3,562	1.6	2.5	4.1
Dec 21 2024	1,782,093	2,340,421	1,354,555	447,250	113,566	4,175	3,562	1.4	2.5	3.9
Jan 19 2024	1,938,009	2,601,784	1,325,235	270,738	66,042	4,181	3,621	1.5	2.7	4.2
Feb 17 2025	1,868,234	2,443,221	1,340,990	443,380	153,271	4,607	3,562	1.4	2.6	4.0

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking:

Tr: 83

To take the scenario where 5,000 extra units of gas are purchased in each of January or March at a price of $10 per unit and provide what is recorded in the PGVA and in the Load Balancing Price Variance Account for that scenario.

Response:

This undertaking deals with the calculation of cost variances associated with gas supply purchases at Dawn and the treatment of the cost variances within the proposed Purchase Gas Variance Account (PGVA) and Load Balancing Price Variance Account (LBPVA).

The proposed treatment of purchases at Dawn recognizes that bundled direct purchase (DP) customers will be required to balance at two checkpoints, in the winter and fall of each year, consistent with the current balancing requirements for bundled DP customers in the Union South rate zone. The checkpoints ensure that bundled DP customers manage their actual load balancing requirements resulting from changes in actual consumption as of the checkpoint dates. As a result, these customers have greater flexibility and control to determine their own incremental load balancing costs rather than receiving an allocation of the Company's cost to manage actual load balancing variances relative to the forecast costs included in rates.

To ensure that the actual incremental load balancing variances are appropriately recovered from sales service customers only, Enbridge Gas has proposed that volume variances associated with the actual incremental load balancing purchases at Dawn be recorded in the PGVA and recovered in the gas supply commodity rider (Rider C) from sales service customers. This approach simplifies the rate design, variance account adjustments and customers' bills while ensuring the recovery of costs from the appropriate group of customers.

While bundled DP customers balance at checkpoints, Enbridge Gas requires base load balancing purchases to meet the total forecast load balancing requirements, as there is not sufficient storage to meet all load balancing needs. As such, all sales service and bundled DP customers receive an allocation of both storage and base load balancing purchase costs in rates. To recognize that the market price for the forecast base load balancing purchases included in rates[1] will vary, Enbridge Gas has proposed to adjust for price variances in the LBPVA quarterly as part of QRAM and dispose of the variance to both sales service and bundled DP customers.

Enbridge Gas has also noted that it will continue to manage any necessary late winter post-checkpoint balancing needs for all bundled customers and recover the costs through disposition of the LBPVA.[2]

In order to provide a wholistic view of the various load balancing requirements and associated costs, Enbridge Gas committed, as part of the Phase 2 Settlement Proposal, to report annually on its market-based storage and load balancing costs, starting in 2024.[3] This reporting will provide the costs associated with load balancing, including the actual cost variances proposed to be recovered in the PGVA and LBPVA.

Attachment 1, page 1 provides the calculation of the variances that would be recorded in the PGVA in the scenario where 5,000 extra units of gas (TJ) are purchased in each of January and March at a price of $10 per unit (GJ). Of the total $100 million gas supply purchase, $44.2 million would be recorded as a debit in the PGVA for the price variance associated with those gas supply purchases above the reference price recovered in gas supply commodity rates. The remaining $55.8 million associated with the volume variance would be recovered in gas supply commodity rates.

A credit of $(43.1) million would be recorded in the LBPVA (with an offsetting debit to the PGVA) relating to the variance for load balancing costs. The actual Dawn average price for January and March, as calculated in page 1, was updated in the Load Balancing calculation in Attachment 1, page 2 to calculate a revised load balancing cost. The variance of $(43.1) million between the revised load balancing costs and the forecast load balancing cost is removed from the PGVA and recorded in the LPBVA. These adjustments result in a net overall reduction in load balancing costs of $(43.1) million due to the higher actual Dawn average price in January and a cost savings in March as a result of no planned Dawn purchases for that month.

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[1] To derive the price variance, Enbridge Gas would exclude the cost and volumes associated with spot gas purchases from the calculation of the monthly Dawn Average price.
[2] Since checkpoints were implemented in the Union South rate zone in 2005, there have only been two winters where it was necessary for the Company to take post-checkpoint balancing action, as described at JT2.18.
[3] EB-2024-0111, Decision on Settlement Proposal and Interim Rate Order, Exhibit N, Tab 1, Schedule 1, November 29, 2024, p.26.

The total variance remaining in the PGVA is $87.3 million ($44.2 million + $43.1 million). For purposes of this scenario, Enbridge Gas has assumed that the incremental purchases are not considered spot gas purchases[4].

The recognition of the $87.3 million in the PGVA reflects that the incremental gas supply purchases in this scenario are to meet the demands of sales service customers due to changes in demand relative to normal weather and will be recovered by sales service customers. The recognition of the $(43.1) million in the LPBVA reflects the price variance associated with base load balancing requirements incurred for both sales service and bundled DP customers.

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[4] Incremental gas supply purchases are considered spot gas purchases when total gas purchases for the winter exceed planned winter purchases.

5,000 TJ of Dawn Supplies above the planned Dawn purchases for January and March at $10/ GJ

Line No.	Particulars	Supplies (TJ)	Unit Cost ($/GJ)	Purchase Cost ($000s)
		(a)	(b)	(c) = (a) * (b)
	January			
1	Actual (1)	25,379	6.726	170,704
2	Approved (2)	20,379	5.923	120,704
3	Variance - Actual vs Approved (3)	5,000	0.803	50,000
4	Volume Variance (4)	5,000	5.923	29,615
5	Price Variance (5)	25,379	0.803	20,385
6	Total Variance			50,000
	March			
7	Actual (1)	5,000	10.000	50,000
8	Approved (2)	0	5.245	0
9	Variance - Actual vs Approved (6)	5,000	4.755	50,000
10	Volume Variance (4)	5,000	5.245	26,225
11	Price Variance (5)	5,000	4.755	23,775
12	Total Variance			50,000
	January & March Total			
13	Volume Variance (7)			55,840
14	Price Variance (8)			44,160
15	Total Variance			100,000

Notes:
(1) 5,000 TJ additional Dawn supplies at a price of $10/GJ.
(2) Refer to Exhibit I.9.1-FRPO-111, Attachment 2.
(3) Line 1 - Line 2.
(4) Volume variance = 5,000 TJ x Approved Price.
(5) Price variance = Actual Purchases x Price Variance.
(6) Line 7 - Line 8.
(7) Line 4 + Line 10. Volume variances dervied based on approved prices are recovered in rates.
(8) Line 5 + Line 11. Price variances are recorded in the PGVA.

EGI Load Balancing Calculation - JT1.37 Scenario

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Days in Month	31	29	31	30	31	30	31	31	30	31	30	31	366
2	Dawn Supplies (TJ)	20,379	23,600	0	2,012	4,000	13,200	7,686	0	10,823	10,440	10,024	24,150	126,314
3	Average Day Demand Per Month (TJ)	10,699	10,008	10,699	10,354	10,699	10,354	10,699	10,699	10,354	10,699	10,354	10,699	126,314
4	Average Purchases Variance (TJ)	9,680	13,592	(10,699)	(8,342)	(6,699)	2,846	(3,012)	(10,699)	469	(259)	(330)	13,451	0
5	Dawn Forecasted Price ($/GJ)	6.726	5.659	10.000	4.867	4.743	4.763	4.787	4.809	4.697	4.709	5.224	5.695	
6	Price Variance - Load Balancing ($000s) (1)	65,109	76,914	(106,987)	(40,598)	(31,772)	13,557	(14,420)	(51,450)	2,203	(1,218)	(1,722)	76,605	(13,779)
7	Peaking Supply ($000s)	1,347	0	0	0	0	0	0	0	0	0	0	0	1,347
8	Demand Cost - Load Balancing ($000s)	494	494	494	483	483	483	483	483	483	483	483	494	5,841
9	Total Load Balancing Costs ($000s) (2)	66,950	77,409	(106,493)	(40,116)	(31,289)	14,040	(13,937)	(50,967)	2,686	(735)	(1,239)	77,099	(6,592)
10	Forecast Load Balancing Cost ($000s) (3)													36,508
11	Load Balancing Price Variance ($000s) (4)													(43,099)

Notes:
(1) Line 4 x line 5.
(2) Line 6 + line 7 + line 8.
(3) Exhibit I.9.1-FRPO-111, Attachment 2, line 9.
(4) Line 9 - line 10.

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking:

Tr: 87

In the scenario where Enbridge purchases the forecast load balancing supplies plus 5,000 units in each of January and March and all of the gas in each month is purchased at $10 per unit, to describe costs recorded in the PGVA and then in the load balancing price variance account.

Response:

Attachment 1, page 1 provides the calculation of cost variances that would be recorded in the Purchase Gas Variance Account (PGVA) in the scenario where 5,000 extra units of gas (TJ) are purchased in each of January and March and all of the gas in both January and March is purchased at a price of $10 per unit (GJ). Under this scenario, a debit would be recorded in the PGVA for $127.2 million for the price variances associated with those gas supply purchases. The volume variances calculated based on the approved prices of $55.8 million would be recovered in gas supply commodity rates.

A credit of $(11.4) million would be recorded in the LBPVA (with an offsetting debit to the PGVA) relating to the variance for load balancing costs. For purposes of this scenario, the actual Dawn average price for January and March, as calculated in Attachment 1, page 1, was updated in the Load Balancing calculation in Attachment 1, page 2 to calculate a revised load balancing cost. The variance of $(11.4) million between the revised load balancing costs and the forecast load balancing cost is removed from the PGVA and recorded in the LPBVA.

The total variance remaining in the PGVA is $138.6 million ($127.2 million + $11.4 million). For purposes of this scenario, Enbridge Gas has assumed that the incremental purchases are not considered spot gas purchases[1].

Please also see response at Exhibit JT1.37.

[1] Incremental gas supply purchases are considered spot gas purchases when total gas purchases for the winter exceed planned winter purchases.

5,000 TJ of Dawn Supplies above the planned Dawn purchases with all Dawn purchases for January and March at $10/ GJ

Line No.	Particulars	Supplies (TJ)	Unit Cost ($/GJ)	Purchase Cost ($000s)
		(a)	(b)	(c) = (a) * (b)
	January			
1	Actual (1)	25,379	10.000	253,790
2	Approved (2)	20,379	5.923	120,705
3	Variance - Actual vs Approved (3)	5,000	4.077	133,085
4	Volume Variance (4)	5,000	5.923	29,615
5	Price Variance (5)	25,379	4.077	103,470
6	Total Variance			133,085
	March			
7	Actual (1)	5,000	10.000	50,000
8	Approved (2)	0	5.245	0
9	Variance - Actual vs Approved (6)	5,000	4.755	50,000
10	Volume Variance (4)	5,000	5.245	26,225
11	Price Variance (5)	5,000	4.755	23,775
12	Total Variance			50,000
	January & March Total			
13	Volume Variance (7)			55,840
14	Price Variance (8)			127,245
15	Total Variance			183,085

Notes:
(1) 5,000 TJ additional Dawn supplies with all supplies at a price of $10/GJ.
(2) Exhibit I.9.1-FRPO-111, Attachment 2.
(3) Line 1 - line 2.
(4) Volume variance = 5,000 TJ x Approved Price.
(5) Price variance = Actual Purchases x Price Variance.
(6) Line 7 - line 8.
(7) Line 4 + line 10. Volume variances dervied based on approved prices are recovered in rates.
(8) Line 5 + line 11. Price variances are recorded in the PGVA.

EGI Load Balancing Calculation - JT1.38 Scenario

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Days in Month	31	29	31	30	31	30	31	31	30	31	30	31	366
2	Dawn Supplies (TJ)	20,379	23,600	0	2,012	4,000	13,200	7,686	0	10,823	10,440	10,024	24,150	126,314
3	Average Day Demand Per Month (TJ)	10,699	10,008	10,699	10,354	10,699	10,354	10,699	10,699	10,354	10,699	10,354	10,699	126,314
4	Average Purchases Variance (TJ)	9,680	13,592	(10,699)	(8,342)	(6,699)	2,846	(3,012)	(10,699)	469	(259)	(330)	13,451	0
5	Dawn Forecasted Price ($/GJ)	10.000	5.659	10.000	4.867	4.743	4.763	4.787	4.809	4.697	4.709	5.224	5.695	
6	Price Variance - Load Balancing ($000s) (1)	96,802	76,914	(106,987)	(40,598)	(31,772)	13,557	(14,420)	(51,450)	2,203	(1,218)	(1,722)	76,605	17,914
7	Peaking Supply ($000s)	1,347	0	0	0	0	0	0	0	0	0	0	0	1,347
8	Demand Cost - Load Balancing ($000s)	494	494	494	483	483	483	483	483	483	483	483	494	5,841
9	Total Load Balancing Costs ($000s) (2)	98,643	77,409	(106,493)	(40,116)	(31,289)	14,040	(13,937)	(50,967)	2,686	(735)	(1,239)	77,099	25,101
10	Forecast Load Balancing Cost (000s) (3)													36,508
11	Load Balancing Price Variance ($000s) (4)													(11,406)

Notes:
(1) Line 4 x line 5.
(2) Line 6 + line 7 + line 8.
(3) Exhibit I.9.1-FRPO-111, Attachment 2.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Greenhouse Vegetable Growers (OGVG)

Undertaking:

Tr: 95

To explain how it is that semi-unbundled customers are allocated a portion of the gas supply portfolio transportation costs in their revenue requirement.

Response:

Under the One Rate Zone – Proposed rate zone alternative, Enbridge Gas has recognized regional differences in the cost allocation, while the rate design is based on the harmonized rate classes for one rate zone. This approach allocates costs to the rate classes based on the gas supply transportation requirements of the harmonized rate classes.

The allocation of gas supply transportation costs to semi-unbundled rate classes, including Rate E20 and Rate E64, includes the transportation contracts specific to the south service area. The south service area includes a small allocation of costs related to a third-party transportation contract that serves the Union CDA, which provides a system-wide benefit to the south service area, as the system capacity is less than would otherwise be required to serve this area without that contract.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Greenhouse Vegetable Growers (OGVG)

Undertaking:

Tr: 100

To explain where within Exhibit 7, Tab 3, Schedule 1, Attachment 13, Page 3 where we can see the gas transportation costs that are allocated to rate E20.

Response:

Please see Phase 3 Exhibit 7, Tab 3, Schedule 1, Attachment 13, page 3, columns (e) and (f), line 4 and line 5 for the allocation of gas supply transportation costs to Rate E20. The Transportation Demand and Transportation Commodity costs are recovered in Delivery Demand Charge and Customer Supplied Fuel, respectively for Rate E20.

ENBRIDGE GAS INC.

Answer to Undertaking from
Energy Probe Research Foundation (EP)

Undertaking:

Tr: 105

To advise as to its information about why average heat values appear to be higher in 2024 versus 2022.

Response:

The determination of the harmonized heat values underpinning the 2024 Test Year Forecast was addressed in Phase 1 at EB-2022-0200, Exhibit 3, Tab 6, Schedule 1, where Enbridge Gas proposed the use of two annual heat values, specifically the Enbridge Gas North heat value[1] and Enbridge Gas South heat value[2].

The conversion of the proposed Weighted Average Reference Price (WARP) is based on the Enbridge Gas South heat value. This heat value is also used for conversions related to storage (TJ) and for recovery in the gas supply commodity rate (cents/m^3). Using the Enbridge Gas South heat value, recognizes the use of heat value in conversions related to gas storage (in the South service area) and also ensures alignment amongst conversion of these processes on a forecast basis. This approach is similar to the approach used in the Union rate zones. As noted in response at Exhibit I.4.2-LPMA-7, part b), on a monthly basis, a true up is recorded in the PGVA to recognize the cost impact between the approved heat value used in the WARP and the actual heat value.

The comparison of the 2024 to 2022 heat values referenced in this undertaking is not analogous given the different time periods. The Enbridge Gas heat value for the 2024 Test Year Forecast of 39.08 GJ/10^3m^3 is based on the annual heat value calculated using 2021 actual measurement. The data shown in EB-2023-0092, Exhibit I.EP.7, page 2, Table 1 is the monthly heat values for the Enbridge CDA and Enbridge EDA, based on 2022 actual heat values.

[1] Enbridge Gas North heat value is a combination of the Enbridge EDA in the EGD rate zone and the Union North rate zone measured activity.
[2] Enbridge Gas South heat value is a combination of the Enbridge CDA in the EGD rate zone and the Union South rate zone measured activity.

Heat value is determined by the chemical composition of the gas in the pipe, specifically the proportions of different hydrocarbons in the gas stream. The composition will vary depending on where the gas is sourced from and how it is blended. Gas is received into the Enbridge Gas system from a variety of producing regions and interconnecting pipelines. As such, the heat value of gas in Enbridge Gas's system will reflect the diversity of supply sources and is subject to change over time.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking:

Tr: 111

To advise as to what would be the weighted average heat value for 2024 and advise how that would be calculated.

Response:

The weighted average annual heat value for the combined EGD and Union rate zones is 39.04 GJ/10^3m^3 for the 2024 Test Year Forecast.[1]

The weighted average heat value is calculated as:

$$\frac{(Receipts - Deliveries)GJ}{(Receipts - Deliveries)103m3}$$

The calculation is based on the total annual measured receipts less deliveries at all receipt points within the EGD and Union rates zones.

The equivalent calculation based on 2024 actual measurement data is 39.00 GJ/$10^3m^{3.}$

[1] EB-2022-0200, Exhibit 3, Tab 6, Schedule 1, Table 1, Line 3. The weighted average heat value calculation for the 2024 Test Year Forecast is based on 2021 actual measurement.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Petroleum Institute Inc. (OPI)

Undertaking:

Tr: 126

To provide whatever information it has available as to the frequency or number of instances of producer stations being painted 5 years, as well as the total population of producer stations.

Response:

Enbridge Gas is not able to provide precise records on the frequency of producer stations being painted over the last five years due to system changes. However, Enbridge Gas was able to confirm that 12 producer stations were painted since 2018 in the Union rate zones.

Enbridge Gas prioritizes station painting on an as-needed basis based on condition assessments using Integrity Management Program information and knowledge of field operations staff. The station painting program is an important aspect of ensuring the long-term maintenance and integrity of producer stations.

The total population of producer stations has not changed significantly over the requested time period. In the last 18 months, one new station has been put into service and was included in the 2024 Test Year Forecast of Rate E82.[1] The 2024 Test Year Forecast for Rate E80 includes 75 stations as provided at Phase 3 Exhibit 8, Tab 2, Schedule 9, Attachment 14, line 2 + line 5 and Rate E82 includes 5 stations as provided in response at Exhibit I.8.2-CBA-1.

[1] Producers currently taking service under Rate 401 in the EGD rate zone until the expiry of the Rate 401 contract.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Petroleum Institute Inc. (OPI)

Undertaking:

Tr: 129

To check for and provide any relevant information on the differences and similarities between the operating cost for distribution stations and producer stations.

Response:

Local producer stations incur higher direct costs than distribution stations due to requirements for gas quality inspections that are not required for distribution stations. Gas flowing through distribution stations has gas quality reviewed where the gas entered Enbridge Gas's network, typically at major pipeline interconnects. Some complex producer stations also require additional sampling equipment to detect contaminants in the gas and associated maintenance costs.

Regarding indirect costs, Enbridge Gas's engineering and operations teams support producer and distribution stations in the same manner. The allocation of general operations and engineering costs is consistent with the costs allocated to all other customer stations in the 2024 Cost Allocation Study, as described at Phase 3 Exhibit 8, Tab 2, Schedule 5, pages 23 and 24, paragraph 50.

ENBRIDGE GAS INC.

Answer to Undertaking from
Energy Probe Research Foundation (EP)

Undertaking:

Tr: 135

To provide an estimate of the average monthly bill for an Enbridge Gas customer with only a tankless water heater under the existing rates, in the EGD rate zone and other SFVD, while also referring to a water heater with tank.

Response:

The following response was provided by Christensen Associates Energy Consulting:

Table 1 below provides estimates of monthly bills for customers with tank and tankless water heaters, using the electric heating scenario from Exhibit I.8.2-ED-12 as the tank water heater base case. The tankless water heater scenario assumes that the customer avoids 30 percent of annual consumption relative to the base case, based on the indicative energy savings at https://natural-resources.canada.ca/energy-efficiency/energy-star/products/list-certified-products/tankless-water-heaters, spread uniformly throughout the year. The tankless water heating design day demand is assumed to be 1.16 cubic metres (versus 1.66 cubic metres in the base case).

We note that the average bill differences between 2024 LEGD rates and the harmonized SFVD rates are not solely due to the SFVD design. The rate differences also reflect effects of factors including rate harmonization, cost allocation changes, and monthly customer charge changes.

Supporting calculations are provided as an Excel workbook in Attachment 1.

Table 1. Estimated Monthly Bills for Tank and Tankless Water Heating Scenarios

	Monthly Avg. Bill ($)	
Scenario	2024 Rates (LEGD)	Harmonized SFVD
Electric Heat/Tank WH	38.21	38.46
Electric Heat/Tankless	34.23	35.65

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Please see Exhibit JT1.45_Attachment 1.xlsx on the OEB's RDS.

ENBRIDGE GAS INC.

Answer to Undertaking from
Energy Probe Research Foundation (EP)

Undertaking:

Tr: 137

To advise as to its information about how many Enbridge Gas customers have tankless water heaters.

Response:

Enbridge Gas does not track the number of customers that have tankless water heaters.

According to Enbridge Gas's 2024 Residential End Use Study – Natural Gas Equipment – Single Family, 16% of surveyed customers report that they have a tankless water heater. If applying this percentage to approximately 3.6 million residential customers,[1] this would equate to approximately 0.6 million customers. This study is conducted among single family residential customers only.

In this same study, 78% of surveyed customers report that they use natural gas for water heating, and among this group of customers, 18% report having a tankless water heater (or approximately 14% of customers). If applying this percentage to 3.6 million residential customers, this would equate to approximately 0.5 million customers.

[1] EB-2022-0200 Exhibit 3, Tab 2, Schedule 6, Attachment 2.

ENBRIDGE GAS INC.

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking:

Tr: 144

On a best-efforts basis, to provide examples showing the implications of using an adjusted HDD versus an unadjusted HDD, where it could increase design day demand used for billing; to advise any conditions or reason for no response.

Response:

The following response was provided by Christensen Associates Energy Consulting:

We understand that the undertaking seeks to compare the regression model used by CAEC with the Enbridge regression model implemented in the Excel workbook provided in Exhibit I.8.2-SEC-17, Attachment 1. The main substantive reason why results from the CAEC regression methodology would differ from the Enbridge bill estimation models is their different treatment of observations for periods with 0-5 HDDs/day, and not the use of adjusted versus unadjusted HDDs as such. Observations from reading periods with 0-5 (unadjusted) HDDs/day are included in the CAEC calculations and excluded in the Enbridge model. In the latter, the average daily consumption for 0-5 HDDs/day periods is used to derive a “summer” base consumption. That is, the Enbridge model estimates the regression from “winter” observations with 5 or more HDDs/day, while the CAEC regression also includes the 0-5 HDD/day observations. As a result, the CAEC model has a single base demand (the intercept or 0 HDD/day demand) while the Enbridge model allows for separate summer and winter base demands. Neither model inherently produces higher or lower estimates of design day demand.

Attachments 1 and 2 provide an example residential customer whose estimated demand is higher using the CAEC regression model (Attachment 1) than the Enbridge model (Attachment 2). Attachments 3 and 4 provide a corresponding example for a commercial customer.

We note the use of adjusted or unadjusted HDDs need not affect the measurement of design day demand at all. In Enbridge’s bill estimation model, the winter base demand may be obtained, equivalently, from a regression using unadjusted HDDs by evaluating the regression line at 5 HDDs, or with the 5-degree adjusted HDDs by evaluating the regression line at 0 adjusted HDDs. The use of adjusted HDDs is a computational convenience that allows the winter base consumption to be obtained directly from the regression intercept.

Conversely, the CAEC model can be implemented with adjusted HDDs by suitably accounting for the shift of the intercept term. This is shown in Attachments 5 and 6, which show (respectively) demand derivations using adjusted HDDs for the Attachment 1 example of the CAEC model and using unadjusted HDDs for the Enbridge model in Attachment 2.

Note that the regression heat parameters and R-squared values are identical between the adjusted and unadjusted HDD cases; the HDD adjustment serves to shift the intercept term. The (identical) design day demands for each model remain the fitted value for daily consumption at the design temperature, represented by adjusted or unadjusted HDDs as appropriate.

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Please see Exhibit JT1.47_Attachments 1-6.xlsx on the OEB's RDS.

ENBRIDGE GAS INC.

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking:

Tr: 146

1. Christensen Associates to run an analysis of bill-impact drivers for the average customer in each of deciles 1, 5, 10 in each rate zone;

2. Christensen Associates to run analyses for a customer who consumes 2,400 cubic metres and has a design-day demand of 50.62, and a second customer with 2,400 cubic metres of annual consumption and a design-day demand of 16.04.

Response:

The following response was provided by Enbridge Gas Inc.:

Please see Attachment 1.

Please note the consumption profiles for each decile are based on the current rate classes, which may differ from the consumption profiles for each decile based on the harmonized rate classes as provided in response at Exhibit I.8.2-CCC-21, part c).

Summary of General Service Bill Impacts by Proposal

Line No.	Particulars ($)	Harmonized Rate Class	Design Day Demand (m^3/d)	Annual Consumption (m^3)	Current Rates July 2024 QRAM (a)	Current Rates, Zones Current Rate Design 7.3.7 (b)	Current Rates, Zones SFVD 7.3.7 - SFVD (c)	Proposed - Harmonized SFVD - E02 (1) 7.3.1 (d)	Proposed - Harmonized SFVD 7.3.1 (e)
	EGD Rate Zone								
1	Rate 1 - Decile 1	Rate E01	11	984	557	557	598	592	592
2	Rate 1 - Decile 5	Rate E01	24	2,341	905	905	898	915	915
3	Rate 1 - Decile 10	Rate E01	49	5,460	1,702	1,697	1,553	1,614	1,614
4	Rate 1 - Low LF	Rate E01	51	2,400	917	915	1,066	1,121	1,121
5	Rate 1 - High LF	Rate E01	16	2,400	922	922	861	866	866
6	Rate 6 - Decile 1	Rate E01	14	556	1,094	1,084	834	542	542
7	Rate 6 - Decile 5	Rate E01	70	5,876	2,490	2,378	2,053	1,843	1,843
8	Rate 6 - Decile 10	Rate E02	2,357	246,573	55,919	51,684	55,440	56,741	58,826
	Union NW Rate Zone								
9	Rate 01 NW - Decile 1	Rate E01	9	882	551	565	669	559	559
10	Rate 01 NW - Decile 5	Rate E01	20	2,185	904	938	956	861	861
11	Rate 01 NW - Decile 10	Rate E01	90	10,074	2,984	3,143	2,689	2,684	2,684
12	Rate 01 NW - Low LF	Rate E01	51	2,400	958	996	1,172	1,121	1,121
13	Rate 01 NW - High LF	Rate E01	16	2,400	962	1,000	967	866	866
14	Rate 10 NW - Decile 1	Rate E02	384	41,745	10,958	11,623	12,125	10,621	10,135
15	Rate 10 NW - Decile 5	Rate E02	686	80,275	19,950	21,256	20,784	18,860	18,768
16	Rate 10 NW - Decile 10	Rate E02	3,989	543,878	123,083	132,681	100,398	95,025	94,934
	Union NE Rate Zone								
17	Rate 01 NE - Decile 1	Rate E01	9	882	617	617	720	559	559
18	Rate 01 NE - Decile 5	Rate E01	20	2,185	1,067	1,068	1,084	861	861
19	Rate 01 NE - Decile 10	Rate E01	90	10,074	3,736	3,741	3,279	2,684	2,684
20	Rate 01 NE - Low LF	Rate E01	51	2,400	1,137	1,139	1,312	1,121	1,121
21	Rate 01 NE - High LF	Rate E01	16	2,400	1,141	1,143	1,107	866	866
22	Rate 10 NE - Decile 1	Rate E02	384	41,745	13,754	13,401	13,999	10,621	10,135
23	Rate 10 NE - Decile 5	Rate E02	686	80,275	25,326	24,676	24,387	18,860	18,768
24	Rate 10 NE - Decile 10	Rate E02	3,989	543,878	159,506	155,854	147,143	115,904	120,116
	Union South Rate Zone								
25	Rate M1 - Decile 1	Rate E01	8	816	498	513	547	545	545
26	Rate M1 - Decile 5	Rate E01	21	2,093	787	824	834	849	849
27	Rate M1 - Decile 10	Rate E01	84	9,204	2,364	2,506	2,393	2,500	2,500
28	Rate M1 - Low LF	Rate E01	51	2,400	852	891	1,072	1,121	1,121
29	Rate M1 - High LF	Rate E01	16	2,400	857	899	855	866	866
30	Rate M2 - Decile 1	Rate E02	419	40,373	10,213	10,176	11,177	10,619	10,180
31	Rate M2 - Decile 5	Rate E02	815	86,306	20,653	20,561	21,176	20,667	20,744
32	Rate M2 - Decile 10	Rate E02	4,761	615,669	138,846	137,850	132,497	132,577	137,795

Note:
(1) Rate E02 Customer Charge updated to remove adjustment to set equal to Rate E01 customer charge.

Summary of General Service Bill Impacts by Proposal

Line No.	Particulars ($)	Harmonized Rate Class	Design Day Demand (m^3/d)	Annual Consumption (m^3)	Impact Drivers (%): Cost Study Update	Impact Drivers (%): SFVD Rate Design	Impact Drivers (%): Harmonization	Impact Drivers (%): Rate E02 Customer Charge	Bill Impacts As Proposed (%)
					(f) = (b / a)	(g) = (c / b)	(h) = (d / c)	(i) = (e / d)	(j) = (e / a)
	EGD Rate Zone								
1	Rate 1 - Decile 1	Rate E01	11	984	0.1%	7.3%	(1.1%)	-	6.2%
2	Rate 1 - Decile 5	Rate E01	24	2,341	(0.1%)	(0.7%)	1.8%	-	1.0%
3	Rate 1 - Decile 10	Rate E01	49	5,460	(0.2%)	(8.5%)	3.9%	-	(5.2%)
4	Rate 1 - Low LF	Rate E01	51	2,400	(0.2%)	16.5%	5.2%	-	22.3%
5	Rate 1 - High LF	Rate E01	16	2,400	(0.1%)	(6.6%)	0.6%	-	(6.1%)
6	Rate 6 - Decile 1	Rate E01	14	556	(1.0%)	(23.0%)	(35.1%)	-	(50.5%)
7	Rate 6 - Decile 5	Rate E01	70	5,876	(4.5%)	(13.6%)	(10.2%)	-	(26.0%)
8	Rate 6 - Decile 10	Rate E02	2,357	246,573	(7.6%)	7.3%	2.3%	3.7%	5.2%
	Union NW Rate Zone								
9	Rate 01 NW - Decile 1	Rate E01	9	882	2.6%	18.3%	(16.3%)	-	1.5%
10	Rate 01 NW - Decile 5	Rate E01	20	2,185	3.9%	1.8%	(9.9%)	-	(4.7%)
11	Rate 01 NW - Decile 10	Rate E01	90	10,074	5.3%	(14.4%)	(0.2%)	-	(10.1%)
12	Rate 01 NW - Low LF	Rate E01	51	2,400	4.0%	17.6%	(4.3%)	-	17.0%
13	Rate 01 NW - High LF	Rate E01	16	2,400	4.0%	(3.4%)	(10.4%)	-	(10.0%)
14	Rate 10 NW - Decile 1	Rate E02	384	41,745	6.1%	4.3%	(12.4%)	(4.6%)	(7.5%)
15	Rate 10 NW - Decile 5	Rate E02	686	80,275	6.6%	(2.2%)	(9.3%)	(0.5%)	(5.9%)
16	Rate 10 NW - Decile 10	Rate E02	3,989	543,878	7.8%	(24.3%)	(5.4%)	(0.1%)	(22.9%)
	Union NE Rate Zone								
17	Rate 01 NE - Decile 1	Rate E01	9	882	0.1%	16.7%	(22.3%)	-	(9.3%)
18	Rate 01 NE - Decile 5	Rate E01	20	2,185	0.1%	1.5%	(20.5%)	-	(19.2%)
19	Rate 01 NE - Decile 10	Rate E01	90	10,074	0.1%	(12.3%)	(18.2%)	-	(28.2%)
20	Rate 01 NE - Low LF	Rate E01	51	2,400	0.1%	15.2%	(14.6%)	-	(1.4%)
21	Rate 01 NE - High LF	Rate E01	16	2,400	0.1%	(3.1%)	(21.8%)	-	(24.1%)
22	Rate 10 NE - Decile 1	Rate E02	384	41,745	(2.6%)	4.5%	(24.1%)	(4.6%)	(26.3%)
23	Rate 10 NE - Decile 5	Rate E02	686	80,275	(2.6%)	(1.2%)	(22.7%)	(0.5%)	(25.9%)
24	Rate 10 NE - Decile 10	Rate E02	3,989	543,878	(2.3%)	(5.6%)	(21.2%)	3.6%	(24.7%)
	Union South Rate Zone								
25	Rate M1 - Decile 1	Rate E01	8	816	3.0%	6.6%	(0.3%)	-	9.4%
26	Rate M1 - Decile 5	Rate E01	21	2,093	4.7%	1.2%	1.9%	-	7.9%
27	Rate M1 - Decile 10	Rate E01	84	9,204	6.0%	(4.5%)	4.4%	-	5.7%
28	Rate M1 - Low LF	Rate E01	51	2,400	4.7%	20.2%	4.6%	-	31.6%
29	Rate M1 - High LF	Rate E01	16	2,400	4.9%	(4.9%)	1.3%	-	1.1%
30	Rate M2 - Decile 1	Rate E02	419	40,373	(0.4%)	9.8%	(5.0%)	(4.1%)	(0.3%)
31	Rate M2 - Decile 5	Rate E02	815	86,306	(0.4%)	3.0%	(2.4%)	0.4%	0.4%
32	Rate M2 - Decile 10	Rate E02	4,761	615,669	(0.7%)	(3.9%)	0.1%	3.9%	(0.8%)

Note:
(1) Rate E02 Customer Charge updated to remove adjustment to set equal to Rate E

Total Bill Calculation - EGD Rate Zone

Line No.	Particulars ($)	Usage	Current Rates July 2024 QRAM (a)	Current Rates, Zones Current Rate Design 7.3.7 (b)	Current Rates, Zones SFVD 7.3.7 - SFVD (c)	Proposed - Harmonized SFVD - E02 (1) 7.3.1 (d)	Proposed - Harmonized SFVD 7.3.1 (e)
	Rate 1 to Rate E01 - Decile 1						
1	Annual Consumption (m^3)	984					
2	Design Demand (m^3/d)	11					
	Delivery Charges						
3	Monthly Charge	12	297	297	374	349	349
4	Delivery Demand	11	-	-	64	79	79
5	Delivery Commodity						
6	First 30 m³	342	40	39	1	1	1
7	Next 55 m³	363	40	38	1	1	1
8	Next 85 m³	266	28	26	1	1	1
9	Over 170 m³	14	1	1	0	0	0
10	Total Delivery Commodity	984	109	104	4	4	4
11	Facility Carbon	984	0	0	0	0	0
12	Total Delivery		406	401	442	432	432
	Gas Supply Charges						
13	Transportation	984	48	22	22	18	18
14	System Commodity	984	103	134	134	142	142
15	Total Gas Supply		151	156	156	159	159
16	Total Bill		557	557	598	592	592
	Rate 1 to Rate E01 - Decile 5						
17	Annual Consumption (m^3)	2,341					
18	Design Demand (m^3/d)	24					
	Delivery Charges						
19	Monthly Charge	12	297	297	374	349	349
20	Delivery Demand	24	-	-	142	177	177
21	Delivery Commodity						
22	First 30 m³	360	42	41	1	1	1
23	Next 55 m³	533	59	56	2	2	2
24	Next 85 m³	591	62	58	2	2	2
25	Over 170 m³	857	86	80	3	3	3
26	Total Delivery Commodity	2,341	249	235	9	9	9
27	Facility Carbon	2,341	0	0	0	0	0
28	Total Delivery		546	532	526	535	535
	Gas Supply Charges						
29	Transportation	2,341	114	53	53	42	42
30	System Commodity	2,341	245	319	319	337	337
31	Total Gas Supply		360	372	372	379	379
32	Total Bill		905	905	898	915	915
	Rate 1 to Rate E01 - Decile 10						
33	Annual Consumption (m^3)	5,460					
34	Design Demand (m^3/d)	49					
	Delivery Charges						
35	Monthly Charge	12	297	297	374	349	349
36	Delivery Demand	49	-	-	288	358	358
37	Delivery Commodity						
38	First 30 m³	360	42	41	1	1	1
39	Next 55 m³	660	73	69	3	3	3
40	Next 85 m³	1,020	107	101	4	4	4
41	Over 170 m³	3,420	344	321	14	13	13
42	Total Delivery Commodity	5,460	565	532	22	21	21
43	Facility Carbon	5,460	1	1	1	1	1
44	Total Delivery		863	829	685	729	729
	Gas Supply Charges						
45	Transportation	5,460	266	124	124	98	98
46	System Commodity	5,460	572	744	744	786	786
47	Total Gas Supply		839	868	868	885	885
48	Total Bill		1,702	1,697	1,553	1,614	1,614

Total Bill Calculation - EGD Rate Zone

Line No.	Particulars ($)	Usage	Current Rates July 2024 QRAM (a)	Current Rates, Zones Current Rate Design 7.3.7 (b)	Current Rates, Zones SFVD 7.3.7 - SFVD (c)	Proposed - Harmonized SFVD - E02 (1) 7.3.1 (d)	Proposed - Harmonized SFVD 7.3.1 (e)
	Rate 1 to Rate E01 - Atypical Low LF						
49	Annual Consumption (m^3)	2,400					
50	Design Demand (m^3/d)	51					
	Delivery Charges						
51	Monthly Charge	12	297	297	374	349	349
52	Delivery Demand	51	-	-	300	373	373
53	Delivery Commodity						
54	First 30 m³	300	35	34	1	1	1
55	Next 55 m³	332	37	35	1	1	1
56	Next 85 m³	425	44	42	2	2	2
57	Over 170 m³	1,343	135	126	5	5	5
58	Total Delivery Commodity	2,400	251	237	10	9	9
59	Facility Carbon	2,400	0	0	0	0	0
60	Total Delivery		548	534	684	732	732
	Gas Supply Charges						
61	Transportation	2,400	117	54	54	43	43
62	System Commodity	2,400	252	327	327	346	346
63	Total Gas Supply		369	382	382	389	389
64	Total Bill		917	915	1,066	1,121	1,121
	Rate 1 to Rate E01 - Atypical High LF						
65	Annual Consumption (m^3)	2,400					
66	Design Demand (m^3/d)	16					
	Delivery Charges						
67	Monthly Charge	12	297	297	374	349	349
68	Delivery Demand	16	-	-	95	118	118
69	Delivery Commodity						
70	First 30 m³	360	42	41	1	1	1
71	Next 55 m³	660	73	69	3	3	3
72	Next 85 m³	714	75	70	3	3	3
73	Over 170 m³	666	67	63	3	3	3
74	Total Delivery Commodity	2,400	256	243	10	9	9
75	Facility Carbon	2,400	0	0	0	0	0
76	Total Delivery		553	540	479	477	477
	Gas Supply Charges						
77	Transportation	2,400	117	54	54	43	43
78	System Commodity	2,400	252	327	327	346	346
79	Total Gas Supply		369	382	382	389	389
80	Total Bill		922	922	861	866	866
	Rate 6 to Rate E01 - Decile 1						
81	Annual Consumption (m^3)	556					
82	Design Demand (m^3/d)	14					
	Delivery Charges						
83	Monthly Charge	12	944	944	658	349	349
84	Delivery Demand	14	-	-	86	100	100
85	Delivery Commodity						
86	First 500 m³	556	65	52	2	2	2
87	Next 1,050 m³	-	-	-	-	-	-
88	Next 4,500 m³	-	-	-	-	-	-
89	Next 7,000 m³	-	-	-	-	-	-
90	Next 15,250 m³	-	-	-	-	-	-
91	Over 28,300 m³	-	-	-	-	-	-
92	Total Delivery Commodity	556	65	52	2	2	2

Total Bill Calculation - EGD Rate Zone

Line No.	Particulars ($)	Usage	Current Rates July 2024 QRAM (a)	Current Rates, Zones Current Rate Design 7.3.7 (b)	Current Rates, Zones SFVD 7.3.7 - SFVD (c)	Proposed - Harmonized SFVD - E02 (1) 7.3.1 (d)	Proposed - Harmonized SFVD 7.3.1 (e)
93	Facility Carbon	556	0	0	0	0	0
94	Total Delivery		1,009	996	746	452	452
	Gas Supply Charges						
95	Transportation	556	27	12	12	10	10
96	System Commodity	556	58	76	76	80	80
97	Total Gas Supply		85	88	88	90	90
98	Total Bill		1,094	1,084	834	542	542
	Rate 6 to Rate E01 - Decile 5						
99	Annual Consumption (m^3)	5,876					
100	Design Demand (m^3/d)	70					
	Delivery Charges						
101	Monthly Charge	12	944	944	658	349	349
102	Delivery Demand	70	-	-	444	518	518
103	Delivery Commodity						
104	First 500 m³	3,831	449	359	14	15	15
105	Next 1,050 m³	2,046	192	146	8	8	8
106	Next 4,500 m³	-	-	-	-	-	-
107	Next 7,000 m³	-	-	-	-	-	-
108	Next 15,250 m³	-	-	-	-	-	-
109	Over 28,300 m³	-	-	-	-	-	-
110	Total Delivery Commodity	5,876	641	505	22	23	23
111	Facility Carbon	5,876	1	1	1	1	1
112	Total Delivery		1,586	1,450	1,125	891	891
	Gas Supply Charges						
113	Transportation	5,876	287	127	127	106	106
114	System Commodity	5,876	617	801	801	846	846
115	Total Gas Supply		904	928	928	952	952
116	Total Bill		2,490	2,378	2,053	1,843	1,843
	Rate 6 to Rate E02 - Decile 10						
117	Annual Consumption (m^3)	246,573					
118	Design Demand (m^3/d)	2,357					
	Delivery Charges						
119	Monthly Charge	12	944	944	658	1,335	349
120	Delivery Demand	2,357	-	-	14,881	14,896	17,967
121	Delivery Commodity						
122	First 500 m³	6,000	704	563	23	23	23
123	Next 1,050 m³	12,600	1,180	898	48	49	49
124	Next 4,500 m³	53,992	4,159	2,993	204	209	209
125	Next 7,000 m³	56,580	3,755	2,562	214	219	219
126	Next 15,250 m³	90,420	5,572	3,686	341	350	350
127	Over 28,300 m³	26,980	1,630	1,069	102	104	104
128	Total Delivery Commodity	246,573	16,999	11,771	931	954	954
129	Facility Carbon	246,573	35	35	35	35	35
130	Total Delivery		17,978	12,750	16,506	17,221	19,306
	Gas Supply Charges						
131	Transportation	246,573	12,034	5,314	5,314	4,009	4,009
132	System Commodity	246,573	25,906	33,621	33,621	35,511	35,511
133	Total Gas Supply		37,940	38,934	38,934	39,520	39,520
134	Total Bill		55,919	51,684	55,440	56,741	58,826

Note:
(1) Rate E02 Customer Charge updated to remove adjustment to set equal to Rate E01 customer charge.

Total Bill Calculation - Union North West Rate Zone

Line No.	Particulars ($)	Usage	Current Rates July 2024 QRAM	Current Rates, Zones Current Rate Design 7.3.7	Current Rates, Zones SFVD 7.3.7 - SFVD	Proposed - Harmonized SFVD - E02 (1) 7.3.1	Proposed - Harmonized SFVD 7.3.1
			(a)	(b)	(c)	(d)	(e)
	Rate 01 NW to Rate E01 - Decile 1						
1	Annual Consumption (m^3)	882					
2	Design Demand (m^3/d)	9					
	Delivery Charges						
3	Monthly Charge	12	310	310	470	349	349
4	Delivery Demand	9	-	-	51	64	64
5	Delivery Commodity						
6	First 100 m³	733	79	83	3	3	3
7	Next 200 m³	149	16	16	1	1	1
8	Next 200 m³	-	-	-	-	-	-
9	Next 500 m³	-	-	-	-	-	-
10	Over 1,000 m³	-	-	-	-	-	-
11	Total Delivery Commodity	882	95	99	3	3	3
12	Facility Carbon	882	0	0	0	0	0
13	Total Delivery		405	410	524	416	416
	Gas Supply Charges						
14	Storage	882	20	11	-	-	-
15	Transportation	882	29	48	48	16	16
16	System Commodity	882	97	97	97	127	127
17	Total Gas Supply		146	155	145	143	143
18	Total Bill		551	565	669	559	559
	Rate 01 NW to Rate E01 - Decile 5						
19	Annual Consumption (m^3)	2,185					
20	Design Demand (m^3/d)	20					
	Delivery Charges						
21	Monthly Charge	12	310	310	470	349	349
22	Delivery Demand	20	-	-	120	149	149
23	Delivery Commodity						
24	First 100 m³	974	105	110	3	4	4
25	Next 200 m³	1,073	113	118	4	4	4
26	Next 200 m³	138	14	15	0	1	1
27	Next 500 m³	-	-	-	-	-	-
28	Over 1,000 m³	-	-	-	-	-	-
29	Total Delivery Commodity	2,185	232	243	8	9	9
30	Facility Carbon	2,185	0	0	0	0	0
31	Total Delivery		542	553	598	507	507
	Gas Supply Charges						
32	Storage	2,185	49	27	-	-	-
33	Transportation	2,185	72	119	119	39	39
34	System Commodity	2,185	240	239	239	315	315
35	Total Gas Supply		361	385	358	354	354
36	Total Bill		904	938	956	861	861
	Rate 01 NW to Rate E01 - Decile 10						
37	Annual Consumption (m^3)	10,074					
38	Design Demand (m^3/d)	90					
	Delivery Charges						
39	Monthly Charge	12	310	310	470	349	349
40	Delivery Demand	90	-	-	531	661	661
41	Delivery Commodity						
42	First 100 m³	1,200	129	136	4	5	5
43	Next 200 m³	2,113	222	233	8	8	8
44	Next 200 m³	1,531	154	162	5	6	6
45	Next 500 m³	3,116	302	317	11	12	12
46	Over 1,000 m³	2,114	198	208	8	8	8
47	Total Delivery Commodity	10,074	1,007	1,056	36	39	39
48	Facility Carbon	10,074	1	1	1	1	1
49	Total Delivery		1,318	1,368	1,038	1,051	1,051

Total Bill Calculation - Union North West Rate Zone

Line No.	Particulars ($)	Usage	Current Rates July 2024 QRAM (a)	Current Rates, Zones Current Rate Design 7.3.7 (b)	Current Rates, Zones SFVD 7.3.7 - SFVD (c)	Proposed - Harmonized SFVD - E02 (1) 7.3.1 (d)	Proposed - Harmonized SFVD 7.3.1 (e)
	Gas Supply Charges						
50	Storage	10,074	226	124	-	-	-
51	Transportation	10,074	332	548	548	182	182
52	System Commodity	10,074	1,108	1,103	1,103	1,451	1,451
53	Total Gas Supply		1,666	1,775	1,652	1,632	1,632
54	Total Bill		2,984	3,143	2,689	2,684	2,684
	Rate 01 NW to Rate E01 - Atypical Low LF						
55	Annual Consumption (m^3)	2,400					
56	Design Demand (m^3/d)	51					
	Delivery Charges						
57	Monthly Charge	12	310	310	470	349	349
58	Delivery Demand	51	-	-	300	373	373
59	Delivery Commodity						
60	First 100 m³	707	76	80	3	3	3
61	Next 200 m³	974	102	107	3	4	4
62	Next 200 m³	597	60	63	2	2	2
63	Next 500 m³	123	12	12	0	0	0
64	Over 1,000 m³	-	-	-	-	-	-
65	Total Delivery Commodity	2,400	251	263	9	9	9
66	Facility Carbon	2,400	0	0	0	0	0
67	Total Delivery		561	573	778	732	732
	Gas Supply Charges						
68	Storage	2,400	54	29	-	-	-
69	Transportation	2,400	79	131	131	43	43
70	System Commodity	2,400	264	263	263	346	346
71	Total Gas Supply		397	423	393	389	389
72	Total Bill		958	996	1,172	1,121	1,121
	Rate 01 NW to Rate E01 - Atypical High LF						
73	Annual Consumption (m^3)	2,400					
74	Design Demand (m^3/d)	16					
	Delivery Charges						
75	Monthly Charge	12	310	310	470	349	349
76	Delivery Demand	16	-	-	95	118	118
77	Delivery Commodity						
78	First 100 m³	1,199	129	135	4	5	5
79	Next 200 m³	976	103	108	3	4	4
80	Next 200 m³	226	23	24	1	1	1
81	Next 500 m³	-	-	-	-	-	-
82	Over 1,000 m³	-	-	-	-	-	-
83	Total Delivery Commodity	2,400	255	267	9	9	9
84	Facility Carbon	2,400	0	0	0	0	0
85	Total Delivery		565	577	573	477	477
	Gas Supply Charges						
86	Storage	2,400	54	29	-	-	-
87	Transportation	2,400	79	131	131	43	43
88	System Commodity	2,400	264	263	263	346	346
89	Total Gas Supply		397	423	393	389	389
90	Total Bill		962	1,000	967	866	866
	Rate 10 NW to Rate E02 - Decile 1						
91	Annual Consumption (m^3)	41,745					
92	Design Demand (m^3/d)	384					
	Delivery Charges						
93	Monthly Charge	12	944	944	2,360	1,335	349
94	Delivery Demand	384	-	-	2,597	2,428	2,928
95	Delivery Commodity						
96	First 1 000 m³	11,606	1,117	1,002	37	45	45
97	Next 9 000 m³	30,139	2,359	2,123	97	117	117
98	Next 20 000 m³	-	-	-	-	-	-
99	Next 70 000 m³	-	-	-	-	-	-
100	Over 100,000 m³	-	-	-	-	-	-
101	Total Delivery Commodity	41,745	3,476	3,125	135	162	162

Total Bill Calculation - Union North West Rate Zone

Line No.	Particulars ($)	Usage	Current Rates July 2024 QRAM	Current Rates, Zones Current Rate Design 7.3.7	Current Rates, Zones SFVD 7.3.7 - SFVD	Proposed - Harmonized SFVD - E02 (1) 7.3.1	Proposed - Harmonized SFVD 7.3.1
			(a)	(b)	(c)	(d)	(e)
102	Facility Carbon	41,745	6	6	6	6	6
103	Total Delivery		4,426	4,075	5,097	3,930	3,445
	Gas Supply Charges						
104	Storage	41,745	740	520	-	-	-
105	Transportation	41,745	1,202	2,457	2,457	679	679
106	System Commodity	41,745	4,590	4,572	4,572	6,012	6,012
107	Total Gas Supply		6,532	7,548	7,028	6,691	6,691
108	Total Bill		10,958	11,623	12,125	10,621	10,135
	Rate 10 NW to Rate E02 - Decile 5						
109	Annual Consumption (m^3)	80,275					
110	Design Demand (m^3/d)	686					
	Delivery Charges						
111	Monthly Charge	12	944	944	2,360	1,335	349
112	Delivery Demand	686	-	-	4,639	4,337	5,231
113	Delivery Commodity						
114	First 1 000 m³	12,000	1,155	1,036	39	46	46
115	Next 9 000 m³	61,917	4,847	4,361	200	240	240
116	Next 20 000 m³	6,358	431	389	20	25	25
117	Next 70 000 m³	-	-	-	-	-	-
118	Over 100,000 m³	-	-	-	-	-	-
119	Total Delivery Commodity	80,275	6,433	5,786	259	311	311
120	Facility Carbon	80,275	11	11	11	11	11
121	Total Delivery		7,388	6,742	7,269	5,994	5,902
	Gas Supply Charges						
122	Storage	80,275	1,423	999	-	-	-
123	Transportation	80,275	2,312	4,724	4,724	1,305	1,305
124	System Commodity	80,275	8,826	8,792	8,792	11,561	11,561
125	Total Gas Supply		12,561	14,515	13,515	12,866	12,866
126	Total Bill		19,950	21,256	20,784	18,860	18,768
	Rate 10 NW to Rate E02 - Decile 10						
127	Annual Consumption (m^3)	543,878					
128	Design Demand (m^3/d)	3,989					
	Delivery Charges						
129	Monthly Charge	12	944	944	2,360	1,335	349
130	Delivery Demand	686	-	-	4,639	4,337	5,231
131	Delivery Commodity						
132	First 1 000 m³	12,000	1,155	1,036	39	46	46
133	Next 9 000 m³	108,000	8,454	7,606	348	418	418
134	Next 20 000 m³	207,613	14,087	12,701	669	803	803
135	Next 70 000 m³	216,265	13,261	11,976	697	837	837
136	Over 100,000 m³	-	-	-	-	-	-
137	Total Delivery Commodity	543,878	36,957	33,320	1,753	2,104	2,104
138	Facility Carbon	543,878	78	78	78	78	78
139	Total Delivery		37,979	34,342	8,829	7,854	7,762
	Gas Supply Charges						
140	Storage	543,878	9,640	6,770	-	-	-
141	Transportation	543,878	15,664	32,005	32,005	8,843	8,843
142	System Commodity	543,878	59,800	59,564	59,564	78,329	78,329
143	Total Gas Supply		85,104	98,339	91,569	87,172	87,172
144	Total Bill		123,083	132,681	100,398	95,025	94,934

Note:
(1) Rate E02 Customer Charge updated to remove adjustment to set equal to Rate E01 customer charge.

Total Bill Calculation - Union North East Rate Zone

Line No.	Particulars ($)	Usage	Current Rates July 2024 QRAM (a)	Current Rates, Zones Current Rate Design 7.3.7 (b)	Current Rates, Zones SFVD 7.3.7 - SFVD (c)	Proposed - Harmonized SFVD - E02 (1) 7.3.1 (d)	Proposed - Harmonized SFVD 7.3.1 (e)
	Rate 01 NE to Rate E01 - Decile 1						
1	Annual Consumption (m^3)	882					
2	Design Demand (m^3/d)	9					
	Delivery Charges						
3	Monthly Charge	12	310	310	470	349	349
4	Delivery Demand	9	-	-	51	64	64
5	Delivery Commodity						
6	First 100 m³	733	79	83	3	3	3
7	Next 200 m³	149	16	16	1	1	1
8	Next 200 m³	-	-	-	-	-	-
9	Next 500 m³	-	-	-	-	-	-
10	Over 1,000 m³	-	-	-	-	-	-
11	Total Delivery Commodity	882	95	99	3	3	3
12	Facility Carbon	882	0	0	0	0	0
13	Total Delivery		405	410	524	416	416
	Gas Supply Charges						
14	Storage	882	52	11	-	-	-
15	Transportation	882	17	53	53	16	16
16	System Commodity	882	142	144	144	127	127
17	Total Gas Supply		212	208	196	143	143
18	Total Bill		617	617	720	559	559
	Rate 01 NE to Rate E01 - Decile 5						
19	Annual Consumption (m^3)	2,185					
20	Design Demand (m^3/d)	20					
	Delivery Charges						
21	Monthly Charge	12	310	310	470	349	349
22	Delivery Demand	20	-	-	120	149	149
23	Delivery Commodity						
24	First 100 m³	974	105	110	3	4	4
25	Next 200 m³	1,073	113	118	4	4	4
26	Next 200 m³	138	14	15	0	1	1
27	Next 500 m³	-	-	-	-	-	-
28	Over 1,000 m³	-	-	-	-	-	-
29	Total Delivery Commodity	2,185	232	243	8	9	9
30	Facility Carbon	2,185	0	0	0	0	0
31	Total Delivery		542	553	598	507	507
	Gas Supply Charges						
32	Storage	2,185	130	28	-	-	-
33	Transportation	2,185	42	130	130	39	39
34	System Commodity	2,185	352	356	356	315	315
35	Total Gas Supply		524	514	486	354	354
36	Total Bill		1,067	1,068	1,084	861	861
	Rate 01 NE to Rate E01 - Decile 10						
37	Annual Consumption (m^3)	10,074					
38	Design Demand (m^3/d)	90					
	Delivery Charges						
39	Monthly Charge	12	310	310	470	349	349
40	Delivery Demand	90	-	-	531	661	661
41	Delivery Commodity						
42	First 100 m³	1,200	129	136	4	5	5
43	Next 200 m³	2,113	222	233	8	8	8
44	Next 200 m³	1,531	154	162	5	6	6
45	Next 500 m³	3,116	302	317	11	12	12
46	Over 1,000 m³	2,114	198	208	8	8	8
47	Total Delivery Commodity	10,074	1,007	1,056	36	39	39

Total Bill Calculation - Union North East Rate Zone

Line No.	Particulars ($)	Usage	Current Rates July 2024 QRAM	Current Rates, Zones Current Rate Design 7.3.7	Current Rates, Zones SFVD 7.3.7 - SFVD	Proposed - Harmonized SFVD - E02 (1) 7.3.1	Proposed - Harmonized SFVD 7.3.1
			(a)	(b)	(c)	(d)	(e)
48	Facility Carbon	10,074	1	1	1	1	1
49	Total Delivery		1,318	1,368	1,038	1,051	1,051
	Gas Supply Charges						
50	Storage	10,074	598	131	-	-	-
51	Transportation	10,074	195	600	600	182	182
52	System Commodity	10,074	1,625	1,641	1,641	1,451	1,451
53	Total Gas Supply		2,418	2,372	2,241	1,632	1,632
54	Total Bill		3,736	3,741	3,279	2,684	2,684
	Rate 01 NE to Rate E01 - Atypical Low LF						
55	Annual Consumption (m^3)	2,400					
56	Design Demand (m^3/d)	51					
	Delivery Charges						
57	Monthly Charge	12	310	310	470	349	349
58	Delivery Demand	51	-	-	300	373	373
59	Delivery Commodity						
60	First 100 m³	707	76	80	3	3	3
61	Next 200 m³	974	102	107	3	4	4
62	Next 200 m³	597	60	63	2	2	2
63	Next 500 m³	123	12	12	0	0	0
64	Over 1,000 m³	-	-	-	-	-	-
65	Total Delivery Commodity	2,400	251	263	9	9	9
66	Facility Carbon	2,400	0	0	0	0	0
67	Total Delivery		561	573	778	732	732
	Gas Supply Charges						
68	Storage	2,400	142	31	-	-	-
69	Transportation	2,400	46	143	143	43	43
70	System Commodity	2,400	387	391	391	346	346
71	Total Gas Supply		576	565	534	389	389
72	Total Bill		1,137	1,139	1,312	1,121	1,121
	Rate 01 NE to Rate E01 - Atypical High LF						
73	Annual Consumption (m^3)	2,400					
74	Design Demand (m^3/d)	16					
	Delivery Charges						
75	Monthly Charge	12	310	310	470	349	349
76	Delivery Demand	16	-	-	95	118	118
77	Delivery Commodity						
78	First 100 m³	1,199	129	135	4	5	5
79	Next 200 m³	976	103	108	3	4	4
80	Next 200 m³	226	23	24	1	1	1
81	Next 500 m³	-	-	-	-	-	-
82	Over 1,000 m³	-	-	-	-	-	-
83	Total Delivery Commodity	2,400	255	267	9	9	9
84	Facility Carbon	2,400	0	0	0	0	0
85	Total Delivery		565	577	573	477	477
	Gas Supply Charges						
86	Storage	2,400	142	31	-	-	-
87	Transportation	2,400	46	143	143	43	43
88	System Commodity	2,400	387	391	391	346	346
89	Total Gas Supply		576	565	534	389	389
90	Total Bill		1,141	1,143	1,107	866	866
	Rate 10 NE to Rate E02 - Decile 1						
91	Annual Consumption (m^3)	41,745					
92	Design Demand (m^3/d)	384					
	Delivery Charges						
93	Monthly Charge	12	944	944	2,360	1,335	349
94	Delivery Demand	384	-	-	2,597	2,428	2,928
95	Delivery Commodity						
96	First 1 000 m³	11,606	1,117	1,002	37	45	45

Total Bill Calculation - Union North East Rate Zone

Line No.	Particulars ($)	Usage	Current Rates July 2024 QRAM (a)	Current Rates, Zones Current Rate Design 7.3.7 (b)	Current Rates, Zones SFVD 7.3.7 - SFVD (c)	Proposed - Harmonized SFVD - E02 (1) 7.3.1 (d)	Proposed - Harmonized SFVD 7.3.1 (e)
97	Next 9 000 m³	30,139	2,359	2,123	97	117	117
98	Next 20 000 m³	-	-	-	-	-	-
99	Next 70 000 m³	-	-	-	-	-	-
100	Over 100,000 m³	-	-	-	-	-	-
101	Total Delivery Commodity	41,745	3,476	3,125	135	162	162
102	Facility Carbon	41,745	6	6	6	6	6
103	Total Delivery		4,426	4,075	5,097	3,930	3,445
	Gas Supply Charges						
104	Storage	41,745	1,852	425	-	-	-
105	Transportation	41,745	740	2,100	2,100	679	679
106	System Commodity	41,745	6,735	6,802	6,802	6,012	6,012
107	Total Gas Supply		9,328	9,327	8,902	6,691	6,691
108	Total Bill		13,754	13,401	13,999	10,621	10,135
	Rate 10 NE to Rate E02 - Decile 5						
109	Annual Consumption (m^3)	80,275					
110	Design Demand (m^3/d)	686					
	Delivery Charges						
111	Monthly Charge	12	944	944	2,360	1,335	349
112	Delivery Demand	686	-	-	4,639	4,337	5,231
113	Delivery Commodity						
114	First 1 000 m³	12,000	1,155	1,036	39	46	46
115	Next 9 000 m³	61,917	4,847	4,361	200	240	240
116	Next 20 000 m³	6,358	431	389	20	25	25
117	Next 70 000 m³	-	-	-	-	-	-
118	Over 100,000 m³	-	-	-	-	-	-
119	Total Delivery Commodity	80,275	6,433	5,786	259	311	311
120	Facility Carbon	80,275	11	11	11	11	11
121	Total Delivery		7,388	6,742	7,269	5,994	5,902
	Gas Supply Charges						
122	Storage	80,275	3,561	816	-	-	-
123	Transportation	80,275	1,424	4,039	4,039	1,305	1,305
124	System Commodity	80,275	12,952	13,080	13,080	11,561	11,561
125	Total Gas Supply		17,937	17,935	17,119	12,866	12,866
126	Total Bill		25,326	24,676	24,387	18,860	18,768
	Rate 10 NE to Rate E02 - Decile 10						
127	Annual Consumption (m^3)	543,878					
128	Design Demand (m^3/d)	3,989					
	Delivery Charges						
129	Monthly Charge	12	944	944	2,360	1,335	349
130	Delivery Demand	3,989	-	-	26,972	25,215	30,413
131	Delivery Commodity						
132	First 1 000 m³	12,000	1,155	1,036	39	46	46
133	Next 9 000 m³	108,000	8,454	7,606	348	418	418
134	Next 20 000 m³	207,613	14,087	12,701	669	803	803
135	Next 70 000 m³	216,265	13,261	11,976	697	837	837
136	Over 100,000 m³	-	-	-	-	-	-
137	Total Delivery Commodity	543,878	36,957	33,320	1,753	2,104	2,104
138	Facility Carbon	543,878	78	78	78	78	78
139	Total Delivery		37,979	34,342	31,162	28,732	32,944
	Gas Supply Charges						
140	Storage	543,878	24,130	5,531	-	-	-
141	Transportation	543,878	9,645	27,362	27,362	8,843	8,843
142	System Commodity	543,878	87,753	88,619	88,619	78,329	78,329
143	Total Gas Supply		121,528	121,512	115,981	87,172	87,172
144	Total Bill		159,506	155,854	147,143	115,904	120,116

Note:
(1) Rate E02 Customer Charge updated to remove adjustment to set equal to Rate E01 customer charge.

Total Bill Calculation - Union South Rate Zone

Line No.	Particulars ($)	Usage	Current Rates July 2024 QRAM	Current Rates, Zones Current Rate Design 7.3.7	Current Rates, Zones SFVD 7.3.7 - SFVD	Proposed - Harmonized SFVD - E02 (1) 7.3.1	Proposed - Harmonized SFVD 7.3.1
			(a)	(b)	(c)	(d)	(e)
	Rate M1 to Rate E01 - Decile 1						
1	Annual Consumption (m^3)	816					
2	Design Demand (m^3/d)	8					
	Delivery Charges						
3	Monthly Charge	12	310	310	362	349	349
4	Delivery Demand	8	-	-	51	60	60
5	Delivery Commodity						
6	First 100 m³	711	48	64	3	3	3
7	Next 150 m³	105	7	9	0	0	0
8	Over 250 m³	-	-	-	-	-	-
9	Total Delivery Commodity	816	55	73	3	3	3
10	Facility Carbon	816	0	0	0	0	0
11	Total Delivery		365	383	417	412	412
	Gas Supply Charges						
12	Transportation	816	-	0	0	15	15
13	System Commodity	816	133	130	130	118	118
14	Total Gas Supply		133	130	130	132	132
15	Total Bill		498	513	547	545	545
	Rate M1 to Rate E01 - Decile 5						
16	Annual Consumption (m^3)	2,093					
17	Design Demand (m^3/d)	21					
	Delivery Charges						
18	Monthly Charge	12	310	310	362	349	349
19	Delivery Demand	21	-	-	130	153	153
20	Delivery Commodity						
21	First 100 m³	957	65	86	4	4	4
22	Next 150 m³	862	56	74	3	3	3
23	Over 250 m³	273	16	21	1	1	1
24	Total Delivery Commodity	2,093	137	180	8	8	8
25	Facility Carbon	2,093	0	0	0	0	0
26	Total Delivery		447	491	501	510	510
	Gas Supply Charges						
27	Transportation	2,093	-	0	0	38	38
28	System Commodity	2,093	340	333	333	301	301
29	Total Gas Supply		340	333	333	339	339
30	Total Bill		787	824	834	849	849
	Rate M1 to Rate E01 - Decile 10						
31	Annual Consumption (m^3)	9,204					
32	Design Demand (m^3/d)	84					
	Delivery Charges						
33	Monthly Charge	12	310	310	362	349	349
34	Delivery Demand	84	-	-	529	622	622
35	Delivery Commodity						
36	First 100 m³	1,200	81	107	5	5	5
37	Next 150 m³	1,784	116	153	7	7	7
38	Over 250 m³	6,221	361	470	24	24	24
39	Total Delivery Commodity	9,204	558	730	36	36	36
40	Facility Carbon	9,204	1	1	1	1	1
41	Total Delivery		869	1,042	928	1,008	1,008
	Gas Supply Charges						
42	Transportation	9,204	-	1	1	166	166
43	System Commodity	9,204	1,495	1,464	1,464	1,326	1,326
44	Total Gas Supply		1,495	1,465	1,465	1,492	1,492
45	Total Bill		2,364	2,506	2,393	2,500	2,500

Total Bill Calculation - Union South Rate Zone

Line No.	Particulars ($)	Usage	Current Rates July 2024 QRAM (a)	Current Rates, Zones Current Rate Design 7.3.7 (b)	Current Rates, Zones SFVD 7.3.7 - SFVD (c)	Proposed - Harmonized SFVD - E02 (1) 7.3.1 (d)	Proposed - Harmonized SFVD 7.3.1 (e)
	Rate M1 to Rate E01 - Atypical Low LF						
46	Annual Consumption (m^3)	2,400					
47	Design Demand (m^3/d)	51					
	Delivery Charges						
48	Monthly Charge	12	310	310	362	349	349
49	Delivery Demand	51	-	-	318	373	373
50	Delivery Commodity						
51	First 100 m³	707	48	63	3	3	3
52	Next 150 m³	750	49	64	3	3	3
53	Over 250 m³	943	55	71	4	4	4
54	Total Delivery Commodity	2,400	151	199	9	9	9
55	Facility Carbon	2,400	0	0	0	0	0
56	Total Delivery		462	509	690	732	732
	Gas Supply Charges						
57	Transportation	2,400	-	0	0	43	43
58	System Commodity	2,400	390	382	382	346	346
59	Total Gas Supply		390	382	382	389	389
60	Total Bill		852	891	1,072	1,121	1,121
	Rate M1 to Rate E01 - Atypical High LF						
61	Annual Consumption (m^3)	2,400					
62	Design Demand (m^3/d)	16					
	Delivery Charges						
63	Monthly Charge	12	310	310	362	349	349
64	Delivery Demand	16	-	-	101	118	118
65	Delivery Commodity						
66	First 100 m³	1,199	81	107	5	5	5
67	Next 150 m³	846	55	72	3	3	3
68	Over 250 m³	356	21	27	1	1	1
69	Total Delivery Commodity	2,400	157	207	9	9	9
70	Facility Carbon	2,400	0	0	0	0	0
71	Total Delivery		467	517	473	477	477
	Gas Supply Charges						
72	Transportation	2,400	-	0	0	43	43
73	System Commodity	2,400	390	382	382	346	346
74	Total Gas Supply		390	382	382	389	389
75	Total Bill		857	899	855	866	866
	Rate M2 to Rate E02 - Decile 1						
76	Annual Consumption (m^3)	40,373					
77	Design Demand (m^3/d)	419					
	Delivery Charges						
78	Monthly Charge	12	944	944	1,933	1,335	349
79	Delivery Demand	419	-	-	2,667	2,652	3,198
80	Delivery Commodity						
81	First 1 000 m3	11,602	786	815	42	45	45
82	Next 6 000 m3	28,725	1,916	1,984	104	111	111
83	Next 13 000 m3	46	3	3	0	0	0
84	All over 20 000 m3	-	-	-	-	-	-
85	Total Delivery Commodity	40,373	2,705	2,801	146	156	156
86	Facility Carbon	40,373	6	6	6	6	6
87	Total Delivery		3,655	3,751	4,752	4,148	3,709
	Gas Supply Charges						
88	Transportation	40,373	-	4	4	656	656
89	System Commodity	40,373	6,558	6,421	6,421	5,814	5,814
90	Total Gas Supply		6,558	6,425	6,425	6,471	6,471
91	Total Bill		10,213	10,176	11,177	10,619	10,180

Total Bill Calculation - Union South Rate Zone

Line No.	Particulars ($)		Usage	Current Rates July 2024 QRAM	Current Rates, Zones Current Rate Design 7.3.7	Current Rates, Zones SFVD 7.3.7 - SFVD	Proposed - Harmonized SFVD - E02 (1) 7.3.1	Proposed - Harmonized SFVD 7.3.1
				(a)	(b)	(c)	(d)	(e)
	Rate M2 to Rate E02 - Decile 5							
92	Annual Consumption (m^3)		86,306					
93	Design Demand (m^3/d)		815					
	Delivery Charges							
94	Monthly Charge		12	944	944	1,933	1,335	349
95	Delivery Demand		815	-	-	5,184	5,153	6,216
96	Delivery Commodity							
97	First	1 000 m3	12,000	813	843	43	46	46
98	Next	6 000 m3	48,241	3,218	3,331	174	187	187
99	Next	13 000 m3	26,065	1,646	1,696	94	101	101
100	All over	20 000 m3	-	-	-	-	-	-
101	Total Delivery Commodity		86,306	5,677	5,870	312	334	334
102	Facility Carbon		86,306	12	12	12	12	12
103	Total Delivery			6,634	6,826	7,441	6,834	6,911
	Gas Supply Charges							
104	Transportation		86,306	-	9	9	1,403	1,403
105	System Commodity		86,306	14,019	13,726	13,726	12,430	12,430
106	Total Gas Supply			14,019	13,735	13,735	13,833	13,833
107	Total Bill			20,653	20,561	21,176	20,667	20,744
	Rate M2 to Rate E02 - Decile 10							
108	Annual Consumption (m^3)		615,669					
109	Design Demand (m^3/d)		4,761					
	Delivery Charges							
110	Monthly Charge		12	944	944	1,933	1,335	349
111	Delivery Demand		4,761	-	-	30,271	30,094	36,297
112	Delivery Commodity							
113	First	1 000 m3	12,000	813	843	43	46	46
114	Next	6 000 m3	72,000	4,803	4,972	260	279	279
115	Next	13 000 m3	156,000	9,852	10,148	563	604	604
116	All over	20 000 m3	375,669	22,341	22,874	1,357	1,454	1,454
117	Total Delivery Commodity		615,669	37,809	38,836	2,224	2,382	2,382
118	Facility Carbon		615,669	88	88	88	88	88
119	Total Delivery			38,841	39,868	34,516	33,899	39,117
	Gas Supply Charges							
120	Transportation		615,669	-	66	66	10,010	10,010
121	System Commodity		615,669	100,005	97,916	97,916	88,668	88,668
122	Total Gas Supply			100,005	97,982	97,982	98,678	98,678
123	Total Bill			138,846	137,850	132,497	132,577	137,795

Note:
(1) Rate E02 Customer Charge updated to remove adjustment to set equal to Rate E01 customer charge.

Unit Rates for Bill Impact Calculations

Line No.	Particulars (cents/m^3)	Current Rates July 2024 QRAM (1)	Current Rates, Zones Current Rate Design 7.3.7 (2)	Current Rates, Zones SFVD 7.3.7 - SFVD (3)	Proposed - Harmonized SFVD - E02 7.3.1 (4)	Proposed - Harmonized SFVD 7.3.1 (5)
		(a)	(b)	(c)	(d)	(e)
1	Facility Carbon Charge	0.0143	0.0143	0.0143	0.0143	0.0143
	Rate 1				Rate E01	Rate E01
	Delivery Charges					
2	Monthly Charge	$24.72	$24.72	$31.19	$29.10	$29.10
3	Delivery Demand	-	-	49.4336	61.4250	61.4250
	Delivery Commodity					
4	First 30 m³	11.6864	11.3023	0.4001	0.3918	0.3918
5	Next 55 m³	10.9990	10.4968	0.4001	0.3918	0.3918
6	Next 85 m³	10.4608	9.8660	0.4001	0.3918	0.3918
7	Over 170 m³	10.0596	9.3958	0.4001	0.3918	0.3918
8	Gas Supply Transportation	4.8806	2.2641	2.2641	1.8032	1.8032
9	Gas Supply Commodity	10.4826	13.6352	13.6352	14.4019	14.4019
	Rate 6				Rate E02	Rate E02
	Delivery Charges					
10	Monthly Charge	$78.64	$78.64	$54.87	$111.24	$29.10
11	Delivery Demand	-	-	52.6238	52.6766	63.5355
	Delivery Commodity					
12	First 500 m³	11.7339	9.3832	0.3776	0.3869	0.3869
13	Next 1,050 m³	9.3630	7.1251	0.3776	0.3869	0.3869
14	Next 4,500 m³	7.7027	5.5438	0.3776	0.3869	0.3869
15	Next 7,000 m³	6.6360	4.5278	0.3776	0.3869	0.3869
16	Next 15,250 m³	6.1620	4.0764	0.3776	0.3869	0.3869
17	Over 28,300 m³	6.0430	3.9630	0.3776	0.3869	0.3869
18	Gas Supply Transportation	4.8806	2.1550	2.1550	1.6259	1.6259
19	Gas Supply Commodity	10.5065	13.6352	13.6352	14.4019	14.4019
	Rate 01				Rate E01	Rate E01
	Delivery Charges					
20	Monthly Charge	$25.85	$25.85	$39.13	$29.10	$29.10
21	Delivery Demand	-	-	49.3272	61.4250	61.4250
	Delivery Commodity					
22	First 100 m³	10.7869	11.3015	0.3553	0.3918	0.3918
23	Next 200 m³	10.5180	11.0258	0.3553	0.3918	0.3918
24	Next 200 m^3	10.0917	10.5887	0.3553	0.3918	0.3918
25	Next 500 m³	9.7006	10.1877	0.3553	0.3918	0.3918
26	Over 1,000 m³	9.3772	9.8561	0.3553	0.3918	0.3918
27	Gas Supply Transportation - NW	3.2989	5.4428	5.4428	1.8032	1.8032
28	Gas Supply Transportation - NE	1.9334	5.9568	5.9568	1.8032	1.8032
29	Storage - NW	2.2441	1.2265	-		
30	Storage - NE	5.9347	1.3000	-		
31	Gas Supply Commodity - NW	10.9951	10.9518	10.9518	14.4019	14.4019
32	Gas Supply Commodity - NE	16.1346	16.2939	16.2939	14.4019	14.4019
	Rate 10				Rate E02	Rate E02
	Delivery Charges					
33	Monthly Charge	$78.65	$78.65	$196.63	$111.24	$29.10
34	Delivery Demand	-	-	56.3480	52.6766	63.5355
	Delivery Commodity					
35	First 1 000 m³	9.6237	8.6370	0.3223	0.3869	0.3869
36	Next 9 000 m³	7.8279	7.0431	0.3223	0.3869	0.3869
37	Next 20 000 m³	6.7852	6.1175	0.3223	0.3869	0.3869
38	Next 70 000 m³	6.1320	5.5378	0.3223	0.3869	0.3869
39	Over 100,000 m³	3.6570	3.3409	0.3223	0.3869	0.3869
40	Gas Supply Transportation - NW	2.8800	5.8845	5.8845	1.6259	1.6259
41	Gas Supply Transportation - NE	1.7734	5.0309	5.0309	1.6259	1.6259
42	Storage - NW	1.7725	1.2448	-		
43	Storage - NE	4.4366	1.0170	-		
44	Gas Supply Commodity - NW	10.9951	10.9518	10.9518	14.4019	14.4019
45	Gas Supply Commodity - NE	16.1346	16.2939	16.2939	14.4019	14.4019

Unit Rates for Bill Impact Calculations

Line No.	Particulars (cents/m^3)	Current Rates July 2024 QRAM (1)	Current Rates, Zones Current Rate Design 7.3.7 (2)	Current Rates, Zones SFVD 7.3.7 - SFVD (3)	Proposed - Harmonized SFVD - E02 7.3.1 (4)	Proposed - Harmonized SFVD 7.3.1 (5)
		(a)	(b)	(c)	(d)	(e)
	Rate M1				Rate E01	Rate E01
	Delivery Charges					
46	Monthly Charge	$25.85	$25.85	$30.19	$29.10	$29.10
47	Delivery Demand	-	-	52.3094	61.4250	61.4250
	Delivery Commodity					
48	First 100 m^3	6.7635	8.9526	0.3865	0.3918	0.3918
49	Next 150 m^3	6.4933	8.5620	0.3865	0.3918	0.3918
50	All over 250 m^3	5.7957	7.5536	0.3865	0.3918	0.3918
51	Gas Supply Transportation	-	0.0107	0.0107	1.8032	1.8032
52	Gas Supply Commodity	16.2433	15.9039	15.9039	14.4019	14.4019
	Rate M2				Rate E02	Rate E02
	Delivery Charges					
53	Monthly Charge	$78.65	$78.65	$161.10	$111.24	$29.10
54	Delivery Demand	-	-	52.9865	52.6766	63.5355
	Delivery Commodity					
55	First 1 000 m^3	6.7748	7.0227	0.3612	0.3869	0.3869
56	Next 6 000 m^3	6.6713	6.9060	0.3612	0.3869	0.3869
57	Next 13 000 m^3	6.3157	6.5048	0.3612	0.3869	0.3869
58	All over 20 000 m^3	5.9469	6.0889	0.3612	0.3869	0.3869
59	Gas Supply Transportation	-	0.0107	0.0107	1.6259	1.6259
60	Gas Supply Commodity	16.2433	15.9039	15.9039	14.4019	14.4019

Notes:

(1) EB-2024-0166, Exhibit F, Tab 1, Schedule 1, Appendix A, column (c), EGD rate zone gas supply load balancing charge included in delivery commodity, Union South rate zone storage charge included in delivery commodity.

(2) Phase 3 Exhibit 8, Tab 2, Schedule 15, Attachment 2, column (h).

(3) Phase 3 Exhibit 8, Tab 2, Schedule 15, Attachment 2, column (h) adjusted to use SFVD rate design.

(4) Phase 3 Exhibit 8, Tab 2, Schedule 9, Attachment 2, column (h) adjusted to remove Rate E02 customer charge adjustment.

(5) Phase 3 Exhibit 8, Tab 2, Schedule 9, Attachment 2, column (h).

ENBRIDGE GAS INC.

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking:

Tr: 148

Christensen Associates to provide a more detailed breakdown of residential customers between the deciles, using customer numbers instead of percentages, i.e., the number of customers in each decile.

Response:

The following response was provided by Christensen Associates Energy Consulting:

Please see Table 1 for the number of residential customers for each decile in each former rate zone.

Table 1
Residential Customer Count by Decile

Rate	Region	Decile	Number of Residential Customers
E01	LEGD	1	153,969
E01	LEGD	2	163,772
E01	LEGD	3	164,373
E01	LEGD	4	165,230
E01	LEGD	5	165,025
E01	LEGD	6	164,803
E01	LEGD	7	164,301
E01	LEGD	8	164,006
E01	LEGD	9	161,175
E01	LEGD	10	130,311
E01	LUG North	1	29,841
E01	LUG North	2	31,319
E01	LUG North	3	31,529
E01	LUG North	4	31,576
E01	LUG North	5	31,556
E01	LUG North	6	31,515
E01	LUG North	7	31,396
E01	LUG North	8	31,031
E01	LUG North	9	30,183
E01	LUG North	10	21,285
E01	LUG South	1	95,589
E01	LUG South	2	101,003
E01	LUG South	3	101,617
E01	LUG South	4	101,923
E01	LUG South	5	101,984
E01	LUG South	6	101,850
E01	LUG South	7	101,532
E01	LUG South	8	100,844
E01	LUG South	9	98,586
E01	LUG South	10	77,335

ENBRIDGE GAS INC.

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking:

Tr: 149

Christensen Associates to provide a further breakout of customer numbers and volumes in the Union North rate zone, referring to CCC-18, Table 4 from 7-0-1.

Response:

The following response was provided by Christensen Associates Energy Consulting:

Table 2A-R below includes further breakout of customer numbers and volumes in the Union North rate zone based on Table 2A provided in Exhibit I.8.2-CCC-18.

Table 2A-R
Customer Migration from Current Rates to Harmonized Rate Classes Based on an Annual Total Consumption Boundary Criterion (LUG North Breakout)

		Harmonized New Rate - Customer Counts				
		Volumetric				
		E01		E02		Total
Original Rate	**Service Area**	No. of Customers	Percentage of New Rate Class	No. of Customers	Percentage of New Rate Class	No. of Customers
R1	Central	1,786,940	46.64%	1,758	1.95%	1,788,698
	East	374,210	9.77%	181	0.20%	374,391
R6	Central	100,461	2.62%	49,450	54.91%	149,910
	East	15,452	0.40%	7,612	8.45%	23,064
1 - North East	East	121,130	3.16%	1,767	1.96%	122,897
	North	145,157	3.79%	2,683	2.98%	147,841
10 - North East	East	26	0.00%	653	0.72%	679
	North	49	0.00%	875	0.97%	925
1 - North West	North	97,661	2.55%	1,473	1.64%	99,133
10 - North West	North	30	0.00%	571	0.63%	601
M1	South	1,189,843	31.06%	15,355	17.05%	1,205,199
M2	South	397	0.01%	7,680	8.53%	8,077
	Total	3,831,356	100.00%	90,058	100.00%	3,921,414

		Harmonized New Rate - Consumption (m^3)				
		Volumetric				
		E01		E02		Total
Original Rate	**Service Area**	Annual Consumption	Percentage of New Rate Class	Annual Consumption	Percentage of New Rate Class	Annual Consumption
R1	Central	4,206,935,655	45.69%	34,545,564	0.53%	4,241,481,220
	East	766,714,737	8.33%	3,391,670	0.05%	770,106,407
R6	Central	380,452,207	4.13%	3,833,849,534	58.95%	4,214,301,741
	East	62,469,535	0.68%	522,468,596	8.03%	584,938,131
1 - North East	East	245,021,194	2.66%	38,286,568	0.59%	283,307,762
	North	371,017,085	4.03%	57,894,901	0.89%	428,911,986
10 - North East	East	3,699,349	0.04%	123,721,939	1.90%	127,421,287
	North	5,195,899	0.06%	119,975,409	1.84%	125,171,308
1 - North West	North	246,106,171	2.67%	32,320,275	0.50%	278,426,446
10- North West	North	3,193,362	0.03%	72,331,076	1.11%	75,524,438
M1	South	2,875,663,885	31.23%	385,109,551	5.92%	3,260,773,436
M2	South	41,004,605	0.45%	1,279,836,665	19.68%	1,320,841,269
	Total	9,207,473,684	100.00%	6,503,731,747	100.00%	15,711,205,432

ENBRIDGE GAS INC.

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking:

Tr: 150

To provide a response on the same basis as described for JT-1.50 with reference to Exhibit 8, Tab 2, Schedule 3, Attachment 7, Page 21, Table 2.

Response:

The following response was provided by Christensen Associates Energy Consulting:

Table 2-R below includes further breakout of customer numbers and volumes in the Union North rate zone based on Phase 3 Exhibit 8, Tab 2, Schedule 3, Attachment 7, page 21, Table 2.

Table 2-R
Customer Migration from Current Rates to Harmonized Rate Classes (LUG North Breakout)

		Harmonized New Rate - Customer Counts				
		SFVD				
		E01		E02		Total
Original Rate	**Service Area**	No. of Customers	Percentage of New Rate Class	No. of Customers	Percentage of New Rate Class	No. of Customers
R1	Central	1,787,470	46.59%	1,227	1.44%	1,788,698
	East	374,251	9.76%	140	0.16%	374,391
R6	Central	102,305	2.67%	47,605	55.94%	149,910
	East	15,916	0.41%	7,148	8.40%	23,064
1 - North East	East	121,229	3.16%	1,668	1.96%	122,897
	North	145,446	3.79%	2,395	2.81%	147,841
10 - North East	East	13	0.00%	666	0.78%	679
	North	4	0.00%	921	1.08%	925
1 - North West	North	97,836	2.55%	1,297	1.52%	99,133
10 - North West	North	3	0.00%	598	0.70%	601
M1	South	1,191,753	31.07%	13,445	15.80%	1,205,198
M2	South	80	0.00%	7,997	9.40%	8,077
	Total	3,836,306	100.00%	85,108	100.00%	3,921,414

		Harmonized New Rate - Consumption (m^3)				
		SFVD				
		E01		E02		Total
Original Rate	**Service Area**	Annual Consumption	Percentage of New Rate Class	Annual Consumption	Percentage of New Rate Class	Annual Consumption
R1	Central	4,198,534,729	45.94%	42,946,491	0.65%	4,241,481,220
	East	764,127,683	8.36%	5,978,724	0.09%	770,106,407
R6	Central	413,531,614	4.52%	3,800,770,126	57.84%	4,214,301,741
	East	73,299,860	0.80%	511,638,271	7.79%	584,938,131
1 - North East	East	242,639,575	2.65%	40,668,186	0.62%	283,307,762
	North	367,392,480	4.02%	61,519,506	0.94%	428,911,986
10 - North East	East	331,497	0.00%	127,089,790	1.93%	127,421,287
	North	13,033	0.00%	125,158,275	1.90%	125,171,308
1 - North West	North	243,926,741	2.67%	34,499,705	0.53%	278,426,446
10- North West	North	13,337	0.00%	75,511,101	1.15%	75,524,438
M1	South	2,834,514,038	31.01%	426,259,398	6.49%	3,260,773,436
M2	South	1,821,759	0.02%	1,319,019,511	20.07%	1,320,841,269
	Total	9,140,146,347	100.00%	6,571,059,085	100.00%	15,711,205,432

ENBRIDGE GAS INC.

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking:

Tr: 150

To provide the detailed schedules that show the derivation of the volumetric rates for rates E01 and E02 in the same format as Exhibit 8, Tab 2, Schedule 9, Attachments 1 and 2.

Response:

Please see Attachment 1 for the derivation of alternate rates for Rate E01 and Rate E02 based on the volumetric approach.

Please note that the revenue summary information provided at Phase 3 Exhibit 8, Tab 2, Schedule 9, Attachment 1 is unchanged for this alternate rate design approach.

The rates in Attachment 1 are slightly different from the rates at Phase 3 Exhibit 8, Tab 2, Schedule 3, Attachment 7, page 37, Table A1.1, updated July 4, 2025, due to minor adjustments, as Enbridge Gas did not provide Christensen with the final version of the proposed general service rates. The difference is not material and results in a difference to typical bill impacts between 0.1% and 0.2% for all general service rate classes.

Derivation of Alternate Volumetric Rates and Revenue - One Rate Zone - Proposed
General Service

				Current Approved			Proposed 2024					
Line No.	Particulars	Billing Units	2024 Forecast Usage	Revenue ($000s)	Rates (cents/m^3)	Revenue (Deficiency) / Sufficiency ($000s)	Revenue Requirement (1) ($000s)	Revenue (Deficiency) / Sufficiency (2) ($000s)	Revenue ($000s)	Rates (cents/m^3)	Revenue-to-Cost Ratios	Rate Change (%)
			(a)	(b)	(c)	(d) = (b - e)	(e)	(f) = (g - e)	(g)	(h)	(i) = (g / e)	(j) = (h - c) / (c)
	Rate E01											
1	Monthly Customer Charge	bills	46,035,671				1,339,528	-	1,339,528	$29.10	1.000	
2	Delivery Commodity Charge	10^3m^3	9,140,146				35,815	667,768	703,583	7.6977		
3	Delivery Demand Charge	10^3m^3/d	1,087,127				677,343	(677,343)	-	-		
4	Total Delivery		9,140,146				2,052,686	(9,575)	2,043,111	22.3532	0.995	
	Gas Supply Transportation Charge											
5	Transportation	10^3m^3	9,095,333				159,931	4,079	164,010	1.8032		
6	Transportation - Western	10^3m^3	44,813				1,949	20	1,970	4.3951		
7	Gas Supply Transportation Charge		9,140,146				161,881	4,099	165,980	1.8159	1.025	
8	Gas Supply Commodity Charge	10^3m^3	8,653,117				1,246,209	-	1,246,209	14.4019	1.000	
9	Total Rate E01		9,140,146	3,492,379	38.2092	31,603	3,460,776	(5,476)	3,455,300	37.8036	0.998	(1%)
	Rate E02											
10	Monthly Customer Charge	bills	1,021,298				113,613	(83,895)	29,717	$29.10	0.262	
11	Delivery Commodity Charge	10^3m^3	6,571,059				25,424	490,874	516,299	7.8572		
12	Delivery Demand Charge	10^3m^3/d	772,599				413,865	(413,865)	-	-		
13	Total Delivery		6,571,059				552,902	(6,886)	546,016	8.3094	0.988	
	Gas Supply Transportation Charge											
14	Transportation	10^3m^3	6,371,556				100,740	2,857	103,598	1.6259		
15	Transportation - Western	10^3m^3	195,622				8,163	88	8,251	4.2178		
16	Gas Supply Transportation Charge		6,567,178				108,903	2,945	111,849	1.7031	1.027	
17	Gas Supply Commodity Charge	10^3m^3	4,113,986				592,490	-	592,490	14.4019	1.000	
18	Total Rate E02		6,571,059	1,227,459	18.6798	(26,837)	1,254,296	(3,941)	1,250,355	19.0282	0.997	2%

Notes:
(1) Revenue requirement by rate component for each rate class provided at Phase 3 Exhibit 7, Tab 3, Schedule 1, Attachment 13.
(2) Allocation of S&T Margin and other rate design adjustments.

ENBRIDGE GAS INC.

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking:

Tr: 151

To provide the bill impacts for general service customers resulting from the one rate zone with traditional volumetric rate design in the same format as the bill impacts are provided in Exhibit 8, Tab 2, Schedule 9, Attachment 10.

Response:

Please see Attachment 1.

In responding to undertakings, Enbridge Gas identified a calculation error in the current approved bill for the average Rate M2 profile filed at Phase 3 Exhibit 8, Tab 2, Schedules 9 to 14, Attachment 10, lines 22 to 28. Please see Attachment 2 for an updated bill impact for the Rate M2 average profile under the one rate zone proposed scenario and rate zone alternatives with SFVD rate design.

The updated calculation corrects the Rate M2 average bill impact from 6.1% to 2.3% for the proposed one rate zone, which impacts the proposed rate mitigation and Rider R adjustment for this rate class. Please see Attachment 3 for an updated version of the proposed Rider R and bill impacts for general service. This attachment corrects evidence that was filed at Phase 3 Exhibit 8, Tab 2, Schedule 9, Attachment 18, updated July 4, 2025. Table 1 summarizes the results of these corrections.

Table 1
Summary of Rider R Bill Impacts

Line No.	Total Bill Impacts	As Filed July 4, 2025 Excluding Rider R Adjustment	As Filed July 4, 2025 Including Rider R Adjustment	Updated Per Attachment 3 Excluding Rider R Adjustment	Updated Per Attachment 3 Including Rider R Adjustment
		(a)	(b)	(c)	(d)
	General Service				
1	Rate 1	0.7%	2.0%	0.7%	1.7%
2	Rate 6	(13.6%)	(12.1%)	(13.6%)	(12.4%)
3	Rate 01 - NW	(5.0%)	(3.9%)	(5.0%)	(4.1%)
4	Rate 01 - NE	(19.5%)	(18.7%)	(19.5%)	(18.8%)
5	Rate 10 - NW	(3.4%)	(1.7%)	(3.4%)	(2.0%)
6	Rate 10 - NE	(24.1%)	(22.7%)	(24.1%)	(23.0%)
7	Rate M1	6.4%	2.8%	6.4%	2.8%
8	Rate M2	6.1%	3.3%	2.3%	3.3%

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - One Rate Zone - Proposed - Alternate Volumetric Rate Design
EGD Rate Zone

Line No.	Particulars	EB-2024-0166 - Current Approved (1)(2) Total Bill ($) (a)	EB-2024-0166 - Current Approved (1)(2) Unit Rate (cents/m^3) (b)	EB-2025-0064 - 2024 Proposed (2) Total Bill ($) (c)	EB-2025-0064 - 2024 Proposed (2) Unit Rate (cents/m^3) (d)	Total Bill Change ($) (e) = (c - a)	Bill Impact Including Federal Carbon Charge (%) (f) = (e / a)	Bill Impact Excluding Federal Carbon Charge (%) (g)
	Small Rate 1 to Rate E01	Demand 24 m^3 Annual Volume 2,400 m^3						
1	Delivery Charges	552	22.9924	534	22.2608	(18)	(3.2%)	(3.2%)
2	Federal Carbon Charge	366	15.2500	366	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	117	4.8806	43	1.8032	(74)	(63.1%)	(63.1%)
4	Gas Supply Commodity	252	10.4826	346	14.4019	94	37.4%	37.4%
5	Total Bill - Sales Service	1,287	53.6056	1,289	53.7159	3	0.2%	0.3%
6	Total Bill - Bundled Direct Purchase WTS	1,381	57.5249	1,351	56.3078	(29)	(2.1%)	(2.9%)
7	Bundled Direct Purchase Impact WTS						(2.8%)	(4.4%)
8	Total Bill - Bundled Direct Purchase DTS	1,286	53.5843	1,289	53.7159	3	0.2%	0.3%
9	Bundled Direct Purchase Impact DTS						0.3%	0.5%
	Large Rate 1 to Rate E01	Demand 51 m^3 Annual Volume 5,048 m^3						
10	Delivery Charges	821	16.2702	738	14.6290	(83)	(10.1%)	(10.1%)
11	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
12	Gas Supply Transportation	246	4.8806	91	1.8032	(155)	(63.1%)	(63.1%)
13	Gas Supply Commodity	529	10.4826	727	14.4019	198	37.4%	37.4%
14	Total Bill - Sales Service	2,367	46.8834	2,326	46.0841	(40)	(1.7%)	(2.5%)
15	Total Bill - Bundled Direct Purchase WTS	2,565	50.8026	2,457	48.6760	(107)	(4.2%)	(6.0%)
16	Bundled Direct Purchase Impact WTS						(5.8%)	(10.1%)
17	Total Bill - Bundled Direct Purchase DTS	2,366	46.8620	2,326	46.0841	(39)	(1.7%)	(2.5%)
18	Bundled Direct Purchase Impact DTS						(2.4%)	(4.5%)
	Small Rate 6 to Rate E01	Demand 51 m^3 Annual Volume 5,048 m^3						
19	Delivery Charges	1,524	30.1901	738	14.6290	(786)	(51.5%)	(51.5%)
20	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
21	Gas Supply Transportation	246	4.8806	91	1.8000	(155)	(63.1%)	(63.1%)
22	Gas Supply Commodity	530	10.5065	727	14.4019	197	37.1%	37.1%
23	Total Bill - Sales Service	3,071	60.8272	2,326	46.0841	(744)	(24.2%)	(32.3%)
24	Total Bill - Bundled Direct Purchase WTS	3,267	64.7226	2,457	48.6760	(810)	(24.8%)	(32.4%)
25	Bundled Direct Purchase Impact WTS						(31.9%)	(45.8%)
26	Total Bill - Bundled Direct Purchase DTS	3,068	60.7820	2,326	46.0841	(742)	(24.2%)	(32.3%)
27	Bundled Direct Purchase Impact DTS						(31.7%)	(47.2%)
	Average Rate 6 to Rate E02	Demand 206 m^3 Annual Volume 22,606 m^3						
28	Delivery Charges	3,046	13.4745	2,129	9.4161	(917)	(30.1%)	(30.1%)
29	Federal Carbon Charge	3,447	15.2500	3,447	15.2500	-	0.0%	0.0%
30	Gas Supply Transportation	1,103	4.8806	368	1.6300	(736)	(66.7%)	(66.7%)
31	Gas Supply Commodity	2,375	10.5065	3,256	14.4019	881	37.1%	37.1%
32	Total Bill - Sales Service	9,972	44.1116	9,199	40.6939	(773)	(7.7%)	(11.8%)
33	Total Bill - Bundled Direct Purchase WTS	10,852	48.0069	9,785	193.8427	(1,067)	(9.8%)	(14.4%)
34	Bundled Direct Purchase Impact WTS						(14.0%)	(25.7%)
35	Total Bill - Bundled Direct Purchase DTS	9,962	44.0663	9,199	182.2356	(762)	(7.7%)	(11.7%)
36	Bundled Direct Purchase Impact DTS						(11.4%)	(23.4%)
	Large Rate 6 to Rate E02	Demand 3,097 m^3 Annual Volume 339,124 m^3						
37	Delivery Charges	23,794	7.0162	27,043	7.9744	3,249	13.7%	13.7%
38	Federal Carbon Charge	51,716	15.2500	51,716	15.2500	-	0.0%	0.0%
39	Gas Supply Transportation	16,551	4.8806	5,514	1.6259	(11,037)	(66.7%)	(66.7%)
40	Gas Supply Commodity	35,630	10.5065	48,840	14.4019	13,210	37.1%	37.1%
41	Total Bill - Sales Service	127,692	37.6533	133,114	39.2522	5,422	4.2%	7.1%
42	Total Bill - Bundled Direct Purchase WTS	140,902	41.5487	141,903	41.8441	1,002	0.7%	1.1%
43	Bundled Direct Purchase Impact WTS						1.1%	2.5%
44	Total Bill - Bundled Direct Purchase DTS	127,538	37.6081	133,114	39.2522	5,576	4.4%	7.4%
45	Bundled Direct Purchase Impact DTS						7.1%	20.7%

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - One Rate Zone - Proposed - Alternate Volumetric Rate Design
Union North Rate Zone

Line No.	Particulars	EB-2024-0166 - Current Approved (1)(2)(3) Total Bill ($)	Unit Rate (cents/m³)	EB-2025-0064 - 2024 Proposed (2) Total Bill ($)	Unit Rate (cents/m³)	Total Bill Change ($)	Bill Impact Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate 01 to Rate E01	Demand 20 m³ Annual Volume 2,200 m³						
1	Delivery Charges	544	24.7128	519	23.5834	(25)	(4.6%)	(4.6%)
2	Federal Carbon Charge	336	15.2500	336	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	173	7.8681	40	1.8032	(133)	(77.1%)	(77.1%)
4	Gas Supply Commodity	355	16.1346	317	14.4019	(38)	(10.7%)	(10.7%)
5	Total Bill - Sales Service	1,407	63.9655	1,211	55.0385	(196)	(14.0%)	(18.3%)
6	Total Bill - Bundled Direct Purchase	1,369	62.2327	1,211	55.0385	(158)	(11.6%)	(15.3%)
7	Bundled Direct Purchase Impact						(15.0%)	(22.1%)
	Large Rate 01 to Rate E02	Demand 365 m³ Annual Volume 40,000 m³						
8	Delivery Charges	4,148	10.3691	3,498	8.7444	(650)	(15.7%)	(15.7%)
9	Federal Carbon Charge	6,100	15.2500	6,100	15.2500	-	0.0%	0.0%
10	Gas Supply Transportation	3,147	7.8681	650	1.6259	(2,497)	(79.3%)	(79.3%)
11	Gas Supply Commodity	6,454	16.1346	5,761	14.4019	(693)	(10.7%)	(10.7%)
12	Total Bill - Sales Service	19,849	49.6218	16,009	40.0222	(3,840)	(19.3%)	(27.9%)
13	Total Bill - Bundled Direct Purchase	19,156	47.8891	16,009	40.0222	(3,147)	(16.4%)	(24.1%)
14	Bundled Direct Purchase Impact						(23.5%)	(43.1%)
	Small Rate 10 to Rate E02	Demand 548 m³ Annual Volume 60,000 m³						
15	Delivery Charges	5,865	9.7744	5,072	8.4534	(793)	(13.5%)	(13.5%)
16	Federal Carbon Charge	9,150	15.2500	9,150	15.2500	-	0.0%	0.0%
17	Gas Supply Transportation	3,726	6.2100	976	1.6259	(2,750)	(73.8%)	(73.8%)
18	Gas Supply Commodity	9,681	16.1346	8,641	14.4019	(1,040)	(10.7%)	(10.7%)
19	Total Bill - Sales Service	28,421	47.3690	23,839	39.7312	(4,583)	(16.1%)	(23.8%)
20	Total Bill - Bundled Direct Purchase	27,382	45.6362	23,839	39.7312	(3,543)	(12.9%)	(19.4%)
21	Bundled Direct Purchase Impact						(18.9%)	(36.9%)
	Average Rate 10 to Rate E02	Demand 850 m³ Annual Volume 93,000 m³						
22	Delivery Charges	8,330	8.9572	7,670	8.2469	(661)	(7.9%)	(7.9%)
23	Federal Carbon Charge	14,183	15.2500	14,183	15.2500	-	0.0%	0.0%
24	Gas Supply Transportation	5,775	6.2100	1,512	1.6259	(4,263)	(73.8%)	(73.8%)
25	Gas Supply Commodity	15,005	16.1346	13,394	14.4019	(1,611)	(10.7%)	(10.7%)
26	Total Bill - Sales Service	43,293	46.5518	36,758	39.5247	(6,535)	(15.1%)	(22.4%)
27	Total Bill - Bundled Direct Purchase	41,682	44.8190	36,758	39.5247	(4,924)	(11.8%)	(17.9%)
28	Bundled Direct Purchase Impact						(17.4%)	(34.9%)
	Large Rate 10 to Rate E02	Demand 2,285 m³ Annual Volume 250,000 m³						
29	Delivery Charges	19,249	7.6998	20,028	8.0111	778	4.0%	4.0%
30	Federal Carbon Charge	38,125	15.2500	38,125	15.2500	-	0.0%	0.0%
31	Gas Supply Transportation	15,525	6.2100	4,065	1.6259	(11,460)	(73.8%)	(73.8%)
32	Gas Supply Commodity	40,337	16.1346	36,005	14.4019	(4,332)	(10.7%)	(10.7%)
33	Total Bill - Sales Service	113,236	45.2944	98,222	39.2889	(15,014)	(13.3%)	(20.0%)
34	Total Bill - Bundled Direct Purchase	108,904	43.5616	98,222	39.2889	(10,682)	(9.8%)	(15.1%)
35	Bundled Direct Purchase Impact						(14.7%)	(30.7%)

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.
(3) Gas Supply charges based on Union North East Rate Zone.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - One Rate Zone - Proposed - Alternate Volumetric Rate Design
Union South Rate Zone

		EB-2024-0166 - Current Approved (1)(2)		EB-2025-0064 - 2024 Proposed (2)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate M1 to Rate E01	Demand 20 m^3 Annual Volume 2,200 m^3						
1	Delivery Charges	453	20.5998	519	23.5834	66	14.5%	14.5%
2	Federal Carbon Charge	336	15.2500	336	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	-	-	40	1.8032	40	100.0%	100.0%
4	Gas Supply Commodity	357	16.2433	317	14.4019	(41)	(11.3%)	(11.3%)
5	Total Bill - Sales Service	1,146	52.0930	1,211	55.0385	65	5.7%	8.0%
6	Total Bill - Bundled Direct Purchase	1,106	50.2516	1,211	55.0385	105	9.5%	13.7%
7	Bundled Direct Purchase Impact						13.4%	23.2%
	Large Rate M1 to Rate E02	Demand 365 m^3 Annual Volume 40,000 m^3						
8	Delivery Charges	2,658	6.6459	3,498	8.7444	839	31.6%	31.6%
9	Federal Carbon Charge	6,100	15.2500	6,100	15.2500	-	0.0%	0.0%
10	Gas Supply Transportation	-	-	650	1.6259	650	100.0%	100.0%
11	Gas Supply Commodity	6,497	16.2433	5,761	14.4019	(737)	(11.3%)	(11.3%)
12	Total Bill - Sales Service	15,256	38.1392	16,009	40.0222	753	4.9%	8.2%
13	Total Bill - Bundled Direct Purchase	14,519	36.2978	16,009	40.0222	1,490	10.3%	17.7%
14	Bundled Direct Purchase Impact						17.0%	56.0%
	Small Rate M2 to Rate E02	Demand 613 m^3 Annual Volume 60,000 m^3						
15	Delivery Charges	4,933	8.2216	5,072	8.4534	139	2.8%	2.8%
16	Federal Carbon Charge	9,150	15.2500	9,150	15.2500	-	0.0%	0.0%
17	Gas Supply Transportation	-	-	976	1.6259	976	100.0%	100.0%
18	Gas Supply Commodity	9,746	16.2433	8,641	14.4019	(1,105)	(11.3%)	(11.3%)
19	Total Bill - Sales Service	23,829	39.7148	23,839	39.7312	10	0.0%	0.1%
20	Total Bill - Bundled Direct Purchase	22,724	37.8734	23,839	39.7312	1,115	4.9%	8.2%
21	Bundled Direct Purchase Impact						7.9%	22.6%
	Average Rate M2 to Rate E02	Demand 746 m^3 Annual Volume 73,000 m^3						
22	Delivery Charges	5,773	7.9082	6,095	8.3498	322	5.6%	5.6%
23	Federal Carbon Charge	11,133	15.2500	11,133	15.2500	-	0.0%	0.0%
24	Gas Supply Transportation	-	-	1,187	1.6259	1,187	100.0%	100.0%
25	Gas Supply Commodity	11,858	16.2433	10,513	14.4019	(1,344)	(11.3%)	(11.3%)
26	Total Bill - Sales Service	28,763	39.4015	28,928	39.6276	165	0.6%	0.9%
27	Total Bill - Bundled Direct Purchase	27,419	37.5601	28,928	39.6276	1,509	5.5%	9.3%
28	Bundled Direct Purchase Impact						8.9%	26.1%
	Large Rate M2 to Rate E02	Demand 2,556 m^3 Annual Volume 250,000 m^3						
29	Delivery Charges	16,762	6.7047	20,028	8.0111	3,266	19.5%	19.5%
30	Federal Carbon Charge	38,125	15.2500	38,125	15.2500	-	0.0%	0.0%
31	Gas Supply Transportation	-	-	4,065	1.6259	4,065	100.0%	100.0%
32	Gas Supply Commodity	40,608	16.2433	36,005	14.4019	(4,603)	(11.3%)	(11.3%)
33	Total Bill - Sales Service	95,495	38.1979	98,222	39.2889	2,727	2.9%	4.8%
34	Total Bill - Bundled Direct Purchase	90,891	36.3565	98,222	39.2889	7,331	8.1%	13.9%
35	Bundled Direct Purchase Impact						13.4%	43.7%

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.

Calculation of Sales Service and Direct Purchase Bill Impacts
One Rate Zone Proposed - Rate M2 Average Profile

		EB-2024-0166 - Current Approved (1)(2)		EB-2025-0064 - 2024 Proposed (2)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Updated - Phase 3 Exhibit 8, Tab 2, Schedule 9, Attachment 10, p. 6, lines 22 - 28							
	Average Rate M2 to Rate E02	Demand 746 m^3 Annual Volume 73,000 m^3						
22	Delivery Charges	5,773	7.9082	6,332	8.6743	559	9.7%	9.7%
23	Federal Carbon Charge	11,133	15.2500	11,133	15.2500	-	0.0%	0.0%
24	Gas Supply Transportation	-	-	1,187	1.6259	1,187	100.0%	100.0%
25	Gas Supply Commodity	11,858	16.2433	10,513	14.4019	(1,344)	(11.3%)	(11.3%)
26	Total Bill - Sales Service	28,763	39.4015	29,165	39.9521	402	1.4%	2.3%
27	Total Bill - Bundled Direct Purchase	27,419	37.5601	29,165	39.9521	1,746	6.4%	10.7%
28	Bundled Direct Purchase Impact						10.3%	30.2%

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.

Derivation of Rate Mitigation Adjustment - Rider R

Line No.	Particulars		Revenue Adjustment Year 1 ($000s)	Year 2 ($000s)	Year 3 ($000s)	Year 4 ($000s)	Year 5 ($000s)	Billing Units ($10^3m^3/d$)	Unit Rate Year 1 (cents/m^3/d)	Year 2 (cents/m^3/d)	Year 3 (cents/m^3/d)	Year 4 (cents/m^3/d)	Year 5 (cents/m^3/d)
			(a)	(b)	(c)	(d)	(e)	(f)	(g) = (a / f)	(h) = (b / f)	(i) = (c / f)	(j) = (d / f)	(k) = (e / f)
	General Service												
	Rider R Unit Rate												
1	Union South Rate Zone	Volume ≤ 50,000 m^3	(56,498)	(42,374)	(28,249)	(14,125)	-	372,816	(15.1544)	(11.3658)	(7.5772)	(3.7886)	-
2	Union South Rate Zone	Volume > 50,000 m^3	(1,645)	(1,234)	(823)	(411)	-	138,060	(1.1918)	(0.8938)	(0.5959)	(0.2979)	-
3	Total Rider R		(58,143)	(43,608)	(29,072)	(14,536)	-						
	Base Rate Adjustment												
4	Rate E01	All Customers	33,988	25,491	16,994	8,497	-	1,087,127	3.1264	2.3448	1.5632	0.7816	-
5	Rate E02	All Customers	24,155	18,116	12,077	6,039	-	772,599	3.1264	2.3448	1.5632	0.7816	-
6	Total Base Rate Adjustment		58,143	43,608	29,072	14,536	-						
7	Total General Service		-	-	-	-	-						

Rate Mitigation Adjustment - Bill Impacts in First Year of Implementation

				Mitigation Unit Rate				Total Bill			2024 Total Bill Impact		2024 Total Bill Impact %	
Line No.	Particulars	Harmonized Rate Class	Annual Demand (m^3/d)	Base Rate Adjustment (1) (cents/m^3/d)	Rider R (2) (cents/m^3/d)	Total Year 1 Adjustment (cents/m^3/d)	Total Year 1 Adjustment ($)	Current Approved (3) ($)	2024 Proposed - Excluding Rider R (4) ($)	2024 Proposed - Including Rider R ($)	Excluding Rider R ($)	Including Rider R ($)	Excluding Rider R (%)	Including Rider R (%)
		(a)	(b)	(c)	(d)	(e) = (c + d)	(f) = (b*e*12/100)	(g)	(h)	(i) = (f + h)	(j) = (h - g)	(k) = (i - g)	(l) = (j / g))	(m) = (k / g)
	General Service													
	EGD Rate Zone													
1	Rate 1 - Small	Rate E01	24	3.1264	-	3.1264	9	921	927	937	7	16	0.7%	1.7%
2	Rate 1 - Large	Rate E01	51	3.1264	-	3.1264	19	1,597	1,565	1,585	(31)	(12)	(2.0%)	(0.8%)
3	Rate 6 - Small	Rate E01	51	3.1264	-	3.1264	19	2,301	1,565	1,585	(735)	(716)	(32.0%)	(31.1%)
4	Rate 6 - Average	Rate E02	206	3.1264	-	3.1264	77	6,524	5,637	5,715	(887)	(810)	(13.6%)	(12.4%)
5	Rate 6 - Large	Rate E02	3,097	3.1264	-	3.1264	1,162	75,975	79,676	80,838	3,701	4,863	4.9%	6.4%
	Union North West Rate Zone													
6	Rate 01 - Small	Rate E01	20	3.1264	-	3.1264	8	908	862	870	(45)	(38)	(5.0%)	(4.1%)
7	Rate 01 - Large	Rate E02	365	3.1264	-	3.1264	137	10,763	9,700	9,837	(1,063)	(926)	(9.9%)	(8.6%)
8	Rate 10 - Small	Rate E02	548	3.1264	-	3.1264	206	15,253	14,388	14,593	(866)	(660)	(5.7%)	(4.3%)
9	Rate 10 - Average	Rate E02	850	3.1264	-	3.1264	319	22,882	22,109	22,428	(774)	(455)	(3.4%)	(2.0%)
10	Rate 10 - Large	Rate E02	2,285	3.1264	-	3.1264	857	58,368	58,843	59,700	474	1,332	0.8%	2.3%
	Union North East Rate Zone													
11	Rate 01 - Small	Rate E01	20	3.1264	-	3.1264	8	1,072	862	870	(209)	(202)	(19.5%)	(18.8%)
12	Rate 01 - Large	Rate E02	365	3.1264	-	3.1264	137	13,749	9,700	9,837	(4,049)	(3,912)	(29.4%)	(28.5%)
13	Rate 10 - Small	Rate E02	548	3.1264	-	3.1264	206	19,271	14,388	14,593	(4,884)	(4,678)	(25.3%)	(24.3%)
14	Rate 10 - Average	Rate E02	850	3.1264	-	3.1264	319	29,111	22,109	22,428	(7,002)	(6,683)	(24.1%)	(23.0%)
15	Rate 10 - Large	Rate E02	2,285	3.1264	-	3.1264	857	75,111	58,843	59,700	(16,268)	(15,411)	(21.7%)	(20.5%)
	Union South Rate Zone													
16	Rate M1 - Small	Rate E01	20	3.1264	(15.1544)	(12.0280)	(29)	811	862	833	52	23	6.4%	2.8%
17	Rate M1 - Large	Rate E02	365	3.1264	(15.1544)	(12.0280)	(526)	9,156	9,700	9,174	544	18	5.9%	0.2%
18	Rate M2 - Small	Rate E02	613	3.1264	(1.1918)	1.9347	142	14,679	14,883	15,026	205	347	1.4%	2.4%
19	Rate M2 - Average	Rate E02	746	3.1264	(1.1918)	1.9347	173	17,631	18,033	18,206	402	575	2.3%	3.3%
20	Rate M2 - Large	Rate E02	2,556	3.1264	(1.1918)	1.9347	593	57,370	60,909	61,502	3,539	4,132	6.2%	7.2%

Notes:
(1) Page 1, column (g).
(2) Ibid.
(3) Total bill for typical general service customers at current approved rates per Exhibit I.JT-1.53 Attachment 2, column (a), excluding federal carbon charge.
(4) Total bill for typical general service customers at 2024 proposed rates per Exhibit I.JT-1.53 Attachment 2, column (c), excluding federal carbon charge.

ENBRIDGE GAS INC.

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking:

Tr: 157

To advise Enbridge's position on whether it can provide the volumetric rates for all the rate zone alternatives in the same format as Exhibit 8.2.9 through 8.2.14, Attachments 1, 2, and 10; and to provide by August 1 an estimated timing.

Response:

Please see Attachments 1 to 5.

Please note that the revenue summary information provided at Phase 3 Exhibit 8, Tab 2, Schedules 10 to 14, Attachment 1 is unchanged for this alternate rate design approach and therefore has not been provided as requested in this undertaking.

Enbridge Gas identified a calculation error in the current approved bill for the average Rate M2 profile included in Phase 3 Exhibit 8, Tab 2, Schedule 10 through 14, Attachment 10. Please see Exhibit JT1.53 for the updated bill impact for the Rate M2 average profile with SFVD rate design for the respective rate zone alternatives.

Derivation of Alternate Volumetric Rates and Revenue - One Rate Zone - No Regional Adjustments
General Service

Line No.	Particulars	Billing Units	2024 Forecast Usage	Current Approved Revenue ($000s)	Current Approved Rates (cents/m^3)	Revenue (Deficiency) / Sufficiency ($000s)	Proposed 2024 Revenue Requirement (1) ($000s)	Proposed 2024 Revenue (Deficiency) / Sufficiency (2) ($000s)	Proposed 2024 Revenue ($000s)	Proposed 2024 Rates (cents/m^3)	Proposed 2024 Revenue-to-Cost Ratios	Proposed 2024 Rate Change (%)
			(a)	(b)	(c)	(d) = (b - e)	(e)	(f) = (g - e)	(g)	(h)	(i) = (g / e)	(j) = (h - c) / (c)
	Rate E01											
1	Monthly Customer Charge	bills	46,035,671				1,339,528	-	1,339,528	$29.10	1.000	
2	Delivery Commodity Charge	10^3m^3	9,140,146				35,832	669,908	705,740	7.7213		
3	Delivery Demand Charge	10^3m^3/d	1,087,127				678,372	(678,372)	-	-		
4	Total Delivery		9,140,146				2,053,732	(8,464)	2,045,268	22.3768	0.996	
	Gas Supply Transportation Charge											
5	Transportation	10^3m^3	9,095,333				131,930	-	131,930	1.4505		
6	Transportation - Western	10^3m^3	44,813				1,812	-	1,812	4.0424		
7	Gas Supply Transportation Charge		9,140,146				133,742	-	133,742	1.4632	1.000	
8	Gas Supply Commodity Charge	10^3m^3	8,653,117				1,246,209	-	1,246,209	14.4019	1.000	
9	Total Rate E01		9,140,146	3,492,379	38.2092	58,696	3,433,683	(8,464)	3,425,220	37.4744	0.998	(2%)
	Rate E02											
10	Monthly Customer Charge	bills	1,021,298				113,613	(83,895)	29,717	$29.10	0.262	
11	Delivery Commodity Charge	10^3m^3	6,571,059				25,521	491,781	517,302	7.8724		
12	Delivery Demand Charge	10^3m^3/d	772,599				413,898	(413,898)	-	-		
13	Total Delivery		6,571,059				553,031	(6,012)	547,019	8.3247	0.989	
	Gas Supply Transportation Charge											
14	Transportation	10^3m^3	6,371,556				91,603	-	91,603	1.4377		
15	Transportation - Western	10^3m^3	195,622				7,883	-	7,883	4.0296		
16	Gas Supply Transportation Charge		6,567,178				99,485	-	99,485	1.5149	1.000	
17	Gas Supply Commodity Charge	10^3m^3	4,113,986				592,490	-	592,490	14.4019	1.000	
18	Total Rate E02		6,571,059	1,227,459	18.6798	(17,548)	1,245,007	(6,012)	1,238,995	18.8553	0.995	1%

Notes:
(1) Revenue requirement by rate component for each rate class provided at Phase 3 Exhibit 7, Tab 3, Schedule 2, Attachment 13.
(2) Allocation of S&T Margin and other rate design adjustments.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - One Rate Zone - No Regional Adjustments - Alternate Volumetric Rate Design
EGD Rate Zone

		EB-2024-0166 - Current Approved (1)(2)		EB-2025-0064 - 2024 Proposed (2)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate 1 to Rate E01	Demand 24 m^3 Annual Volume 2,400 m^3						
1	Delivery Charges	552	22.9924	535	22.2844	(17)	(3.1%)	(3.1%)
2	Federal Carbon Charge	366	15.2500	366	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	117	4.8806	35	1.4505	(82)	(70.3%)	(70.3%)
4	Gas Supply Commodity	252	10.4826	346	14.4019	94	37.4%	37.4%
5	Total Bill - Sales Service	1,287	53.6056	1,281	53.3868	(5)	(0.4%)	(0.6%)
6	Total Bill - Bundled Direct Purchase WTS	1,381	57.5249	1,343	55.9787	(37)	(2.7%)	(3.7%)
7	Bundled Direct Purchase Impact WTS						(3.6%)	(5.5%)
8	Total Bill - Bundled Direct Purchase DTS	1,286	53.5843	1,281	53.3868	(5)	(0.4%)	(0.5%)
9	Bundled Direct Purchase Impact DTS						(0.5%)	(0.8%)
	Large Rate 1 to Rate E01	Demand 51 m^3 Annual Volume 5,048 m^3						
10	Delivery Charges	821	16.2702	740	14.6526	(82)	(9.9%)	(9.9%)
11	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
12	Gas Supply Transportation	246	4.8806	73	1.4505	(173)	(70.3%)	(70.3%)
13	Gas Supply Commodity	529	10.4826	727	14.4019	198	37.4%	37.4%
14	Total Bill - Sales Service	2,367	46.8834	2,310	45.7550	(57)	(2.4%)	(3.6%)
15	Total Bill - Bundled Direct Purchase WTS	2,565	50.8026	2,441	48.3469	(124)	(4.8%)	(6.9%)
16	Bundled Direct Purchase Impact WTS						(6.7%)	(11.6%)
17	Total Bill - Bundled Direct Purchase DTS	2,366	46.8620	2,310	45.7550	(56)	(2.4%)	(3.5%)
18	Bundled Direct Purchase Impact DTS						(3.4%)	(6.4%)
	Small Rate 6 to Rate E01	Demand 51 m^3 Annual Volume 5,048 m^3						
19	Delivery Charges	1,524	30.1901	740	14.6526	(784)	(51.5%)	(51.5%)
20	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
21	Gas Supply Transportation	246	4.8806	73	1.4500	(173)	(70.3%)	(70.3%)
22	Gas Supply Commodity	530	10.5065	727	14.4019	197	37.1%	37.1%
23	Total Bill - Sales Service	3,071	60.8272	2,310	45.7550	(761)	(24.8%)	(33.1%)
24	Total Bill - Bundled Direct Purchase WTS	3,267	64.7226	2,441	48.3469	(827)	(25.3%)	(33.1%)
25	Bundled Direct Purchase Impact WTS						(32.5%)	(46.7%)
26	Total Bill - Bundled Direct Purchase DTS	3,068	60.7820	2,310	45.7550	(759)	(24.7%)	(33.0%)
27	Bundled Direct Purchase Impact DTS						(32.4%)	(48.3%)
	Average Rate 6 to Rate E02	Demand 206 m^3 Annual Volume 22,606 m^3						
28	Delivery Charges	3,046	13.4745	2,132	9.4313	(914)	(30.0%)	(30.0%)
29	Federal Carbon Charge	3,447	15.2500	3,447	15.2500	-	0.0%	0.0%
30	Gas Supply Transportation	1,103	4.8806	325	1.4400	(778)	(70.5%)	(70.5%)
31	Gas Supply Commodity	2,375	10.5065	3,256	14.4019	881	37.1%	37.1%
32	Total Bill - Sales Service	9,972	44.1116	9,160	40.5209	(812)	(8.1%)	(12.4%)
33	Total Bill - Bundled Direct Purchase WTS	10,852	48.0069	9,746	193.0680	(1,106)	(10.2%)	(14.9%)
34	Bundled Direct Purchase Impact WTS						(14.6%)	(26.7%)
35	Total Bill - Bundled Direct Purchase DTS	9,962	44.0663	9,160	181.4609	(801)	(8.0%)	(12.3%)
36	Bundled Direct Purchase Impact DTS						(12.0%)	(24.6%)
	Large Rate 6 to Rate E02	Demand 3,097 m^3 Annual Volume 339,124 m^3						
37	Delivery Charges	23,794	7.0162	27,095	7.9897	3,301	13.9%	13.9%
38	Federal Carbon Charge	51,716	15.2500	51,716	15.2500	-	0.0%	0.0%
39	Gas Supply Transportation	16,551	4.8806	4,876	1.4377	(11,676)	(70.5%)	(70.5%)
40	Gas Supply Commodity	35,630	10.5065	48,840	14.4019	13,210	37.1%	37.1%
41	Total Bill - Sales Service	127,692	37.6533	132,527	39.0792	4,836	3.8%	6.4%
42	Total Bill - Bundled Direct Purchase WTS	140,902	41.5487	141,317	41.6711	415	0.3%	0.5%
43	Bundled Direct Purchase Impact WTS						0.5%	1.0%
44	Total Bill - Bundled Direct Purchase DTS	127,538	37.6081	132,527	39.0792	4,989	3.9%	6.6%
45	Bundled Direct Purchase Impact DTS						6.3%	18.5%

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - One Rate Zone - No Regional Adjustments - Alternate Volumetric Rate Design
Union North Rate Zone

Line No.	Particulars	EB-2024-0166 - Current Approved (1)(2)(3) Total Bill ($)	Unit Rate (cents/m³)	EB-2025-0064 - 2024 Proposed (2) Total Bill ($)	Unit Rate (cents/m³)	Total Bill Change ($)	Bill Impact Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate 01 to Rate E01	Demand 20 m³ Annual Volume 2,200 m³						
1	Delivery Charges	544	24.7128	519	23.6070	(24)	(4.5%)	(4.5%)
2	Federal Carbon Charge	336	15.2500	336	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	173	7.8681	32	1.4505	(141)	(81.6%)	(81.6%)
4	Gas Supply Commodity	355	16.1346	317	14.4019	(38)	(10.7%)	(10.7%)
5	Total Bill - Sales Service	1,407	63.9655	1,204	54.7094	(204)	(14.5%)	(19.0%)
6	Total Bill - Bundled Direct Purchase	1,369	62.2327	1,204	54.7094	(166)	(12.1%)	(16.0%)
7	Bundled Direct Purchase Impact						(15.7%)	(23.1%)
	Large Rate 01 to Rate E02	Demand 365 m³ Annual Volume 40,000 m³						
8	Delivery Charges	4,148	10.3691	3,504	8.7597	(644)	(15.5%)	(15.5%)
9	Federal Carbon Charge	6,100	15.2500	6,100	15.2500	-	0.0%	0.0%
10	Gas Supply Transportation	3,147	7.8681	575	1.4377	(2,572)	(81.7%)	(81.7%)
11	Gas Supply Commodity	6,454	16.1346	5,761	14.4019	(693)	(10.7%)	(10.7%)
12	Total Bill - Sales Service	19,849	49.6218	15,940	39.8492	(3,909)	(19.7%)	(28.4%)
13	Total Bill - Bundled Direct Purchase	19,156	47.8891	15,940	39.8492	(3,216)	(16.8%)	(24.6%)
14	Bundled Direct Purchase Impact						(24.0%)	(44.1%)
	Small Rate 10 to Rate E02	Demand 548 m³ Annual Volume 60,000 m³						
15	Delivery Charges	5,865	9.7744	5,081	8.4687	(783)	(13.4%)	(13.4%)
16	Federal Carbon Charge	9,150	15.2500	9,150	15.2500	-	0.0%	0.0%
17	Gas Supply Transportation	3,726	6.2100	863	1.4377	(2,863)	(76.8%)	(76.8%)
18	Gas Supply Commodity	9,681	16.1346	8,641	14.4019	(1,040)	(10.7%)	(10.7%)
19	Total Bill - Sales Service	28,421	47.3690	23,735	39.5582	(4,686)	(16.5%)	(24.3%)
20	Total Bill - Bundled Direct Purchase	27,382	45.6362	23,735	39.5582	(3,647)	(13.3%)	(20.0%)
21	Bundled Direct Purchase Impact						(19.5%)	(38.0%)
	Average Rate 10 to Rate E02	Demand 850 m³ Annual Volume 93,000 m³						
22	Delivery Charges	8,330	8.9572	7,684	8.2622	(646)	(7.8%)	(7.8%)
23	Federal Carbon Charge	14,183	15.2500	14,183	15.2500	-	0.0%	0.0%
24	Gas Supply Transportation	5,775	6.2100	1,337	1.4377	(4,438)	(76.8%)	(76.8%)
25	Gas Supply Commodity	15,005	16.1346	13,394	14.4019	(1,611)	(10.7%)	(10.7%)
26	Total Bill - Sales Service	43,293	46.5518	36,597	39.3517	(6,696)	(15.5%)	(23.0%)
27	Total Bill - Bundled Direct Purchase	41,682	44.8190	36,597	39.3517	(5,085)	(12.2%)	(18.5%)
28	Bundled Direct Purchase Impact						(18.0%)	(36.0%)
	Large Rate 10 to Rate E02	Demand 2,285 m³ Annual Volume 250,000 m³						
29	Delivery Charges	19,249	7.6998	20,066	8.0264	817	4.2%	4.2%
30	Federal Carbon Charge	38,125	15.2500	38,125	15.2500	-	0.0%	0.0%
31	Gas Supply Transportation	15,525	6.2100	3,594	1.4377	(11,931)	(76.8%)	(76.8%)
32	Gas Supply Commodity	40,337	16.1346	36,005	14.4019	(4,332)	(10.7%)	(10.7%)
33	Total Bill - Sales Service	113,236	45.2944	97,790	39.1159	(15,446)	(13.6%)	(20.6%)
34	Total Bill - Bundled Direct Purchase	108,904	43.5616	97,790	39.1159	(11,114)	(10.2%)	(15.7%)
35	Bundled Direct Purchase Impact						(15.2%)	(32.0%)

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.
(3) Gas Supply charges based on Union North East Zone.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - One Rate Zone - No Regional Adjustments - Alternate Volumetric Rate Design
Union South Rate Zone

Line No.	Particulars	EB-2024-0166 - Current Approved (1)(2) Total Bill ($)	Unit Rate (cents/m³)	EB-2025-0064 - 2024 Proposed (2) Total Bill ($)	Unit Rate (cents/m³)	Total Bill Change ($)	Bill Impact Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate M1 to Rate E01	Demand 20 m³ Annual Volume 2,200 m³						
1	Delivery Charges	453	20.5998	519	23.6070	66	14.6%	14.6%
2	Federal Carbon Charge	336	15.2500	336	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	-	-	32	1.4505	32	100.0%	100.0%
4	Gas Supply Commodity	357	16.2433	317	14.4019	(41)	(11.3%)	(11.3%)
5	Total Bill - Sales Service	1,146	52.0930	1,204	54.7094	58	5.0%	7.1%
6	Total Bill - Bundled Direct Purchase	1,106	50.2516	1,204	54.7094	98	8.9%	12.7%
7	Bundled Direct Purchase Impact						12.4%	21.6%
	Large Rate M1 to Rate E02	Demand 365 m³ Annual Volume 40,000 m³						
8	Delivery Charges	2,658	6.6459	3,504	8.7597	845	31.8%	31.8%
9	Federal Carbon Charge	6,100	15.2500	6,100	15.2500	-	0.0%	0.0%
10	Gas Supply Transportation	-	-	575	1.4377	575	100.0%	100.0%
11	Gas Supply Commodity	6,497	16.2433	5,761	14.4019	(737)	(11.3%)	(11.3%)
12	Total Bill - Sales Service	15,256	38.1392	15,940	39.8492	684	4.5%	7.5%
13	Total Bill - Bundled Direct Purchase	14,519	36.2978	15,940	39.8492	1,421	9.8%	16.9%
14	Bundled Direct Purchase Impact						16.2%	53.4%
	Small Rate M2 to Rate E02	Demand 613 m³ Annual Volume 60,000 m³						
15	Delivery Charges	4,933	8.2216	5,081	8.4687	148	3.0%	3.0%
16	Federal Carbon Charge	9,150	15.2500	9,150	15.2500	-	0.0%	0.0%
17	Gas Supply Transportation	-	-	863	1.4377	863	100.0%	100.0%
18	Gas Supply Commodity	9,746	16.2433	8,641	14.4019	(1,105)	(11.3%)	(11.3%)
19	Total Bill - Sales Service	23,829	39.7148	23,735	39.5582	(94)	(0.4%)	(0.6%)
20	Total Bill - Bundled Direct Purchase	22,724	37.8734	23,735	39.5582	1,011	4.4%	7.4%
21	Bundled Direct Purchase Impact						7.2%	20.5%
	Average Rate M2 to Rate E02	Demand 746 m³ Annual Volume 73,000 m³						
22	Delivery Charges	5,773	7.9082	6,106	8.3650	333	5.8%	5.8%
23	Federal Carbon Charge	11,133	15.2500	11,133	15.2500	-	0.0%	0.0%
24	Gas Supply Transportation	-	-	1,050	1.4377	1,050	100.0%	100.0%
25	Gas Supply Commodity	11,858	16.2433	10,513	14.4019	(1,344)	(11.3%)	(11.3%)
26	Total Bill - Sales Service	28,763	39.4015	28,802	39.4546	39	0.1%	0.2%
27	Total Bill - Bundled Direct Purchase	27,419	37.5601	28,802	39.4546	1,383	5.0%	8.5%
28	Bundled Direct Purchase Impact						8.2%	24.0%
	Large Rate M2 to Rate E02	Demand 2,556 m³ Annual Volume 250,000 m³						
29	Delivery Charges	16,762	6.7047	20,066	8.0264	3,304	19.7%	19.7%
30	Federal Carbon Charge	38,125	15.2500	38,125	15.2500	-	0.0%	0.0%
31	Gas Supply Transportation	-	-	3,594	1.4377	3,594	100.0%	100.0%
32	Gas Supply Commodity	40,608	16.2433	36,005	14.4019	(4,603)	(11.3%)	(11.3%)
33	Total Bill - Sales Service	95,495	38.1979	97,790	39.1159	2,295	2.4%	4.0%
34	Total Bill - Bundled Direct Purchase	90,891	36.3565	97,790	39.1159	6,898	7.6%	13.1%
35	Bundled Direct Purchase Impact						12.6%	41.2%

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.

Derivation of Alternate Volumetric Rates and Revenue - One Rate Zone - As Filed in Phase 1
General Service

Line No.	Particulars	Billing Units	2024 Forecast Usage	Current Approved Revenue ($000s)	Current Approved Rates (cents/m^3)	Revenue (Deficiency) / Sufficiency ($000s)	Proposed 2024 Revenue Requirement (1) ($000s)	Revenue (Deficiency) / Sufficiency (2) ($000s)	Revenue ($000s)	Rates (cents/m^3)	Revenue-to-Cost Ratios	Rate Change (%)
			(a)	(b)	(c)	(d) = (b - e)	(e)	(f) = (g - e)	(g)	(h)	(i) = (g / e)	(j) = (h - c) / (c)
	Rate E01											
1	Monthly Customer Charge	bills	46,035,671				1,339,528	-	1,339,528	$29.10	1.000	
2	Delivery Commodity Charge	10^3m^3	9,140,146				35,755	670,705	706,460	7.7292		
3	Delivery Demand Charge	$10^3m^3/d$	1,087,127				679,654	(679,654)	-	-		
4	Total Delivery		9,140,146				2,054,938	(8,949)	2,045,988	22.3846	0.996	
	Gas Supply Transportation Charge											
5	Transportation	10^3m^3	9,095,333				152,074	-	152,074	1.6720		
6	Transportation - Western	10^3m^3	44,813				1,911	-	1,911	4.2639		
7	Gas Supply Transportation Charge		9,140,146				153,985	-	153,985	1.6847	1.000	
8	Gas Supply Commodity Charge	10^3m^3	8,653,117				1,246,209	-	1,246,209	14.4019	1.000	
9	Total Rate E01		9,140,146	3,492,379	38.2092	37,247	3,455,132	(8,949)	3,446,183	37.7038	0.997	(1%)
	Rate E02											
10	Monthly Customer Charge	bills	1,021,298				113,613	(83,895)	29,717	$29.10	0.262	
11	Delivery Commodity Charge	10^3m^3	6,571,059				25,466	492,347	517,813	7.8802		
12	Delivery Demand Charge	$10^3m^3/d$	772,599				414,809	(414,809)	-	-		
13	Total Delivery		6,571,059				553,887	(6,357)	547,530	8.3325	0.989	
	Gas Supply Transportation Charge											
14	Transportation	10^3m^3	6,371,556				105,674	-	105,674	1.6585		
15	Transportation - Western	10^3m^3	195,622				8,315	-	8,315	4.2504		
16	Gas Supply Transportation Charge		6,567,178				113,988	-	113,988	1.7357	1.000	
17	Gas Supply Commodity Charge	10^3m^3	4,113,986				592,490	-	592,490	14.4019	1.000	
18	Total Rate E02		6,571,059	1,227,459	18.6798	(32,907)	1,260,366	(6,357)	1,254,009	19.0838	0.995	2%

Notes:
(1) Revenue requirement by rate component for each rate class provided at Phase 3 Exhibit 7, Tab 3, Schedule 3, Attachment 13.
(2) Allocation of S&T Margin and other rate design adjustments.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - One Rate Zone - As Filed in Phase 1 - Alternate Volumetric Rate Design
EGD Rate Zone

		EB-2024-0166 - Current Approved (1)(2)		EB-2025-0064 - 2024 Proposed (2)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate 1 to Rate E01	Demand 24 m^3 Annual Volume 2,400 m^3						
1	Delivery Charges	552	22.9924	535	22.2923	(17)	(3.0%)	(3.0%)
2	Federal Carbon Charge	366	15.2500	366	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	117	4.8806	40	1.6720	(77)	(65.7%)	(65.7%)
4	Gas Supply Commodity	252	10.4826	346	14.4019	94	37.4%	37.4%
5	Total Bill - Sales Service	1,287	53.6056	1,287	53.6162	0	0.0%	0.0%
6	Total Bill - Bundled Direct Purchase WTS	1,381	57.5249	1,349	56.2081	(32)	(2.3%)	(3.1%)
7	Bundled Direct Purchase Impact WTS						(3.1%)	(4.7%)
8	Total Bill - Bundled Direct Purchase DTS	1,286	53.5843	1,287	53.6162	1	0.1%	0.1%
9	Bundled Direct Purchase Impact DTS						0.1%	0.1%
	Large Rate 1 to Rate E01	Demand 51 m^3 Annual Volume 5,048 m^3						
10	Delivery Charges	821	16.2702	740	14.6605	(81)	(9.9%)	(9.9%)
11	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
12	Gas Supply Transportation	246	4.8806	84	1.6720	(162)	(65.7%)	(65.7%)
13	Gas Supply Commodity	529	10.4826	727	14.4019	198	37.4%	37.4%
14	Total Bill - Sales Service	2,367	46.8834	2,321	45.9844	(45)	(1.9%)	(2.8%)
15	Total Bill - Bundled Direct Purchase WTS	2,565	50.8026	2,452	48.5763	(112)	(4.4%)	(6.3%)
16	Bundled Direct Purchase Impact WTS						(6.1%)	(10.5%)
17	Total Bill - Bundled Direct Purchase DTS	2,366	46.8620	2,321	45.9844	(44)	(1.9%)	(2.8%)
18	Bundled Direct Purchase Impact DTS						(2.7%)	(5.1%)
	Small Rate 6 to Rate E01	Demand 51 m^3 Annual Volume 5,048 m^3						
19	Delivery Charges	1,524	30.1901	740	14.6605	(784)	(51.4%)	(51.4%)
20	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
21	Gas Supply Transportation	246	4.8806	84	1.6700	(162)	(65.7%)	(65.7%)
22	Gas Supply Commodity	530	10.5065	727	14.4019	197	37.1%	37.1%
23	Total Bill - Sales Service	3,071	60.8272	2,321	45.9844	(749)	(24.4%)	(32.6%)
24	Total Bill - Bundled Direct Purchase WTS	3,267	64.7226	2,452	48.5763	(815)	(24.9%)	(32.6%)
25	Bundled Direct Purchase Impact WTS						(32.1%)	(46.0%)
26	Total Bill - Bundled Direct Purchase DTS	3,068	60.7820	2,321	45.9844	(747)	(24.3%)	(32.5%)
27	Bundled Direct Purchase Impact DTS						(31.9%)	(47.5%)
	Average Rate 6 to Rate E02	Demand 206 m^3 Annual Volume 22,606 m^3						
28	Delivery Charges	3,046	13.4745	2,134	9.4391	(912)	(29.9%)	(29.9%)
29	Federal Carbon Charge	3,447	15.2500	3,447	15.2500	-	0.0%	0.0%
30	Gas Supply Transportation	1,103	4.8806	375	1.6600	(728)	(66.0%)	(66.0%)
31	Gas Supply Commodity	2,375	10.5065	3,256	14.4019	881	37.1%	37.1%
32	Total Bill - Sales Service	9,972	44.1116	9,212	40.7495	(760)	(7.6%)	(11.6%)
33	Total Bill - Bundled Direct Purchase WTS	10,852	48.0069	9,798	194.0918	(1,055)	(9.7%)	(14.2%)
34	Bundled Direct Purchase Impact WTS						(13.9%)	(25.4%)
35	Total Bill - Bundled Direct Purchase DTS	9,962	44.0663	9,212	182.4847	(750)	(7.5%)	(11.5%)
36	Bundled Direct Purchase Impact DTS						(11.2%)	(23.0%)
	Large Rate 6 to Rate E02	Demand 3,097 m^3 Annual Volume 339,124 m^3						
37	Delivery Charges	23,794	7.0162	27,121	7.9975	3,328	14.0%	14.0%
38	Federal Carbon Charge	51,716	15.2500	51,716	15.2500	-	0.0%	0.0%
39	Gas Supply Transportation	16,551	4.8806	5,624	1.6585	(10,927)	(66.0%)	(66.0%)
40	Gas Supply Commodity	35,630	10.5065	48,840	14.4019	13,210	37.1%	37.1%
41	Total Bill - Sales Service	127,692	37.6533	133,302	39.3078	5,611	4.4%	7.4%
42	Total Bill - Bundled Direct Purchase WTS	140,902	41.5487	142,092	41.8998	1,190	0.8%	1.3%
43	Bundled Direct Purchase Impact WTS						1.3%	3.0%
44	Total Bill - Bundled Direct Purchase DTS	127,538	37.6081	133,302	39.3078	5,764	4.5%	7.6%
45	Bundled Direct Purchase Impact DTS						7.3%	21.4%

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - One Rate Zone - As Filed in Phase 1 - Alternate Volumetric Rate Design
Union North Rate Zone

		EB-2024-0166 - Current Approved (1)(2)(3)		EB-2025-0064 - 2024 Proposed (2)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate 01 to Rate E01	Demand 20 m^3 Annual Volume 2,200 m^3						
1	Delivery Charges	544	24.7128	520	23.6149	(24)	(4.4%)	(4.4%)
2	Federal Carbon Charge	336	15.2500	336	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	173	7.8681	37	1.6720	(136)	(78.7%)	(78.7%)
4	Gas Supply Commodity	355	16.1346	317	14.4019	(38)	(10.7%)	(10.7%)
5	Total Bill - Sales Service	1,407	63.9655	1,209	54.9388	(199)	(14.1%)	(18.5%)
6	Total Bill - Bundled Direct Purchase	1,369	62.2327	1,209	54.9388	(160)	(11.7%)	(15.5%)
7	Bundled Direct Purchase Impact						(15.2%)	(22.4%)
	Large Rate 01 to Rate E02	Demand 365 m^3 Annual Volume 40,000 m^3						
8	Delivery Charges	4,148	10.3691	3,507	8.7674	(641)	(15.4%)	(15.4%)
9	Federal Carbon Charge	6,100	15.2500	6,100	15.2500	-	0.0%	0.0%
10	Gas Supply Transportation	3,147	7.8681	663	1.6585	(2,484)	(78.9%)	(78.9%)
11	Gas Supply Commodity	6,454	16.1346	5,761	14.4019	(693)	(10.7%)	(10.7%)
12	Total Bill - Sales Service	19,849	49.6218	16,031	40.0778	(3,818)	(19.2%)	(27.8%)
13	Total Bill - Bundled Direct Purchase	19,156	47.8891	16,031	40.0778	(3,125)	(16.3%)	(23.9%)
14	Bundled Direct Purchase Impact						(23.3%)	(42.8%)
	Small Rate 10 to Rate E02	Demand 548 m^3 Annual Volume 60,000 m^3						
15	Delivery Charges	5,865	9.7744	5,086	8.4765	(779)	(13.3%)	(13.3%)
16	Federal Carbon Charge	9,150	15.2500	9,150	15.2500	-	0.0%	0.0%
17	Gas Supply Transportation	3,726	6.2100	995	1.6585	(2,731)	(73.3%)	(73.3%)
18	Gas Supply Commodity	9,681	16.1346	8,641	14.4019	(1,040)	(10.7%)	(10.7%)
19	Total Bill - Sales Service	28,421	47.3690	23,872	39.7868	(4,549)	(16.0%)	(23.6%)
20	Total Bill - Bundled Direct Purchase	27,382	45.6362	23,872	39.7868	(3,510)	(12.8%)	(19.3%)
21	Bundled Direct Purchase Impact						(18.7%)	(36.6%)
	Average Rate 10 to Rate E02	Demand 850 m^3 Annual Volume 93,000 m^3						
22	Delivery Charges	8,330	8.9572	7,691	8.2700	(639)	(7.7%)	(7.7%)
23	Federal Carbon Charge	14,183	15.2500	14,183	15.2500	-	0.0%	0.0%
24	Gas Supply Transportation	5,775	6.2100	1,542	1.6585	(4,233)	(73.3%)	(73.3%)
25	Gas Supply Commodity	15,005	16.1346	13,394	14.4019	(1,611)	(10.7%)	(10.7%)
26	Total Bill - Sales Service	43,293	46.5518	36,810	39.5803	(6,483)	(15.0%)	(22.3%)
27	Total Bill - Bundled Direct Purchase	41,682	44.8190	36,810	39.5803	(4,872)	(11.7%)	(17.7%)
28	Bundled Direct Purchase Impact						(17.2%)	(34.5%)
	Large Rate 10 to Rate E02	Demand 2,285 m^3 Annual Volume 250,000 m^3						
29	Delivery Charges	19,249	7.6998	20,085	8.0342	836	4.3%	4.3%
30	Federal Carbon Charge	38,125	15.2500	38,125	15.2500	-	0.0%	0.0%
31	Gas Supply Transportation	15,525	6.2100	4,146	1.6585	(11,379)	(73.3%)	(73.3%)
32	Gas Supply Commodity	40,337	16.1346	36,005	14.4019	(4,332)	(10.7%)	(10.7%)
33	Total Bill - Sales Service	113,236	45.2944	98,361	39.3446	(14,875)	(13.1%)	(19.8%)
34	Total Bill - Bundled Direct Purchase	108,904	43.5616	98,361	39.3446	(10,543)	(9.7%)	(14.9%)
35	Bundled Direct Purchase Impact						(14.5%)	(30.3%)

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.
(3) Gas Supply charges based on Union North East Zone.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - One Rate Zone - As Filed in Phase 1 - Alternate Volumetric Rate Design
Union South Rate Zone

		EB-2024-0166 - Current Approved (1)(2)		EB-2025-0064 - 2024 Proposed (2)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate M1 to Rate E01	Demand 20 m^3 Annual Volume 2,200 m^3						
1	Delivery Charges	453	20.5998	520	23.6149	66	14.6%	14.6%
2	Federal Carbon Charge	336	15.2500	336	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	-	-	37	1.6720	37	100.0%	100.0%
4	Gas Supply Commodity	357	16.2433	317	14.4019	(41)	(11.3%)	(11.3%)
5	Total Bill - Sales Service	1,146	52.0930	1,209	54.9388	63	5.5%	7.7%
6	Total Bill - Bundled Direct Purchase	1,106	50.2516	1,209	54.9388	103	9.3%	13.4%
7	Bundled Direct Purchase Impact						13.1%	22.8%
	Large Rate M1 to Rate E02	Demand 365 m^3 Annual Volume 40,000 m^3						
8	Delivery Charges	2,658	6.6459	3,507	8.7674	849	31.9%	31.9%
9	Federal Carbon Charge	6,100	15.2500	6,100	15.2500	-	0.0%	0.0%
10	Gas Supply Transportation	-	-	663	1.6585	663	100.0%	100.0%
11	Gas Supply Commodity	6,497	16.2433	5,761	14.4019	(737)	(11.3%)	(11.3%)
12	Total Bill - Sales Service	15,256	38.1392	16,031	40.0778	775	5.1%	8.5%
13	Total Bill - Bundled Direct Purchase	14,519	36.2978	16,031	40.0778	1,512	10.4%	18.0%
14	Bundled Direct Purchase Impact						17.3%	56.9%
	Small Rate M2 to Rate E02	Demand 613 m^3 Annual Volume 60,000 m^3						
15	Delivery Charges	4,933	8.2216	5,086	8.4765	153	3.1%	3.1%
16	Federal Carbon Charge	9,150	15.2500	9,150	15.2500	-	0.0%	0.0%
17	Gas Supply Transportation	-	-	995	1.6585	995	100.0%	100.0%
18	Gas Supply Commodity	9,746	16.2433	8,641	14.4019	(1,105)	(11.3%)	(11.3%)
19	Total Bill - Sales Service	23,829	39.7148	23,872	39.7868	43	0.2%	0.3%
20	Total Bill - Bundled Direct Purchase	22,724	37.8734	23,872	39.7868	1,148	5.1%	8.5%
21	Bundled Direct Purchase Impact						8.2%	23.3%
	Average Rate M2 to Rate E02	Demand 746 m^3 Annual Volume 73,000 m^3						
22	Delivery Charges	5,773	7.9082	6,112	8.3728	339	5.9%	5.9%
23	Federal Carbon Charge	11,133	15.2500	11,133	15.2500	-	0.0%	0.0%
24	Gas Supply Transportation	-	-	1,211	1.6585	1,211	100.0%	100.0%
25	Gas Supply Commodity	11,858	16.2433	10,513	14.4019	(1,344)	(11.3%)	(11.3%)
26	Total Bill - Sales Service	28,763	39.4015	28,969	39.6832	206	0.7%	1.2%
27	Total Bill - Bundled Direct Purchase	27,419	37.5601	28,969	39.6832	1,550	5.7%	9.5%
28	Bundled Direct Purchase Impact						9.2%	26.8%
	Large Rate M2 to Rate E02	Demand 2,556 m^3 Annual Volume 250,000 m^3						
29	Delivery Charges	16,762	6.7047	20,085	8.0342	3,324	19.8%	19.8%
30	Federal Carbon Charge	38,125	15.2500	38,125	15.2500	-	0.0%	0.0%
31	Gas Supply Transportation	-	-	4,146	1.6585	4,146	100.0%	100.0%
32	Gas Supply Commodity	40,608	16.2433	36,005	14.4019	(4,603)	(11.3%)	(11.3%)
33	Total Bill - Sales Service	95,495	38.1979	98,361	39.3446	2,867	3.0%	5.0%
34	Total Bill - Bundled Direct Purchase	90,891	36.3565	98,361	39.3446	7,470	8.2%	14.2%
35	Bundled Direct Purchase Impact						13.6%	44.6%

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.

Derivation of Alternate Volumetric Rates and Revenue - Two Rate Zones - With One Rate Zone Distribution
General Service

Line No.	Particulars	Billing Units	2024 Forecast Usage (a)	Current Approved: Revenue ($000s) (b)	Current Approved: Rates (cents/m^3) (c)	Revenue (Deficiency) / Sufficiency ($000s) (d) = (b - e)	Proposed: Revenue Requirement (1) ($000s) (e)	Proposed: Revenue (Deficiency) / Sufficiency (2) ($000s) (f) = (g - e)	Proposed: Revenue ($000s) (g)	Proposed: Rates (cents/m^3) (h)	Proposed: Revenue-to-Cost Ratios (i) = (g / e)	Proposed: Rate Change (%) (j) = (h - c) / (c)
	Rate E01											
	Monthly Customer Charge											
1	North	bills	9,056,375				263,519	-	263,519	$29.10	1.000	
2	South	bills	36,979,296				1,076,009	-	1,076,009	$29.10	1.000	
	Delivery Commodity Charge											
3	North	10^3m^3	1,691,744				1,131	119,609	120,740	7.1370		
4	South	10^3m^3	7,448,402				4,979	537,130	542,109	7.2782		
	Delivery Demand Charge											
5	North	$10^3m^3/d$	202,329				121,179	(121,179)	-	-		
6	South	$10^3m^3/d$	884,798				543,909	(543,909)	-	-		
7	Total Delivery		9,140,146				2,010,726	(8,348)	2,002,377	21.9075	0.996	
	Gas Supply Transportation Charge											
	Transportation											
8	North	10^3m^3	1,676,335				139,369	-	139,369	8.3139	1.000	
9	South	10^3m^3	7,418,999				49,578	-	49,578	0.6683	1.000	
	Transportation - Western											
10	North	10^3m^3	15,410				1,681	-	1,681	10.9058	1.000	
11	South	10^3m^3	29,403				959	-	959	3.2602	1.000	
12	Gas Supply Transportation Charge		9,140,146				191,586	-	191,586	2.0961	1.000	
	Gas Supply Commodity Charge											
13	North	10^3m^3	1,600,988				181,286	150	181,436	11.3328	1.001	
14	South	10^3m^3	7,052,128				1,064,627	(199)	1,064,427	15.0937	1.000	
15	Total Rate E01		9,140,146	3,492,379	38.2092	44,154	3,448,225	(8,397)	3,439,827	37.6343	0.998	(2%)
16	Total Rate E01 - North		1,691,744	716,211	42.3357	8,046	708,165	(1,420)	706,745	41.7761	0.998	(1%)
17	Total Rate E01 - South		7,448,402	2,776,168	37.2720	36,108	2,740,060	(6,978)	2,733,082	36.6935	0.997	(2%)
	Rate E02											
	Monthly Customer Charge											
18	North	bills	177,993				19,800	(14,621)	5,179	$29.10	0.262	
19	South	bills	843,305				93,812	(69,274)	24,538	$29.10	0.262	
	Delivery Commodity Charge											
20	North	10^3m^3	982,064				656	81,322	81,978	8.3475		
21	South	10^3m^3	5,588,996				3,736	394,383	398,119	7.1233		
	Delivery Demand Charge											
22	North	$10^3m^3/d$	130,797				67,674	(67,674)	-	-		
23	South	$10^3m^3/d$	641,802				329,268	(329,268)	-	-		
24	Total Delivery		6,571,059				514,947	(5,133)	509,814	7.7585	0.990	
	Gas Supply Transportation Charge											
	Transportation											
25	North	10^3m^3	925,764				85,635	-	85,635	9.2501	1.000	
26	South	10^3m^3	5,445,792				33,590	-	33,590	0.6168	1.000	
	Transportation - Western											
27	North	10^3m^3	52,418				6,207	-	6,207	11.8420	1.000	
28	South	10^3m^3	143,203				4,595	-	4,595	3.2087	1.000	
29	Gas Supply Transportation Charge		6,567,178				130,027	-	130,027	1.9800	1.000	
	Gas Supply Commodity Charge											
30	North	10^3m^3	620,987				70,317	58	70,375	11.3328	1.001	
31	South	10^3m^3	3,493,000				527,322	(99)	527,223	15.0937	1.000	
32	Total Rate E02		6,571,059	1,227,459	18.6798	(15,154)	1,242,613	(5,173)	1,237,439	18.8317	0.996	1%
33	Total Rate E02 - North		982,064	212,686	21.6570	(37,604)	250,290	(915)	249,374	25.3929	0.996	17%
34	Total Rate E02 - South		5,588,996	1,014,773	18.1566	22,450	992,323	(4,258)	988,065	17.6788	0.996	(3%)

Notes:
(1) Revenue requirement by rate component for each rate class provided at Phase 3 Exhibit 7, Tab 3, Schedule 4, Attachment 13.
(2) Allocation of S&T Margin and other rate design adjustments.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - Two Rate Zones One Distribution - North - Alternate Volumteric Rate Design
EGD Rate Zone

		EB-2024-0166 - Current Approved (1)(2)		EB-2025-0064 - 2024 Proposed (2)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate 1 to Rate E01 North	Demand 24 m^3 Annual Volume 2,400 m^3						
1	Delivery Charges	552	22.9924	521	21.7001	(31)	(5.6%)	(5.6%)
2	Federal Carbon Charge	366	15.2500	366	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	117	4.8806	200	8.3139	82	70.3%	70.3%
4	Gas Supply Commodity	252	10.4826	272	11.3328	20	8.1%	8.1%
5	Total Bill - Sales Service	1,287	53.6056	1,358	56.5968	72	5.6%	7.8%
6	Total Bill - Bundled Direct Purchase WTS	1,307	54.4558	1,421	59.1887	114	8.7%	12.1%
7	Bundled Direct Purchase Impact WTS						11.0%	17.0%
8	Total Bill - Bundled Direct Purchase DTS	1,212	50.5152	1,358	56.5968	146	12.0%	17.2%
9	Bundled Direct Purchase Impact DTS						15.5%	25.4%
	Large Rate 1 to Rate E01 North	Demand 51 m^3 Annual Volume 5,048 m^3						
10	Delivery Charges	821	16.2702	710	14.0683	(111)	(13.5%)	(13.5%)
11	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
12	Gas Supply Transportation	246	4.8806	420	8.3139	173	70.3%	70.3%
13	Gas Supply Commodity	529	10.4826	572	11.3328	43	8.1%	8.1%
14	Total Bill - Sales Service	2,367	46.8834	2,472	48.9650	105	4.4%	6.6%
15	Total Bill - Bundled Direct Purchase WTS	2,410	47.7336	2,603	51.5569	193	8.0%	11.8%
16	Bundled Direct Purchase Impact WTS						10.5%	18.1%
17	Total Bill - Bundled Direct Purchase DTS	2,211	43.7930	2,472	48.9650	261	11.8%	18.1%
18	Bundled Direct Purchase Impact DTS						15.9%	30.1%
	Small Rate 6 to Rate E01 North	Demand 51 m^3 Annual Volume 5,048 m^3						
19	Delivery Charges	1,524	30.1901	710	14.0683	(814)	(53.4%)	(53.4%)
20	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
21	Gas Supply Transportation	246	4.8806	420	8.3100	173	70.3%	70.3%
22	Gas Supply Commodity	530	10.5065	572	11.3328	42	7.9%	7.9%
23	Total Bill - Sales Service	3,071	60.8272	2,472	48.9650	(599)	(19.5%)	(26.0%)
24	Total Bill - Bundled Direct Purchase WTS	3,112	61.6535	2,603	51.5569	(510)	(16.4%)	(21.8%)
25	Bundled Direct Purchase Impact WTS						(20.1%)	(28.8%)
26	Total Bill - Bundled Direct Purchase DTS	2,913	57.7129	2,472	48.9650	(442)	(15.2%)	(20.6%)
27	Bundled Direct Purchase Impact DTS						(18.9%)	(28.1%)
	Average Rate 6 to Rate E02 North	Demand 206 m^3 Annual Volume 22,606 m^3						
28	Delivery Charges	3,046	13.4745	2,239	9.9064	(807)	(26.5%)	(26.5%)
29	Federal Carbon Charge	3,447	15.2500	3,447	15.2500	-	0.0%	0.0%
30	Gas Supply Transportation	1,103	4.8806	2,091	9.2500	988	89.5%	89.5%
31	Gas Supply Commodity	2,375	10.5065	2,562	11.3328	187	7.9%	7.9%
32	Total Bill - Sales Service	9,972	44.1116	10,340	45.7394	368	3.7%	5.6%
33	Total Bill - Bundled Direct Purchase WTS	10,159	44.9378	10,926	216.4375	767	7.6%	11.4%
34	Bundled Direct Purchase Impact WTS						10.1%	18.5%
35	Total Bill - Bundled Direct Purchase DTS	9,268	40.9972	10,340	204.8304	1,072	11.6%	18.4%
36	Bundled Direct Purchase Impact DTS						16.0%	32.9%
	Large Rate 6 to Rate E02 North	Demand 3,097 m^3 Annual Volume 339,124 m^3						
37	Delivery Charges	23,794	7.0162	28,706	8.4648	4,912	20.6%	20.6%
38	Federal Carbon Charge	51,716	15.2500	51,716	15.2500	-	0.0%	0.0%
39	Gas Supply Transportation	16,551	4.8806	31,369	9.2501	14,818	89.5%	89.5%
40	Gas Supply Commodity	35,630	10.5065	38,432	11.3328	2,802	7.9%	7.9%
41	Total Bill - Sales Service	127,692	37.6533	150,224	44.2977	22,533	17.6%	29.7%
42	Total Bill - Bundled Direct Purchase WTS	130,494	38.4796	159,014	46.8896	28,520	21.9%	36.2%
43	Bundled Direct Purchase Impact WTS						31.0%	70.7%
44	Total Bill - Bundled Direct Purchase DTS	117,130	34.5390	150,224	44.2977	33,094	28.3%	50.6%
45	Bundled Direct Purchase Impact DTS						42.1%	122.7%

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - Two Rate Zones One Distribution - South - Alternate Volumteric Rate Design
EGD Rate Zone

Line No.	Particulars	EB-2024-0166 - Current Approved (1)(2) Total Bill ($)	Unit Rate (cents/m^3)	EB-2025-0064 - 2024 Proposed (2) Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Bill Impact Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate 1 to Rate E01 South	Demand 24 m^3 Annual Volume 2,400 m^3						
1	Delivery Charges	552	22.9924	524	21.8413	(28)	(5.0%)	(5.0%)
2	Federal Carbon Charge	366	15.2500	366	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	117	4.8806	16	0.6683	(101)	(86.3%)	(86.3%)
4	Gas Supply Commodity	252	10.4826	362	15.0937	111	44.0%	44.0%
5	Total Bill - Sales Service	1,287	53.6056	1,268	52.8533	(18)	(1.4%)	(2.0%)
6	Total Bill - Bundled Direct Purchase WTS	1,397	58.2167	1,331	55.4452	(67)	(4.8%)	(6.5%)
7	Bundled Direct Purchase Impact WTS						(6.4%)	(9.9%)
8	Total Bill - Bundled Direct Purchase DTS	1,303	54.2761	1,268	52.8533	(34)	(2.6%)	(3.6%)
9	Bundled Direct Purchase Impact DTS						(3.6%)	(5.9%)
	Large Rate 1 to Rate E01 South	Demand 51 m^3 Annual Volume 5,048 m^3						
10	Delivery Charges	821	16.2702	717	14.2095	(104)	(12.7%)	(12.7%)
11	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
12	Gas Supply Transportation	246	4.8806	34	0.6683	(213)	(86.3%)	(86.3%)
13	Gas Supply Commodity	529	10.4826	762	15.0937	233	44.0%	44.0%
14	Total Bill - Sales Service	2,367	46.8834	2,283	45.2215	(84)	(3.5%)	(5.3%)
15	Total Bill - Bundled Direct Purchase WTS	2,599	51.4945	2,414	47.8134	(186)	(7.1%)	(10.2%)
16	Bundled Direct Purchase Impact WTS						(10.1%)	(17.4%)
17	Total Bill - Bundled Direct Purchase DTS	2,401	47.5539	2,283	45.2215	(118)	(4.9%)	(7.2%)
18	Bundled Direct Purchase Impact DTS						(7.2%)	(13.6%)
	Small Rate 6 to Rate E01 South	Demand 51 m^3 Annual Volume 5,048 m^3						
19	Delivery Charges	1,524	30.1901	717	14.2095	(807)	(52.9%)	(52.9%)
20	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
21	Gas Supply Transportation	246	4.8806	34	0.6700	(213)	(86.3%)	(86.3%)
22	Gas Supply Commodity	530	10.5065	762	15.0937	232	43.7%	43.7%
23	Total Bill - Sales Service	3,071	60.8272	2,283	45.2215	(788)	(25.7%)	(34.2%)
24	Total Bill - Bundled Direct Purchase WTS	3,302	65.4144	2,414	47.8134	(889)	(26.9%)	(35.1%)
25	Bundled Direct Purchase Impact WTS						(35.0%)	(50.2%)
26	Total Bill - Bundled Direct Purchase DTS	3,103	61.4738	2,283	45.2215	(820)	(26.4%)	(35.2%)
27	Bundled Direct Purchase Impact DTS						(35.0%)	(52.2%)
	Average Rate 6 to Rate E02 South	Demand 206 m^3 Annual Volume 22,606 m^3						
28	Delivery Charges	3,046	13.4745	1,963	8.6822	(1,083)	(35.6%)	(35.6%)
29	Federal Carbon Charge	3,447	15.2500	3,447	15.2500	-	0.0%	0.0%
30	Gas Supply Transportation	1,103	4.8806	139	0.6200	(964)	(87.4%)	(87.4%)
31	Gas Supply Commodity	2,375	10.5065	3,412	15.0937	1,037	43.7%	43.7%
32	Total Bill - Sales Service	9,972	44.1116	8,962	39.6427	(1,010)	(10.1%)	(15.5%)
33	Total Bill - Bundled Direct Purchase WTS	11,009	48.6988	9,548	189.1353	(1,461)	(13.3%)	(19.3%)
34	Bundled Direct Purchase Impact WTS						(19.2%)	(35.2%)
35	Total Bill - Bundled Direct Purchase DTS	10,118	44.7582	8,962	177.5282	(1,156)	(11.4%)	(17.3%)
36	Bundled Direct Purchase Impact DTS						(17.2%)	(35.5%)
	Large Rate 6 to Rate E02 South	Demand 3,097 m^3 Annual Volume 339,124 m^3						
37	Delivery Charges	23,794	7.0162	24,554	7.2405	761	3.2%	3.2%
38	Federal Carbon Charge	51,716	15.2500	51,716	15.2500	-	0.0%	0.0%
39	Gas Supply Transportation	16,551	4.8806	2,092	0.6168	(14,460)	(87.4%)	(87.4%)
40	Gas Supply Commodity	35,630	10.5065	51,186	15.0937	15,556	43.7%	43.7%
41	Total Bill - Sales Service	127,692	37.6533	129,549	38.2010	1,857	1.5%	2.4%
42	Total Bill - Bundled Direct Purchase WTS	143,248	42.2406	138,339	40.7929	(4,909)	(3.4%)	(5.4%)
43	Bundled Direct Purchase Impact WTS						(5.3%)	(12.2%)
44	Total Bill - Bundled Direct Purchase DTS	129,884	38.3000	129,549	38.2010	(335)	(0.3%)	(0.4%)
45	Bundled Direct Purchase Impact DTS						(0.4%)	(1.2%)

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - Two Rate Zones One Distribution - North - Alternate Volumteric Rate Design
Union North Rate Zone

		EB-2024-0166 - Current Approved (1)(2)(3)		EB-2025-0064 - 2024 Proposed (2)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m³)	Total Bill ($)	Unit Rate (cents/m³)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate 01 to Rate E01 North	Demand 20 m³ Annual Volume 2,200 m³						
1	Delivery Charges	544	24.7128	507	23.0227	(37)	(6.8%)	(6.8%)
2	Federal Carbon Charge	336	15.2500	336	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	173	7.8681	183	8.3139	10	5.7%	5.7%
4	Gas Supply Commodity	355	16.1346	249	11.3328	(106)	(29.8%)	(29.8%)
5	Total Bill - Sales Service	1,407	63.9655	1,274	57.9194	(133)	(9.5%)	(12.4%)
6	Total Bill - Bundled Direct Purchase	1,302	59.1636	1,274	57.9194	(27)	(2.1%)	(2.8%)
7	Bundled Direct Purchase Impact						(2.6%)	(3.8%)
	Large Rate 01 to Rate E02 North	Demand 365 m³ Annual Volume 40,000 m³						
8	Delivery Charges	4,148	10.3691	3,694	9.2348	(454)	(10.9%)	(10.9%)
9	Federal Carbon Charge	6,100	15.2500	6,100	15.2500	-	0.0%	0.0%
10	Gas Supply Transportation	3,147	7.8681	3,700	9.2501	553	17.6%	17.6%
11	Gas Supply Commodity	6,454	16.1346	4,533	11.3328	(1,921)	(29.8%)	(29.8%)
12	Total Bill - Sales Service	19,849	49.6218	18,027	45.0677	(1,822)	(9.2%)	(13.2%)
13	Total Bill - Bundled Direct Purchase	17,928	44.8200	18,027	45.0677	99	0.6%	0.8%
14	Bundled Direct Purchase Impact						0.7%	1.4%
	Small Rate 10 to Rate E02 North	Demand 548 m³ Annual Volume 60,000 m³						
15	Delivery Charges	5,865	9.7744	5,366	8.9438	(498)	(8.5%)	(8.5%)
16	Federal Carbon Charge	9,150	15.2500	9,150	15.2500	-	0.0%	0.0%
17	Gas Supply Transportation	3,726	6.2100	5,550	9.2501	1,824	49.0%	49.0%
18	Gas Supply Commodity	9,681	16.1346	6,800	11.3328	(2,881)	(29.8%)	(29.8%)
19	Total Bill - Sales Service	28,421	47.3690	26,866	44.7767	(1,555)	(5.5%)	(8.1%)
20	Total Bill - Bundled Direct Purchase	25,540	42.5671	26,866	44.7767	1,326	5.2%	8.1%
21	Bundled Direct Purchase Impact						7.1%	13.8%
	Average Rate 10 to Rate E02 North	Demand 850 m³ Annual Volume 93,000 m³						
22	Delivery Charges	8,330	8.9572	8,126	8.7373	(204)	(2.5%)	(2.5%)
23	Federal Carbon Charge	14,183	15.2500	14,183	15.2500	-	0.0%	0.0%
24	Gas Supply Transportation	5,775	6.2100	8,603	9.2501	2,827	49.0%	49.0%
25	Gas Supply Commodity	15,005	16.1346	10,539	11.3328	(4,466)	(29.8%)	(29.8%)
26	Total Bill - Sales Service	43,293	46.5518	41,450	44.5702	(1,843)	(4.3%)	(6.3%)
27	Total Bill - Bundled Direct Purchase	38,827	41.7500	41,450	44.5702	2,623	6.8%	10.6%
28	Bundled Direct Purchase Impact						9.3%	18.6%
	Large Rate 10 to Rate E02 North	Demand 2,285 m³ Annual Volume 250,000 m³						
29	Delivery Charges	19,249	7.6998	21,254	8.5015	2,004	10.4%	10.4%
30	Federal Carbon Charge	38,125	15.2500	38,125	15.2500	-	0.0%	0.0%
31	Gas Supply Transportation	15,525	6.2100	23,125	9.2501	7,600	49.0%	49.0%
32	Gas Supply Commodity	40,337	16.1346	28,332	11.3328	(12,005)	(29.8%)	(29.8%)
33	Total Bill - Sales Service	113,236	45.2944	110,836	44.3344	(2,400)	(2.1%)	(3.2%)
34	Total Bill - Bundled Direct Purchase	101,231	40.4925	110,836	44.3344	9,605	9.5%	15.2%
35	Bundled Direct Purchase Impact						13.2%	27.6%

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.
(3) Gas Supply charges based on Union North East Zone.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - Two Rate Zones One Distribution - South - Alternate Volumteric Rate Design
Union South Rate Zone

		EB-2024-0166 - Current Approved (1)(2)		EB-2025-0064 - 2024 Proposed (2)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate M1 to Rate E01 South	Demand 20 m³ Annual Volume 2,200 m³						
1	Delivery Charges	453	20.5998	510	23.1639	56	12.4%	12.4%
2	Federal Carbon Charge	336	15.2500	336	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	-	0.0000	15	0.6683	15	100.0%	100.0%
4	Gas Supply Commodity	357	16.2433	332	15.0937	(25)	(7.1%)	(7.1%)
5	Total Bill - Sales Service	1,146	52.0930	1,192	54.1759	46	4.0%	5.7%
6	Total Bill - Bundled Direct Purchase	1,121	50.9435	1,192	54.1759	71	6.3%	9.1%
7	Bundled Direct Purchase Impact						9.0%	15.7%
	Large Rate M1 to Rate E02 South	Demand 365 m³ Annual Volume 40,000 m³						
8	Delivery Charges	2,658	6.6459	3,204	8.0105	546	20.5%	20.5%
9	Federal Carbon Charge	6,100	15.2500	6,100	15.2500	-	0.0%	0.0%
10	Gas Supply Transportation	-	0.0000	247	0.6168	247	100.0%	100.0%
11	Gas Supply Commodity	6,497	16.2433	6,037	15.0937	(460)	(7.1%)	(7.1%)
12	Total Bill - Sales Service	15,256	38.1392	15,588	38.9710	333	2.2%	3.6%
13	Total Bill - Bundled Direct Purchase	14,796	36.9896	15,588	38.9710	793	5.4%	9.1%
14	Bundled Direct Purchase Impact						9.0%	29.8%
	Small Rate M2 to Rate E02 South	Demand 613 m³ Annual Volume 60,000 m³						
15	Delivery Charges	4,933	8.2216	4,632	7.7195	(301)	(6.1%)	(6.1%)
16	Federal Carbon Charge	9,150	15.2500	9,150	15.2500	-	0.0%	0.0%
17	Gas Supply Transportation	-	0.0000	370	0.6168	370	100.0%	100.0%
18	Gas Supply Commodity	9,746	16.2433	9,056	15.0937	(690)	(7.1%)	(7.1%)
19	Total Bill - Sales Service	23,829	39.7148	23,208	38.6800	(621)	(2.6%)	(4.2%)
20	Total Bill - Bundled Direct Purchase	23,139	38.5653	23,208	38.6800	69	0.3%	0.5%
21	Bundled Direct Purchase Impact						0.5%	1.4%
	Average Rate M2 to Rate E02 South	Demand 746 m³ Annual Volume 73,000 m³						
22	Delivery Charges	5,773	7.9082	5,560	7.6159	(213)	(3.7%)	(3.7%)
23	Federal Carbon Charge	11,133	15.2500	11,133	15.2500	-	0.0%	0.0%
24	Gas Supply Transportation	-	0.0000	450	0.6168	450	100.0%	100.0%
25	Gas Supply Commodity	11,858	16.2433	11,018	15.0937	(839)	(7.1%)	(7.1%)
26	Total Bill - Sales Service	28,763	39.4015	28,161	38.5764	(602)	(2.1%)	(3.4%)
27	Total Bill - Bundled Direct Purchase	27,924	38.2519	28,161	38.5764	237	0.8%	1.4%
28	Bundled Direct Purchase Impact						1.4%	4.1%
	Large Rate M2 to Rate E02 South	Demand 2,556 m³ Annual Volume 250,000 m³						
29	Delivery Charges	16,762	6.7047	18,193	7.2772	1,431	8.5%	8.5%
30	Federal Carbon Charge	38,125	15.2500	38,125	15.2500	-	0.0%	0.0%
31	Gas Supply Transportation	-	0.0000	1,542	0.6168	1,542	100.0%	100.0%
32	Gas Supply Commodity	40,608	16.2433	37,734	15.0937	(2,874)	(7.1%)	(7.1%)
33	Total Bill - Sales Service	95,495	38.1979	95,594	38.2377	100	0.1%	0.2%
34	Total Bill - Bundled Direct Purchase	92,621	37.0484	95,594	38.2377	2,973	3.2%	5.5%
35	Bundled Direct Purchase Impact						5.4%	17.7%

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.

Derivation of Alternate Volumetric Rates and Revenue - Two Rate Zones
General Service

Line No.	Particulars	Billing Units	2024 Forecast Usage	Current Approved Revenue ($000s)	Current Approved Rates (cents/m^3)	Revenue (Deficiency) / Sufficiency ($000s)	Proposed Revenue Requirement (1) ($000s)	Proposed Revenue (Deficiency) / Sufficiency (2) ($000s)	Proposed Revenue ($000s)	Proposed Rates (cents/m^3)	Proposed Revenue-to-Cost Ratios	Proposed Rate Change (%)
			(a)	(b)	(c)	(d) = (b - e)	(e)	(f) = (g - e)	(g)	(h)	(i) = (g / e)	(j) = (h - c) / (c)
	Rate E01											
	Monthly Customer Charge											
1	North	bills	9,056,375				291,499	(28,269)	263,230	$29.07	0.903	
2	South	bills	36,979,296				1,046,560	28,269	1,074,829	$29.07	1.027	
	Delivery Commodity Charge											
3	North	10^3m^3	1,691,744				6,607	158,151	164,758	9.7389		
4	South	10^3m^3	7,448,402				29,208	498,803	528,011	7.0889		
	Delivery Demand Charge											
5	North	$10^3m^3/d$	202,329				131,452	(131,452)	-	-		
6	South	$10^3m^3/d$	884,798				533,851	(533,851)	-	-		
7	Total Delivery		9,140,146				2,039,176	(8,348)	2,030,828	22.2188	0.996	
	Gas Supply Transportation Charge											
	Transportation											
8	North	10^3m^3	1,676,335				137,263	-	137,263	8.1883	1.000	
9	South	10^3m^3	7,418,999				22,128	-	22,128	0.2983	1.000	
	Transportation - Western											
10	North	10^3m^3	15,410				1,661	-	1,661	10.7802	1.000	
11	South	10^3m^3	29,403				850	-	850	2.8902	1.000	
12	Gas Supply Transportation Charge		9,140,146				161,902	-	161,902	1.7713	1.000	
	Gas Supply Commodity Charge											
13	North	10^3m^3	1,600,988				181,286	150	181,436	11.3328	1.001	
14	South	10^3m^3	7,052,128				1,064,627	(199)	1,064,427	15.0937	1.000	
15	Total Rate E01		9,140,146	3,492,379	38.2092	45,388	3,446,991	(8,397)	3,438,593	37.6208	0.998	(2%)
16	Total Rate E01 - North		1,691,744	716,211	42.3357	(33,556)	749,767	(1,420)	748,348	44.2353	0.998	4%
17	Total Rate E01 - South		7,448,402	2,776,168	37.2720	78,945	2,697,223	(6,978)	2,690,245	36.1184	0.997	(3%)
	Rate E02											
	Monthly Customer Charge											
18	North	bills	177,993				20,942	(15,768)	5,173	$29.07	0.247	
19	South	bills	843,305				92,602	(68,091)	24,511	$29.07	0.265	
	Delivery Commodity Charge											
20	North	10^3m^3	982,064				4,171	88,603	92,774	9.4468		
21	South	10^3m^3	5,588,996				21,345	386,808	408,153	7.3028		
	Delivery Demand Charge											
22	North	$10^3m^3/d$	130,797				73,808	(73,808)	-	-		
23	South	$10^3m^3/d$	641,802				322,876	(322,876)	-	-		
24	Total Delivery		6,571,059				535,745	(5,133)	530,612	8.0750	0.990	
	Gas Supply Transportation Charge											
	Transportation											
25	North	10^3m^3	925,764				81,121	-	81,121	8.7626	1.000	
26	South	10^3m^3	5,445,792				12,384	-	12,384	0.2274	1.000	
	Transportation - Western											
27	North	10^3m^3	52,418				5,952	-	5,952	11.3545	1.000	
28	South	10^3m^3	143,203				4,037	-	4,037	2.8193	1.000	
29	Gas Supply Transportation Charge		6,567,178				103,494	-	103,494	1.5759	1.000	
	Gas Supply Commodity Charge											
30	North	10^3m^3	620,987				70,317	58	70,375	11.3328	1.001	
31	South	10^3m^3	3,493,000				527,322	(99)	527,223	15.0937	1.000	
32	Total Rate E02		6,571,059	1,227,459	18.6798	(9,418)	1,236,877	(5,173)	1,231,704	18.7444	0.996	0%
33	Total Rate E02 - North		982,064	212,686	21.6570	(43,625)	256,311	(915)	255,395	26.0060	0.996	20%
34	Total Rate E02 - South		5,588,996	1,014,773	18.1566	34,207	980,566	(4,258)	976,309	17.4684	0.996	(4%)

Notes:
(1) Revenue requirement by rate component for each rate class provided at Phase 3 Exhibit 7, Tab 3, Schedule 5, Attachment 13.
(2) Allocation of S&T Margin and other rate design adjustments.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - Two Rate Zones - North - Alternate Volumetric Rate Design
EGD Rate Zone

		EB-2024-0166 - Current Approved (1)(2)		EB-2025-0064 - 2024 Proposed (2)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate 1 to Rate E01 North	Demand 24 m^3 Annual Volume 2,400 m^3						
1	Delivery Charges	552	22.9924	583	24.2861	31	5.6%	5.6%
2	Federal Carbon Charge	366	15.2500	366	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	117	4.8806	197	8.1883	79	67.8%	67.8%
4	Gas Supply Commodity	252	10.4826	272	11.3328	20	8.1%	8.1%
5	Total Bill - Sales Service	1,287	53.6056	1,417	59.0571	131	10.2%	14.2%
6	Total Bill - Bundled Direct Purchase WTS	1,307	54.4558	1,480	61.6490	173	13.2%	18.3%
7	Bundled Direct Purchase Impact WTS						16.7%	25.8%
8	Total Bill - Bundled Direct Purchase DTS	1,212	50.5152	1,417	59.0571	205	16.9%	24.2%
9	Bundled Direct Purchase Impact DTS						21.8%	35.7%
	Large Rate 1 to Rate E01 North	Demand 51 m^3 Annual Volume 5,048 m^3						
10	Delivery Charges	821	16.2702	841	16.6627	20	2.4%	2.4%
11	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
12	Gas Supply Transportation	246	4.8806	413	8.1883	167	67.8%	67.8%
13	Gas Supply Commodity	529	10.4826	572	11.3328	43	8.1%	8.1%
14	Total Bill - Sales Service	2,367	46.8834	2,596	51.4337	230	9.7%	14.4%
15	Total Bill - Bundled Direct Purchase WTS	2,410	47.7336	2,727	54.0256	318	13.2%	19.4%
16	Bundled Direct Purchase Impact WTS						17.3%	29.7%
17	Total Bill - Bundled Direct Purchase DTS	2,211	43.7930	2,596	51.4337	386	17.4%	26.8%
18	Bundled Direct Purchase Impact DTS						23.5%	44.4%
	Small Rate 6 to Rate E01 North	Demand 51 m^3 Annual Volume 5,048 m^3						
19	Delivery Charges	1,524	30.1901	841	16.6627	(683)	(44.8%)	(44.8%)
20	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
21	Gas Supply Transportation	246	4.8806	413	8.1900	167	67.8%	67.8%
22	Gas Supply Commodity	530	10.5065	572	11.3328	42	7.9%	7.9%
23	Total Bill - Sales Service	3,071	60.8272	2,596	51.4337	(474)	(15.4%)	(20.6%)
24	Total Bill - Bundled Direct Purchase WTS	3,112	61.6535	2,727	54.0256	(385)	(12.4%)	(16.4%)
25	Bundled Direct Purchase Impact WTS						(15.2%)	(21.8%)
26	Total Bill - Bundled Direct Purchase DTS	2,913	57.7129	2,596	51.4337	(317)	(10.9%)	(14.8%)
27	Bundled Direct Purchase Impact DTS						(13.5%)	(20.2%)
	Average Rate 6 to Rate E02 North	Demand 206 m^3 Annual Volume 22,606 m^3						
28	Delivery Charges	3,046	13.4745	2,488	11.0040	(558)	(18.3%)	(18.3%)
29	Federal Carbon Charge	3,447	15.2500	3,447	15.2500	-	0.0%	0.0%
30	Gas Supply Transportation	1,103	4.8806	1,981	8.7600	878	79.5%	79.5%
31	Gas Supply Commodity	2,375	10.5065	2,562	11.3328	187	7.9%	7.9%
32	Total Bill - Sales Service	9,972	44.1116	10,478	46.3494	506	5.1%	7.8%
33	Total Bill - Bundled Direct Purchase WTS	10,159	44.9378	11,064	219.1695	905	8.9%	13.5%
34	Bundled Direct Purchase Impact WTS						11.9%	21.8%
35	Total Bill - Bundled Direct Purchase DTS	9,268	40.9972	10,478	207.5624	1,210	13.1%	20.8%
36	Bundled Direct Purchase Impact DTS						18.0%	37.1%
	Large Rate 6 to Rate E02 North	Demand 3,097 m^3 Annual Volume 339,124 m^3						
37	Delivery Charges	23,794	7.0162	32,434	9.5640	8,640	36.3%	36.3%
38	Federal Carbon Charge	51,716	15.2500	51,716	15.2500	-	0.0%	0.0%
39	Gas Supply Transportation	16,551	4.8806	29,716	8.7626	13,165	79.5%	79.5%
40	Gas Supply Commodity	35,630	10.5065	38,432	11.3328	2,802	7.9%	7.9%
41	Total Bill - Sales Service	127,692	37.6533	152,298	44.9094	24,607	19.3%	32.4%
42	Total Bill - Bundled Direct Purchase WTS	130,494	38.4796	161,088	47.5013	30,595	23.4%	38.8%
43	Bundled Direct Purchase Impact WTS						33.2%	75.8%
44	Total Bill - Bundled Direct Purchase DTS	117,130	34.5390	152,298	44.9094	35,168	30.0%	53.8%
45	Bundled Direct Purchase Impact DTS						44.7%	130.3%

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - Two Rate Zones - South - Alternate Volumetric Rate Design
EGD Rate Zone

		EB-2024-0166 - Current Approved (1)(2)		EB-2025-0064 - 2024 Proposed (2)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m³)	Total Bill ($)	Unit Rate (cents/m³)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate 1 to Rate E01 South	Demand 24 m³ Annual Volume 2,400 m³						
1	Delivery Charges	552	22.9924	519	21.6361	(33)	(5.9%)	(5.9%)
2	Federal Carbon Charge	366	15.2500	366	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	117	4.8806	7	0.2983	(110)	(93.9%)	(93.9%)
4	Gas Supply Commodity	252	10.4826	362	15.0937	111	44.0%	44.0%
5	Total Bill - Sales Service	1,287	53.6056	1,255	52.2780	(32)	(2.5%)	(3.5%)
6	Total Bill - Bundled Direct Purchase WTS	1,397	58.2167	1,317	54.8699	(80)	(5.7%)	(7.8%)
7	Bundled Direct Purchase Impact WTS						(7.8%)	(12.0%)
8	Total Bill - Bundled Direct Purchase DTS	1,303	54.2761	1,255	52.2780	(48)	(3.7%)	(5.1%)
9	Bundled Direct Purchase Impact DTS						(5.1%)	(8.3%)
	Large Rate 1 to Rate E01 South	Demand 51 m³ Annual Volume 5,048 m³						
10	Delivery Charges	821	16.2702	707	14.0127	(114)	(13.9%)	(13.9%)
11	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
12	Gas Supply Transportation	246	4.8806	15	0.2983	(231)	(93.9%)	(93.9%)
13	Gas Supply Commodity	529	10.4826	762	15.0937	233	44.0%	44.0%
14	Total Bill - Sales Service	2,367	46.8834	2,254	44.6546	(113)	(4.8%)	(7.0%)
15	Total Bill - Bundled Direct Purchase WTS	2,599	51.4945	2,385	47.2465	(214)	(8.2%)	(11.7%)
16	Bundled Direct Purchase Impact WTS						(11.7%)	(20.1%)
17	Total Bill - Bundled Direct Purchase DTS	2,401	47.5539	2,254	44.6546	(146)	(6.1%)	(9.0%)
18	Bundled Direct Purchase Impact DTS						(8.9%)	(16.8%)
	Small Rate 6 to Rate E01 South	Demand 51 m³ Annual Volume 5,048 m³						
19	Delivery Charges	1,524	30.1901	707	14.0127	(817)	(53.6%)	(53.6%)
20	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
21	Gas Supply Transportation	246	4.8806	15	0.3000	(231)	(93.9%)	(93.9%)
22	Gas Supply Commodity	530	10.5065	762	15.0937	232	43.7%	43.7%
23	Total Bill - Sales Service	3,071	60.8272	2,254	44.6546	(816)	(26.6%)	(35.5%)
24	Total Bill - Bundled Direct Purchase WTS	3,302	65.4144	2,385	47.2465	(917)	(27.8%)	(36.2%)
25	Bundled Direct Purchase Impact WTS						(36.1%)	(51.8%)
26	Total Bill - Bundled Direct Purchase DTS	3,103	61.4738	2,254	44.6546	(849)	(27.4%)	(36.4%)
27	Bundled Direct Purchase Impact DTS						(36.3%)	(54.0%)
	Average Rate 6 to Rate E02 South	Demand 206 m³ Annual Volume 22,606 m³						
28	Delivery Charges	3,046	13.4745	2,003	8.8600	(1,043)	(34.2%)	(34.2%)
29	Federal Carbon Charge	3,447	15.2500	3,447	15.2500	-	0.0%	0.0%
30	Gas Supply Transportation	1,103	4.8806	51	0.2300	(1,052)	(95.3%)	(95.3%)
31	Gas Supply Commodity	2,375	10.5065	3,412	15.0937	1,037	43.7%	43.7%
32	Total Bill - Sales Service	9,972	44.1116	8,914	39.4311	(1,058)	(10.6%)	(16.2%)
33	Total Bill - Bundled Direct Purchase WTS	11,009	48.6988	9,500	188.1878	(1,509)	(13.7%)	(20.0%)
34	Bundled Direct Purchase Impact WTS						(19.9%)	(36.4%)
35	Total Bill - Bundled Direct Purchase DTS	10,118	44.7582	8,914	176.5807	(1,204)	(11.9%)	(18.1%)
36	Bundled Direct Purchase Impact DTS						(18.0%)	(37.0%)
	Large Rate 6 to Rate E02 South	Demand 3,097 m³ Annual Volume 339,124 m³						
37	Delivery Charges	23,794	7.0162	25,163	7.4200	1,369	5.8%	5.8%
38	Federal Carbon Charge	51,716	15.2500	51,716	15.2500	-	0.0%	0.0%
39	Gas Supply Transportation	16,551	4.8806	771	0.2274	(15,780)	(95.3%)	(95.3%)
40	Gas Supply Commodity	35,630	10.5065	51,186	15.0937	15,556	43.7%	43.7%
41	Total Bill - Sales Service	127,692	37.6533	128,837	37.9911	1,145	0.9%	1.5%
42	Total Bill - Bundled Direct Purchase WTS	143,248	42.2406	137,627	40.5830	(5,621)	(3.9%)	(6.1%)
43	Bundled Direct Purchase Impact WTS						(6.1%)	(13.9%)
44	Total Bill - Bundled Direct Purchase DTS	129,884	38.3000	128,837	37.9911	(1,048)	(0.8%)	(1.3%)
45	Bundled Direct Purchase Impact DTS						(1.3%)	(3.9%)

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - Two Rate Zones - North - Alternate Volumetric Rate Design
Union North Rate Zone

Line No.	Particulars	EB-2024-0166 - Current Approved (1)(2)(3) Total Bill ($)	Unit Rate (cents/m^3)	EB-2025-0064 - 2024 Proposed (2) Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Bill Impact Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate 01 to Rate E01 North	Demand 20 m³ Annual Volume 2,200 m³						
1	Delivery Charges	544	24.7128	563	25.6072	20	3.6%	3.6%
2	Federal Carbon Charge	336	15.2500	336	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	173	7.8681	180	8.1883	7	4.1%	4.1%
4	Gas Supply Commodity	355	16.1346	249	11.3328	(106)	(29.8%)	(29.8%)
5	Total Bill - Sales Service	1,407	63.9655	1,328	60.3783	(79)	(5.6%)	(7.4%)
6	Total Bill - Bundled Direct Purchase	1,302	59.1636	1,328	60.3783	27	2.1%	2.8%
7	Bundled Direct Purchase Impact						2.5%	3.7%
	Large Rate 01 to Rate E02 North	Demand 365 m³ Annual Volume 40,000 m³						
8	Delivery Charges	4,148	10.3691	4,133	10.3331	(14)	(0.3%)	(0.3%)
9	Federal Carbon Charge	6,100	15.2500	6,100	15.2500	-	0.0%	0.0%
10	Gas Supply Transportation	3,147	7.8681	3,505	8.7626	358	11.4%	11.4%
11	Gas Supply Commodity	6,454	16.1346	4,533	11.3328	(1,921)	(29.8%)	(29.8%)
12	Total Bill - Sales Service	19,849	49.6218	18,271	45.6785	(1,577)	(7.9%)	(11.5%)
13	Total Bill - Bundled Direct Purchase	17,928	44.8200	18,271	45.6785	343	1.9%	2.9%
14	Bundled Direct Purchase Impact						2.6%	4.7%
	Small Rate 10 to Rate E02 North	Demand 548 m³ Annual Volume 60,000 m³						
15	Delivery Charges	5,865	9.7744	6,025	10.0424	161	2.7%	2.7%
16	Federal Carbon Charge	9,150	15.2500	9,150	15.2500	-	0.0%	0.0%
17	Gas Supply Transportation	3,726	6.2100	5,258	8.7626	1,532	41.1%	41.1%
18	Gas Supply Commodity	9,681	16.1346	6,800	11.3328	(2,881)	(29.8%)	(29.8%)
19	Total Bill - Sales Service	28,421	47.3690	27,233	45.3878	(1,189)	(4.2%)	(6.2%)
20	Total Bill - Bundled Direct Purchase	25,540	42.5671	27,233	45.3878	1,692	6.6%	10.3%
21	Bundled Direct Purchase Impact						9.0%	17.6%
	Average Rate 10 to Rate E02 North	Demand 850 m³ Annual Volume 93,000 m³						
22	Delivery Charges	8,330	8.9572	9,148	9.8362	817	9.8%	9.8%
23	Federal Carbon Charge	14,183	15.2500	14,183	15.2500	-	0.0%	0.0%
24	Gas Supply Transportation	5,775	6.2100	8,149	8.7626	2,374	41.1%	41.1%
25	Gas Supply Commodity	15,005	16.1346	10,539	11.3328	(4,466)	(29.8%)	(29.8%)
26	Total Bill - Sales Service	43,293	46.5518	42,019	45.1816	(1,274)	(2.9%)	(4.4%)
27	Total Bill - Bundled Direct Purchase	38,827	41.7500	42,019	45.1816	3,191	8.2%	12.9%
28	Bundled Direct Purchase Impact						11.3%	22.6%
	Large Rate 10 to Rate E02 North	Demand 2,285 m³ Annual Volume 250,000 m³						
29	Delivery Charges	19,249	7.6998	24,002	9.6006	4,752	24.7%	24.7%
30	Federal Carbon Charge	38,125	15.2500	38,125	15.2500	-	0.0%	0.0%
31	Gas Supply Transportation	15,525	6.2100	21,907	8.7626	6,382	41.1%	41.1%
32	Gas Supply Commodity	40,337	16.1346	28,332	11.3328	(12,005)	(29.8%)	(29.8%)
33	Total Bill - Sales Service	113,236	45.2944	112,365	44.9460	(871)	(0.8%)	(1.2%)
34	Total Bill - Bundled Direct Purchase	101,231	40.4925	112,365	44.9460	11,134	11.0%	17.6%
35	Bundled Direct Purchase Impact						15.3%	32.0%

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.
(3) Gas Supply charges based on Union North East Zone.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - Two Rate Zones - South - Alternate Volumetric Rate Design
Union South Rate Zone

		EB-2024-0166 - Current Approved (1)(2)		EB-2025-0064 - 2024 Proposed (2)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate M1 to Rate E01 South	Demand 20 m³ Annual Volume 2,200 m³						
1	Delivery Charges	453	20.5998	505	22.9572	52	11.4%	11.4%
2	Federal Carbon Charge	336	15.2500	336	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	-	0.0000	7	0.2983	7	100.0%	100.0%
4	Gas Supply Commodity	357	16.2433	332	15.0937	(25)	(7.1%)	(7.1%)
5	Total Bill - Sales Service	1,146	52.0930	1,179	53.5992	33	2.9%	4.1%
6	Total Bill - Bundled Direct Purchase	1,121	50.9435	1,179	53.5992	58	5.2%	7.4%
7	Bundled Direct Purchase Impact						7.4%	12.9%
	Large Rate M1 to Rate E02 South	Demand 365 m³ Annual Volume 40,000 m³						
8	Delivery Charges	2,658	6.6459	3,276	8.1891	617	23.2%	23.2%
9	Federal Carbon Charge	6,100	15.2500	6,100	15.2500	-	0.0%	0.0%
10	Gas Supply Transportation	-	0.0000	91	0.2274	91	100.0%	100.0%
11	Gas Supply Commodity	6,497	16.2433	6,037	15.0937	(460)	(7.1%)	(7.1%)
12	Total Bill - Sales Service	15,256	38.1392	15,504	38.7602	248	1.6%	2.7%
13	Total Bill - Bundled Direct Purchase	14,796	36.9896	15,504	38.7602	708	4.8%	8.1%
14	Bundled Direct Purchase Impact						8.1%	26.6%
	Small Rate M2 to Rate E02 South	Demand 613 m³ Annual Volume 60,000 m³						
15	Delivery Charges	4,933	8.2216	4,739	7.8984	(194)	(3.9%)	(3.9%)
16	Federal Carbon Charge	9,150	15.2500	9,150	15.2500	-	0.0%	0.0%
17	Gas Supply Transportation	-	0.0000	136	0.2274	136	100.0%	100.0%
18	Gas Supply Commodity	9,746	16.2433	9,056	15.0937	(690)	(7.1%)	(7.1%)
19	Total Bill - Sales Service	23,829	39.7148	23,082	38.4695	(747)	(3.1%)	(5.1%)
20	Total Bill - Bundled Direct Purchase	23,139	38.5653	23,082	38.4695	(57)	(0.2%)	(0.4%)
21	Bundled Direct Purchase Impact						(0.4%)	(1.2%)
	Average Rate M2 to Rate E02 South	Demand 746 m³ Annual Volume 73,000 m³						
22	Delivery Charges	5,773	7.9082	5,690	7.7949	(83)	(1.4%)	(1.4%)
23	Federal Carbon Charge	11,133	15.2500	11,133	15.2500	-	0.0%	0.0%
24	Gas Supply Transportation	-	0.0000	166	0.2274	166	100.0%	100.0%
25	Gas Supply Commodity	11,858	16.2433	11,018	15.0937	(839)	(7.1%)	(7.1%)
26	Total Bill - Sales Service	28,763	39.4015	28,007	38.3660	(756)	(2.6%)	(4.3%)
27	Total Bill - Bundled Direct Purchase	27,924	38.2519	28,007	38.3660	83	0.3%	0.5%
28	Bundled Direct Purchase Impact						0.5%	1.4%
	Large Rate M2 to Rate E02 South	Demand 2,556 m³ Annual Volume 250,000 m³						
29	Delivery Charges	16,762	6.7047	18,642	7.4566	1,880	11.2%	11.2%
30	Federal Carbon Charge	38,125	15.2500	38,125	15.2500	-	0.0%	0.0%
31	Gas Supply Transportation	-	0.0000	568	0.2274	568	100.0%	100.0%
32	Gas Supply Commodity	40,608	16.2433	37,734	15.0937	(2,874)	(7.1%)	(7.1%)
33	Total Bill - Sales Service	95,495	38.1979	95,069	38.0277	(426)	(0.4%)	(0.7%)
34	Total Bill - Bundled Direct Purchase	92,621	37.0484	95,069	38.0277	2,448	2.6%	4.5%
35	Bundled Direct Purchase Impact						4.5%	14.6%

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.

Derivation of Alternate Volumetric Rates and Revenue - Four Rate Zones - With One Rate Zone Distribution
General Service

Line No.	Particulars	Billing Units	2024 Forecast Usage	Current Approved Revenue ($000s)	Current Approved Rates (cents/m^3)	Revenue (Deficiency) / Sufficiency ($000s)	Proposed Revenue Requirement (1) ($000s)	Proposed Revenue (Deficiency) / Sufficiency (2) ($000s)	Proposed Revenue ($000s)	Proposed Rates (cents/m^3)	Revenue-to-Cost Ratios	Rate Change (%)
			(a)	(b)	(c)	(d) = (b - e)	(e)	(f) = (g - e)	(g)	(h)	(i) = (g / e)	(j) = (h - c) / (c)
	Rate E01											
	Monthly Customer Charge											
1	North	bills	2,919,472				84,950	-	84,950	$29.10	1.000	
2	East	bills	6,136,903				178,569	-	178,569	$29.10	1.000	
3	Central	bills	22,677,301				659,855	-	659,855	$29.10	1.000	
4	South	bills	14,301,994				416,154	-	416,154	$29.10	1.000	
	Delivery Commodity Charge											
5	North	10^3m^3	611,346				409	40,052	40,461	6.6184		
6	East	10^3m^3	1,080,399				722	79,373	80,096	7.4135		
7	Central	10^3m^3	4,612,066				3,083	357,010	360,093	7.8076		
8	South	10^3m^3	2,836,336				1,896	191,141	193,037	6.8059		
	Delivery Demand Charge											
9	North	$10^3m^3/d$	66,272				40,573	(40,573)	-	-		
10	East	$10^3m^3/d$	136,058				80,410	(80,410)	-	-		
11	Central	$10^3m^3/d$	567,526				362,722	(362,722)	-	-		
12	South	$10^3m^3/d$	317,272				193,377	(193,377)	-	-		
13	Total Delivery		9,140,146				2,022,720	(9,505)	2,013,215	22.0261	0.995	
	Gas Supply Transportation Charge											
	Transportation											
14	North	10^3m^3	600,071				27,360	-	27,360	4.5594	1.000	
15	East	10^3m^3	1,076,264				111,724	-	111,724	10.3807	1.000	
16	Central	10^3m^3	4,582,663				40,891	-	40,891	0.8923	1.000	
17	South	10^3m^3	2,836,336				9,091	-	9,091	0.3205	1.000	
	Transportation - Western											
18	North	10^3m^3	11,275				806	-	806	7.1513	1.000	
19	East	10^3m^3	4,135				536	-	536	12.9726	1.000	
20	Central	10^3m^3	29,403				1,024	-	1,024	3.4842	1.000	
21	South	10^3m^3	-				-	-	-	2.9124		
22	Gas Supply Transportation Charge		9,140,146				191,433	-	191,433	2.0944	1.000	
	Gas Supply Commodity Charge											
23	North	10^3m^3	576,969				77,523	(25)	77,498	13.4319	1.000	
24	East	10^3m^3	1,024,019				108,366	150	108,516	10.5971	1.001	
25	Central	10^3m^3	4,375,566				642,907	(188)	642,719	14.6888	1.000	
26	South	10^3m^3	2,676,563				420,068	-	420,068	15.6943	1.000	
27	Total Rate E01		9,140,146	3,492,379	38.2092	29,362	3,463,017	(9,569)	3,453,448	37.7833	0.997	(1%)
28	Total Rate E01 - North		611,346	263,114	43.0385	31,494	231,620	(546)	231,074	37.7977	0.998	(12%)
29	Total Rate E01 - East		1,080,399	453,097	41.9379	(27,230)	480,327	(886)	479,441	44.3763	0.998	6%
30	Total Rate E01 - Central		4,612,066	1,790,025	38.8118	79,542	1,710,483	(5,901)	1,704,583	36.9592	0.997	(5%)
31	Total Rate E01 - South		2,836,336	986,143	34.7682	(54,443)	1,040,586	(2,236)	1,038,350	36.6089	0.998	5%

Derivation of Alternate Volumetric Rates and Revenue - Four Rate Zones - With One Rate Zone Distribution
General Service

Line No.	Particulars	Billing Units	2024 Forecast Usage	Current Approved Revenue ($000s)	Current Approved Rates (cents/m^3)	Revenue (Deficiency) / Sufficiency ($000s)	Proposed Revenue Requirement (1) ($000s)	Proposed Revenue (Deficiency) / Sufficiency (2) ($000s)	Proposed Revenue ($000s)	Proposed Rates (cents/m^3)	Proposed Revenue-to-Cost Ratios	Proposed Rate Change (%)
			(a)	(b)	(c)	(d) = (b - e)	(e)	(f) = (g - e)	(g)	(h)	(i) = (g / e)	(j) = (h - c) / (c)
	Rate E02											
	Monthly Customer Charge											
32	North	bills	62,525				6,955	(5,136)	1,819	$29.10	0.262	
33	East	bills	115,468				12,845	(9,485)	3,360	$29.10	0.262	
34	Central	bills	585,995				65,188	(48,137)	17,051	$29.10	0.262	
35	South	bills	257,311				28,624	(21,137)	7,487	$29.10	0.262	
	Delivery Commodity Charge											
36	North	10^3m^3	296,689				198	23,326	23,524	7.9288		
37	East	10^3m^3	685,375				458	57,595	58,053	8.4703		
38	Central	10^3m^3	3,843,717				2,569	289,381	291,950	7.5955		
39	South	10^3m^3	1,745,279				1,167	120,719	121,886	6.9838		
	Delivery Demand Charge											
40	North	$10^3m^3/d$	34,892				18,466	(18,466)	-	-		
41	East	$10^3m^3/d$	95,905				48,797	(48,797)	-	-		
42	Central	$10^3m^3/d$	448,198				245,801	(245,801)	-	-		
43	South	$10^3m^3/d$	193,603				100,947	(100,947)	-	-		
44	Total Delivery		6,571,059				532,015	(6,884)	525,131	7.9916	0.987	
	Gas Supply Transportation Charge											
	Transportation											
45	North	10^3m^3	257,681				11,736	-	11,736	4.5544	1.000	
46	East	10^3m^3	668,083				74,964	-	74,964	11.2208	1.000	
47	Central	10^3m^3	3,700,513				28,205	-	28,205	0.7622	1.000	
48	South	10^3m^3	1,745,279				5,552	-	5,552	0.3181	1.000	
	Transportation - Western											
49	North	10^3m^3	36,822				2,631	-	2,631	7.1463	1.000	
50	East	10^3m^3	15,597				2,154	-	2,154	13.8127	1.000	
51	Central	10^3m^3	143,203				4,803	-	4,803	3.3541	1.000	
52	South	10^3m^3	-				-	-	-	2.9100	-	
53	Gas Supply Transportation Charge		6,567,178				130,046	-	130,046	1.9802	1.000	
	Gas Supply Commodity Charge											
54	North	10^3m^3	193,328				25,976	(8)	25,968	13.4319	1.000	
55	East	10^3m^3	427,659				45,257	63	45,319	10.5971	1.001	
56	Central	10^3m^3	2,400,793				352,751	(103)	352,648	14.6888	1.000	
57	South	10^3m^3	1,092,207				171,414	-	171,414	15.6943	1.000	
58	Total Rate E02		6,571,059	1,227,459	18.6798	(30,000)	1,257,459	(6,934)	1,250,526	19.0308	0.994	2%
59	Total Rate E02 - North		296,689	70,905	23.8987	4,942	65,963	(285)	65,678	22.1371	0.996	(7%)
60	Total Rate E02 - East		685,375	141,781	20.6866	(42,695)	184,476	(624)	183,851	26.8249	0.997	30%
61	Total Rate E02 - Central		3,843,717	718,174	18.6844	18,856	699,317	(4,660)	694,657	18.0725	0.993	(3%)
62	Total Rate E02 - South		1,745,279	296,600	16.9944	(11,104)	307,703	(1,364)	306,339	17.5524	0.996	3%

Notes:
(1) Revenue requirement by rate component for each rate class provided at Phase 3 Exhibit 7, Tab 3, Schedule 6, Attachment 13.
(2) Allocation of S&T Margin and other rate design adjustments.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - Four Rate Zones - With One Rate Zone Distribution - Alternate Volumetric Rate Design
EGD Rate Zone

		EB-2024-0166 - Current Approved (1)(2)		EB-2025-0064 - 2024 Proposed (2)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate 1 to Rate E01 Central	Demand 24 m^3 Annual Volume 2,400 m^3						
1	Delivery Charges	552	22.9924	537	22.3707	(15)	(2.7%)	(2.7%)
2	Federal Carbon Charge	366	15.2500	366	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	117	4.8806	21	0.8923	(96)	(81.7%)	(81.7%)
4	Gas Supply Commodity	252	10.4826	353	14.6888	101	40.1%	40.1%
5	Total Bill - Sales Service	1,287	53.6056	1,277	53.2018	(10)	(0.8%)	(1.1%)
6	Total Bill - Bundled Direct Purchase WTS	1,387	57.8119	1,339	55.7938	(48)	(3.5%)	(4.7%)
7	Bundled Direct Purchase Impact WTS						(4.7%)	(7.2%)
8	Total Bill - Bundled Direct Purchase DTS	1,293	53.8713	1,277	53.2018	(16)	(1.2%)	(1.7%)
9	Bundled Direct Purchase Impact DTS						(1.7%)	(2.8%)
	Small Rate 1 to Rate E01 East	Demand 24 m^3 Annual Volume 2,400 m^3						
10	Delivery Charges	552	22.9924	537	22.3707	(15)	(2.7%)	(2.7%)
11	Federal Carbon Charge	366	15.2500	366	15.2500	-	0.0%	0.0%
12	Gas Supply Transportation	117	4.8806	249	10.3807	132	112.7%	112.7%
13	Gas Supply Commodity	252	10.4826	254	10.5971	3	1.1%	1.1%
14	Total Bill - Sales Service	1,287	53.6056	1,406	58.5985	120	9.3%	13.0%
15	Total Bill - Bundled Direct Purchase WTS	1,289	53.7201	1,469	61.1904	179	13.9%	19.4%
16	Bundled Direct Purchase Impact WTS						17.3%	26.8%
17	Total Bill - Bundled Direct Purchase DTS	1,195	49.7795	1,406	58.5985	212	17.7%	25.5%
18	Bundled Direct Purchase Impact DTS						22.5%	36.8%
	Large Rate 1 to Rate E01 Central	Demand 51 m^3 Annual Volume 5,048 m^3						
19	Delivery Charges	821	16.2702	744	14.7390	(77)	(9.4%)	(9.4%)
20	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
21	Gas Supply Transportation	246	4.8806	45	0.8923	(201)	(81.7%)	(81.7%)
22	Gas Supply Commodity	529	10.4826	741	14.6888	212	40.1%	40.1%
23	Total Bill - Sales Service	2,367	46.8834	2,300	45.5701	(66)	(2.8%)	(4.2%)
24	Total Bill - Bundled Direct Purchase WTS	2,579	51.0896	2,431	48.1620	(148)	(5.7%)	(8.2%)
25	Bundled Direct Purchase Impact WTS						(8.0%)	(13.8%)
26	Total Bill - Bundled Direct Purchase DTS	2,380	47.1490	2,300	45.5701	(80)	(3.3%)	(4.9%)
27	Bundled Direct Purchase Impact DTS						(4.9%)	(9.2%)
	Large Rate 1 to Rate E01 East	Demand 51 m^3 Annual Volume 5,048 m^3						
28	Delivery Charges	821	16.2702	744	14.7390	(77)	(9.4%)	(9.4%)
29	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
30	Gas Supply Transportation	246	4.8806	524	10.3807	278	112.7%	112.7%
31	Gas Supply Commodity	529	10.4826	535	10.5971	6	1.1%	1.1%
32	Total Bill - Sales Service	2,367	46.8834	2,573	50.9668	206	8.7%	12.9%
33	Total Bill - Bundled Direct Purchase WTS	2,372	46.9979	2,704	53.5587	331	14.0%	20.7%
34	Bundled Direct Purchase Impact WTS						18.0%	31.0%
35	Total Bill - Bundled Direct Purchase DTS	2,174	43.0573	2,573	50.9668	399	18.4%	28.4%
36	Bundled Direct Purchase Impact DTS						24.4%	46.0%
	Small Rate 6 to Rate E01 Central	Demand 51 m^3 Annual Volume 5,048 m^3						
37	Delivery Charges	1,524	30.1901	744	14.7390	(780)	(51.2%)	(51.2%)
38	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
39	Gas Supply Transportation	246	4.8806	45	0.8900	(201)	(81.7%)	(81.7%)
40	Gas Supply Commodity	530	10.5065	741	14.6888	211	39.8%	39.8%
41	Total Bill - Sales Service	3,071	60.8272	2,300	45.5701	(770)	(25.1%)	(33.5%)
42	Total Bill - Bundled Direct Purchase WTS	3,282	65.0095	2,431	48.1620	(850)	(25.9%)	(33.9%)
43	Bundled Direct Purchase Impact WTS						(33.5%)	(48.0%)
44	Total Bill - Bundled Direct Purchase DTS	3,083	61.0689	2,300	45.5701	(782)	(25.4%)	(33.8%)
45	Bundled Direct Purchase Impact DTS						(33.4%)	(49.8%)
	Small Rate 6 to Rate E01 East	Demand 51 m^3 Annual Volume 5,048 m^3						
46	Delivery Charges	1,524	30.1901	744	14.7390	(780)	(51.2%)	(51.2%)
47	Federal Carbon Charge	770	15.2500	770	15.2500	-	0.0%	0.0%
48	Gas Supply Transportation	246	4.8806	524	10.3800	278	112.7%	112.7%
49	Gas Supply Commodity	530	10.5065	535	10.5971	5	0.9%	0.9%
50	Total Bill - Sales Service	3,071	60.8272	2,573	50.9668	(498)	(16.2%)	(21.6%)
51	Total Bill - Bundled Direct Purchase WTS	3,075	60.9178	2,704	53.5587	(371)	(12.1%)	(16.1%)
52	Bundled Direct Purchase Impact WTS						(14.6%)	(21.0%)
53	Total Bill - Bundled Direct Purchase DTS	2,876	56.9772	2,573	50.9668	(303)	(10.5%)	(14.4%)
54	Bundled Direct Purchase Impact DTS						(13.0%)	(19.3%)

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - Four Rate Zones - With One Rate Zone Distribution - Alternate Volumetric Rate Design
EGD Rate Zone

		EB-2024-0166 - Current Approved (1)(2)		EB-2025-0064 - 2024 Proposed (2)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Average Rate 6 to Rate E02 Central	Demand 206 m^3 Annual Volume 22,606 m^3						
55	Delivery Charges	3,046	13.4745	2,069	9.1544	(977)	(32.1%)	(32.1%)
56	Federal Carbon Charge	3,447	15.2500	3,447	15.2500	-	0.0%	0.0%
57	Gas Supply Transportation	1,103	4.8806	172	0.7600	(931)	(84.4%)	(84.4%)
58	Gas Supply Commodity	2,375	10.5065	3,321	14.6888	945	39.8%	39.8%
59	Total Bill - Sales Service	9,972	44.1116	9,010	39.8554	(962)	(9.6%)	(14.7%)
60	Total Bill - Bundled Direct Purchase WTS	10,917	48.2939	9,596	42.4473	(1,322)	(12.1%)	(17.7%)
61	Bundled Direct Purchase Impact WTS						(17.4%)	(31.9%)
62	Total Bill - Bundled Direct Purchase DTS	10,026	44.3533	9,010	39.8554	(1,017)	(10.1%)	(15.5%)
63	Bundled Direct Purchase Impact DTS						(15.2%)	(31.2%)
	Average Rate 6 to Rate E02 East	Demand 206 m^3 Annual Volume 22,606 m^3						
64	Delivery Charges	3,046	13.4745	2,267	10.0292	(779)	(25.6%)	(25.6%)
65	Federal Carbon Charge	3,447	15.2500	3,447	15.2500	-	0.0%	0.0%
66	Gas Supply Transportation	1,103	4.8806	2,537	11.2200	1,433	129.9%	129.9%
67	Gas Supply Commodity	2,375	10.5065	2,396	10.5971	20	0.9%	0.9%
68	Total Bill - Sales Service	9,972	44.1116	10,647	47.0971	675	6.8%	10.3%
69	Total Bill - Bundled Direct Purchase WTS	9,992	44.2021	11,233	49.6890	1,240	12.4%	19.0%
70	Bundled Direct Purchase Impact WTS						16.3%	29.9%
71	Total Bill - Bundled Direct Purchase DTS	9,102	40.2615	10,647	47.0971	1,545	17.0%	27.3%
72	Bundled Direct Purchase Impact DTS						23.0%	47.4%
	Large Rate 6 to Rate E02 Central	Demand 3,097 m^3 Annual Volume 339,124 m^3						
73	Delivery Charges	23,794	7.0162	26,156	7.7128	2,362	9.9%	9.9%
74	Federal Carbon Charge	51,716	15.2500	51,716	15.2500	-	0.0%	0.0%
75	Gas Supply Transportation	16,551	4.8806	2,585	0.7622	(13,967)	(84.4%)	(84.4%)
76	Gas Supply Commodity	35,630	10.5065	49,813	14.6888	14,183	39.8%	39.8%
77	Total Bill - Sales Service	127,692	37.6533	130,270	38.4138	2,579	2.0%	3.4%
78	Total Bill - Bundled Direct Purchase WTS	141,875	41.8357	139,060	41.0057	(2,815)	(2.0%)	(3.1%)
79	Bundled Direct Purchase Impact WTS						(3.1%)	(7.0%)
80	Total Bill - Bundled Direct Purchase DTS	128,511	37.8951	130,270	38.4138	1,759	1.4%	2.3%
81	Bundled Direct Purchase Impact DTS						2.2%	6.5%
	Large Rate 6 to Rate E02 East	Demand 3,097 m^3 Annual Volume 339,124 m^3						
82	Delivery Charges	23,794	7.0162	29,123	8.5876	5,329	22.4%	22.4%
83	Federal Carbon Charge	51,716	15.2500	51,716	15.2500	-	0.0%	0.0%
84	Gas Supply Transportation	16,551	4.8806	38,052	11.2208	21,501	129.9%	129.9%
85	Gas Supply Commodity	35,630	10.5065	35,937	10.5971	307	0.9%	0.9%
86	Total Bill - Sales Service	127,692	37.6533	154,829	45.6554	27,137	21.3%	35.7%
87	Total Bill - Bundled Direct Purchase WTS	127,999	37.7439	163,618	48.2473	35,620	27.8%	46.7%
88	Bundled Direct Purchase Impact WTS						38.7%	88.3%
89	Total Bill - Bundled Direct Purchase DTS	114,635	33.8033	154,829	45.6554	40,193	35.1%	63.9%
90	Bundled Direct Purchase Impact DTS						51.1%	149.0%

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - Four Rate Zones - With One Rate Zone Distribution - Alternate Volumetric Rate Design
Union North Rate Zone

		EB-2024-0166 - Current Approved (1)(2)(3)		EB-2025-0064 - 2024 Proposed (2)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate 01 to Rate E01 North	Demand 20 m³ Annual Volume 2,200 m³						
1	Delivery Charges	544	24.7128	495	22.5041	(49)	(8.9%)	(8.9%)
2	Federal Carbon Charge	336	15.2500	336	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	173	7.8681	100	4.5594	(73)	(42.1%)	(42.1%)
4	Gas Supply Commodity	355	16.1346	296	13.4319	(59)	(16.8%)	(16.8%)
5	Total Bill - Sales Service	1,407	63.9655	1,226	55.7453	(181)	(12.9%)	(16.9%)
6	Total Bill - Bundled Direct Purchase	1,348	61.2627	1,226	55.7453	(121)	(9.0%)	(12.0%)
7	Bundled Direct Purchase Impact						(11.5%)	(16.9%)
	Small Rate 01 to Rate E01 East	Demand 20 m³ Annual Volume 2,200 m³						
8	Delivery Charges	544	24.7128	513	23.2992	(31)	(5.7%)	(5.7%)
9	Federal Carbon Charge	336	15.2500	336	15.2500	-	0.0%	0.0%
10	Gas Supply Transportation	173	7.8681	228	10.3807	55	31.9%	31.9%
11	Gas Supply Commodity	355	16.1346	233	10.5971	(122)	(34.3%)	(34.3%)
12	Total Bill - Sales Service	1,407	63.9655	1,310	59.5270	(98)	(6.9%)	(9.1%)
13	Total Bill - Bundled Direct Purchase	1,285	58.4279	1,310	59.5270	24	1.9%	2.5%
14	Bundled Direct Purchase Impact						2.3%	3.4%
	Large Rate 01 to Rate E02 North	Demand 365 m³ Annual Volume 40,000 m³						
15	Delivery Charges	4,148	10.3691	3,526	8.8161	(621)	(15.0%)	(15.0%)
16	Federal Carbon Charge	6,100	15.2500	6,100	15.2500	-	0.0%	0.0%
17	Gas Supply Transportation	3,147	7.8681	1,822	4.5544	(1,325)	(42.1%)	(42.1%)
18	Gas Supply Commodity	6,454	16.1346	5,373	13.4319	(1,081)	(16.8%)	(16.8%)
19	Total Bill - Sales Service	19,849	49.6218	16,821	42.0524	(3,028)	(15.3%)	(22.0%)
20	Total Bill - Bundled Direct Purchase	18,768	46.9191	16,821	42.0524	(1,947)	(10.4%)	(15.4%)
21	Bundled Direct Purchase Impact						(14.5%)	(26.7%)
	Large Rate 01 to Rate E02 East	Demand 365 m³ Annual Volume 40,000 m³						
22	Delivery Charges	4,148	10.3691	3,743	9.3575	(405)	(9.8%)	(9.8%)
23	Federal Carbon Charge	6,100	15.2500	6,100	15.2500	-	0.0%	0.0%
24	Gas Supply Transportation	3,147	7.8681	4,488	11.2208	1,341	42.6%	42.6%
25	Gas Supply Commodity	6,454	16.1346	4,239	10.5971	(2,215)	(34.3%)	(34.3%)
26	Total Bill - Sales Service	19,849	49.6218	18,570	46.4254	(1,279)	(6.4%)	(9.3%)
27	Total Bill - Bundled Direct Purchase	17,634	44.0843	18,570	46.4254	936	5.3%	8.1%
28	Bundled Direct Purchase Impact						7.0%	12.8%
	Small Rate 10 to Rate E02 North	Demand 548 m³ Annual Volume 60,000 m³						
29	Delivery Charges	5,865	9.7744	5,115	8.5251	(750)	(12.8%)	(12.8%)
30	Federal Carbon Charge	9,150	15.2500	9,150	15.2500	-	0.0%	0.0%
31	Gas Supply Transportation	3,726	6.2100	2,733	4.5544	(993)	(26.7%)	(26.7%)
32	Gas Supply Commodity	9,681	16.1346	8,059	13.4319	(1,622)	(16.8%)	(16.8%)
33	Total Bill - Sales Service	28,421	47.3690	25,057	41.7614	(3,365)	(11.8%)	(17.5%)
34	Total Bill - Bundled Direct Purchase	26,800	44.6662	25,057	41.7614	(1,743)	(6.5%)	(9.9%)
35	Bundled Direct Purchase Impact						(9.3%)	(18.2%)
	Small Rate 10 to Rate E02 East	Demand 548 m³ Annual Volume 60,000 m³						
36	Delivery Charges	5,865	9.7744	5,440	9.0666	(425)	(7.2%)	(7.2%)
37	Federal Carbon Charge	9,150	15.2500	9,150	15.2500	-	0.0%	0.0%
38	Gas Supply Transportation	3,726	6.2100	6,732	11.2208	3,006	80.7%	80.7%
39	Gas Supply Commodity	9,681	16.1346	6,358	10.5971	(3,323)	(34.3%)	(34.3%)
40	Total Bill - Sales Service	28,421	47.3690	27,681	46.1344	(741)	(2.6%)	(3.8%)
41	Total Bill - Bundled Direct Purchase	25,099	41.8314	27,681	46.1344	2,582	10.3%	16.2%
42	Bundled Direct Purchase Impact						13.8%	26.9%

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - Four Rate Zones - With One Rate Zone Distribution - Alternate Volumetric Rate Design
Union North Rate Zone

		EB-2024-0166 - Current Approved (1)(2)(3)		EB-2025-0064 - 2024 Proposed (2)			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill ($)	Unit Rate (cents/m^3)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Average Rate 10 to Rate E02 North	Demand 850 m³ Annual Volume 93,000 m³						
43	Delivery Charges	8,330	8.9572	7,736	8.3186	(594)	(7.1%)	(7.1%)
44	Federal Carbon Charge	14,183	15.2500	14,183	15.2500	-	0.0%	0.0%
45	Gas Supply Transportation	5,775	6.2100	4,236	4.5544	(1,540)	(26.7%)	(26.7%)
46	Gas Supply Commodity	15,005	16.1346	12,492	13.4319	(2,514)	(16.8%)	(16.8%)
47	Total Bill - Sales Service	43,293	46.5518	38,646	41.5549	(4,647)	(10.7%)	(16.0%)
48	Total Bill - Bundled Direct Purchase	40,780	43.8490	38,646	41.5549	(2,134)	(5.2%)	(8.0%)
49	Bundled Direct Purchase Impact						(7.5%)	(15.1%)
	Average Rate 10 to Rate E02 East	Demand 850 m³ Annual Volume 93,000 m³						
50	Delivery Charges	8,330	8.95718174	8,240	8.8601	(90)	(1.1%)	(1.1%)
51	Federal Carbon Charge	14,183	15.2500	14,183	15.2500	-	0.0%	0.0%
52	Gas Supply Transportation	5,775	6.2100	10,435	11.2208	4,660	80.7%	80.7%
53	Gas Supply Commodity	15,005	16.1346	9,855	10.5971	(5,150)	(34.3%)	(34.3%)
54	Total Bill - Sales Service	43,293	46.5518	42,713	45.9279	(580)	(1.3%)	(2.0%)
55	Total Bill - Bundled Direct Purchase	38,143	41.0143	42,713	45.9279	4,570	12.0%	19.1%
56	Bundled Direct Purchase Impact						16.2%	32.4%
	Large Rate 10 to Rate E02 North	Demand 2,285 m³ Annual Volume 250,000 m³						
57	Delivery Charges	19,249	7.6998	20,207	8.0828	958	5.0%	5.0%
58	Federal Carbon Charge	38,125	15.2500	38,125	15.2500	-	0.0%	0.0%
59	Gas Supply Transportation	15,525	6.2100	11,386	4.5544	(4,139)	(26.7%)	(26.7%)
60	Gas Supply Commodity	40,337	16.1346	33,580	13.4319	(6,757)	(16.8%)	(16.8%)
61	Total Bill - Sales Service	113,236	45.2944	103,298	41.3191	(9,938)	(8.8%)	(13.2%)
62	Total Bill - Bundled Direct Purchase	106,479	42.5916	103,298	41.3191	(3,181)	(3.0%)	(4.7%)
63	Bundled Direct Purchase Impact						(4.4%)	(9.1%)
	Large Rate 10 to Rate E02 East	Demand 2,285 m³ Annual Volume 250,000 m³						
64	Delivery Charges	19,249	7.6998	21,561	8.6243	2,311	12.0%	12.0%
65	Federal Carbon Charge	38,125	15.2500	38,125	15.2500	-	0.0%	0.0%
66	Gas Supply Transportation	15,525	6.2100	28,052	11.2208	12,527	80.7%	80.7%
67	Gas Supply Commodity	40,337	16.1346	26,493	10.5971	(13,844)	(34.3%)	(34.3%)
68	Total Bill - Sales Service	113,236	45.2944	114,230	45.6921	994	0.9%	1.3%
69	Total Bill - Bundled Direct Purchase	99,392	39.7568	114,230	45.6921	14,838	14.9%	24.2%
70	Bundled Direct Purchase Impact						20.4%	42.7%

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.
(3) Gas Supply charges based on Union North East Zone.

Calculation of Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers - Four Rate Zones - With One Rate Zone Distribution - Alternate Volumetric Rate Design
Union South Rate Zone

Line No.	Particulars	EB-2024-0166 - Current Approved (1)(2) Total Bill ($)	EB-2024-0166 - Current Approved (1)(2) Unit Rate (cents/m³)	EB-2025-0064 - 2024 Proposed (2) Total Bill ($)	EB-2025-0064 - 2024 Proposed (2) Unit Rate (cents/m³)	Total Bill Change ($)	Bill Impact Including Federal Carbon Charge (%)	Bill Impact Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate M1 to Rate E01 South	Demand 20 m³ Annual Volume 2,200 m³						
1	Delivery Charges	453	20.5998	499	22.6916	46	10.2%	10.2%
2	Federal Carbon Charge	336	15.2500	336	15.2500	-	0.0%	0.0%
3	Gas Supply Transportation	-	-	7	0.3205	7	100.0%	100.0%
4	Gas Supply Commodity	357	16.2433	345	15.6943	(12)	(3.4%)	(3.4%)
5	Total Bill - Sales Service	1,146	52.0930	1,187	53.9564	41	3.6%	5.1%
6	Total Bill - Bundled Direct Purchase	1,134	51.5441	1,187	53.9564	53	4.7%	6.6%
7	Bundled Direct Purchase Impact						6.7%	11.7%
	Large Rate M1 to Rate E02 South	Demand 365 m³ Annual Volume 40,000 m³						
8	Delivery Charges	2,658	6.6459	3,148	7.8710	490	18.4%	18.4%
9	Federal Carbon Charge	6,100	15.2500	6,100	15.2500	-	0.0%	0.0%
10	Gas Supply Transportation	-	-	127	0.3181	127	100.0%	100.0%
11	Gas Supply Commodity	6,497	16.2433	6,278	15.6943	(220)	(3.4%)	(3.4%)
12	Total Bill - Sales Service	15,256	38.1392	15,653	39.1334	398	2.6%	4.3%
13	Total Bill - Bundled Direct Purchase	15,036	37.5902	15,653	39.1334	617	4.1%	6.9%
14	Bundled Direct Purchase Impact						7.0%	23.2%
	Small Rate M2 to Rate E02 South	Demand 613 m³ Annual Volume 60,000 m³						
15	Delivery Charges	4,933	8.2216	4,548	7.5800	(385)	(7.8%)	(7.8%)
16	Federal Carbon Charge	9,150	15.2500	9,150	15.2500	-	0.0%	0.0%
17	Gas Supply Transportation	-	-	191	0.3181	191	100.0%	100.0%
18	Gas Supply Commodity	9,746	16.2433	9,417	15.6943	(329)	(3.4%)	(3.4%)
19	Total Bill - Sales Service	23,829	39.7148	23,305	38.8424	(523)	(2.2%)	(3.6%)
20	Total Bill - Bundled Direct Purchase	23,500	39.1659	23,305	38.8424	(194)	(0.8%)	(1.4%)
21	Bundled Direct Purchase Impact						(1.4%)	(3.9%)
	Average Rate M2 to Rate E02 South	Demand 746 m³ Annual Volume 73,000 m³						
22	Delivery Charges	5,773	7.9082	5,458	7.4764	(315)	(5.5%)	(5.5%)
23	Federal Carbon Charge	11,133	15.2500	11,133	15.2500	-	0.0%	0.0%
24	Gas Supply Transportation	-	-	232	0.3181	232	100.0%	100.0%
25	Gas Supply Commodity	11,858	16.2433	11,457	15.6943	(401)	(3.4%)	(3.4%)
26	Total Bill - Sales Service	28,763	39.4015	28,279	38.7388	(484)	(1.7%)	(2.7%)
27	Total Bill - Bundled Direct Purchase	28,362	38.8525	28,279	38.7388	(83)	(0.3%)	(0.5%)
28	Bundled Direct Purchase Impact						(0.5%)	(1.4%)
	Large Rate M2 to Rate E02 South	Demand 2,556 m³ Annual Volume 250,000 m³						
29	Delivery Charges	16,762	6.7047	17,844	7.1377	1,083	6.5%	6.5%
30	Federal Carbon Charge	38,125	15.2500	38,125	15.2500	-	0.0%	0.0%
31	Gas Supply Transportation	-	-	795	0.3181	795	100.0%	100.0%
32	Gas Supply Commodity	40,608	16.2433	39,236	15.6943	(1,372)	(3.4%)	(3.4%)
33	Total Bill - Sales Service	95,495	38.1979	96,000	38.4001	505	0.5%	0.9%
34	Total Bill - Bundled Direct Purchase	94,122	37.6490	96,000	38.4001	1,878	2.0%	3.4%
35	Bundled Direct Purchase Impact						3.4%	11.2%

Notes:
(1) EB-2024-0166, Exhibit F, Tab 1, Appendix D.
(2) Bill impacts exclude Rider K and Rider R.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking:

Tr: 159

To provide information about what types of exceptions would be treated under the SFVD proposal and how those would be handled once identified.

Response:

As laid out in the evidence at Phase 3 Exhibit 8, Tab 2, Schedule 3, paragraphs 74 and 75, and in response at Exhibit I.8.2-EP-8, the Company has determined it will use the Azure platform to derive design day demands and to manage exceptions for its general service customers.

The Company would like to highlight that by leveraging the existing Azure platform, which is part of the billing system, implementation of SFVD rate design only requires the addition of Design Day temperature (i.e. Design Day HDDs) by area to the information already contained in the billing system in order to derive design day demands using regression analysis for general service customers. For example, see Figure 1 at Phase 3 Exhibit 8, Tab 2, Schedule 3, Attachment 7, page 17.

Given that the Azure platform is used by the Company to derive estimated meter readings, protocols to identify and manage exceptions not related to derivation of design day demands are already in place, such as protocols to resolve negative base load or negative heat parameters, outlier readings, and year-to-year instability in regression results.

The Company, as part of its SFVD implementation plan, will develop exception management related to year-over-year changes in customers' design day demands that exceed certain tolerances (for example, see Phase 3 Exhibit 8, Tab 2, Schedule 3, Attachment 5, pages 35 and 36 which applies Atlanta Gas Light (AGL) tolerances to illustrate exception frequency for Enbridge Gas general service customers), for new customers without historical usage data, and for customers with uncommon usage patterns.

Potential handling / resolution of the exceptions identified above is laid out at Phase 3 Exhibit 8, Tab 2, Schedule 3, Attachment 5, pages 38 through 42.

The Company also notes that alternative methods will be needed for customers with hybrid-heating systems to ensure they are billed on appropriate demands under SFVD rate design. The alternative approaches to derivation of hybrid-heating design day demands are provided in response at Exhibit I.8.2-ED-17, Attachment 1, pages 11 through 14.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking:

Tr: 165

With reference to LPMA-18, to explain how Enbridge moved from the sum of the billing determinants provided by Christensen for Rates E01 and E02 to the 2024 billing determinants used for the derivation of the example rates provided in this application.

Response:

Please see response at Exhibit JT2.1.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking:

Tr: 166

For the example in 8.2-SEC-17, Attachment 8, to provide a bill impact analysis showing bill impact versus 2024 rates, both distribution and total bill, for each of SFVD and volumetric, including relevant calculations, with or without mitigation, for the impact of the mitigation.

Response:

The requested bill impacts are provided in Exhibit JT1.58 Attachment 1, with supporting calculations provided in Attachments 2 and 3.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking:

Tr: 169

For each school in KT-1.7, to provide the calculated design day demand based on this information as well as, similarly as I just asked related to Attachment 8, the bill impact, again both distribution and total bill, for each of SFVD and the volumetric rate option, both with and without mitigation as applicable, with supporting calculations.

Response:

The following response was provided by Christensen Associates Energy Consulting:

The requested design day demands and bill impacts for the schools listed in KT-1.7, and the bill impact for the school in Attachment 8 to Exhibit I.8.2-SEC-17, are provided in Attachment 1 to this response. The detailed bill calculations are provided in the Attachment 2 and Attachment 3 Excel files. Attachment 2 provides the calculations without mitigation; Attachment 3 applies Rider R to the SFVD distribution bills.

We note that the harmonized SFVD and harmonized volumetric bill impacts combine the effects of several factors including cost allocation changes, rate design, monthly customer charges, and rate harmonization.

The demand calculations and bill impacts use consumption and billing cycle data provided by Enbridge Gas for the KT-1.7 schools, to better reflect the actual process of deriving demands than the KT-1.7 data alone.

The consumption data in KT-1.7 lacks information whether the amounts were based on actual reads versus estimated consumption, as well as consumption history before or after the 2023-4 period shown. This omission is significant since the proposed demand approach uses actual consumption and would analyze up to 10 years of bill history subject to data availability. The data from the Enbridge Gas billing system also indicated that rebilled consumption was treated differently for some of the schools—i.e., some of the KT-1.7 consumption quantities included rebilled consumption while others excluded rebilled consumption.

Using only the KT-1.7 consumption data without auxiliary information from the Enbridge billing system also would require us to assume that billing cycles aligned with the calendar months shown in the exhibit (e.g., that consumption data for the period labeled “Dec-23” covered the period December 1, 2023, to December 31, 2023 for the purpose of calculating daily consumption and HDDs for the period). While several of the schools’ billing cycles did roughly correspond to calendar months, some schools had mid-month billing cycles. Where billing cycles and months were relatively aligned overall, we observed some normal variability in billing cycle lengths, presumably due to calendar effects such as reading dates falling on weekends or holidays.

We found that using the Enbridge billing data improved—often considerably—the demand model fit versus assuming that the KT-1.7 data represented calendar month actual consumption, and resulted in a somewhat narrower range of load factors (the ratio of the average consumption to the design day demand). In addition to providing bill impacts using the Enbridge data, Attachment 1 compares the estimated design day demands, load factors, and model R-squared with results from using only the KT-1.7 data to derive the demands.

The design day demand calculations for the schools in KT-1.7 are provided in Attachments 4-12. The Excel model provided in Exhibit I.8.2-SEC-17 was used to derive the demands. Toronto weather was used for the schools in the LEGD rate zone. For the other schools in KT-1.7, weather data from Exhibit I.8.2-SEC-18 Attachment 1 for the applicable weather station listed in Attachment 1 to this response, along with design HDDs, were substituted for the Thunder Bay data in the Excel demand model starting at January 1, 2021 which covers the relevant time period. Please note that while weather and design HDDs were substituted in the applicable model attachments, the Thunder Bay weather zone label was not changed.

This page is intentionally left blank. Due to size, these Attachments have not been included.

Please see Exhibit JT1.58_Attachments 1-12.xlsx on the OEB's RDS.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking:

Tr: 170

To reproduce the decile information for rate classes E01 and E02 shown in 8.2-SEC-29, to show it inclusive of the rate mitigation proposal.

Response:

The following response was provided by Christensen Associates Energy Consulting:

Please see Attachment 1 for the decile graphs showing bill impacts of one rate zone harmonized SFVD rate with the rate mitigation proposal (Rider R) included compared to the 2024 QRAM rate. The four graphs show bill impacts of the SFVD design for E01 and E02 customers separately and for both distribution and total bill, the same as the graphs provided for Exhibit I.8.2-SEC-29. As we only have Rider R information available for the SFVD rate, we are unable to show the same set of decile graphs with rate mitigation for the SFV and Volumetric alternatives.

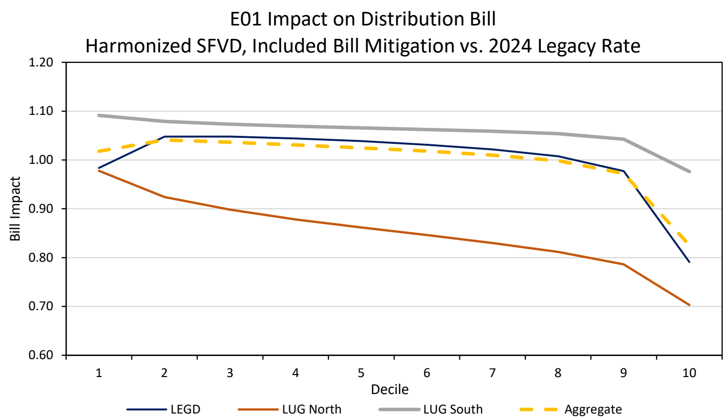
Bill Impacts by Decile

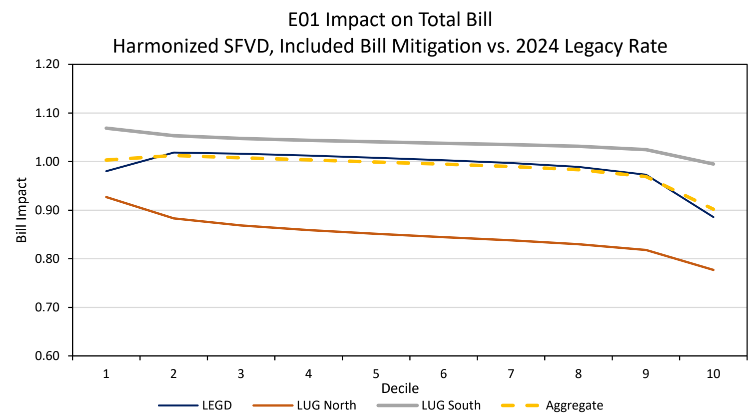
New Rate E01

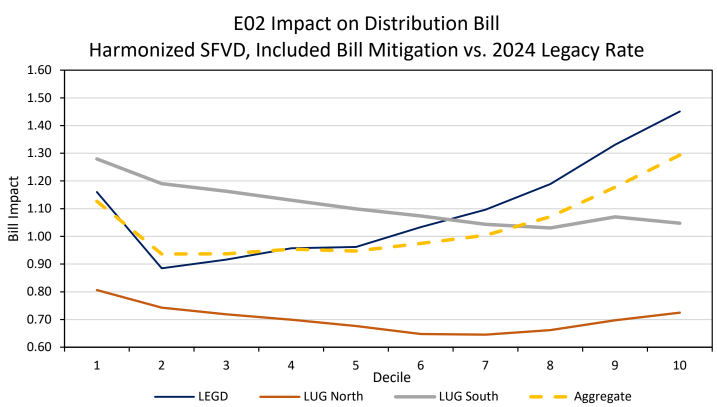
	Total Bill				Distribution Part Only			
Decile_cons	LEGD	LUG North	LUG South	Aggregate	LEGD	LUG North	LUG South	Aggregate
1	0.98	0.93	1.07	1.00	0.98	0.98	1.09	1.02
2	1.02	0.88	1.05	1.01	1.05	0.92	1.08	1.04
3	1.02	0.87	1.05	1.01	1.05	0.90	1.07	1.04
4	1.01	0.86	1.04	1.00	1.04	0.88	1.07	1.03
5	1.01	0.85	1.04	1.00	1.04	0.86	1.07	1.02
6	1.00	0.84	1.04	0.99	1.03	0.85	1.06	1.02
7	1.00	0.84	1.03	0.99	1.02	0.83	1.06	1.01
8	0.99	0.83	1.03	0.98	1.01	0.81	1.05	1.00
9	0.97	0.82	1.02	0.97	0.98	0.79	1.04	0.97
10	0.89	0.78	1.00	0.90	0.79	0.70	0.98	0.83

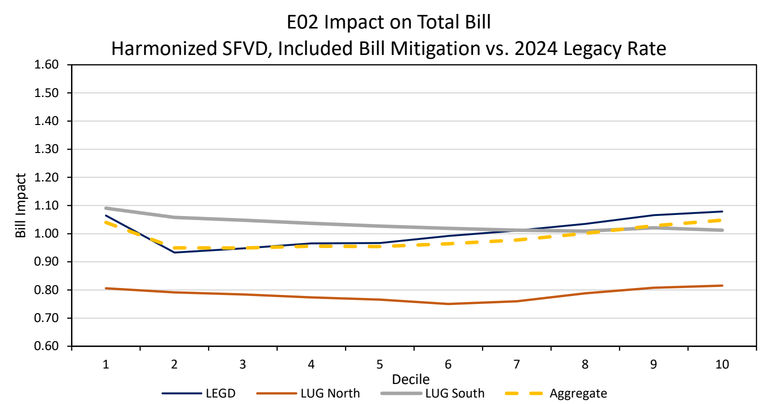
New Rate E02

	Total Bill				Distribution Part Only			
Decile_cons	LEGD	LUG North	LUG South	Aggregate	LEGD	LUG North	LUG South	Aggregate
1	1.06	0.81	1.09	1.04	1.16	0.81	1.28	1.13
2	0.93	0.79	1.06	0.95	0.88	0.74	1.19	0.94
3	0.95	0.78	1.05	0.95	0.92	0.72	1.16	0.94
4	0.97	0.77	1.04	0.96	0.96	0.70	1.13	0.95
5	0.97	0.77	1.03	0.95	0.96	0.68	1.10	0.95
6	0.99	0.75	1.02	0.96	1.03	0.65	1.07	0.97
7	1.01	0.76	1.01	0.98	1.10	0.65	1.04	1.00
8	1.03	0.79	1.01	1.00	1.19	0.66	1.03	1.07
9	1.07	0.81	1.02	1.03	1.33	0.70	1.07	1.18
10	1.08	0.82	1.01	1.05	1.45	0.72	1.05	1.29









ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking:

Tr: 172

On a best efforts basis, to provide a map of where customers fall into specific weather zones.

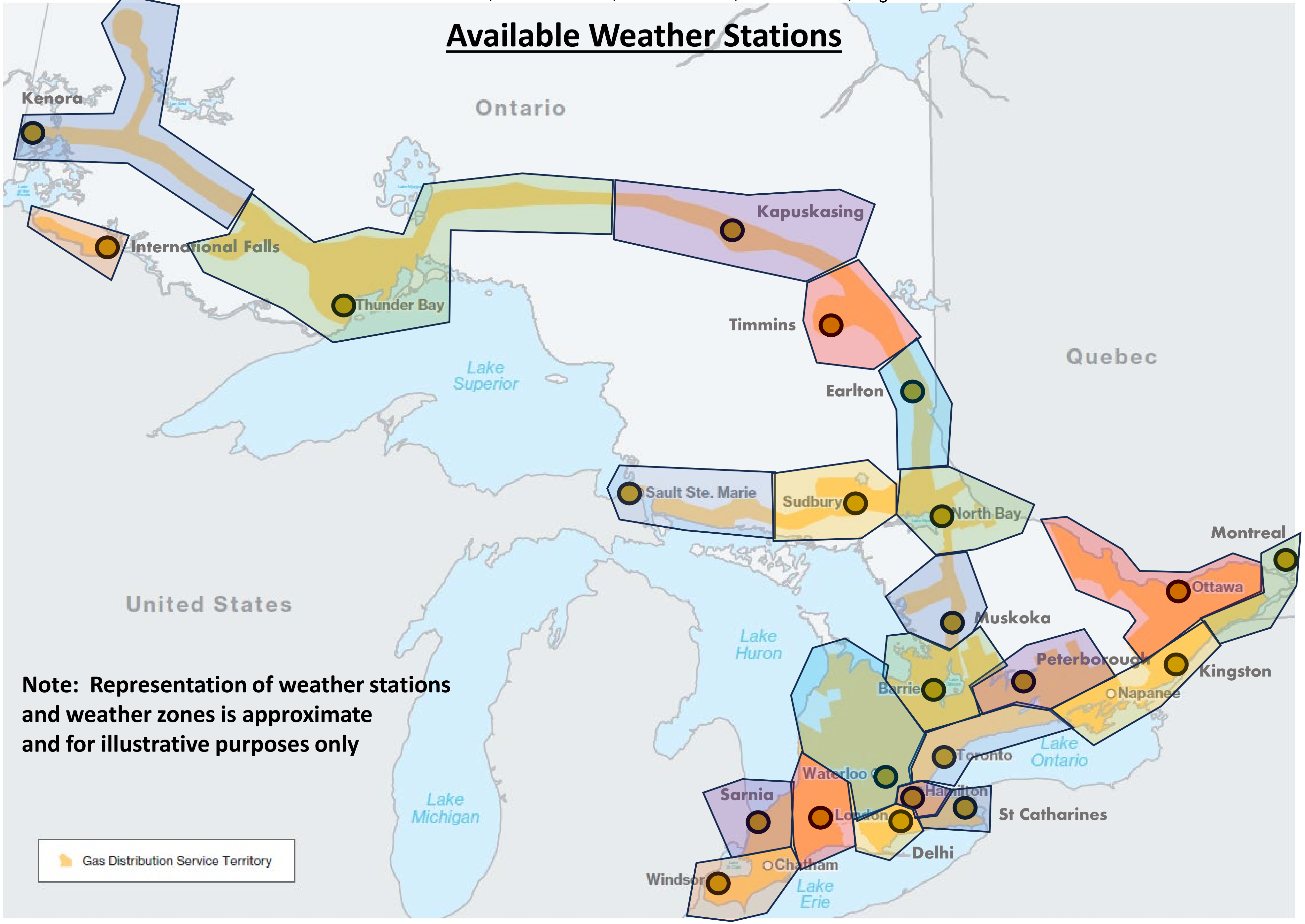
Response:

Attachment 1 provides a map of available weather stations and associated weather zones. The map is provided on a best-efforts basis and is meant for illustrative purposes only.

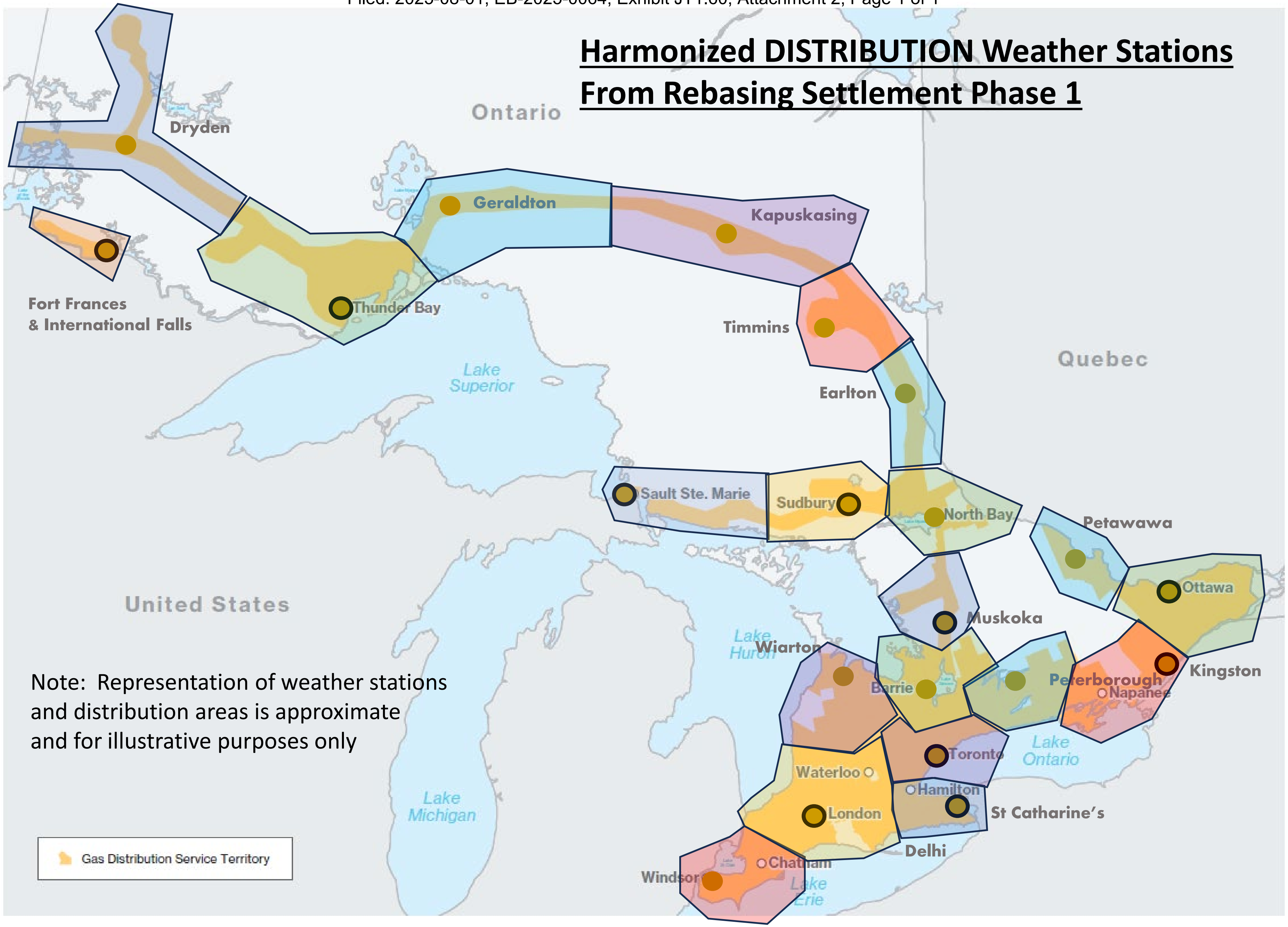
As part of Phase 1,[1] Enbridge Gas established harmonized weather stations. Enbridge Gas anticipates it will implement harmonized weather stations into the billing system with the implementation of SFVD rate design, subject to OEB approval in Phase 3. Please see Attachment 2 for an illustrative map of the harmonized weather stations.

[1] EB-2022-0200, Exhibit 4, Tab 2, Schedule 3, p.18, Table 1.

Available Weather Stations



Harmonized DISTRIBUTION Weather Stations From Rebasing Settlement Phase 1



Note: Representation of weather stations and distribution areas is approximate and for illustrative purposes only

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking:

Tr: 175

To advise about Enbridge's current plans to fill in missing weather data for the determination of the HDD, and how that weather data service identifies values for what Enbridge has called "missing days".

Response:

This response describes the current process.

The heating degree day (HDD) data is provided by DTN, which is a subscription weather service. DTN provides data that fill in missing values, if needed, from the source weather stations using proprietary methods. The data is then automatically uploaded daily (on a next-day basis, e.g. Monday’s data is uploaded on Tuesday) to the Gas Control (eWeather) reporting system. A script fetches the HDD data from the reporting system and automatically sends it to the Customer Information System (CIS) (i.e. billing system). The uploaded HDD data is then subject to a review. If the review identifies that the upload script resulted in missing data, format issues, etc., any missing HDD data is filled in manually by consulting the eWeather report.

This process is followed daily and results in a complete set of HDD data for each day.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking:

Tr: 3

To provide the 2024 system design day demand on an m³ basis and explain why that would be different from the billing determinants used for SFVD and if there is a reason, why the difference would be consistently higher or lower when this is considered in subsequent years.

Response:

The system design day demand (SDDD) for the 2024 Test Year Forecast is 90,594 10^3m^3 for Rate E01 and 64,383 10^3m^3 for Rate E02. The SDDD represents the demand requirement to which the system is designed and is used for cost allocation, gas supply planning and storage and transmission facilities in the Asset Management Plan. The SDDD drives the capacity cost of the system and allocation of demand-related costs in the cost allocation study. The allocation of system demand-related costs can be seen at Phase 3 Exhibit 7, Tab 3, Schedule 1, Attachment 12, page 11, lines 27 to 28. The sum of customer class allocation factors equals the SDDD. The HIGHPRESS>4 allocation factor allocates the SDDD to in-franchise rate classes.

The billing design day demand (BDDD) used in Phase 3 for the general service SFVD rate design is set to equal the SDDD (90,594 10^3m^3 for Rate E01 and 64,383 10^3m^3 for Rate E02). These amounts represent the forecast billing determinants, adjusted for 2024 and used for SFVD rate design. The BDDDs represent the individual customer demands, aggregated by customer class, and are used to derive unit rates (i.e., unit rates per unit of demand) which, when charged to customers, recover the allocated capacity costs from customers. Specifically, once demand-related costs are allocated to each customer class using SDDD, the allocated demand-related costs are divided by billing determinants to derive unit rates.

The BDDD have been set the same as the SDDD in Phase 3, as Enbridge Gas has not yet implemented changes to its Azure platform (as laid out in Phase 3 Exhibit 8, Tab 2, Schedule 3, paragraphs 74 and 75 and response at Exhibit I.8.2.-EP-8) that would facilitate derivation of 2024 billing determinants for general service customers. As a substitute, in order to derive 2024 unit rates the Company used 2019 general service billing determinants derived by Christensen as part of the general service rate harmonization project and scaled them to match 2024 system design day demands.

Under SFVD rate design, general service customers' BDDDs are used for rate design and billing. Each customer's BDDD for a given year will be based on an estimated regression equation and the customer's design day heating degree days. Individual customer BDDDs, aggregated by customer class, are used to derive unit rates (i.e., rates or prices per unit of demand).

BDDDs do not need to equal or be trued up to the SDDD as they differ in purpose. Enbridge Gas does not plan to rely on individual customers' BDDDs derived for rates and billing for cost allocation, system planning and design, or system operations. Having said that, the SFVD rate design, in using BDDD instead of volumetric consumption values, bases customer bills on a metric that reflects individual demand-related cost to serve. This is the closest that rate design can get to reflect how the system is designed, built and operated, and to recover the cost of the system capacity accordingly from customers.

This approach to cost allocation and rate design is standard for regulated utilities. SDDD drives costs and allocation of costs in the cost allocation study, while billing determinants are used to derive rates / prices.

In terms of implementation of the SFVD rate design, Enbridge Gas has reconsidered the response previously provided at Exhibit I.8.2-LPMA-18, part c) and determined that the proposed 2024 unit rates should be viewed as a placeholder. The SFVD unit rates would be updated to account for billing determinants following the implementation of the changes to its Azure platform, which would facilitate derivation of billing determinants for general service customers. The updated unit rates will be proposed on a revenue neutral basis and stakeholders will have an opportunity to review materials laying out derivation of rates through the associated draft rate order process. As described at Phase 3 Exhibit 8, Tab 2, Schedule 1, Enbridge Gas expects to file a more detailed implementation plan as part of its 2027 Rates Application, including updating the proposed rates prior to implementation in 2027. The update would reflect the updated billing determinants for general service rate classes and also the approved IRM adjustments for each year following 2024 until the date of implementation. Given this approach to determine the billing units, Enbridge Gas does not know if the BDDD will be higher or lower than the SDDD once implemented.

With respect to undertaking Exhibit JT2.2[1], please see Attachment 1 for a reconciliation of the winter 2023/2024 design day demand at EB-2022-0200, Exhibit 4, Tab 2, Schedule 3, page 32, Table 3 to the 2024 Cost Allocation Study.

With respect to undertaking Exhibit JT1.13[2], the response to part a) is “confirmed”. Also, please see the description above. In response to part b), Christensen derived the aggregate sum of BDDDs of customers in E01 and E02 based on customers’ historical consumption information up to and including 2019 as follows:

- E01 = 76,240 $10^3 m^3$/day; and
- E02 = 53,680 10^3 m^3/day.

The response to undertaking Exhibit JT1.14[3], parts a) and b) is “not confirmed”. Please also see the description above. The final 2024 SFVD unit rates will be set based on updated billing determinants to recover the approved revenue requirement on a revenue neutral basis upon implementation.

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[1] To look at EB-2022-0200, Exhibit 4, Tab 2, Schedule 3, at Table 3, at page 32, which shows the winter 2023/2024 Design Day Demand, and explain why this is significantly different than the indicated billing determinants using SFVD for 2024.

[2]a) Please confirm that the billing demand figures noted above are not related to the sum of the design day estimates using the CAEC regression methodology based on 2018 an/or 2019 data or any other period.

b) Does EGI and/or CAEC have the aggregate sum of all customers under each of Rate E01 and E02 based on the CAEC regression methodology? If yes, please provide the two figures.

[3]a) If the billing units from the CAEC methodology derived from 2018/2019 data or any period prior to the end of 2024 are higher than the figures used to derive the delivery demand rates, will this not result in higher revenues to EGI because the delivery demand rate is higher than it should be based on the lower forecast of delivery demand forecasts?

b) If the billing units from the CAEC methodology derived from 2018/2019 data or any period prior to the end of 2024 are lower than the figures used to derive the delivery demand rates, will this not result in lower revenues to EGI because the delivery demand rate is lower than it should be based on the higher forecast of delivery demand forecasts?

Reconciliation of Distribution Design Day Demands

Line No.	Particulars	EGD CDA	EGD EDA	Total EGD	Union MDA	Union WDA	Union NDA	Union NCDA	Union SSMDA	Union EDA	Total Union North	Union South	Total Rate Zones
		(a)	(b)	(c) = (a+b)	(d)	(e)	(f)	(g)	(h)	(i)	(j) = (sum d:i)	(k)	(l) = (c+j+k)
	Winter 2023/2024 Design Day Demand (TJ/d) (1)												
1	Firm Bundled / Semi-unbundled	3,485	698	4,183	6	88	155	45	42	173	507	3,283	7,973
2	Firm Unbundled	584	-	584	-	31	103	3	61	207	404	-	987
3	Firm Total	4,069	698	4,767	6	119	257	47	102	379	911	3,283	8,960
	Winter 2023/2024 Design Day Demand (10^3m^3) (2)												
4	Firm Bundled / Semi-unbundled	89,176	17,861	107,037	154	2,265	3,976	1,148	1,071	4,442	13,055	84,007	204,099
5	Firm Unbundled	14,944	-	14,944	-	798	2,645	67	1,559	5,317	10,386		25,330
6	Firm Total	104,120	17,861	121,981	154	3,062	6,621	1,215	2,630	9,758	23,440	84,007	229,428
	Cost Allocation Study												
7	Distribution Demand Design Day Demand (10^3m^3)			117,032 (3)							23,612 (4)	84,394 (5)	225,038
8	Difference (line 6 - line 7) (6)			4,948 (7)							(172) (8)	(387) (9)	4,390

Notes:

(1) Phase 1 Exhibit 4, Tab 2, Schedule 3, Table 3, p. 32
(2) Converted using heat value of 39.08 for South and 38.86 for North
(3) Phase 3 Exhibit 7, Tab 3, Schedule 7, Attachment 12, p. 14, column (a), line 27
(4) Phase 3 Exhibit 7, Tab 3, Schedule 7, Attachment 12, p. 16, column (a), line 27
(5) Phase 3 Exhibit 7, Tab 3, Schedule 7, Attachment 12, p. 18, column (a), line 27 + Phase 3 Exhibit 7, Tab 3, Schedule 7, Attachment 12, p. 20, column (j), line 27
(6) Rounding differences exist due to rounding of volumes on lines 1-3
(7) Cost Allocation Study includes Billing Contract Demand (BCD) for Rate 125 customers in place of firm design day demands
(8) Cost Allocation Study includes Rate 10 T-service design day demands
(9) Cost Allocation Study includes M17 design day demands

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking:

Tr: 5

To look at Phase 1, Exhibit 4, Tab 2, Schedule 3, at Table 3, at page 32, which shows the winter 2023/2024 Design Day Demand, and explain why this is significantly different than the indicated billing determinants using SFVD for 2024.

Response:

Please see response at Exhibit JT2.1.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking:

Tr: 10

To provide a representation of what a customer bill would look like, using a sample SFVD rate design and including line items.

Response:

Enbridge Gas plans to roll out a simplified bill along with the implementation of general service rate harmonization into billing.

In June 2022, Enbridge Gas conducted focus groups with residential customers and provided customers with examples of the proposed charges on the bill. Please see Attachment 1, previously filed at EB-2022-0200, Exhibit 8, Tab 2, Schedule 3, Attachment 9.

Based on the findings of the customer engagement, Enbridge Gas concluded that there is support for bill simplification, as long as details and explanations of charges are still readily available for customers who choose to delve deeper into their bill. Based on the feedback received, Enbridge Gas also plans to simplify its general service bills to two billing line items: Natural Gas charge (volumetric) and Delivery charge (fixed).[1]

Attachment 1, page 25, shows an example of a simplified bill that was used to solicit customer feedback through the focus groups on the “Charges for Natural Gas” section of the customer bill. Attachment 2 shows another illustrative example of a simplified bill with changes based on the feedback received. Notably the changes made were to change the name from Gas Supply charge to Natural Gas charge so it is more intuitive and reflective of what the charge represents, and to reorder the billing line items so that the Natural Gas charge is first followed by Delivery charge.

The planned simplified bill is similar to the categorization used by electric utilities

[1] The customer engagement also included the Federal Carbon charge (volumetric), which Enbridge Gas removed as part of its April 2025 QRAM Application (EB-2025-0078).

which is set out in Ontario Regulation 275/0422. Through customer engagement focus groups Enbridge Gas heard from residential customers that they would find it beneficial if the "look and feel" of the various charges on utility bills they receive were similar so that it is easier to compare across the utilities, as provided at Attachment 1, page 20. The bill simplification being planned is responsive to this feedback and is consistent with the bill structure that electric utilities have already implemented for their customers.

INNOVATIVE
RESEARCH GROUP

2024 Rate Rebasing Customer Engagement:
Rate and Bill Design

ENBRIDGE

Qualitative Research with Residential and Business Customers

RESEARCH REPORT

July 2022

Table of Contents

Project Overview

Enbridge Gas 2024 Rate Rebasing Customer Engagement: Rate and Bill Design

Innovative Research Group Inc. (INNOVATIVE) was engaged by Enbridge Gas to assist in meeting its customer engagement commitments for its 2024 Rate Rebasing requirements. This preliminary report summarises the findings of a qualitative research engagement that included a series of 10 focus groups with residential customers and 20 one-on-one interviews conducted with small and medium-large business customers.

Research Objectives

- Enbridge Gas is considering changing the way they charge customers for fixed costs of service and what they show on their bills to more closely align with the directives the OEB has set for electrical utilities.
- The objective of this research was to gauge customer response to potential changes to the way Enbridge Gas bills customers for fixed costs, as well as a simplified version of the bill.

About Qualitative Research:

The value of in-depth interview and focus group research lies in the depth and range of information provided by the participants, rather than in the number of individuals holding each view.

Qualitative research is an exploratory research technique and does not hold the statistical reliability of quantitative research.

Methodology: Discussion Guide [1/3]

Research Methodology

The discussion guide was developed by Enbridge Gas and finalized with input from INNOVATIVE.

- The guide recognized that participants would have a range of existing knowledge and was planned to ensure even people with no knowledge of the natural gas system or bills would have enough information to provide meaningful feedback on potential changes.
- Visual stimuli were developed to provide participants with a system overview and then to progress the discussion from the relatively straightforward potential bill changes to the more complex issue of how to charge customers for fixed costs incurred by Enbridge Gas.
- Feedback was collected on existing bills before moving to potential changes.

Outline of the Discussion*

1. Core components of Natural Gas and Electricity Networks
2. Example of Enbridge Gas current bill
3. Mock-up of proposed Enbridge Gas bill charges
4. Explanation of Delivery Charges on Electricity and Natural Gas Bill
5. System Overview showing Fixed and Variable Costs
6. Current cost recovery
7. Ways to recover fixed charges
8. Impact on average customers
9. Impact on small and large demand customers

* See APPENDICES for accompanying stimulus

Methodology | Focus Groups [2/3]

- A total of 10 online focus groups with a total of 45 Enbridge Gas residential customers were held between June 22nd and July 5th, 2022. The groups lasted an average of 90 minutes and were conducted on Zoom.
- Eight of the 10 focus groups were moderated by Susan Oakes (Vice President at INNOVATIVE), while the other two were moderated by Greg Lyle (President).
- Participants were recruited using a combination of telephone and online methodologies, and screened to ensure they have sole or joint responsibility for decisions regarding natural gas, including viewing and paying their Enbridge Gas bill.
- All participants were paid a $100 honorarium in appreciation of their time.

The breakdown of the focus groups is shown below.

Date	Rate Zone	Region	# of Participants
June 22nd, 2022	Enbridge Gas	GTA	Group One: 5 / Group Two: 4
June 23rd, 2022	Enbridge Gas	Non-GTA	Group One: 4 / Group Two: 5
June 28th, 2022	Union Gas	Central	Group One: 3 / Group Two: 5
June 29th, 2022	Union Gas	North/East	Group One: 4 / Group Two: 4
July 5th, 2022	Union Gas	South/West	Group One: 6 / Group Two: 5

Methodology | In Depth-Interviews [3/3]

- A total of 20 in-depth interviews were held with small and medium-large businesses between July 6th and July 25th. Interviews lasted an average of 45 minutes and were conducted on Microsoft Teams.
- Sixteen of the 20 interviews were conducted by Brendan Frank (Senior Consultant at INNOVATIVE), while the other four were conducted by Olga Rodriguez Sierra (Director at INNOVATIVE).
- Potential participants were recruited via an email invitation from INNOVATIVE. This allowed the invitations to give background about the interviews and to ask to be referred to the most appropriate person to participate—that is, a person in the organization who makes decisions regarding the use of natural gas.
- In appreciation of their time, a $100 donation was made to a charity of the participants' choosing.

The breakdown of in-depth interviews is shown below.

Rate Zone	Size	# of Participants
Enbridge Gas	Medium-Large	4
Enbridge Gas	Small	6
Union Gas	Medium-Large	5
Union Gas	Small	5

Key Findings | Context

Context: Residential Customers

Most residential participants do not look at their Enbridge Gas bill closely from month to month. It is worth pointing out that almost all participants receive their bill electronically. Many simply look at what they owe and pay it without further consideration. Others will take a closer look to find the cause of a noticeable increase, or perhaps to do a quarterly review for budgeting purposes.

For many, looking at the current charges for natural gas on a sample Enbridge Gas bill was new to them. In several groups, there was a lack of understanding of the Customer Charge and confusion between the Delivery to You and Gas Supply Charge. Several remarked that the word "supply" implies delivery rather than consumption. Most wanted to be able to access a description of each line item, whether it be on their paper bill or accessible on their e-bill. Some mentioned www.enbridgegas.com as a source of such information, but the general preference was for a more "at your fingertips" option.

Context: Business Customers

Unlike residential customers, most business customers do look at their bills closely every month.

In other ways small business responses closely resembled those of residential customers. They tended to focus on the bottom line. Bill literacy and understanding was fairly low for small businesses, even among those that look at their bill monthly. Most do not pay close attention to the line items or other details on their bills.

For some of these smaller businesses, there was confusion around the current charges, particularly the customer charge, the transportation charge, and the cost adjustment. However, there was mixed interest in learning more about the bill. Several customers held the view that since they do not have a choice but to pay their natural gas bill, it was not worth investing any additional effort or time to understand it in greater depth.

Many medium-large customers indicated that they have a person on staff dedicated to energy management or invoice analysis. As such, these organizations are more likely to break out each line item in their bill and look for changes month over month. Bill literacy and understanding were much better among medium-large customers, though this was not universal. Several mentioned enbridgegas.com as a resource. Others said they found the website unhelpful given that most resources seem tailored for residential customers.

Key Findings | Bill Presentment

Reaction to Simplified Bill

Response to the simplified version of the bill was generally favourable for both business and residential customers. Many welcomed a simplified, streamlined approach. The main caveat is that just as some participants expressed a desire for descriptions of the line items on the current bill, they would also like the same for the simplified version.

In one focus group, a participant suggested that the Gas Supply Charge should appear before the Delivery Charge, as on the electricity utility bill. Others in the group agreed with this suggestion.

Learning that the simplified Enbridge Gas bill reflected the OEB's requirements for electricity bills was generally met with indifference among both residential and business customers. In a few cases, participants suggested the electrical utilities should change their bills to match the breakdown on the current Enbridge Gas bill.

Many customers who typically just look at the bottom line don't have an opinion one way or the other when it comes to how much detail is shown on their Enbridge Gas bill.

There were some suggestions related to combining Customer Charge, Delivery to You and Transportation to Enbridge into a single Delivery Charge:

- Some residential customers felt that it didn't make sense to combine the Customer Charge with the other two charges once they learned that it is currently a fixed charge, while the Delivery and Transportation charges are currently variable.
- When the simplified version of the bill was revisited after discussing options for how to charge customers for those costs, a few residential participants suggested that if Enbridge Gas proceeds with the Two-Charges option, the Customer Charge should remain a separate line item because it is fixed and not within their control. Whereas with conservation efforts or electrification, customers can monitor the decrease or increase in their yearly Delivery/Demand Charge over time.
- Some residential participants were concerned that combining the three existing "delivery" charges highlights the fact that they are paying more for delivery than they are for their gas consumption, which does not make intuitive sense to them.
- Some business customers suggested that combining charges was a way for Enbridge Gas to conceal new charges or collect more money from customers.

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Bill Presentment

Current Enbridge Gas Bill [1/4]

Overview: Most residential customers do not typically pay close attention to their bills. Small business customers tend to look at their bills less carefully than med/large business customers. Most small businesses view natural gas as an expense like any other, with little consideration for anything other than the total at the bottom of the bill. Some larger business customers are rigorous with analysis of their bills, and many have a dedicated employee who looks at utility costs.

Little attention paid, with some exceptions

"I just look at the end monthly costs, I might look at the individual items, maybe once a year." –EGD Other Residential

"I get the email. I look at the balance showing. And then it's electronically paid. So, I haven't looked at a bill in the last 10 years, frankly. Providing that the balances appear reasonable and consistent with the past, I'm happy." –Union North/East Residential

"If by closely you mean the bottom line, I look at it pretty closely, I kind of just skim the rest of the email until I see what the cost is. But I look at that every month." –Union South/West Residential

"I know that there's a lot of different breakdowns on the bill. But I also know I have no control over any of them. So I don't really pay attention." –EGD Small Business

"To be honest with you, after seeing [the bill] one or two times, you give up. There's nothing you can do. You just have to live at their mercy, more or less. This is my strong word for it." –EGD Small Business

"To be honest, now, when I get my monthly bills, I just look at what was being charged. I don't go through it by line by line anymore." –Union Small Business

"Knowing that we can't change anything, we do track everything. I have a spreadsheet that somebody sends to me monthly that tracks all of these costs and our cubic meter usage. So I do quite a bit of analysis on it and have obviously also been watching the carbon charge." –Union Med/Large Business

Current Enbridge Gas Bill [2/4]

Overview: While most customers do not typically pay close attention to their bill, some review it for comparison across months and occasionally years. This is more common with business customers who keep close track of expenses.

Looking for changes

"Yes, I sometimes look at it because I've found differences with estimated numbers. And sometimes it's a big difference with the real number." –Union Central Residential

"I'm on the monthly payment plan. So nothing has changed. And about every three months, I'll see how I'm doing against that budget plan, and look for any anomalies." –Union South/West Residential

"Yeah, I review it. And I've actually monitored over the years too, so I know the highs, the peak and the lows." –Union Central Residential

"I look at the charges daily. I'm always looking at bills, the changes, doing something with them. I see them on a regular basis." –EGD Small Business

"We've been in the space for less than a year, so we're still in the very early stages of going through the year and figuring out what our pattern of gas use will be over the course of the different seasons." –EGD Small Business

"I take a quick peek at them just to see if there's any anomalies, but it's very superficial in some ways." –EGD Med/Large Business

Current Enbridge Gas Bill [3/4]

Overview: Both business and residential customers were generally satisfied with the level of detail on their bill but expressed a lack of understanding as to what the charges actually are, often reporting confusion about the customer charge, the gas supply charge, and the cost adjustment.

Lack of understanding

"I see this every month, but I don't know what a lot of these things are. Like a gas supply charge. I don't know what that is. Because we've already paid for the gas with the customer charge." – EGD GTA Residential

"I don't really know what I'm looking at, like, I understand obviously, what the words mean, but like, in terms of the service they provide, I have no clue." – Union Central Residential

"When you look at it and say, well, there's a delivery charge, there's a supply charge. For me, that sounds like it should be the same thing, right? And then there's the customer charge. So it looks like there's multiple ways of saying similar things and then there's just values for it." –Union Central Residential

"I have no idea why there's a cost adjustment, to be honest." –EGD Small Business

"There are storage charges, transportation charges… the gas comes through a pipeline that's been there for 20 or 30 years. That hasn't changed. I wish they'd just say your gas bill was $200 this month, and that's it. I don't need all the other stuff… why don't we just get a bill for gas?" –Union Small Business

"I don't find there's enough information about what that cost adjustment is and why it's made." –Union Med/Large Business

Current Enbridge Gas Bill [4/4]

Level of detail

"I think detail is great. But if nobody understands what the detail means then it's kind of irrelevant." – EGD Other Residential

"To me, it seems okay. It'd be nice to know what each one actually means. Like, what is a customer charge? Is that the actual cost of the gas or is that something else?"— EGD Other Residential

"I like the amount of detail but I feel like it could have even more because even amongst us there has been a bit of confusion about what charge is really for what, so if there could be some distinction between what the charges are, that could be helpful for some people." – Union North/East Residential

"I actually really like it, because instead of just seeing one complete price, I like how it's kind of broken down so you can kind of see what portions went towards what part of it." –Union North/East Residential

"I guess it's about right. The truth is, I just scan right down to the bottom when I look at it, I honestly don't think I've ever looked at those line items before. But I mean, looking at it now, it is nice to see that detail if you cared to do that." – Union South/West Residential

"It does seem a lot. It's like, 'Okay, there's a lot that goes into this bill.' I'd like an explanation somewhere that told me what made up the delivery, and the supply, but I think simpler is better." –EGD Med/Large Business

"Like I said, I don't understand why we pay some of those charges. They're breaking it down, but to me, we're just a customer, right? It should be a direct, buy-one price." –Union Small Business

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New Enbridge Gas Bill [1/6]

Overview: Most customers preferred the new bill, motivated by simplicity. Even if they preferred fewer line items, some still wanted information on the charges without having to expend too much energy looking for them. Some customers favoured the detail of the current bill, reporting a sentiment along the lines of "if it ain't broke, don't fix it."

Prefer simplicity

"I think the simpler one is better actually. I don't think I get that much from more headings. I mean, my initial comment was that the headings weren't that meaningful to me anyway." – EGD GTA Residential

"It's not as overwhelming as the other ones. More simplified." – Union Central Residential

"Even though I said the other one needs more details, I do like the simplified version only because I feel like there's less questions that I have when I look at it. I just kind of accept that." – Union Central Residential

"This does simplify it, so for someone like myself, you can look at it and say okay, it was costing me this much for the gas. So, in this case for delivery, and then you've got your carbon charge. So, it simplifies it a fair bit." – Union Central Residential

"I prefer this. It doesn't seem so overwhelming." – Union South/West Residential

"I like it. It's simplified in my mind. Even on the other bill, that delivery charge to Enbridge and Enbridge to me, I'm still paying the same thing when you add those two lines up. It made no difference, right? It doesn't make it any cheaper or not. It's going to be the same price whether up or down." – Union South/West Residential

"Seems a lot less confusing and scary, more straightforward." –EGD Small Business

"I don't see why I would need all that extra information about the bill, because I can't control it. At the end of the day, most people don't want to know how you cook the chicken, we just want to know how the chicken tastes… things that we can control, that's what I need to see." –Union Med/Large Business

New Enbridge Gas Bill [2/6]

Note: Some residential customers who liked the simplified bill expressed an interest in more detail or description of what the charges actually cover. This view was somewhat less common among business customers, but still present.

Like the simplicity, but want an option for detail

"I like to see detail. But, I mean, I do like to look at the simpler invoice just for quick reference. But I would like maybe if I can see the simple one on my billing, but then have the option to click to see more detail if I want to on those specific areas." – EGD GTA Residential

"I like it a lot more. Just wish the detail like the delivery charge are changed to more, I guess, descriptive labels. Once again, I'd like to see, a footnote at the bottom of the bill." – EGD Other Residential

"I understand it better. I would still like an explanation of why I'm getting charged 50 bucks to get gas delivered to my house. But if it's one or the other, I prefer this one over the other one." – Union Central Residential

"I guess since I didn't completely understand the charges on the previous bill, this makes more sense now that it's broken down into literally just the three pieces that deal with it: what I used, what it costs to get to me, and then, of course, the federal government's portion of it. So to me, this is simple, but […], if different things make up the delivery charge, and only one of those pieces of the delivery charge changes, how do we know? I mean, I like this, it's simple, it's clean. But again, so long as we can understand when it changes, what is involved in the change." – Union South/West Residential

"Speaking in more layman's terms, I would say that a customer charge is kind of generic. There isn't too much detail as far as what that entails considering there's six other charges on there as well. So having something just called customer charge without an explanation is could be misleading for most people." –EGD Med/Large Business

"I guess for those who are unaware or don't care, that's fine. But I would just want more detail somewhere." –Union Med/Large Business

New Enbridge Gas Bill [3/6]

Prefer current bill

“I'd like the original bill, just leave it as is. It's just a little bit clearer. It's a little bit more itemized.” – EGD Other Residential

“I personally prefer the old version; I like to know how the cost is breaking down. So if I had just the delivery charge where it was like that $52, I would want to know what is incorporated in that.” – Union North/East Residential

“I personally prefer the previous version. If there's going to be a large fluctuation in price between one of the categories on the previous bill, I might have more information about where that fluctuation is happening. But if it's all combined in the delivery charge line, I don't have as much information to start with when I inquire.” – Union Central Residential

“I definitely liked it better when it was broken down into more specific things. Because now when you're combining charges, but keeping it with the same name, it just seems like you're hiding a charge.” – Union South/West Residential

“The number of charges is very reasonable. It's actually a lot less than compared to a lot of the Alberta utilities. We don't find the number of charges on these bills to be excessive... Having the customer charge rolled up, that’s something that we would want separate, because it's always good to know what kind of standard fee that's being charged by the utilities.” –EGD Med/Large Business

“I think it's good. Like it gives you the exact breakdown of how they came up to the number.” –Union Small Business

“Probably the more detail, the better. People nowadays are really concerned about what each portion is getting them.” –Union Med/Large Business

“My initial comment would be now I'm scared, skeptical, right? Why do you have to combine them? At least before I could be watching and making sure that things were in line, but now you're just moving to one big pot. So I'm a skeptic in terms of how these are being charged.” –Union Med/Large Business

New Enbridge Gas Bill [4/6]

Note: Some customers expressed concern over a higher delivery charge that combines certain costs. Concerns fell into two broad categories: the amount of the new Demand Charge (more common for residential customers), and the lack of transparency related to the new line item (more common for business customers).

Transparency

"If they switch to the simpler one, a lot of people are gonna see an increased cost on a certain thing all of a sudden not realizing that they combined stuff." – EGD GTA Residential

"[It] draws my attention to the delivery charge, and I would question that. Will it change anything? I would doubt it, but I will be upset looking at those numbers month in and month out." – Union Central Residential

"I do I like the old bill, I prefer to see the breakdown. I also don't like, it also just sort of shows a bit more blatantly, that I'm paying almost double in delivery fee for my actual usage. So from a number perspective, it's nice to see smaller numbers next to my actual usage versus it all into one." – Union South/West Residential

"I mean, I'm fine with it. But at the end of the day, there's still all them [sic] charges. They're just hiding them." –Union Small Business

"I don't want to go to have to go somewhere else to get the information. I just want it on the bill. Like it was simple. I don't like having to go search for it. I just want it the way it was. To me that's more transparent. It's the information is all there. Why not do that? Why dumb it down?" –Union Med/Large Business

New Enbridge Gas Bill [5/6]

Building understanding

“I think I mostly care about the end result, the final bill, but it would be kind of nice to have on the back of the bill, a descriptor of each of those items. Just because I would imagine people have questions about them.” – Union North/East Residential

“I think I'd rather see it on the actual statement. I think just from a usability perspective. Not everyone is proficient with computers enough to go to the website. If they're receiving a paper bill, then it's probably easier for them just to look at the bill.” – Union Central Residential

“My basic question here is last year, we were using 16 cubic metres. This year, 11 cubic metres. But it does not really tell us dollar value of that. We are not here a corporation with 20 accountants working in it that can dig out everything. It's like a family business, one guy looking after everything. He doesn't have time, right? Let me put this way. Sure, big corporations, they want to see their $50,000 bill for the gas. They have reason to find out what is happening, why it is like this. When my bill is only $300, how much I can really dig into it? Why does it make sense for me to spend two hours on that?” –EGD Small Business

“I don't think having all of those charges adds any value. In fact, it just opens a Pandora's box to questions and speculation as to, you know, are these really valid? Delivery and supply? Seems to mean the same thing to me. I’m not sure what the distinction is. Should be on the bill itself.” –EGD Med/Large Business

“It should be enough for the normal guy. For me, I'm a little bit more of a detail person. I don't know if it's if there's any way Enbridge can solve it, but there is no mention of exactly how much the meter is. There is no meter reading on this bill. I don't see any place where it says the meter reading this month and the meter reading next month.” –Union Small Business

INNOVATIVE RESEARCH GROUP

New Enbridge Gas Bill [6/6]

Building understanding

"I'm not sure if it's feasible, but if we're downloading them from the online site, if there's some sort of like clickable link, that brings up some sort of definition or, like, a breakdown in customer-friendly terms." –Union Central Residential

"You could have an 'i' that stands for information somewhere after delivery charge, and if you hover the mouse over that you see what delivery charge means actually to you or as footnotes on the same page if it's a printed invoice." –EGD GTA Residential

"I think if, like, for people who do like to see the older version if this one came out, there should almost be like a drop down box or something that would give you that information. People who just quickly skim over it, they can just look, but if you want more information, then you can click the drop down, and it will show you the breakdown." –Union South/West Residential

"Whenever I talk to customer service agents and ask 'Well, where's this particular policy?' … There's information for homeowners, but nothing for commercial? There was nothing they could point me to online. So yeah, in general I don't think the website is great." –EGD Small Business

"If [the details on the bill] were easy to find on the website, I would. I rely on the website a lot." –Union Small Business

Note: One residential customer made a suggestion regarding the order of the line items, and the rest of the group agreed:

"Can we put the gas charge above the delivery charge? […]The gas is the actual product that we're purchasing. The delivery charges. […] It's kind of like, you know, if you buy a pizza, there's a total for the pizza, and then you have your delivery charge after in the sense that your product is going to be the top thing you look for." – Union Central Residential

Gas Bill vs Electricity Bill [1/3]

Overview: Most residential participants appreciated the more simplified and streamlined approach to their bills that aligning gas and electricity charges offered. The remainder reported mostly indifference. Some cited a preference for increased detail and differences in what they look for on the bills. A few were opposed based on concerns over combining fixed and variable costs into a single line item, and some preferred the transparency of the current Enbridge Gas bill.

Streamlined

"I think it makes some sense, because almost everybody's going to have both gas and electric. It makes it more digestible and more easily consumable for a wider variety of audiences if they look similar." –EGD Other Residential

"I like the idea of like the continuity between, like, going in this direction, just because I think consumers kind of pair the two together a lot and to have more similarities might make it easier for understanding." – Union Central Residential

"Well, I like the simplified version, and, like, aligning it with the same as the electricity style bill, only because it just kind of streamlines things for people. But I agree, it might raise more questions when you don't have all the information. And people don't like change. So it could be an adjustment for sure. But I do think there's a good call for simplicity when it comes to our bills. And either way, it doesn't change the final amount that we pay." – Union North/East Residential

"I feel like it makes it more understandable for the consumer if they see things that they can understand across the board and make it easier so if they see just a delivery charge on both bills, instead of having three different charges, […] that could make just more consistency and just more understanding." – Union North/East Residential

"I think you wouldn't have to spend as much time trying to go through the detail of it. You know, because you pretty much know where you should be looking, as opposed to the two different bills and trying to figure out the difference of the two. So, it'd be just to simplify where you're going and what you're looking for, and, you know, less time." – Union Central Residential

Gas Bill vs Electricity Bill [2/3]

Different bills

"I like the way that the electricity bills are laid out right now, you know, we can see the off peak and on peak charges and the consumption that we have for each level, the prices for each level. But I don't think that really matters with the gas because there isn't different price tiers for the gas. It's a standard price regardless, so I can't really compare the two like an apple to apple kind of thing." – EGD GTA Residential

"I'm happy with two approaches, as long as I understand what each line item is." – EGD GTA Residential

"I still think it's the more intelligent choice to break it down for everyone, as opposed to follow the other company. Just because they're not doing it doesn't mean everybody's company should follow suit." – Union South/West Residential

"I don't care what it looks like to be honest, I only care about the impacts to my to my bills." – EGD Other Residential

Note: A few residential participants expressed concern over fixed and variable costs being combined into one line item as on the electricity bill and made the following comments:

"Having seen the explanation at the bottom box, how the customer charge is fixed, I don't agree. I don't think that should be put in the same space as delivery as a delivery heading, because it affects customer charge and does not explain to me my consumption. This is just what you're charging me for being a member or having to have gas from Enbridge. But it does not talk to me about the variability of my consumption, or the delivery charge that can change by month. And so I don't know if customer charge under delivery would be the most telling of what it is." – Union Central Residential

"Because the two ones on the bottom there are variable, I think it's good to have them apart so that, you know, based on your usage while you're paying more or less." – Union North/East Residential

Gas Bill vs Electricity Bill [3/3]

Note: Most business customers were entirely indifferent to aligning their electricity and natural gas utility bills. A few smaller businesses saw some minor benefits to aligning the bills, but these were not strong preferences. A few were surprised that the Ontario Energy Board did not already require utility bills to look alike.

Indifference

"From a visual perspective, understanding intuitively where things are placed on a bill, how the information is presented. Really, that to me is the main benefit of having electric and natural gas utility bills look similar. Yeah, I don't necessarily have an opinion either way." –EGD Small Business

"We'd look at them as different utilities. I don't think most people know whether that's regulated by this board or that board. We both know their consumption. We know they're both consumption bills. The more you use, the more it's going to cost. And we all feel a little helpless that we don't have any impact on what those things are going to cost." – EGD Small Business

"To be honest, the breakdown is not really important to me. I need to be able to extract how much I owe for the bill and I need to immediately be able to extract the amount of the HST because a portion of the HST is recoverable for me as a charitable organization. [The number of charges is] fine. I wouldn't want to see more. But, I mean, the bill is what it is. I gotta pay, it doesn't matter where the charges came from, to be honest." –EGD Small Business

"To me, I see very little point in comparing the two for what I'm doing, for my needs, because they're completely different functions." –EGD Small Business

"I don't see a benefit, but I would think that [the Ontario Energy Board] should be telling both utilities how to present it to the customer." –EGD /MedLarge Business

"It's not going to impact anything for me." –Union Small Business

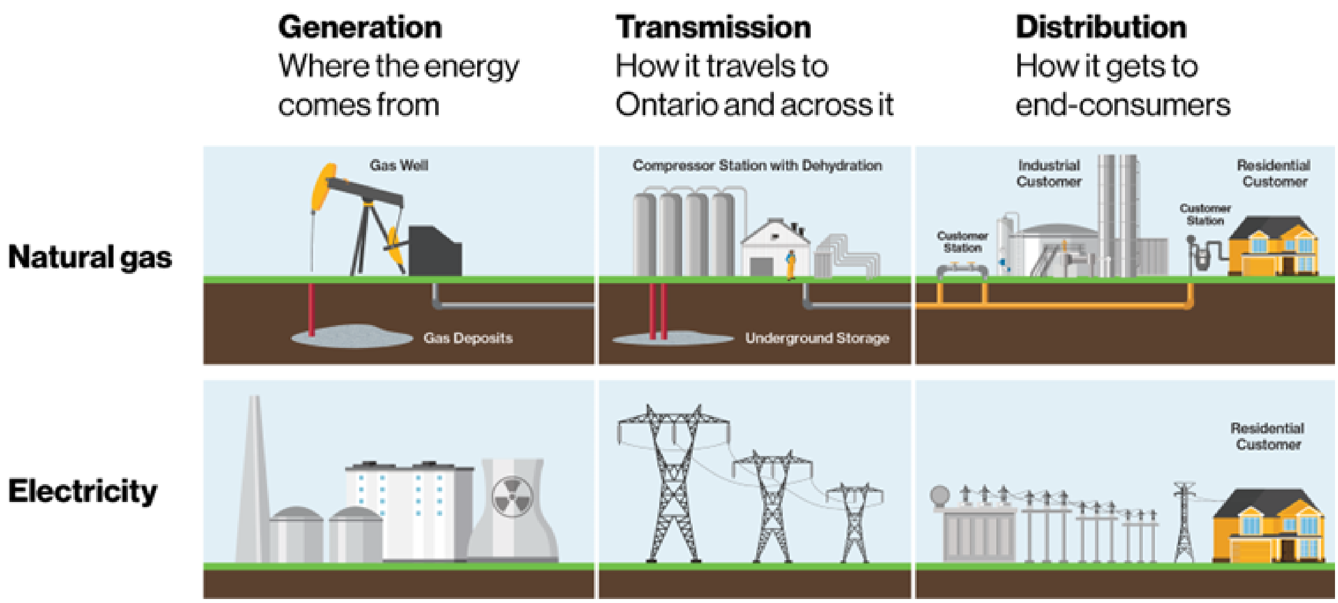
"I can't see how that would make a big difference… but I think simpler is generally better." –Union Small Business

APPENDIX: Stimulus

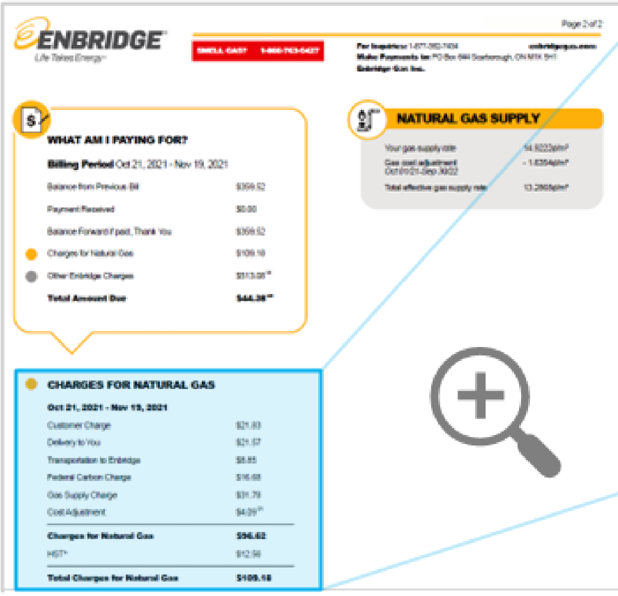
(Residential Version)

Residential Stimulus [1/6]

Core components of natural gas and electricity networks



Example of Enbridge Gas bill (charges)



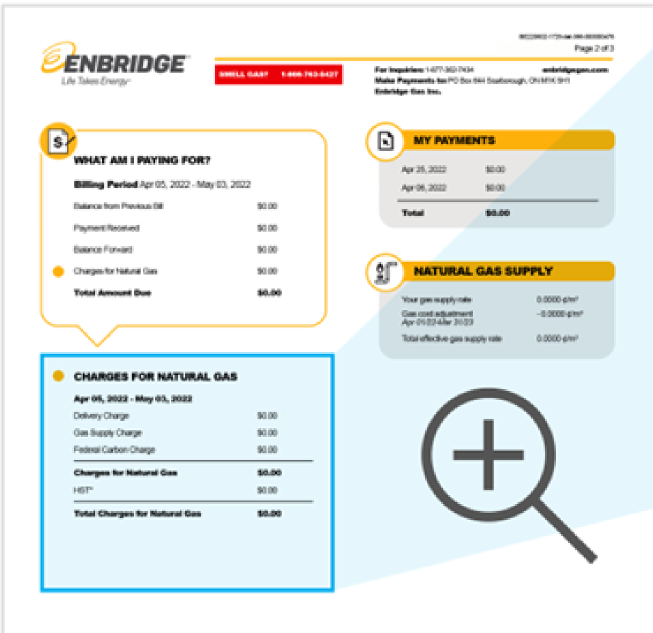
CHARGES FOR NATURAL GAS

Oct 21, 2021 - Nov 19, 2021

Customer Charge	$21.83
Delivery to You	$21.57
Transportation to Enbridge	$8.85
Federal Carbon Charge	$16.68
Gas Supply Charge	$31.78
Cost Adjustment	$4.09 CR
Charges for Natural Gas	**$96.62**
HST*	$12.56
Total Charges for Natural Gas	**$109.18**

Residential Stimulus [2/6]

Mock-up of proposed Enbridge Gas bill charges



Using previous sample bill:

CHARGES FOR NATURAL GAS

Apr 05, 2022 - May 03, 2022

Delivery Charge	$0.00	$52.25
Gas Supply Charge	$0.00	$31.78
Federal Carbon Charge	$0.00	$16.68
Cost Adjustment	*$0.00*	*$4.09CR*
Charges for Natural Gas	**$0.00**	**$96.62**
HST*	$0.00	$12.56
Total Charges for Natural Gas	**$0.00**	**$109.18**

Delivery Charge	$52.25
Customer Charge	$21.83
Delivery to You	$21.57
Transportation to Enbridge	$8.85

Explanation of delivery charges on electricity and natural gas bill

- ✓ Your electricity bill shows only **one Delivery charge** to cover all the Transmission and Distribution charges and is comprised of 4-line items
- ✓ Some of these charges are variable and some of these are fixed
- ✓ The largest, the fixed customer service charge, covers the entire cost of the network
- ✓ Your Enbridge Gas bill shows **three charges** for delivery to cover the cost of the network

Your Electricity Charges

Electricity	
448 kWh Off-peak (lowest price) @ XX ¢/kWh	0.00
126 kWh Mid-peak (mid price) @ XX ¢/kWh	0.00
126 kWh On-peak (highest price) @ XX ¢kWh	0.00
Delivery	0.00
Regulatory Charges	0.00
Your Total Electricity Charges	0.00
H.S.T.	0.00
Ontario Electricity Rebate	(0.00)
Total Amount	**$0.00**

Delivery charge	Type of charge
Customer Service Charge	Fixed
Distribution Charge	Variable based on consumption
Transmission Charge	Variable based on consumption
Line Loss Adjustment	Adjustment factor

CHARGES FOR NATURAL GAS

Oct 21, 2021 - Nov 19, 2021

Customer Charge	$21.83
Delivery to You	$21.57
Transportation to Enbridge	$8.85
Federal Carbon Charge	$16.68
Gas Supply Charge	$31.78
Cost Adjustment	$4.09CR
Charges for Natural Gas	**$96.62**
HST*	$12.56
Total Charges for Natural Gas	**$109.18**

Delivery charge	Type of charge
Customer Charge	Fixed
Delivery to You	Variable based on consumption
Transportation to Enbridge	Variable based on consumption

INNOVATIVE
RESEARCH GROUP

APPENDIX: Stimulus

(Business Version)

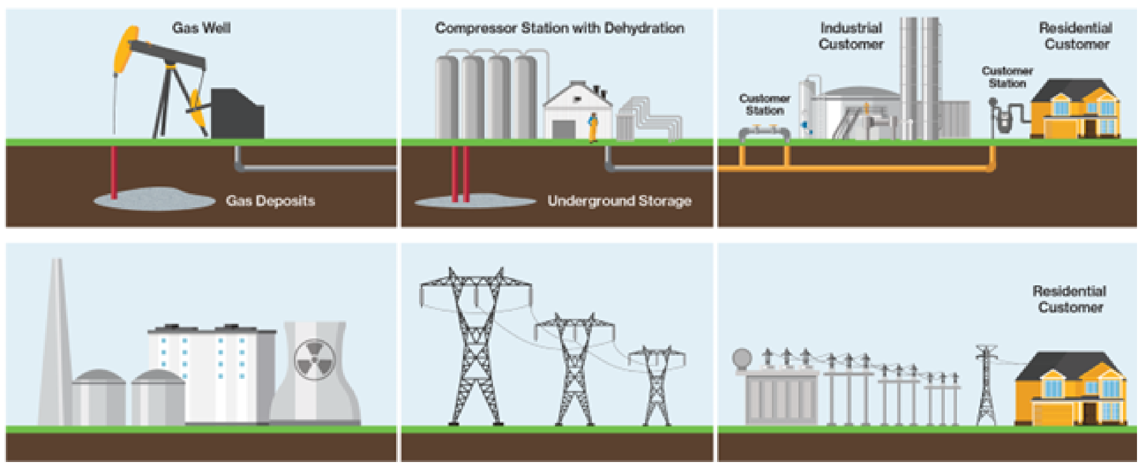
Business Stimulus [1/6]

Core components of natural gas and electricity networks

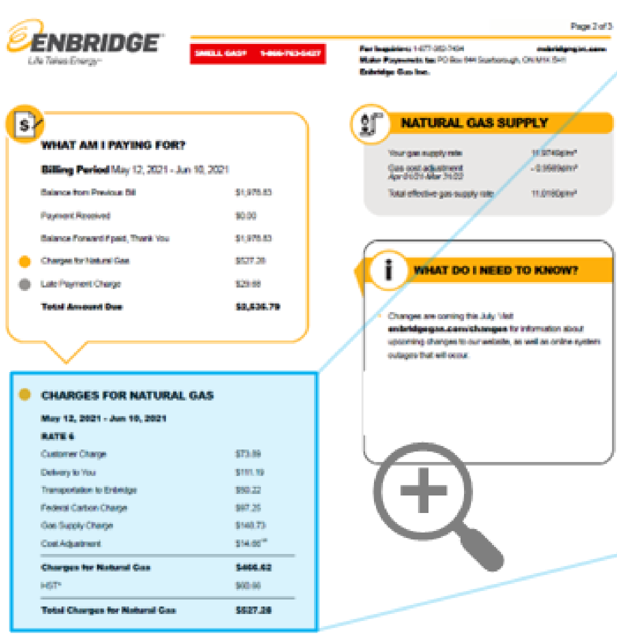
	Generation Where the energy comes from	**Transmission** How it travels to Ontario and across it	**Distribution** How it gets to end-consumers

Natural gas

Electricity



Example of Enbridge Gas bill (charges)



CHARGES FOR NATURAL GAS

May 12, 2021 - Jun 10, 2021

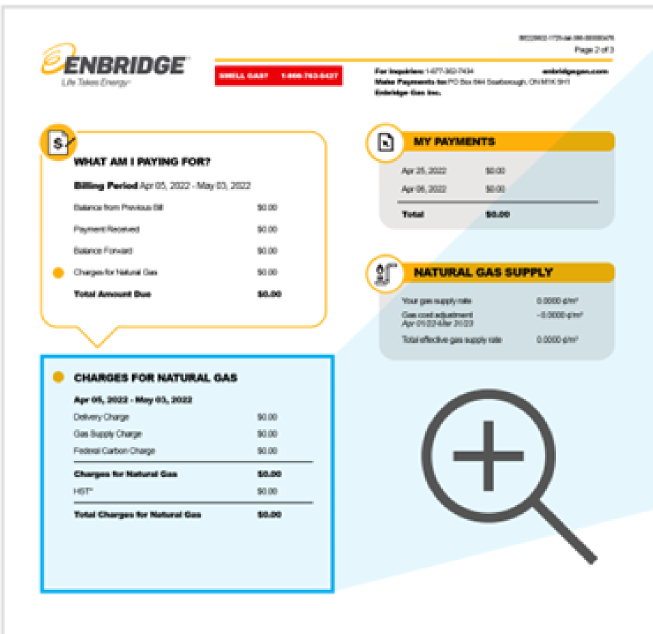
RATE 6

Customer Charge	$73.89
Delivery to You	$111.19
Transportation to Enbridge	$50.22
Federal Carbon Charge	$97.25
Gas Supply Charge	$148.73
Cost Adjustment	$14.66 CR
Charges for Natural Gas	**$466.62**
HST*	$60.66
Total Charges for Natural Gas	**$527.28**

Business Stimulus [2/6]

Mock-up of proposed Enbridge Gas bill charges

Using previous sample bill:



CHARGES FOR NATURAL GAS

Apr 05, 2022 - May 03, 2022

Delivery Charge	$0.00	$235.30
Gas Supply Charge	$0.00	$148.73
Federal Carbon Charge	$0.00	$97.25
Cost Adjustment	*$0.00*	*$14.66CR*
Charges for Natural Gas	**$0.00**	**$466.62**
HST*	$0.00	$60.66
Total Charges for Natural Gas	**$0.00**	**$527.28**

Delivery Charge	$235.30
Customer Charge	$73.89
Delivery to You	$111.19
Transportation to Enbridge	$50.22

Explanation of delivery charges on electricity and natural gas bill

- ✓ Your electricity bill shows only **one Delivery charge** to cover all the Transmission and Distribution charges and is comprised of 4-line items
- ✓ Some of these charges are variable and some of these are fixed
- ✓ The largest, the fixed customer service charge, covers the entire cost of the network
- ✓ Your Enbridge Gas bill shows **three charges** for delivery to cover the cost of the network

Your Electricity Charges

Electricity	
448 kWh Off-peak (lowest price) @ XX ¢/kWh	0.00
126 kWh Mid-peak (mid price) @ XX ¢/kWh	0.00
126 kWh On-peak (highest price) @ XX ¢kWh	0.00
Delivery	0.00
Regulatory Charges	0.00
Your Total Electricity Charges	0.00
H.S.T.	0.00
Ontario Electricity Rebate	(0.00)
Total Amount	$0.00

CHARGES FOR NATURAL GAS

May 12, 2021 - Jun 10, 2021

RATE 6

Customer Charge	$73.89
Delivery to You	$111.19
Transportation to Enbridge	$50.22
Federal Carbon Charge	$97.25
Gas Supply Charge	$148.73
Cost Adjustment	$14.66CR
Charges for Natural Gas	**$466.62**
HST*	$60.66
Total Charges for Natural Gas	**$527.28**

Delivery charge	Type of charge
Customer Service Charge	Fixed
Distribution Charge	Variable based on consumption
Transmission Charge	Variable based on consumption
Line Loss Adjustment	Adjustment factor

Delivery charge	Type of charge
Customer Charge	Fixed
Delivery to You	Variable based on consumption
Transportation to Enbridge	Variable based on consumption

Example of the Simplified bill

Simplified bill

CHARGES FOR NATURAL GAS

May 01, 2025 – May 31, 2025

Natural Gas	$84.36
Delivery	$73.60
Charges for Natural Gas	**$157.96**
HST*	$20.53
Total Charges for Natural Gas	**$178.49**

Comparing Charges for Natural Gas on the Current bill and the Simplified bill

Current bill

CHARGES FOR NATURAL GAS

May 01, 2025 – May 31, 2025

Customer Charge	$22.12
Delivery to You	$27.85
Transportation to Enbridge	$23.63
Gas Supply Charge	$84.36
Charges for Natural Gas	**$157.96**
HST*	$20.53
Total Charges for Natural Gas	**$178.49**

Simplified bill

CHARGES FOR NATURAL GAS

May 01, 2025 – May 31, 2025

Natural Gas	$84.36
Delivery	$73.60
Charges for Natural Gas	**$157.96**
HST*	$20.53
Total Charges for Natural Gas	**$178.49**

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking:

Tr: 15

a) To explain or point to the evidence already filed which explains what costs are allocated differently under each of the one rate zone proposed which has regional adjustments versus one rate zone with no regional adjustments, versus two rate zones;

b) To explain or point to the evidence already filed which explains what costs are allocated differently under each of the one rate zone proposed which has regional adjustments versus one rate zone with no regional adjustments, versus two rate zones

Response:

a-b) Under the proposed one rate zone alternative, Enbridge Gas has recognized regional differences in the allocation of gas supply and transmission costs to the harmonized rate classes. The allocation of gas supply related costs is based on the four service areas and the allocation of transmission costs is based on design day demands of the respective system. This approach reduces bill impacts for certain rate classes relative to one rate zone with no regional adjustments.

While the gas supply and transmission costs are allocated based on service area, the derivation of rates is based on one rate zone in the proposed alternative. For example, the gas supply transportation charge is based on one rate zone where customers pay either a common transportation rate or a common Western transportation rate. Conversely under the two rate zones alternative, the gas transportation charge is based on the allocated costs by rate class for each rate zone (North and South).

Under the one rate zone with no regional adjustments alternative, the allocation of all costs, including gas supply transportation and transmission costs, are allocated to rate classes based on the average embedded costs of the Company's integrated system of gas supply, storage, transmission and distribution facilities to deliver gas to customers in different geographical regions of Ontario.

Please see Attachment 1 for an example of how the allocation of gas supply-related costs are impacted by the regional allocation approach. The example shows the derivation of the Transportation Demand allocation factor for the rate zone alternatives. The following details support the calculations:

- Firm transportation demand costs are allocated to in-franchise bunded rate classes using average day demand for sales service and bundled DP customers. The firm transportation demand costs are direct assigned to unbundled storage service based on the cost of transportation demand. There is also a westerly transportation adjustment to recognize the Western transportation service for bundled DP customers with an obligated DCQ at Empress.

- In the one rate zone – proposed alternative, the allocation to rate classes is based on the weighted average transportation demand costs by service area, as shown at Attachment 1, lines 21 to 24.

- Conversely, in the one rate zone – no regional allocations alternative, the allocation to rate classes is based on total volumes excluding unbundled customers, as shown at Attachment 1 lines 26 to 29. This results in more significant bill impacts to semi-unbundled customers in Rate E20 as these customers are located in the South service area and require less third-party gas transportation contracts to move gas to the delivery points.

- In the two rate zones – one rate zone distribution alternative, the allocation to rate classes is based on the sum of the allocations to the North and East service areas, as shown at Attachment 1, lines 30 to 35.

- Similarly, in the four rate zones – one rate zone distribution alternative, the allocation to rate classes is based on the individual allocations to each of the North, East, Central and South service areas, as shown at Attachment 1, lines 36 to 45.

Please see Attachment 2 for an example of how the allocation of transmission costs are impacted by the regional allocation approach. The example shows the derivation of the Dawn Parkway Transmission Demand allocation factor for the rate zone alternatives. The following details support the calculations:

- Dawn Parkway System costs are allocated between in-franchise and ex-franchise rate classes in proportion to distance weighted design day demands. In-franchise costs are allocated to in-franchise bundled rate classes in proportion to Dawn Parkway System design day demands with a direct assignment to unbundled storage service.

- In the one rate zone – proposed alternative, the allocation to rate classes is based on design day demands of each respective current rate zone, as shown at Attachment 2, lines 1 to 5 and lines 18 to 19.

- Conversely, in the one rate zone – no regional allocations alternative, the allocation to rate classes is based on total design day demands excluding unbundled customers, as shown at Attachment 2, lines 20 to 22. This results in more significant bill impacts to semi-unbundled customers in Rate E20 as these customers are located in the South service area and are directly connected to the Dawn Parkway System

- In the two rate zones – one rate zone distribution alternative, the allocation to rate classes is based on the sum design day demands to the North and East service areas, as shown at Attachment 2, lines 23 to 31

- Similarly, in the four rate zones – one rate zone distribution alternative, the allocation to rate classes is based on the individual design day demands for each of the North, East, Central and South service areas, as shown at Attachment 2, lines 32 to 46

2024 Cost Allocation Study
Derivation of Transportation Demand Allocator by Rate Zone Alternative

Line No.	Particulars ($000s)	In-franchise Total	Rate E01	Rate E02	Rate E10	Rate E20-F	Rate E20-I	Rate E22-F	Rate E22-I	Rate E24-F	Rate E24-I	Rate E30	Rate E34	Rate E38	Rate E62	Rate E64
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Allocation Detail															
	Volumes excl Unbundled (1)															
1	North Service Area	962,572	611,346	292,808	52,931	-	-	-	-	-	-	5,488	-	-	-	-
2	East Service Area	2,266,667	1,080,399	685,375	265,469	-	-	-	-	-	-	38,112	8,462	-	188,852	-
3	Central Service Area	10,095,547	4,612,066	3,843,717	1,294,509	-	-	-	-	-	-	301,070	44,185	-	-	-
4	South Service Area	11,800,950	2,836,336	1,745,279	1,311,595	3,930,332	79,298	-	-	1,427,303	-	129,360	2,174	-	90,073	249,200
5	Total	25,125,737	9,140,146	6,567,178	2,924,503	3,930,332	79,298	-	-	1,427,303	-	474,030	54,821	-	278,926	249,200
	Transportation Demand Direct Assignment by Service Area (2)															
6	North Service Area (in proportion to line 1)	16,638	10,429	4,995	903	-	-	-	-	-	-	94	-	218	-	-
7	East Service Area (in proportion to line 2)	94,879	45,224	28,689	11,112	-	-	-	-	-	-	1,595	354	-	7,905	-
8	Central Service Area (in proportion to line 3)	39,862	18,211	15,177	5,111	-	-	-	-	-	-	1,189	174	-	-	-
9	South Service Area (in proportion to line 4)	1,144	275	169	127	381	8	-	-	138	-	13	0	-	9	24
10	Total	152,523	74,138	49,030	17,254	381	8	-	-	138	-	2,890	529	218	7,914	24
	Western Transportation Adjustment (2)															
11	North Service Area	(2,004)	(1,273)	(610)	(110)	-	-	-	-	-	-	(11)	-	-	-	-
12	East Service Area	(537)	(256)	(162)	(63)	-	-	-	-	-	-	(9)	(2)	-	(45)	-
13	Central Service Area	(4,738)	(2,164)	(1,804)	(608)	-	-	-	-	-	-	(141)	(21)	-	-	-
14	South Service Area	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Total	(7,279)	(3,693)	(2,576)	(781)	-	-	-	-	-	-	(162)	(23)	-	(45)	-
	Western Transportation Allocation (2)															
16	North Service Area	2,004	934	313	758	-	-	-	-	-	-	-	-	-	-	-
17	East Service Area	537	361	151	26	-	-	-	-	-	-	-	-	-	-	-
18	Central Service Area	4,738	2,889	1,585	264	-	-	-	-	-	-	-	-	-	-	-
19	South Service Area	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Total	7,279	4,183	2,049	1,047	-	-	-	-	-	-	-	-	-	-	-
	Rate Zone Alternatives															
	One Rate Zone - Proposed															
	Weighted Allocation Based on Costs by Service Area															
21	North Service Area (lines 6+11+16)	16,638	10,090	4,698	1,550	-	-	-	-	-	-	82	-	218	-	-
22	East Service Area (lines 7+12+17)	94,879	45,328	28,677	11,075	-	-	-	-	-	-	1,586	352	-	7,860	-
23	Central Service Area (lines 8+13+18)	39,862	18,935	14,958	4,768	-	-	-	-	-	-	1,047	154	-	-	-
24	South Service Area (lines 9+14+19)	1,144	275	169	127	381	8	-	-	138	-	13	0	-	9	24
25	Total Allocation (3)	152,523	74,628	48,502	17,520	381	8	-	-	138	-	2,728	506	218	7,869	24
	One Rate Zone - No Regional Allocations (4)	25,129,618	9,140,146	6,571,059	2,924,503	3,930,332	79,298	-	-	1,427,303	-	474,030	54,821	-	278,926	249,200
26	Allocation Factor (in proportion to line 5)	152,523	55,397	39,826	17,725	23,821	481	-	-	8,651	-	2,873	332	218	1,691	1,510
27	Western Transportation Adjustment (in proportion to line 5)	(7,279)	(2,648)	(1,903)	(847)	(1,138)	(23)	-	-	(413)	-	(137)	(16)	-	(81)	(72)
28	Western Transportation Allocation (in proportion to line 5)	7,279	1,161	5,071	1,047	-	-	-	-	-	-	-	-	-	-	-
29	Total Allocation (5)	152,523	53,910	42,993	17,925	22,682	458	-	-	8,237	-	2,736	316	218	1,610	1,438

2024 Cost Allocation Study
Derivation of Transportation Demand Allocator by Rate Zone Alternative

Line No.	Particulars ($000s)	In-franchise Total	Rate E01	Rate E02	Rate E10	Rate E20-F	Rate E20-I	Rate E22-F	Rate E22-I	Rate E24-F	Rate E24-I	Rate E30	Rate E34	Rate E38	Rate E62	Rate E64
	Two Rate Zones - One Rate Zone Distribution															
	North Rate Zone (North + East)															
30	Allocation Factor (line 1 + line 2)	3,229,240	1,691,744	978,183	318,399	-	-	-	-	-	-	43,600	8,462	-	188,852	-
31	Allocation (lines 6+7+11+12+16+17) (6)	111,517	55,418	33,375	12,625	-	-	-	-	-	-	1,668	352	218	7,860	-
	South (Central + South)															
32	Allocation Factor (line 3 + line 4)	21,896,497	7,448,402	5,588,996	2,606,104	3,930,332	79,298	-	-	1,427,303	-	430,430	46,359	-	90,073	249,200
33	Allocation (lines 8+9+13+14+18+19) (7)	41,006	19,210	15,127	4,895	381	8	-	-	138	-	1,060	154	-	9	24
	Four Rate Zones - One Rate Zone Distribution															
	North Rate Zone															
34	Allocation Factor (line 1)	962,572	611,346	292,808	52,931	-	-	-	-	-	-	5,488	-	-	-	-
35	Allocation (lines 6+11+16) (8)	16,638	10,090	4,698	1,550	-	-	-	-	-	-	82	-	218	-	-
	East Rate Zone															
36	Allocation Factor (line 2)	2,266,667	1,080,399	685,375	265,469	-	-	-	-	-	-	38,112	8,462	-	188,852	-
37	Allocation (lines 7+12+17) (8)	94,879	45,328	28,677	11,075	-	-	-	-	-	-	1,586	352	-	7,860	-
	Central Rate Zone															
38	Allocation Factor (line 3)	10,095,547	4,612,066	3,843,717	1,294,509	-	-	-	-	-	-	301,070	44,185	-	-	-
39	Allocation (lines 8+13+18) (8)	39,862	18,935	14,958	4,768	-	-	-	-	-	-	1,047	154	-	-	-
	South Service Area															
40	Allocation Factor (line 4)	11,800,950	2,836,336	1,745,279	1,311,595	3,930,332	79,298	-	-	1,427,303	-	129,360	2,174	-	90,073	249,200
41	Allocation (lines 9+14+19) (8)	1,144	275	169	127	381	8	-	-	138	-	13	0	-	9	24

Notes:
(1) Exhibit I.7.1-SEC-11 Attachment 4, p.2, line 18.
(2) Exhibit I.7.1-SEC-11 Attachment 4, p.1.
(3) Exhibit I.7.1-SEC-11 Attachment 4, p.3.
(4) Rate E02 adjusted by 3,881 to account for minor difference in cost study.
(5) Phase 3 Exhibit 7, Tab 3, Schedule 2, Attachment 10, line 4.
(6) Phase 3 Exhibit 7, Tab 3, Schedule 4, Attachment 10, pp.2-3, line 4.
(7) Phase 3 Exhibit 7, Tab 3, Schedule 4, Attachment 10, pp.4-5, line 4.
(8) Phase 3 Exhibit 7, Tab 3, Schedule 6, Attachment 10, pp.2-9, line 4.

2024 Cost Allocation Study
Derivation of Dawn Parkway Transmission Demand Allocator by Rate Zone Alternative

Line No.	Particulars ($000s)	Total	Rate E01	Rate E02	Rate E10	Rate E20-F	Rate E20-I	Rate E22-F	Rate E22-I	Rate E24-F	Rate E24-I	Rate E30	Rate E34	Rate E38	Rate E62	Rate E64	Rate E70	Rate E72	Rate E80
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	Allocation Detail																		
	Dawn Parkway Transmission Demand Allocation Factor (1)																		
1	EGD Rate Zone	18,855	9,783	7,678	1,172	-	-	-	-	-	-	-	3	-	219	-	0	-	-
2	Union North Rate Zone	2,354	1,431	758	113	-	-	-	-	-	-	-	-	52	-	-	0	-	-
3	Union South Rate Zone	8,127	3,416	2,084	604	930	-	-	-	576	-	3	-	-	82	431	0	-	-
4	Ex-franchise	11,966															11,966		
5	Total	41,302	14,629	10,520	1,889	930	-	-	-	576	-	3	3	52	301	431	11,966	-	-
	Design Day Demand Volumes excl Unbundled																		
6	North Service Area	9,031	5,523	2,878	329	-	-	-	-	-	-	-	-	302	-	-	-	-	-
7	East Service Area	21,843	11,338	7,992	1,261	-	-	-	-	-	-	-	1	-	1,252	-	-	-	-
8	Central Service Area	90,423	47,294	37,350	5,761	-	-	-	-	-	-	-	18	-	-	-	-	-	-
9	South Service Area	84,168	26,439	16,134	10,192	18,373	-	-	-	9,932	-	1	-	-	495	2,601	-	-	-
10	Total	205,465	90,594	64,353	17,543	18,373	-	-	-	9,932	-	1	19	302	1,747	2,601	-	-	-
11	South Dawn Parkway Design Day Demands (2)	49,060	20,620	12,583	3,646	5,614	-	-	-	3,480	-	21	-	-	495	2,601	-	-	-
	Dawn Parkway Transmission Demand Allocation Factor by Service Area																		
12	North Service Area (in proportion to line 6)	1,364	834	435	50	-	-	-	-	-	-	-	-	46	-	-			
13	East Service Area (in proportion to line 7)	2,608	1,353	954	150	-	-	-	-	-	-	-	0	-	149	-	-	-	-
14	Central Service Area (in proportion to line 8)	17,237	9,015	7,120	1,098	-	-	-	-	-	-	-	3	-	-	-	-	-	-
15	South Service Area (in proportion to line 9)	8,127	2,553	1,558	984	1,774	-	-	-	959	-	0	-	-	48	251	-	-	-
16	Ex-franchise (direct assigned)	11,966	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11,966	0	0
17	Total	41,302	13,756	10,066	2,282	1,774	-	-	-	959	-	0	4	46	197	251	11,966	-	-
	Rate Zone Alternatives																		
	One Rate Zone - Proposed																		
18	Allocation Factor (line 5) (3)	41,302	14,629	10,520	1,889	930	-	-	-	576	-	3	3	52	301	431	11,966	-	-
19	Allocation (in proportion to line 18 x DP TRANS Rev Req) (4)	229,744	81,374	58,518	10,508	5,173	-	-	-	3,207	-	19	18	291	1,674	2,397	66,563	-	
	One Rate Zone - No Regional Allocations																		
20	Design Day Demand (line 10)	205,465	90,594	64,353	17,543	18,373	-	-	-	9,932	-	1	19	302	1,747	2,601	-	-	-
21	Allocation Factor (in proportion to line 20) (5)	41,302	12,930	9,185	2,504	2,622	-	-	-	1,418	-	0	3	53	249	371	-	-	-
22	Allocation (in proportion to line 21 x DP TRANS Rev Req) (6)	229,744	71,925	51,092	13,928	14,587	-	-	-	7,885	-	1	15	295	1,387	2,065	-	-	-

2024 Cost Allocation Study
Derivation of Dawn Parkway Transmission Demand Allocator by Rate Zone Alternative

Line No.	Particulars ($000s)	Total	Rate E01	Rate E02	Rate E10	Rate E20-F	Rate E20-I	Rate E22-F	Rate E22-I	Rate E24-F	Rate E24-I	Rate E30	Rate E34	Rate E38	Rate E62	Rate E64	Rate E70	Rate E72	Rate E80
	Two Rate Zones - One Rate Zone Distribution																		
	North Rate Zone (North + East)																		
23	Allocation Factor (line 6 + line 7)	30,875	16,861	10,870	1,590	-	-	-	-	-	-	-	1	302	1,252	-	-	-	-
24	Allocator (in proportion to line 23) (7)	3,972	2,169	1,398	205	-	-	-	-	-	-	-	0	39	161	-	-	-	-
	South Rate Zone (Central + South)																		
25	Allocation Factor (line 8 + line 11)	139,483	67,914	49,933	9,407	5,614	-	-	-	3,480	-	21	18	-	495	2,601	-	-	-
26	Allocator (in proportion to line 25) (8)	25,364	12,350	9,080	1,711	1,021	-	-	-	633	-	4	3	-	90	473		-	-
27	Ex-franchise (line 4)	11,966	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11,966	-	-
28	North Rate Zone Allocation (in proportion to line 24) (9)	22,094	12,066	7,778	1,138	-	-	-	-	-	-	-	0	216	896	-	-	-	-
29	South Rate Zone Allocation (in proportion to line 26) (10)	141,086	68,695	50,507	9,515	5,679	-	-	-	3,520	-	21	19	-	500	2,631	-	-	-
30	Ex-franchise (in proportion to line 27) (11)	66,563	-	-	-	-	-	-	-	-	-	-	-	-	-	-	66,563	-	-
31	Total	229,744	80,760	58,285	10,653	5,679	-	-	-	3,520	-	21	19	216	1,396	2,631	66,563	-	-
	Four Rate Zones - One Rate Zone Distribution																		
	North Rate Zone																		
32	Allocation Factor (line 6)	9,031	5,523	2,878	329	-	-	-	-	-	-	-	-	302	-	-	-	-	-
33	Allocator (in proportion to line 32) (12)	1,364	834	435	50	-	-	-	-	-	-	-	-	46	-	-	-	-	-
	East Rate Zone																		
34	Allocation Factor (line 7)	21,843	11,338	7,992	1,261	-	-	-	-	-	-	-	1	-	1,252	-	-	-	-
35	Allocator (in proportion to line 34) (12)	2,608	1,353	954	150	-	-	-	-	-	-	-	0	-	149	-	-	-	-
	Central Rate Zone																		
36	Allocation Factor (line 8)	90,423	47,294	37,350	5,761	-	-	-	-	-	-	-	18	-	-	-	-	-	-
37	Allocator (in proportion to line 36) (12)	17,237	9,015	7,120	1,098	-	-	-	-	-	-	-	3	-	-	-	-	-	-
	South Rate Zone																		
38	Allocation Factor (line 11)	49,060	20,620	12,583	3,646	5,614	-	-	-	3,480	-	21	-	-	495	2,601	-	-	-
39	Allocator (in proportion to line 38) (12)	8,127	3,416	2,084	604	930	-	-	-	576	-	3	-	-	82	431	-	-	-
40	Ex-franchise (line 4)	11,966	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11,966	-	-
41	North Rate Zone Allocation (in proportion to line 33) (13)	7,590	4,641	2,418	277	-	-	-	-	-	-	-	-	254	-	-	-	-	-
42	East Rate Zone Allocation (in proportion to line 35) (13)	14,504	7,529	5,307	837	-	-	-	-	-	-	-	0	-	831	-	-	-	-
43	Central Rate Zone Allocation (in proportion to line 37) (13)	95,881	50,149	39,605	6,108	-	-	-	-	-	-	-	19	-	-	-	-	-	-
44	South Rate Zone Allocation (in proportion to line 39) (13)	45,205	19,000	11,594	3,360	5,173	-	-	-	3,207	-	19	-	-	456	2,397	-	-	-
45	Ex-franchise Allocation (in proportion to line 40) (13)	66,563	-	-	-	-	-	-	-	-	-	-	-	-	-	-	66,563	-	-
46	Total	229,744	81,318	58,924	10,582	5,173	-	-	-	3,207	-	19	20	254	1,287	2,397	66,563	-	-

Notes:
(1) Exhibit I.7.1-SEC-11 Attachment 10, p.1, column (c).
(2) Exhibit I.7.1-SEC-11 Attachment 10, p.2, column (e).
(3) Phase 3 Exhibit 7, Tab 3, Schedule 1, Attachment 12, p.11, line 19.
(4) Phase 3 Exhibit 7, Tab 3, Schedule 1, Attachment 8, line 16.
(5) Phase 3 Exhibit 7, Tab 3, Schedule 2, Attachment 12, p.11, line 19.
(6) Phase 3 Exhibit 7, Tab 3, Schedule 2, Attachment 8, line 16.
(7) Phase 3 Exhibit 7, Tab 3, Schedule 4, Attachment 12, p.13, line 11.
(8) Phase 3 Exhibit 7, Tab 3, Schedule 4, Attachment 12, p.15, line 11, corrected for Exhibit I.7.3-CCC-7.
(9) Phase 3 Exhibit 7, Tab 3, Schedule 4, Attachment 8, p.2, line 16.
(10) Phase 3 Exhibit 7, Tab 3, Schedule 4, Attachment 8, p.4, line 16, corrected for Exhibit I.7.3-CCC-7.
(11) Phase 3 Exhibit 7, Tab 3, Schedule 4, Attachment 8, p.6, line 16.
(12) Phase 3 Exhibit 7, Tab 3, Schedule 6, Attachment 12, pp.13-19, line 11.
(13) Phase 3 Exhibit 7, Tab 3, Schedule 6, Attachment 8, pp.2-10, line 16.

ENBRIDGE GAS INC.

Answer to Undertaking from
Pollution Probe (PP)

Undertaking:

Tr: 26

To provide a written response to Exhibit KT-2.1.

In Enbridge's July 4th letter accompanying the IR responses, Enbridge indicates on Page 3 of that letter that:

"While the removal of the federal carbon charge does not (on its own) impact the dollar impact on customer bills from the changes proposed in Phase 3, it does impact the percentage change to the total bill."

And then Enbridge provided a summary of the impacts to different residential rate zones.

Can Enbridge explain why this change is causing some bills to go up and some bill to go down? It seems like all rate zone bills should go down due to this change.

Response:

Total bill impact percentage changes are fraction calculations derived by dividing the dollar change to the total bill (numerator) by the current total bill (denominator).

$$\text{Total Bill Impact} = \frac{\$\,Change\ to\ the\ Total\ Bill}{\$\,Current\ Total\ Bill}$$

Removing the federal carbon charge yields a smaller denominator and thereby a larger overall fraction. Reducing the denominator in a fraction calculation effectively magnifies the sensitivity of percentage changes for both total bill increases and decreases, such that a bill increase will result in a larger positive percentage and a bill decrease will result in a larger negative percentage of the total bill.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Association of Physical Plant Administrators (OAPPA)

Undertaking:

Tr: 28

To provide how many of the 466 to 485 customers were required to take action to meet the imputed checkpoint requirements for February and September of the 2021 to 2025 period; to provide a summary of the total GJs required to take action for those checkpoints for the same period.

Response:

Table 1 supplements Exhibit I.8.4-OAPPA-3 Table 1 by providing the number of customers that had to take action to meet the February checkpoint, and the action quantity communicated in the month of February to those customers.

Table 1
Winter Checkpoint

Line No.	Year	Number of Customers to Take Action	Communicated Action Quantity (GJ)
	(a)	(b)	(c)
1	2021	139	695,141
2	2022	173	1,341,522
3	2023	54	303,077
4	2024	114	933,091
5	2025	160	820,429

Table 2 supplements Exhibit I.8.4-OAPPA-3 Table 2 by providing the number of customers that had to take action to meet the September checkpoint, and the action quantity communicated in the month of September to those customers.

Table 2
Fall Checkpoint

Line No.	Year	Number of Customers to Take Action	Communicated Action Quantity (GJ)
	(a)	(b)	(c)
1	2020	299	1,668,357
2	2021	226	1,201,777
3	2022	226	1,330,654
4	2023	289	2,628,091
5	2024	318	2,887,829

The actions taken by bundled DP customers to meet checkpoint obligations reduces the action that would otherwise be taken by Enbridge Gas to balance on behalf of bundled DP customers as these customers manage their actual load balancing requirements at the fall and winter checkpoints.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Greenhouse Vegetable Growers (OGVG)

Undertaking:

Tr: 31

With reference to I.3.2-OGVG-4, Attachment 1, to break down column a and column b between rate zones; or to provide a citation to this breakdown in the evidence.

Response:

Please see Attachment 1.

Customers & Volumes by Rate Zone

Line No.	Particulars	Rate Zone	2024 Test Year Forecast Total (average) Customers	Annual Throughput (10^3m^3)
			(a)	(b)
	General Service			
1	Rate 1	EGD (Enbridge CDA)	1,788,698	4,241,481
2	Rate 1	EGD (Enbridge EDA)	374,391	770,106
3	Rate 6 (including Rate 9)	EGD (Enbridge CDA)	149,910	4,214,302
4	Rate 6 (including Rate 9)	EGD (Enbridge EDA)	23,064	584,938
	Contract			
5	Rate 100	EGD (Enbridge CDA)	12	16,671
6	Rate 100	EGD (Enbridge EDA)	2	10,758
7	Rate 110	EGD (Enbridge CDA)	366	895,965
8	Rate 110	EGD (Enbridge EDA)	50	172,317
9	Rate 115	EGD (Enbridge CDA)	22	381,873
10	Rate 125	EGD (Enbridge CDA)	4	824,971
11	Rate 135	EGD (Enbridge CDA)	33	44,185
12	Rate 135	EGD (Enbridge EDA)	8	8,462
13	Rate 145	EGD (Enbridge CDA)	14	13,443
14	Rate 145	EGD (Enbridge EDA)	2	2,270
15	Rate 170	EGD (Enbridge CDA)	19	287,627
16	Rate 170	EGD (Enbridge EDA)	3	35,627
17	Rate 200	EGD (Enbridge EDA)	1	188,852
18	Rate 300	N/A	0	0
19	Rate 315	N/A	0	0
	General Service			
20	Rate M1	Union South	1,204,177	3,238,864
21	Rate M2	Union South	8,077	1,343,314
22	Rate 01	Union North East	270,531	702,089
23	Rate 01	Union North West	99,063	274,791
24	Rate 10	Union North East	1,602	263,850
25	Rate 10	Union North West	602	77,814
	Contract			
26	Rate M4	Union South	225	593,899
27	Rate M7	Union South	61	789,737
28	Rate M9	Union South	4	90,073
29	Rate M10	Union South	0	0
30	Rate 20	Union North East	53	861,941
31	Rate 20	Union North West	10	67,160
32	Rate 100	Union North East	7	364,304
33	Rate 100	Union North West	5	712,074
34	Rate T1	Union South	39	431,289
35	Rate T2	Union South	26	5,005,643
36	Rate T3	Union South	1	249,200
37	Rate M5	Union South	38	51,961
38	Rate 25	Union North East	65	74,870
39	Rate 25	Union North West	7	59,493
40	Rate 30	N/A	0	0
41	Grand Total		3,921,191	27,946,215

Notes:
(1) EB-2022-0200 Exhibit I.3.2-OGVG-4 column (a), updated for Phase 1 Decision.
(2) EB-2022-0200 Exhibit I.3.2-OGVG-4 column (b), updated for Phase 1 Decision.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Greenhouse Vegetable Growers (OGVG)

Undertaking:

Tr: 36

With reference to I.8.2-OGVG-13, produce the analysis shown taking into account the smallest, medium and large volume M7 customers.

Response:

Please see Attachment 1.

Bill Impact Comparison for Rate E10 and Rate E20 - One Rate Zone - Proposed

Line No.	Particulars	Usage	Rate E10 Total Bill ($)	Rate E10 Unit Rate (1) (cents/m³)	Rate E20 Total Bill ($)	Rate E20 Unit Rate (1) (2) (cents/m³)	Total Bill Impact ($)	Total Bill Impact (%)
			(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)
	Small M7 Greenhouse - Rate E10 to Rate E20							
	Demand 60,000 m³ Annual Volume 11,486,789 m³							
	Delivery Charges							
1	Monthly Customer Charge	12	6,000	$500.00	36,000	$3,000.00	30,000	500.0%
2	Monthly Demand Charge							
	Rate E10							
3	First 20,000 m³	20,000	142,013	59.1720				
4	All over 20,000 m³	40,000	193,215	40.2532				
	Rate E20							
5	First 30,000 m³	30,000			189,748	52.7078		
6	Next 120,000 m³	30,000			108,322	30.0893		
7	All over 150,000 m³	-			-	20.0116		
8	Total Demand Charge	60,000	335,228		298,069		(37,159)	(11.1%)
9	Delivery Commodity Charge	11,486,789	31,069	0.2705	-	-	(31,069)	
10	Transportation Fuel Ratio				12,353	0.754%	12,353	
11	Facility Carbon Charge	11,486,789	1,643	0.0143	1,643	0.0143	-	
12	Total Delivery Charges		373,940		348,065		(25,875)	(6.9%)
	Storage							
13	Space Demand ($/GJ)	18,448			3,309	0.015	3,309	
14	Firm Injection/Withdrawal Right ($/GJ) (3)	553			17,090	2.573	17,090	
15	Injection/Withdrawal Commodity ($/GJ)	36,896			-	-	-	
16	Storage Fuel Ratio				1,076	0.799%	1,076	
17	Storage Total		-		21,476		21,476	100.0%
18	Gas Supply Transportation	11,486,789	92,795	0.8078			(92,795)	
19	Gas Supply Commodity	11,486,789	1,654,311	14.4019	1,654,311	14.4019	-	
20	Total Bill - Bundled Direct Purchase (4)		2,121,046		2,023,852		(97,194)	(4.6%)
21	Bundled Direct Purchase Impact		466,735		369,541		(97,194)	(20.8%)

Bill Impact Comparison for Rate E10 and Rate E20 - One Rate Zone - Proposed

Line No.	Particulars	Usage	Rate E10 Total Bill ($)	Rate E10 Unit Rate (1) (cents/m^3)	Rate E20 Total Bill ($)	Rate E20 Unit Rate (1) (2) (cents/m^3)	Total Bill Impact ($)	Total Bill Impact (%)
			(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)
	Medium M7 Greenhouse - Rate E10 to Rate E20							
	Demand 74,424 m^3 Annual Volume 12,847,667 m^3							
	Delivery Charges							
22	Monthly Customer Charge	12	6,000	$500.00	36,000	$3,000.00	30,000	500.0%
23	Monthly Demand Charge							
	Rate E10							
24	First 20,000 m^3	20,000	142,013	59.1720				
25	All over 20,000 m^3	54,424	262,889	40.2532				
	Rate E20							
26	First 30,000 m^3	30,000			189,748	52.7078		
27	Next 120,000 m^3	44,424			160,403	30.0893		
28	All over 150,000 m^3	-			-	20.0116		
29	Total Demand Charge	74,424	404,902		350,151		(54,751)	(13.5%)
30	Delivery Commodity Charge	12,847,667	34,750	0.2705	-	-	(34,750)	
31	Transportation Fuel Ratio				13,816	0.754%	13,816	
32	Facility Carbon Charge	12,847,667	1,837	0.0143	1,837	0.0143	-	
33	Total Delivery Charges		447,488		401,804		(45,684)	(10.2%)
	Storage							
34	Space Demand ($/GJ)	20,634			3,701	0.015	3,701	
35	Firm Injection/Withdrawal Right ($/GJ) (3)	619			19,115	2.573	19,115	
36	Injection/Withdrawal Commodity ($/GJ)	41,267			-	-	-	
37	Storage Fuel Ratio				1,204	0.799%	1,204	
38	Storage Total		-		24,020		24,020	100.0%
39	Gas Supply Transportation	12,847,667	103,789	0.8078			(103,789)	
40	Gas Supply Commodity	12,847,667	1,850,303	14.4019	1,850,303	14.4019	-	
41	Total Bill - Bundled Direct Purchase (4)		2,401,580		2,252,107		(149,474)	(6.2%)
42	Bundled Direct Purchase Impact		551,277		401,804		(149,474)	(27.1%)

Bill Impact Comparison for Rate E10 and Rate E20 - One Rate Zone - Proposed

Line No.	Particulars	Usage	Rate E10 Total Bill ($)	Rate E10 Unit Rate (1) (cents/m³)	Rate E20 Total Bill ($)	Rate E20 Unit Rate (1) (2) (cents/m³)	Total Bill Impact ($)	Total Bill Impact (%)
			(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)
	Large M7 Greenhouse - Rate E10 to Rate E20							
	Demand 210,485 m^3 Annual Volume 24,553,946 m^3							
	Delivery Charges							
43	Monthly Customer Charge	12	6,000	$500.00	36,000	$3,000.00	30,000	500.0%
44	Monthly Demand Charge							
	Rate E10							
45	First 20,000 m^3	20,000	142,013	59.1720				
46	All over 20,000 m^3	190,485	920,115	40.2532				
	Rate E20							
47	First 30,000 m^3	30,000			189,748	52.7078		
48	Next 120,000 m^3	120,000			433,286	30.0893		
49	All over 150,000 m^3	60,485			145,248	20.0116		
50	Total Demand Charge	210,485	1,062,128		768,282		(293,846)	(27.7%)
51	Delivery Commodity Charge	24,553,946	66,412	0.2705	-	-	(66,412)	
52	Transportation Fuel Ratio				26,405	0.754%	26,405	
53	Facility Carbon Charge	24,553,946	3,511	0.0143	3,511	0.0143	-	
54	Total Delivery Charges		1,138,051		834,199		(303,853)	(26.7%)
	Storage							
55	Space Demand ($/GJ)	39,434			7,074	0.015	7,074	
56	Firm Injection/Withdrawal Right ($/GJ) (3)	1,183			36,532	2.573	36,532	
57	Injection/Withdrawal Commodity ($/GJ)	78,869			-	-	-	
58	Storage Fuel Ratio				2,301	0.799%	2,301	
59	Storage Total		-		45,906		45,906	100.0%
60	Gas Supply Transportation	24,553,946	198,357	0.8078			(198,357)	
61	Gas Supply Commodity	24,553,946	3,536,224	14.4019	3,536,224	14.4019	-	
62	Total Bill - Bundled Direct Purchase (4)		4,872,633		4,370,423		(502,210)	(10.3%)
63	Bundled Direct Purchase Impact		1,336,409		834,199		(502,210)	(37.6%)

Notes:
(1) Phase 3 Exhibit 8, Tab 2, Schedule 9, Attachment 2, column (h).
(2) Assuming Rate E20 South service area customer and therefore excludes central transportation charge as proposed for Rate E20.
(3) Firm injection/withdrawal rights utility provides deliverability inventory.
(4) Total bill impact calculations for direct purchase customers include an assumed gas supply commodity charge.

Bill Impact Comparison for Rate E10 and Rate E20 - Four Rate Zones One Distribution (South)

Line No.	Particulars	Usage	Rate E10 Total Bill ($)	Rate E10 Unit Rate (1) (cents/m³)	Rate E20 Total Bill ($)	Rate E20 Unit Rate (1) (cents/m³)	Total Bill Impact ($)	Total Bill Impact (%)
			(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)
	Small M7 Greenhouse - Rate E10 to Rate E20							
	Demand 60,000 m^3 Annual Volume 11,486,789 m^3							
	Delivery Charges							
1	Monthly Customer Charge	12	6,000	$500.00	36,000	$3,000.00	30,000	500.0%
2	Monthly Demand Charge							
	Rate E10							
3	First 20,000 m^3	20,000	153,579	63.9913				
4	All over 20,000 m^3	40,000	176,129	36.6936				
	Rate E20							
5	First 30,000 m^3	30,000			151,588	42.1077		
6	Next 120,000 m^3	30,000			100,661	27.9614		
7	All over 150,000 m^3	-			-	23.0858		
8	Total Demand Charge	60,000	329,708		252,249		(77,460)	(23.5%)
9	Delivery Commodity Charge	11,486,789	7,678	0.0668			(7,678)	
10	Transportation Fuel Ratio				12,353	0.754%	12,353	
11	Facility Carbon Charge	11,486,789	1,643	0.0143	1,643	0.0143	-	
12	Total Delivery Charges		345,030		302,244		(42,785)	(12.4%)
	Storage							
13	Space Demand ($/GJ)	18,448			3,309	0.015	3,309	
14	Firm Injection/Withdrawal Right ($/GJ) (2)	553			17,090	2.573	17,090	
15	Injection/Withdrawal Commodity ($/GJ)	36,896			-	-		
16	Storage Fuel Ratio				1,076	0.799%	1,076	
17	Storage Total		-		21,476		21,476	100.0%
18	Gas Supply Transportation	11,486,789	31,315	0.2726			(31,315)	
19	Gas Supply Commodity	11,486,789	1,802,771	15.6943	1,802,771	15.6943	-	
20	Total Bill - Bundled Direct Purchase (3)		2,179,116		2,105,016		(74,101)	(3.4%)
21	Bundled Direct Purchase Impact		376,345		302,244		(74,101)	(19.7%)

Bill Impact Comparison for Rate E10 and Rate E20 - Four Rate Zones One Distribution (South)

Line No.	Particulars	Usage	Rate E10 Total Bill ($)	Rate E10 Unit Rate (1) (cents/m³)	Rate E20 Total Bill ($)	Rate E20 Unit Rate (1) (cents/m³)	Total Bill Impact ($)	Total Bill Impact (%)
			(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)
	Medium M7 Greenhouse - Rate E10 to Rate E20							
	Demand 74,424 m³ Annual Volume12,847,667 m³							
	Delivery Charges							
22	Monthly Customer Charge	12	6,000	$500.00	36,000	$3,000.00	30,000	500.0%
23	Monthly Demand Charge							
	Rate E10							
24	First 20,000 m³	20,000	153,579	63.9913				
25	All over 20,000 m³	54,424	239,642	36.6936				
	Rate E20							
26	First 30,000 m³	30,000			151,588	42.1077		
27	Next 120,000 m³	44,424			149,059	27.9614		
28	All over 150,000 m³	-			-	23.0858		
29	Total Demand Charge	74,424	393,221		300,647		(92,574)	(23.5%)
30	Delivery Commodity Charge	12,847,667	8,588	0.0668	-	-	(8,588)	
31	Transportation Fuel Ratio				13,816	0.754%	13,816	
32	Facility Carbon Charge	12,847,667	1,837	0.0143	1,837	0.0143	-	
33	Total Delivery Charges		409,646		352,300		(57,346)	(14.0%)
	Storage							
34	Space Demand ($/GJ)	20,634			3,701	0.015	3,701	
35	Firm Injection/Withdrawal Right ($/GJ) (2)	619			19,115	2.573	19,115	
36	Injection/Withdrawal Commodity ($/GJ)	41,267			-	-	-	
37	Storage Fuel Ratio				1,204	0.799%	1,204	
38	Storage Total		-		24,020		24,020	100.0%
39	Gas Supply Transportation	12,847,667	35,025	0.2726			(35,025)	
40	Gas Supply Commodity	12,847,667	2,016,352	15.6943	2,016,352	15.6943	-	
41	Total Bill - Bundled Direct Purchase (3)		2,461,023		2,392,672		(68,351)	(2.8%)
42	Bundled Direct Purchase Impact		444,671		376,320		(68,351)	(15.4%)

Bill Impact Comparison for Rate E10 and Rate E20 - Four Rate Zones One Distribution (South)

Line No.	Particulars	Usage	Rate E10 Total Bill ($)	Rate E10 Unit Rate (1) (cents/m^3)	Rate E20 Total Bill ($)	Rate E20 Unit Rate (1) (cents/m^3)	Total Bill Impact ($)	Total Bill Impact (%)
			(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)
	Large M7 Greenhouse - Rate E10 to Rate E20							
	Demand 210,485 m^3 Annual Volume 24,553,946 m^3							
	Delivery Charges							
43	Monthly Customer Charge	12	6,000	$500.00	36,000	$3,000.00	30,000	500.0%
44	Monthly Demand Charge							
	Rate E10							
45	First 20,000 m^3	20,000	153,579	63.9913				
46	All over 20,000 m^3	190,485	838,750	36.6936				
	Rate E20							
47	First 30,000 m^3	30,000			151,588	42.1077		
48	Next 120,000 m^3	120,000			402,644	27.9614		
49	All over 150,000 m^3	60,485			167,561	23.0858		
50	Total Demand Charge	210,485	992,329		721,793		(270,536)	(27.3%)
51	Delivery Commodity Charge	24,553,946	16,413	0.0668	-	-	(16,413)	
52	Transportation Fuel Ratio				26,405	0.754%	26,405	
53	Facility Carbon Charge	24,553,946	3,511	0.0143	3,511	0.0143	-	
54	Total Delivery Charges		1,018,254		787,709		(230,544)	(22.6%)
	Storage							
55	Space Demand ($/GJ)	39,434			7,074	0.015	7,074	
56	Firm Injection/Withdrawal Right ($/GJ) (2)	1,183			36,531	2.573	36,531	
57	Injection/Withdrawal Commodity ($/GJ)	78,869			-	-	-	
58	Storage Fuel Ratio				2,301	0.799%	2,301	
59	Storage Total		-		45,906		45,906	100.0%
60	Gas Supply Transportation	24,553,946	66,939	0.2726			(66,939)	
61	Gas Supply Commodity	24,553,946	3,853,571	15.6943	3,853,571	15.6943	-	
62	Total Bill - Bundled Direct Purchase (3)		4,938,763		4,641,280		(297,483)	(6.0%)
63	Bundled Direct Purchase Impact		1,085,192		787,709		(297,483)	(27.4%)

Notes:
(1) Phase 3 Exhibit 8, Tab 2, Schedule 14, Attachment 2, column (h), unit rates for South service area.
(2) Firm injection/withdrawal rights utility provides deliverability inventory.
(3) Total bill impact calculations for direct purchase customers include an assumed gas supply commodity charge.

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking:

Tr: 40

To show the mechanics of what will be recorded in the PGVA and the price variance account in the circumstance where the experienced Dawn-purchased cost is lower than the prevailing.

Response:

Attachment 1, page 1 provides the calculation of cost variances that would be recorded in the Purchase Gas Variance Account (PGVA) in the scenario where 5,000 extra units of gas (TJ) are purchased in each of January and March at a price of $4 per unit (GJ). Under this scenario, a credit would be recorded in the PGVA for $(15.8) million for the price variances associated with those gas supply purchases. The volume variances calculated based on the approved prices of $55.8 million would be recovered in gas supply commodity rates.

A debit for $9.7 million would be recorded in the Load Balancing Price Variance Account (LBPVA) (with an offsetting credit to the PGVA) relating to the variance for load balancing cost. For purposes of this scenario, the actual Dawn average price for January and March, as calculated in Attachment 1, page 1, was updated in the Load Balancing calculation in Attachment 1, page 2 to calculate a revised load balancing cost. The variance of $9.7 million between the revised load balancing costs and the forecast load balancing cost is removed from the PGVA and recorded in the LPBVA

The total variance remaining in the PGVA is $(25.5) million ($(15.8) million + $(9.7) million). For purposes of this scenario, Enbridge Gas has assumed that the incremental purchases are not considered spot gas purchases[1].

Please also see response at Exhibit JT1.37.

[1] Incremental gas supply purchases are considered spot gas purchases when total gas purchases for the winter exceed planned winter purchases.

5,000 TJ of Dawn Supplies above the planned Dawn purchases for January and March at $4/GJ

Line No.	Particulars	Supplies (TJ)	Unit Cost ($/GJ)	Purchase Cost ($000s)
		(a)	(b)	(c) = (a) * (b)
	January			
1	Actual (1)	25,379	5.544	140,704
2	Approved (2)	20,379	5.923	120,704
3	Variance - Actual vs Approved (3)	5,000	(0.379)	20,000
4	Volume Variance (4)	5,000	5.923	29,615
5	Price Variance (5)	25,379	(0.379)	(9,615)
6	Total Variance			20,000
	March			
7	Actual (1)	5,000	4.000	20,000
8	Approved (2)	0	5.245	0
9	Variance - Actual vs Approved (6)	5,000	(1.245)	20,000
10	Volume Variance (4)	5,000	5.245	26,225
11	Price Variance (5)	5,000	(1.245)	(6,225)
12	Total Variance			20,000
	January & March Total			
13	Volume Variance (7)			55,840
14	Price Variance (8)			(15,840)
15	Total Variance			40,000

Notes:
(1) 5,000 TJ additional Dawn supplies at a price of $10/GJ.
(2) Exhibit I.9.1-FRPO-111, Attachment 2.
(3) Line 1 - line 2.
(4) Volume variance = 5,000 TJ x Approved Price.
(5) Price variance = Actual Purchases x Price Variance.
(6) Line 7 - line 8.
(7) Line 4 + line 10. Volume variances dervied based on approved prices are recovered in rates.
(8) Line 5 + line 11. Price variances are recorded in the PGVA.

EGI Load Balancing Calculation - JT2.9 Scenario

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Days in Month	31	29	31	30	31	30	31	31	30	31	30	31	366
2	Dawn Supplies (TJ)	20,379	23,600	0	2,012	4,000	13,200	7,686	0	10,823	10,440	10,024	24,150	126,314
3	Average Day Demand Per Month (TJ)	10,699	10,008	10,699	10,354	10,699	10,354	10,699	10,699	10,354	10,699	10,354	10,699	126,314
4	Average Purchases Variance (TJ)	9,680	13,592	(10,699)	(8,342)	(6,699)	2,846	(3,012)	(10,699)	469	(259)	(330)	13,451	0
5	Dawn Forecasted Price ($/GJ)	5.544	5.659	4.000	4.867	4.743	4.763	4.787	4.809	4.697	4.709	5.224	5.695	
6	Price Variance - Load Balancing ($000s) (1)	53,668	76,914	(42,795)	(40,598)	(31,772)	13,557	(14,420)	(51,450)	2,203	(1,218)	(1,722)	76,605	38,972
7	Peaking Supply	1,347	0	0	0	0	0	0	0	0	0	0	0	1,347
8	Demand Cost - Load Balancing ($000s)	494	494	494	483	483	483	483	483	483	483	483	494	5,841
9	Total Load Balancing Costs ($000s) (2)	55,509	77,409	(42,300)	(40,116)	(31,289)	14,040	(13,937)	(50,967)	2,686	(735)	(1,239)	77,099	46,160
10	Forecast Load Balancing Cost ($000s) (3)													36,508
11	Load Balancing Price Variance ($000s) (4)													9,652

Notes:
(1) Line 4 x line 5.
(2) Line 6 + line 7 + line 8.
(3) Exhibit I.9.1-FRPO-111, Attachment 2, line 9.
(4) Line 9 - line 10.

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking:

Tr: 49

To provide the mapping of transportation contracts as shown at FRPO-43, Attachment 1 between the transportation demand and load balancing transportation function and explain the principles that underlie or relate to that mapping or allocation.

Response:

Please see Attachment 1 for the mapping of third-party transportation contracts to transportation demand and load balancing transportation functional classifications and Attachment 2 for the annual volumes used to allocate a portion of those contracts to transportation demand.

Third-party demand costs to transport gas to the delivery area from a gas supply point of receipt to meet average annual demands are classified as transportation demand. To allocate transportation demand costs, Enbridge Gas first uses the annual volumes to determine the average annual demands for each delivery area (Attachment 2). Enbridge Gas then determines which contracts are used to meet the average annual demands for cost allocation purposes as follows:

- Enbridge Gas has assumed that long-haul transportation contracts from Empress are first used to meet average annual transportation demand.[1] This approach recognizes gas supply purchased at, or upstream of, Empress is transported on long-haul contracts to the Enbridge Gas franchise area. The gas supply from Empress is first used to meet daily demands in the delivery area with any excess transported to Dawn to fill storage.

- To the extent that there is not sufficient long-haul transportation capacity to meet the annual volumes, then it has been assumed that these volumes would be met using other firm transportation contracts, such as short-haul transportation contracts from Dawn or Parkway to the delivery area.

[1] As noted in the Technical Conference, both parts of the Empress to North Bay Junction (NBJ) and NBJ to the Enbridge CDA or Enbridge EDA are required on a combined basis to transport gas from Empress to the delivery area and are treated the same from a cost allocation perspective.

Enbridge Gas notes the following details in the allocation of these costs to transportation demand:

- In Attachment 1, line 15, the Empress to Union EDA contract should have been fully allocated to transportation demand based on these cost allocation assumptions, however this does not result in material differences;

- The NCDA uses the TCPL Storage Transportation Service (STS) and STS balance for the Union North rate zones to meet their requirements. For the purposes of cost allocation, the NCDA is assumed to be served in part using the Empress to Union EDA transportation, which contributed to the STS balance for the Union North rate zones;

- Union South is primarily served by the Dawn Parkway, St. Clair and Panhandle Systems and includes an Empress to Union CDA contract; and

- The Enbridge CDA is partly served direct from the Dawn Parkway System and as such, not all annual volumes require the use of third-party transportation contracts.

The remaining third-party transportation contracts and associated demand costs are used to meet above average demand and are classified as load balancing transportation.

Breakdown of Third-Party Transportation Demand Costs
Between Transportation Demand and Load Balancing Transportation

Line No.	Particulars	Rate Zone	Annual Volume (TJ)	Rate ($/GJ/mth)	Transportation Demand Annual Volume (TJ)	Transportation Demand Cost (1) ($000s)	Attachment 2 Reference	Load Balancing Transportation Annual Volume (TJ)	Load Balancing Transportation Cost (2) ($000s)	Total Cost ($000s)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i) = (e + h)
	Union North West									
1	Empress to Central MDA	Union NW	2,031	10.2652	591	199	a	1,440	485	684
2	Empress to Union WDA	Union NW	19,930	14.4452	9,914	4,696	b	10,016	4,744	9,439
3	STS - Parkway to Union WDA	Union NW	1,150	21.1473	-	-		1,150	797	797
4	Empress to Union SSMDA	Union NW	7,644	20.0662	4,733	3,114	c	2,912	1,916	5,029
5	Diversion - Union MDA to Parkway	Union NW	112	21.0528	-	-		112	77	77
6	Diversion - Union SSMDA to Parkway	Union NW	3,066	11.2518	-	-		3,066	1,131	1,131
7	Diversion - Union WDA to Parkway	Union NW	1,969	16.8727	-	-		1,969	1,089	1,089
8	Total Union North West		35,902		15,238	8,008		20,663	10,238	18,247
	Union North East									
9	Empress to Union NDA	Union NE	761	22.5104	761	562	d	-	-	562
10	Parkway to Union NDA	Union NE	40,150	12.7325	16,649	6,950	d	23,501	9,811	16,761
11	STS - Parkway to Union NDA	Union NE	17,922	12.7325	-	-		17,922	7,482	7,482
12	STS - Parkway to Union CDA	Union NE	-	-	-	-		-	-	-
13	Empress to Union NCDA	Union NE	365	29.6816	365	355	e	-	-	355
14	Parkway to Union NCDA	Union NE	3,576	6.5088	3,576	763	e	-	-	763
15	Empress to Union EDA	Union NE	1,825	35.7862	831	976	e	994	1,166	2,141
16	Parkway to Union EDA	Union NE	43,482	8.8813	19,087	5,558	f	24,395	7,104	12,661
17	STS - Parkway to Union EDA	Union NE	9,618	8.8813	-	-		9,618	2,801	2,801
18	Parkway to Union EDA EMB	Union NE	9,125	9.7834	-	-		9,125	2,927	2,927
19	Total Union North East		126,823		41,269	15,164		85,554	31,289	46,453
	Union South									
20	Empress to Union CDA	Union South	1,095	31.8533	1,095	1,144		-	-	1,144
21	Total Union South		1,095		1,095	1,144		-	-	1,144
	Enbridge CDA									
22	Empress to NBJ	EGD	1,825	28.2875	1,825	1,693	h	-	-	1,693
23	NBJ to Enbridge CDA	EGD	1,825	9.7360	1,825	583	h	-	-	583
24	Parkway to CDA - FTSN	EGD	31,025	4.0207	31,025	4,090	h	-	-	4,090
25	Dawn to Enbridge CDA	EGD	54,684	8.8453	54,684	15,859	h	-	-	15,859
26	STS - Parkway to Enbridge CDA	EGD	103,621	4.4192	-	-		103,621	15,014	15,014
27	Parkway to Enbridge CDA	EGD	121,736	4.4192	121,736	17,638	h	-	-	17,638
28	Total Enbridge CDA		314,715		211,095	39,862		103,621	15,014	54,876
	Enbridge EDA									
29	Empress to NBJ	EGD	94,900	28.2875	69,302	64,275	g	25,598	23,741	88,016
30	NBJ to Enbridge EDA	EGD	94,900	10.5937	69,302	24,071	g	25,598	8,891	32,962
31	Dawn to Enbridge EDA	EGD	41,610	16.5104	-	-		41,610	22,524	22,524
32	Dawn to Iroquois	EGD	14,600	16.4739	-	-		14,600	7,886	7,886
33	Parkway to Enbridge EDA	EGD	78,152	11.8804	-	-		78,152	30,442	30,442
34	STS - Kirkwall to Enbridge EDA	EGD	25,877	11.8804	-	-		25,877	10,079	10,079
35	STS - Parkway to Enbridge EDA	EGD	3,546	11.8804	-	-		3,546	1,381	1,381
36	Total Enbridge EDA		353,585		138,603	88,345		214,981	104,945	193,291
37	Total Third-Party Transportation Demand Cost (3)					152,523			161,486	314,010

Notes:
(1) Column (c) x column (d) x 12 / 366.
(2) Column (c) x column (g) x 12 / 366.
(3) Line 8 + line 19 + line 21 + line 28 + line 36.

Annual Demand by Rate Zone and Delivery Area

Line No.	Rate Zones (1)	Annual Volumes TJ	Annual Volumes 10^3m^3	Reference
	Union North Rate Zones			
1	Central MDA	591	15,216	a
2	Union WDA	9,914	255,134	b
3	Union SSMDA	4,733	121,788	c
4	Union NDA	17,410	448,016	d
5	Union NCDA	4,772	122,801	e
6	Union EDA	19,087	491,171	f
7	Total Union North Rate Zones	56,507	1,454,125	
	EGD Rate Zone			
8	Enbridge EDA	69,302	1,773,330	g
9	Enbridge CDA (2)	392,313	10,095,547	h
10	Total EGD Rate Zone	461,615	11,868,877	

Notes:

(1) Union South is primarily served by the Enbridge Gas System, with one third-party transportation contract from Empress to Union CDA.

(2) 211,095 TJ of the total 392,313 TJ annual volumes for the Enbridge CDA is transported using third-party transportation contracts. The remaining demand is served directly from the Dawn Parkway System. STS Parkway to Enbridge CDA is load balancing transportation.

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking:

Tr: 59

To provide the horsepower study that is used to underpin this filing.

Response:

As the Enbridge Gas witness (Mr. Kaminski) stated in testimony, there are further details that Enbridge Gas can provide about the horsepower values used for allocations in the cost allocation study. In preparing this response, Enbridge Gas has determined that there is no "horsepower study" that underpins the 2024 Test Year Forecast. There are, however, more details that can be provided.

The details supporting the derivation of the horsepower allocation used to functionalize storage and transmission shared compressor-related assets at the Dawn facility to the storage and transmission functions are provided at Attachment 1. The compression horsepower required to bring the pressure up to 4,926 kPa (700 psig) on design day is storage-related. The compression horsepower required to bring the pressure from 4,926 kPa to 6,270 kPa (700 to 895 psig) on design day is transmission related.

Enbridge Gas also notes that other compressors at the Dawn facility are directly assigned to the storage function or to the transmission function based on the use of the compressor on design day.

Derivation of the Horsepower Allocation Factor used to Functionalize Compressor-Related Assets at Dawn W23/24

Line No.	Particulars	Unit Suction Pressure (psig)	Unit Discharge Pressure (psig)	Compressor Allocation	Horsepower Allocation (HP) Storage	Horsepower Allocation (HP) Transmission		Total Horsepower
		(a)	(b)	(c)	(d)	(e)		(f) = (d + e)
	Horsepower							
1	Dawn Plant C	200	700	Storage	19,412	-		19,412
2	Dawn Plant D	200	700	Storage	32,649	-		32,649
3	Dawn Plant F	700	895	Transmission	-	24,550		24,550
4	Dawn Plant J	700	895	Transmission	-	12,275		12,275
5	Outboard - Dow A	200	700	Storage	2,392	258		2,650
6	Total Horsepower				54,452	37,083		91,535
7	% Horsepower				59.49%	40.51%	(1)	
	Transmission Allocation (mmcf)							
8	Total Dawn Station					6,704		37.12%
9	Total Panhandle					614		3.40%
10	Total					7,318		40.51%

Note:
(1) The transmission horsepower is further split between Dawn Station and the Panhandle System based on the total transmission of gas.

ENBRIDGE GAS INC.

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking:

Tr: 76

To provide a mitigation example for one rate zone with volumetric rates, within whatever reasonable time it can be completed and including any appropriate sort of explanatory notes or caveats.

Response:

Please see Attachment 1.

Enbridge Gas has proposed SFVD rate design as part of this Application and outlined the key benefits of this approach at Phase 3 Exhibit 8, Tab 2, Schedule 3, page 14, paragraph 36. If the OEB does not approve the SFVD rate design, the Company has provided two other alternatives including a Straight Fixed Variable (SFV) and a traditional volumetric rate design option. Should the OEB prefer the traditional volumetric rate design, the Company also proposes a Volume Variance Account to replace the existing Average Use Variance Account.

The Rate Mitigation Plan (Rider R) is flexible and scalable to various rate zone alternatives. Attachment 1 proposes an approach to Rider R that is consistent with the proposed approach under the SFVD rate design. Rider R smooths the impacts of the implementation of the Rate Harmonization Plan over a five-year period and mitigates total average bill impacts to 2%[1], as described at Phase 3 Exhibit 8, Tab 2, Schedule 6.

Enbridge Gas identified a calculation error in the current approved bill for the average Rate M2 profile filed at Phase 3 Exhibit 8, Tab 2, Schedule 9, Attachment 10, p. 6, line 22 to 28, which impacts the rate mitigation and Rider R adjustment for this rate class. Please see Exhibit JT1.53 for an updated bill impact for the Rate M2 average profile under the one rate zone proposed scenario with SFVD rate design and the updated version of the proposed Rider R and bill impacts for general service.

[1] Rider R mitigates total bill impacts to 2% including the federal carbon charge of 15.25 cents/m^3.

Derivation of Alternate Volumetric Rate Mitigation Adjustment - Rider R

Line No.	Particulars		Revenue Adjustment Year 1 ($000s) (a)	Revenue Adjustment Year 2 ($000s) (b)	Revenue Adjustment Year 3 ($000s) (c)	Revenue Adjustment Year 4 ($000s) (d)	Revenue Adjustment Year 5 ($000s) (e)	Billing Units (10^3m^3) (f)	Unit Rate Year 1 (cents/m^3) (g) = (a / f)	Unit Rate Year 2 (cents/m^3) (h) = (b / f)	Unit Rate Year 3 (cents/m^3) (i) = (c / f)	Unit Rate Year 4 (cents/m^3) (j) = (d / f)	Unit Rate Year 5 (cents/m^3) (k) = (e / f)
	General Service												
	Rider R Unit Rate												
1	Union South Rate Zone	Volume ≤ 50,000 m^3	(78,330)	(58,748)	(39,165)	(19,583)	-	3,260,773	(2.4022)	(1.8017)	(1.2011)	(0.6006)	-
2	Union South Rate Zone	Volume > 50,000 m^3	-	-	-	-	-	1,320,841	-	-	-	-	-
3	Total Rider R		(78,330)	(58,748)	(39,165)	(19,583)	-						
	Base Rate Adjustment												
4	Rate E01	All Customers	45,569	34,177	22,785	11,392	-	9,140,146	0.4986	0.3739	0.2493	0.1246	-
5	Rate E02	All Customers	32,761	24,571	16,380	8,190	-	6,571,059	0.4986	0.3739	0.2493	0.1246	-
6	Total Base Rate Adjustment		78,330	58,748	39,165	19,583	-						
7	Total General Service		-	-	-	-	-						

Alternate Volumetric Rate Mitigation Adjustment - Bill Impacts in First Year of Implementation

				Mitigation Unit Rate				Total Bill			2024 Total Bill Impact		2024 Total Bill Impact %	
Line No.	Particulars	Harmonized Rate Class	Annual Volume (m^3)	Base Rate Adjustment (1) (cents/m^3)	Rider R (2) (cents/m^3)	Total Year 1 Adjustment (cents/m^3)	Total Year 1 Adjustment ($)	Current Approved (3) ($)	2024 Proposed - Excluding Rider R (4) ($)	2024 Proposed - Including Rider R ($)	Excluding Rider R ($)	Including Rider R ($)	Excluding Rider R (%)	Including Rider R (%)
		(a)	(b)	(c)	(d)	(e) = (c + d)	(f) = (b * e / 100)	(g)	(h)	(i) = (f + h)	(j) = (h - g)	(k) = (i - g)	(l) = (j / g)	(m) = (k / g)
	General Service													
	EGD Rate Zone													
1	Rate 1 - Small	Rate E01	2,400	0.4986	-	0.4986	12	921	923	935	3	15	0.3%	1.6%
2	Rate 1 - Large	Rate E01	5,048	0.4986	-	0.4986	25	1,597	1,557	1,582	(40)	(15)	(2.5%)	(1.0%)
3	Rate 6 - Small	Rate E01	5,048	0.4986	-	0.4986	25	2,301	1,557	1,582	(744)	(719)	(32.3%)	(31.3%)
4	Rate 6 - Average	Rate E02	22,606	0.4986	-	0.4986	113	6,524	5,752	5,865	(773)	(660)	(11.8%)	(10.1%)
5	Rate 6 - Large	Rate E02	339,124	0.4986	-	0.4986	1,691	75,975	81,397	83,088	5,422	7,113	7.1%	9.4%
	Union North West Rate Zone													
6	Rate 01 - Small	Rate E01	2,200	0.4986	-	0.4986	11	908	875	886	(32)	(21)	(3.5%)	(2.3%)
7	Rate 01 - Large	Rate E02	40,000	0.4986	-	0.4986	199	10,763	9,909	10,108	(854)	(655)	(7.9%)	(6.1%)
8	Rate 10 - Small	Rate E02	60,000	0.4986	-	0.4986	299	15,253	14,689	14,988	(564)	(265)	(3.7%)	(1.7%)
9	Rate 10 - Average	Rate E02	93,000	0.4986	-	0.4986	464	22,882	22,575	23,039	(307)	157	(1.3%)	0.7%
10	Rate 10 - Large	Rate E02	250,000	0.4986	-	0.4986	1,246	58,368	60,097	61,344	1,729	2,975	3.0%	5.1%
	Union North East Rate Zone													
11	Rate 01 - Small	Rate E01	2,200	0.4986	-	0.4986	11	1,072	875	886	(196)	(185)	(18.3%)	(17.3%)
12	Rate 01 - Large	Rate E02	40,000	0.4986	-	0.4986	199	13,749	9,909	10,108	(3,840)	(3,640)	(27.9%)	(26.5%)
13	Rate 10 - Small	Rate E02	60,000	0.4986	-	0.4986	299	19,271	14,689	14,988	(4,583)	(4,284)	(23.8%)	(22.2%)
14	Rate 10 - Average	Rate E02	93,000	0.4986	-	0.4986	464	29,111	22,575	23,039	(6,535)	(6,072)	(22.4%)	(20.9%)
15	Rate 10 - Large	Rate E02	250,000	0.4986	-	0.4986	1,246	75,111	60,097	61,344	(15,014)	(13,767)	(20.0%)	(18.3%)
	Union South Rate Zone													
16	Rate M1 - Small	Rate E01	2,200	0.4986	(2.4022)	(1.9036)	(42)	811	875	833	65	23	8.0%	2.8%
17	Rate M1 - Large	Rate E02	40,000	0.4986	(2.4022)	(1.9036)	(761)	9,156	9,909	9,147	753	(8)	8.2%	(0.1%)
18	Rate M2 - Small	Rate E02	60,000	0.4986	-	0.4986	299	14,679	14,689	14,988	10	309	0.1%	2.1%
19	Rate M2 - Average	Rate E02	73,000	0.4986	-	0.4986	364	17,631	17,796	18,160	165	529	0.9%	3.0%
20	Rate M2 - Large	Rate E02	250,000	0.4986	-	0.4986	1,246	57,370	60,097	61,344	2,727	3,974	4.8%	6.9%

Notes:
(1) P.1, column (g).
(2) Ibid.
(3) Total bill for typical general service customers at current approved rates per Exhibit I.JT1.53 Attachment 1, column (a), excluding federal carbon charge.
(4) Total bill for typical general service customers at 2024 proposed rates per Exhibit I.JT1.53 Attachment 1, column (c), excluding federal carbon charge.

ENBRIDGE GAS INC.

Answer to Undertaking from
City of Kitchener (Kitchener)

Undertaking:

Tr: 79

To expand undertaking JT-1.40 to include the same information relevant to the E64 rate class as is being provided for the E20 rate class.

Response:

Please see Phase 3 Exhibit 7, Tab 3, Schedule 1, Attachment 13, page 3, column (o), line 4 and line 5 for the allocation of gas supply transportation costs to Rate E64. The Transportation Demand and Transportation Commodity costs are recovered in Delivery Demand Charge and Customer Supplied Fuel, respectively for Rate E64.

Please also see response at Exhibit JT1.39.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking:

Tr: 80

To provide working papers behind the allocators in a single Excel document.

Response:

Please see Exhibit I.7.1-SEC-11 Attachments 1 through 26, provided in Excel format.

This page is intentionally left blank. Due to size, these Attachments have not been included.

Please see Exhibit JT2.14_Attachments 1-26.xlsx on the OEB's RDS.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking:

Tr: 82

To provide detail on assumptions made on the CDA versus the EDA re the split of cost allocations.

Response:

The proposed 2024 Cost Allocation Study has been prepared using an integrated approach that reflects the harmonization of cost allocation methodologies for the amalgamated utility. Enbridge Gas reviewed and compared the cost allocation studies that were last approved by the OEB and to the extent possible, incorporated the same principles and methodologies into the integrated cost allocation study. Enbridge Gas is not able to update the previously approved cost allocation studies as the underpinning data is no longer available in the same format.

To separate costs by rate zone in the various rate zone alternatives, as described at Exhibit 7, Tab 0, Schedule 1, Table 3, page 15, Enbridge Gas used a combination of direct assignments and allocations of costs. For example, Enbridge Gas is able to separate plant assets and rate base for the current EGD and Union rate zones as the underlying accounting detail has been maintained by rate zone. However, O&M is no longer available at the rate zone level, and therefore costs are allocated based on existing allocation factors such as number of customers.

- Please see Attachment 1 for additional allocation detail of distribution rate base by rate zone, which primarily uses direct assignments to separate costs, and the corresponding return on rate base.

- Please see Attachment 2 for additional allocation detail of distribution depreciation expense, income tax, and property tax by rate zone, which primarily uses an allocation based on rate base.

- Please see Attachment 3 for additional allocation detail of O&M expense by rate zone, which uses various allocation factors depending on the nature of the expense.

The EGD rate zone used postage stamp rates and did not record its distribution assets by location. As a result, Enbridge Gas is not able to separate the cost of distribution assets for the EGD rate zone between the Enbridge EDA and Enbridge CDA without using an allocation methodology. To allocate costs by service area, the Company applied allocation factors consistent with the allocation factors used to allocate costs to rate classes, such as design day demand and customer count by service area.

- Please see Attachment 4 for the allocation of EGD rate zone revenue requirement by rate zone, including a further allocation of the EGD rate zone for the Enbridge CDA and Enbridge EDA.

- Please see Attachment 5 for the supporting distribution allocation factors by rate zone, including a further allocation of the EGD rate zone for the Enbridge EDA and Enbridge CDA.

Enbridge Gas notes that for cost accounting purposes, the Union rate zones recorded distribution assets by regional areas that consist of Eastern, Northeast and Northwest, as described at EB-2022-0200, Exhibit I.7.1-IGUA-73 parts c) and d). From a rate-making perspective, Union had one rate zone for purposes of distribution costs but two rate zones for gas supply costs. Within the Northeast regional area, Sudbury, North Bay, and Orillia areas are in the Union North East gas supply rate zone but the Sault Ste. Marie area is in the Union North West gas supply rate zone. As such, the Company does not have the asset information detail to separate the cost of distribution assets in the Northeast regional area without using an allocation methodology, which would be similar to the approach used to separate the Enbridge EDA and CDA distribution assets.

2024 Cost Allocation Study - Current Rate Zones
Distribution Rate Base by Rate Zone

Line No.	Particulars ($000s)	As Filed Total (1)(2)	Rate Zone Allocation (3)	Rate Zones: EGD	Rate Zones: Union North	Rate Zones: Union South	Rate Zones: Rate Zones Total
		(a)	(b)	(c)	(d)	(e)	(f)
	Distribution Gross Plant						
1	Land	111,377	Direct	77,450	6,535	27,392	111,377
2	Land Rights	90,928	Direct	43,904	12,140	34,884	90,928
3	Structures & Improvements	334,785	Direct	72,817	62,830	199,137	334,785
4	Measuring & Regulating	1,039,223	Direct	450,708	200,145	388,369	1,039,223
5	Mains	8,788,881	Direct	5,034,210	1,160,020	2,594,650	8,788,881
6	Compressor Equipment	37,552	Direct	8,154	-	29,398	37,552
7	Services	5,648,598	Direct	3,501,916	749,147	1,397,534	5,648,598
8	Meters & Regulators	1,686,510	Direct	917,866	169,730	598,914	1,686,510
9	Customer Stations	421,047	Direct	256,653	55,655	108,739	421,047
10	Linepack	2,387	Direct	1,238	276	873	2,387
11	Subtotal (sum lines 1-10)	18,161,286		10,364,916	2,416,479	5,379,891	18,161,286
12	General Plant	679,229	GEN_PLANT	401,088	75,650	202,491	679,229
13	Total Gross Plant (lines 11 + 12)	18,840,515		10,766,004	2,492,130	5,582,382	18,840,515
	Distribution Accumulated Depreciation						
14	Land	-	Direct	-	-	-	-
15	Land Rights	(20,931)	Direct	(6,797)	(5,079)	(9,055)	(20,931)
16	Structures & Improvements	(107,521)	Direct	(7,334)	(28,148)	(72,039)	(107,521)
17	Measuring & Regulating	(371,325)	Direct	(158,087)	(102,650)	(110,587)	(371,325)
18	Mains	(3,164,609)	Direct	(1,614,445)	(515,705)	(1,034,459)	(3,164,609)
19	Compressor Equipment	(7,071)	Direct	(4,363)	-	(2,708)	(7,071)
20	Services	(2,151,619)	Direct	(1,151,918)	(359,979)	(639,723)	(2,151,619)
21	Meters & Regulators	(656,729)	Direct	(410,912)	(59,902)	(185,916)	(656,729)
22	Customer Stations	(167,236)	Direct	(104,118)	(22,423)	(40,695)	(167,236)
23	Linepack	-	Direct	-			-
24	Subtotal (sum lines 14-23)	(6,647,042)		(3,457,973)	(1,093,886)	(2,095,183)	(6,647,042)
25	General Plant	(339,597)	DIST_GENPLANT	(200,534)	(37,823)	(101,240)	(339,597)
26	Total Accumulated Depreciation (lines 24 + 25)	(6,986,639)		(3,658,507)	(1,131,709)	(2,196,423)	(6,986,639)
	Distribution Net Plant						
27	Land	111,377		77,450	6,535	27,392	111,377
28	Land Rights	69,997		37,107	7,061	25,829	69,997
29	Structures & Improvements	227,263		65,483	34,683	127,098	227,263
30	Measuring & Regulating	667,898		292,621	97,495	277,782	667,898
31	Mains	5,624,271		3,419,766	644,315	1,560,191	5,624,271
32	Compressor Equipment	30,481		3,791	-	26,690	30,481
33	Services	3,496,978		2,349,998	389,169	757,811	3,496,978
34	Meters & Regulators	1,029,781		506,955	109,828	412,998	1,029,781
35	Customer Stations	253,810		152,534	33,233	68,044	253,810
36	Linepack	2,387		1,238	276	873	2,387
37	Subtotal (sum lines 27-36)	11,514,244		6,906,943	1,322,594	3,284,708	11,514,244
38	General Plant	339,632		200,554	37,827	101,250	339,632
39	Total Net Plant (lines 37 + 38)	11,853,876		7,107,497	1,360,421	3,385,958	11,853,876
	Distribution Working Capital						
40	Materials and Supplies	84,077	DIST_NETPLANT	50,436	9,658	23,983	84,077
41	DCB Receivable/(Payable)	(3,989)	DIST_NETPLANT	(2,393)	(458)	(1,138)	(3,989)
42	Customer Security Deposits	(47,296)	DIST_NETPLANT	(28,372)	(5,433)	(13,492)	(47,296)
43	Working Cash Allowance	(102,473)	DIST_NETPLANT	(61,471)	(11,771)	(29,231)	(102,473)
44	Subtotal (sum lines 40-43)	(69,682)		(41,801)	(8,004)	(19,877)	(69,682)
45	Total Rate Base (lines 39 + 44)	11,784,194		7,065,696	1,352,417	3,366,081	11,784,194

Notes:
(1) Phase 3 Exhibit 7, Tab 3, Schedule 7, Attachment 7.
(2) Adjustments made for direct assignments, if applicable.
(3) Allocation factors for rate zones are consistent with the factor descriptions provided at Phase 3 Exhibit 7, Tab 3, Schedule 7, Attachment 11 and the derivation of the factors provided at Phase 3 Exhibit 7, Tab 3, Schedule 7, Attachment 12.

2024 Cost Allocation Study - Current Rate Zones
Distribution Depreciation Expense and Income & Property Tax by Rate Zone

Line No.	Particulars ($000s)	As Filed Total (1)(2)	Rate Zone Allocation (3)	Rate Zones EGD	Union North	Union South	Rate Zones Total
		(a)	(b)	(c)	(d)	(e)	(f)
	Distribution Depreciation Expense						
1	Land	-	DIST_DEPEXP	-	-	-	-
2	Land Rights	1,508	DIST_DEPEXP	728	201	579	1,508
3	Structures & Improvements	13,904	DIST_DEPEXP	3,024	2,609	8,270	13,904
4	Measuring & Regulating	26,337	DIST_DEPEXP	11,422	5,072	9,842	26,337
5	Mains	191,590	DIST_DEPEXP	109,741	25,287	56,561	191,590
6	Compressor Equipment	1,242	DIST_DEPEXP	270	-	972	1,242
7	Services	167,835	DIST_DEPEXP	104,051	22,259	41,524	167,835
8	Meters & Regulators	150,968	DIST_DEPEXP	82,163	15,193	53,612	150,968
9	Customer Stations	12,241	DIST_DEPEXP	7,462	1,618	3,161	12,241
10	Linepack	-	DIST_DEPEXP	-	-	-	-
11	Subtotal (sum lines 1-10)	565,625		318,861	72,241	174,522	565,625
12	General Plant	47,227	DIST_GENPLANT	27,888	5,260	14,079	47,227
13	Total Depreciation Expense (lines 11 + 12)	612,851		346,749	77,501	188,601	612,851
	Distribution Income & Property Taxes						
14	Income Taxes	92,492	DIST_RATEBASE	55,457	10,615	26,420	92,492
15	Property Taxes	95,279	DIST_PROPTAX	41,234	16,736	37,309	95,279
16	Total Taxes	187,771		96,692	27,351	63,728	187,771

Notes:
(1) Phase 3 Exhibit 7, Tab 3, Schedule 7, Attachment 7.
(2) Adjustments made for direct assignments, if applicable.
(3) Allocation factors for rate zones are consistent with the factor descriptions provided at Phase 3 Exhibit 7, Tab 3, Schedule 7, Attachment 11 and the derivation of the factors provided at Phase 3 Exhibit 7, Tab 3, Schedule 7, Attachment 12.

2024 Cost Allocation Study - Current Rate Zones
Distribution O&M by Rate Zone

Line No.	Particulars ($000s)	As Filed Total (1)(2)	Rate Zone Allocation (3)	Rate Zones EGD	Union North	Union South	Rate Zones Total
		(a)	(b)	(c)	(d)	(e)	(f)
	Distribution O&M						
	Gas Supply						
1	Unaccounted For Gas	16,615		7,378	2,090	7,146	16,615
2	Company Use Gas	1,725		241	336	1,149	1,725
3	Other Transportation	10,710		-	-	10,710	10,710
	Distribution						
4	Supervision	10,617	DIST_SUPER	6,026	1,389	3,202	10,617
5	Meter & Regulator	19,652	CUST_METERS	10,695	1,978	6,979	19,652
6	Service & Equipment on Customer Premise	-	CUST_METERS	-	-	-	-
7	Mains & Services	59,330	DIST_MAINS&SERVICES	35,079	7,846	16,406	59,330
8	Measuring & Regulating	8,158	DISTDEMAND	3,538	1,571	3,049	8,158
9	Other Distribution	353	DIST_MAINS&SERVICES	209	47	98	353
10	Customer Stations	3,222	CUST_STATIONS	1,964	426	832	3,222
	General Operating & Engineering						
11	System Operation & Engineering	169,987	DIST_NETPLANT	101,972	19,526	48,490	169,987
	Sales Promotion & Merchandise						
12	Sales Promotion & Supervision	10,183	TOTAL_CUSTOMERS	6,066	966	3,151	10,183
13	Demand Side Management - Program	150,928	DSM Detail	87,805	8,646	54,477	150,928
14	Demand Side Management - Administration	32,154	DSM Detail	18,628	1,891	11,635	32,154
	Distribution Customer Accounting						
15	Supervision	2,999	CUSTACCT_SUPER	1,773	282	944	2,999
16	Customer Contracts & Orders	19,535	TOTAL_CUSTOMERS	11,637	1,853	6,045	19,535
17	Meter Reading	23,437	TOTAL_CUSTOMERS	13,962	2,224	7,252	23,437
18	Customer Billing, Accounting and Bill Delivery	47,499	TOTAL_CUSTOMERS	28,295	4,507	14,697	47,499
19	Large Volume Customer Care	6,053	CUST_EXCL_GS	3,090	469	2,495	6,053
20	Credit & Collection	6,259	TOTAL_CUSTOMERS	3,728	594	1,937	6,259
21	Uncollectible Accounts	11,815	TOTAL_CUSTOMERS	7,038	1,121	3,656	11,815
	Administrative & General Expense						
22	Employee Benefits	151,459		87,544	16,341	47,574	151,459
23	Administrative & General	184,250		104,464	19,717	60,069	184,250
24	Total O&M Expenses (sum lines 1-23)	946,939		541,131	93,817	311,992	946,939
	Distribution Other Revenue						
25	Late Payment Penalties	26,871	TOTAL_CUSTOMERS	16,007	2,549	8,314	26,871
26	Customer Accounting Charge	14,283	TOTAL_CUSTOMERS	8,508	1,355	4,420	14,283
27	Other Income	17,762	TOTAL_CUSTOMERS	10,581	1,685	5,496	17,762
28	Other Revenue Surcharges	6,017	COMMUNITY_EXP	2,024	331	3,663	6,017
29	Total Other Revenue (sum lines 25-28)	64,933		37,119	5,920	21,893	64,933

Notes:
(1) Phase 3 Exhibit 7, Tab 3, Schedule 7, Attachment 7.
(2) Adjustments made for direct assignments, if applicable.
(3) Allocation factors for rate zones are consistent with the factor descriptions provided at Phase 3 Exhibit 7, Tab 3, Schedule 7, Attachment 11 and the derivation of the factors provided at Phase 3 Exhibit 7, Tab 3, Schedule 7, Attachment 12.

2024 Cost Allocation Study - Current Rate Zones

Total Distribution Allocation - All Rate Zones

Line No.	Particulars ($000s)	Total Revenue Requirement (1)	Total Revenue Requirement Net of Other Revenue	Total Direct Assignment	Direct Assignment Factor	Balance to be Allocated	Allocation Factor	Rate Zones: EGD	Rate Zones: Union North	Rate Zones: Union South	Rate Zones: Ex-franchise	EGD Rate Zone: Enbridge CDA (2)	EGD Rate Zone: Enbridge EDA (2)	EGD Rate Zone: Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m) = (k + l)
	Distribution Revenue Requirement													
1	Distribution Demand - High Pressure > 4"	311,341	311,341			311,341	HIGHPRESS>4_RZ	164,062	39,696	107,269	314	139,741	24,321	164,062
2	Distribution Demand - High Pressure <= 4"	57,500	57,500			57,500	HIGHPRESS<=4_RZ	31,379	7,592	18,528	-	26,535	4,844	31,379
3	Distribution Demand - Low Pressure	306,176	305,621			305,621	LOWPRESS_RZ	166,608	40,441	98,572	-	140,731	25,877	166,608
	Distribution Demand - Specific Allocation													
4	Distribution Demand Specific - DSM Program	150,928	150,928			150,928	DSM_PRO_RZ	87,805	8,646	54,477	-	73,825	13,980	87,805
5	Distribution Demand Specific - DSM Admin	65,804	65,804			65,804	DSM_ADM_RZ	37,661	3,852	24,292	-	31,550	6,111	37,661
6	Distribution Customer - Mains	407,482	406,739			406,739	MAINS_RZ	232,505	50,861	123,373	-	192,950	39,555	232,505
7	Distribution Customer - Services	582,976	581,901			581,901	SERVICES_RZ	374,448	70,561	136,892	-	310,745	63,703	374,448
8	Distribution Customer - Meters	293,252	292,716			292,716	METERS_RZ	153,466	30,043	109,207	-	129,095	24,371	153,466
9	Distribution Customer - Stations	48,424	45,316			45,316	STATIONS_RZ	27,084	5,684	12,548	-	23,958	3,126	27,084
	Distribution Customer- Specific													
10	Uncollectible Accounts	12,566	12,566			12,566	BAD_DEBT_RZ	7,481	1,192	3,893	-	6,427	1,054	7,481
11	Distribution Customer Accounting	190,762	131,846	11,616	SALESPROMO_RZ	120,231	TOTAL_CUST_RZ	77,322	12,448	42,055	21	64,168	13,154	77,322
12	Large Volume Customer Care	18,741	18,741			18,741	LVCC_RZ	9,757	1,562	7,421	-	8,097	1,660	9,757
13	Distribution Commodity	18,340	18,340	-		18,340	DISTCOMM_RZ	7,619	2,426	8,295	-	6,555	1,064	7,619
14	Total Distribution Revenue Requirement	2,464,292	2,399,359	11,616		2,387,744		1,377,197	275,004	746,823	335	1,154,375	222,822	1,377,197

Notes:

(1) Phase 3 Exhibit 7, Tab 3, Schedule 7, Attachment 8, p. 1.

(2) Allocated based on delivery area factors at Attachment 5, columns (g) and (f).

Cost Allocation Study - Current Rate Zones

			Allocation Factors - Distribution - All Rate Zones					Allocation Factors - EGD Rate Zone by Delivery Area			
Line No.	Allocation Factors (1)		Total	EGD	Union North	Union South	Ex-franchise	Total	Enbridge CDA	Enbridge EDA	Factor Description
			(a)	(b)	(c)	(d)	(e)	(f) = (g + h)	(g)	(h)	(i)
1	SALESPROMO_RZ	EXT	11,616	6,919	1,102	3,573	21	2,331,869	1,935,158	396,711	Allocated based on customer count by delivery area
2			100%	60%	9%	31%	0%	100%	83%	17%	
3	BAD_DEBT_RZ	EXT	12,566	7,481	1,192	3,893	-	6,936	5,958	978	Allocated based on volume for general service and customers for
4			100%	60%	9%	31%	0%	100%	86%	14%	contract
5	DISTCOMM_RZ	EXT	18,340	7,619	2,426	8,295	-	12,679,740	10,908,424	1,771,316	Allocated based on volume
6			100%	42%	13%	45%	0%	100%	86%	14%	
7	DSM_ADM_RZ	EXT	65,804	37,661	3,852	24,292	-	37,661	31,550	6,111	Allocated based on 50/50 split between customer count and volume
8			100%	57%	6%	37%	0%	100%	84%	16%	for general service. Contract allocated based on volume
9	DSM_PRO_RZ	EXT	150,928	87,805	8,646	54,477	-	87,805	73,825	13,980	Allocated based on 50/50 split between customer count and volume
10			100%	58%	6%	36%	0%	100%	84%	16%	for general service. Contract allocated based on volume
11	HIGHPRESS<=4_RZ	EXT	57,500	31,379	7,592	18,528.29	-	103,365	87,407	15,958	Allocated based on design day demands by delivery area
12			100%	55%	13%	32%	0%	100%	85%	15%	
13	HIGHPRESS>4_RZ	EXT	311,341	164,062	39,696	107,269	314	117,032	99,683	17,349	Allocated based on design day demands by delivery area
14			100%	53%	13%	34%	0%	100%	85%	15%	
15	LOWPRESS_RZ	EXT	305,621	166,608	40,441	98,572	-	102,839	86,866	15,973	Allocated based on design day demands by delivery area
16			100%	55%	13%	32%	0%	100%	84%	16%	
17	LVCC_RZ	EXT	18,746	9,760	1,563	7,423	-	2,331,869	1,935,158	396,711	Allocated based on customer count by delivery area
18			100%	52%	8%	40%	0%	100%	83%	17%	
19	MAINS_RZ	EXT	406,739	232,505	50,861	123,373	-	2,331,869	1,935,158	396,711	Allocated based on customer count by delivery area
20			100%	57%	13%	30%	0%	100%	83%	17%	
21	METERS_RZ	EXT	292,716	153,466	30,043	109,207	-	834,204,350	701,726,915	132,477,435	Allocated based on meter replacement cost by delivery area
22			100%	52%	10%	37%	0%	100%	84%	16%	
23	SERVICES_RZ	EXT	581,901	374,448	70,561	136,892	-	2,331,869	1,935,158	396,711	Allocated based on customer count by delivery area
24			100%	64%	12%	24%	0%	100%	83%	17%	
25	STATIONS_RZ	EXT	45,316	27,084	5,684	12,548	-	167,927,195	148,544,110	19,383,086	Allocated based on station replacement cost by delivery area
26			100%	60%	13%	28%	0%	100%	88%	12%	
27	TOTAL_CUST_RZ	EXT	120,226	70,400	11,346	38,480	-	2,331,869	1,935,158	396,711	Allocated based on customer count by delivery area
28			100%	59%	9%	32%	0%	100%	83%	17%	

Note:
(1) Phase 3 Exhibit 7, Tab 3, Schedule 7, Attachment 12, p. 13

ENBRIDGE GAS INC.

Answer to Undertaking from
Three Fires Group Inc./Minogi (TFG/M)

Undertaking:

Tr: 96

To provide the scope of the agenda item that could be added to the Indigenous Working Group to deal with or consider the future communication plan for rate harmonization implementation; and whether the IWG would be involved prior to plan development or as an information-sharing activity.

Response:

Enbridge Gas proposes that the following agenda item could be added to the agenda for the Indigenous Working Group (IWG) if requested by the IWG members:

Discussion on how to develop a plan to communicate rate harmonization to Indigenous Nations

- Receive IWG feedback on how Enbridge Gas would, if needed, communicate rate harmonization implementation to the First Nations communities that have natural gas customers.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking:

Tr: 101

To identify whether the postage stamp rates for the five identified Canadian Gas utilities in I.7.0-STAFF-14 are postage stamp rates for distribution.

Response:

The five utilities have common postage stamp distribution rates, as noted below (except for delivery rates for PNG, as noted):

- FortisBC Energy Inc. (FEI) - FEI has both common delivery and commodity rates for its franchise area. Note that the BCUC has established a rate rider for Fort Nelson residential customers to mitigate and phase in the change to common rates over a period of five years.

- Pacific Northern Gas (PNG) - PNG commodity costs are common; however, delivery rates vary across PNG's four service areas.

- SaskEnergy - SaskEnergy has both common delivery and commodity rates for its franchise area.

- Centra Gas Manitoba - Centra Gas Manitoba has both common delivery and commodity rates for its franchise area.

- Énergir - Énergir has both common delivery and commodity rates for its franchise area.

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking:

Tr: 109

To provide the specific reference to where the OEB either approved or acknowledged the treatment of additional BGA costs for direct purchase customers in or around the time of the Polar Vortex.

Response:

The OEB approved the recovery of post-checkpoint load balancing costs from bundled direct purchase (DP) customers in the Union South rate zone for the winter of 2014 as part of Union's 2013 Annual Deferral Account proceeding.[1]

In Union's 2014 Annual Deferral Account proceeding,[2] a similar allocation and recovery of post-checkpoint load balancing costs to bundled DP customers in the Union South rate zone for the winter of 2015 had been proposed. This proposal was accepted by parties in the Settlement Agreement for that proceeding and subsequently approved by the OEB.[3].

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[1] EB-2014-0145 Decision and Order, pp. 3-6.
[2] EB-2015-0010.
[3] Ibid, Decision and Order, August 13, 2015, p.3.

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking:

Tr: 113

To advise whether there are steps Enbridge might be prepared to take to inform direct-purchase customers of their forecast BGA balance for the end of March, inclusive of heat-sensitive forecast information for the rest of the month, when that balance is provided to them in their March statement.

Response:

Direct purchase (DP) customers will have a monthly Banked Gas Account (BGA) status report available to them containing a monthly continuity of the customer's actual and projected BGA balance for the pool term. The report, available to customers in early March, will include a projection of March's balance. In order to include a forecast of colder-than-normal March weather impact on the projected March balance, Enbridge Gas would need to implement changes to internal and customer-facing business applications. Enbridge Gas could consider designing and implementing necessary changes coincident with the system changes required to implement Phase 3 outcomes.

Enbridge Gas notes that an inclusion of a forecast of March weather impacts will not eliminate the bundled DP customer's risk of an allocation of post-checkpoint load balancing costs incurred by Enbridge Gas as the customer's actual March 31 BGA balance could still be less than planned due to differences between actual and forecast weather as well as other differences in the customer's consumption profile.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Association of Physical Plant Administrators (OAPPA)

Undertaking:

Tr: 136

To confirm whether, when checkpoint balancing is going to be applied to all rate zones, Enbridge will be prepared and able to report consumption in the next month, to be able to better inform balancing activities for these clients

Response:

Enbridge Gas will develop an implementation plan for new rates and services, including the checkpoint balancing requirement, subject to OEB approval in Phase 3. As part of this plan, Enbridge Gas will ensure a process is in place to inform balancing activities to all customers with checkpoint requirements.

General service consumption is recorded based on billing cycles. The quantities billed in each month are reflected as that month's activity in the Banked Gas Account (BGA). All other things being equal, the monthly consumption quantities reflected in the BGA reflect this same mix of billing cycles on a forecast and actual basis such that the action to be taken for the checkpoint is consistent.

There are times when there can be a delay in the reporting of consumption. When the delay is significant enough, particularly in later billing cycles, it could result in consumption being recorded one month later than desired. When a significant billing delay has been identified, Enbridge Gas will work with the customer by adjusting the BGA by an appropriate quantity to determine the necessary checkpoint balancing action to be taken by the customer.

Enbridge Gas will continue to work on improving processes to meet targeted reporting dates and reduce exceptions. While there may be exceptions, Enbridge Gas expects that there will be fewer than there are today.

ENBRIDGE GAS INC.

Answer to Undertaking from
Building Owners and Managers Association (BOMA)

Undertaking:

Tr: 140

To break down the interruptible customer count between commercial and industrial.

Response:

Please see Table 1. As stated in EB-2022-0200, Exhibit I.3.2-BOMA-2, Enbridge Gas does not track commercial and industrial customers within the distribution contract market. For the purpose of this response, Enbridge Gas has provided the buildings sector as a proxy for commercial customers.

Table 1
Number of Interruptible Customers & Volumes by Rate Class
Based on the 2024 Forecast

Line No.	Rate Zone	Rate Class	Customer Count			Interruptible Volume (10^3m^3)		
			Buildings	Other	Total (1)	Buildings	Other	Total (2)
			(a)	(b)	(c)	(d)	(e)	(f)
1	EGD	Rate 145	6	10	16	5,653	10,061	15,714
2	EGD	Rate 170	4	18	22	35,964	287,290	323,254
3	Union North	Rate 25	4	68	72	3,202	123,628	126,831
4	Union South	Rate M4	1	2	3	238	0	238
5	Union South	Rate M5	4	33	37	5,152	49,935	55,087
6	Union South	Rate M7	3	8	11	40,781	33,044	73,825
7	Union South	Rate T1	1	1	2	0	37,536	37,536
8	Union South	Rate T2	0	28	28	0	41,762	41,762
9	Total		23	168	191	90,989	583,257	674,246

Notes:
(1) Phase 3 Exhibit 8, Tab 4, Schedule 7, p. 10, Table 2, column (a).
(2) Phase 3 Exhibit 8, Tab 4, Schedule 7, p. 10, Table 2, column (b).