VIA RESS and EMAIL

June 5, 2025

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

Dear Ritchie Murray:

Re: Enbridge Gas Inc.
2024 Rebasing – Phase 3
Consumers Council of Canada (CCC) Interrogatories
OEB File No. EB-2025-0064

In accordance with Decision on Issues List and Procedural Order No. 2, dated May 16, 2025, please find attached CCC's interrogatories with respect to Phase 3 of Enbridge Gas's 2024 Rebasing application.

Yours truly,

Lawrie Gluck

Lawrie Gluck
Consultant for the Consumers Council of Canada

cc: All parties in EB-2025-0064

Enbridge Gas Inc.

2024 Rebasing – Phase 3

Consumers Council of Canada

Interrogatories

June 5, 2025

2.5-CCC-1

Ref: Ex. 2/5/5/pp. 4-12

a) If available, please provide a breakdown showing the forecast capital costs that were deferred to after 2024 and the forecast capital costs that were eliminated (as opposed to deferred).

b) (P. 12) Please provide a version of Figure 7 that shows the pre-optimization spend profile by capital program.

2.7-CCC-2

Ref: Ex. 2/7/2/p. 9

a) Please advise whether it is: (i) already Enbridge Gas's intent to develop a plan for large-scale AMI implementation; or (ii) that decision will be made after the pilot is completed.

b) Please confirm that Enbridge Gas intends to seek OEB approval at the time of its next rebasing prior to any deployment/implementation of an AMI program (beyond the pilot).

4.2-CCC-3

Ref: Ex. 4/2/2/p. 9

With respect to the heat value used to derive the WARP, please advise:

i. Whether the proposal is to continue to use the harmonized Enbridge Gas South heat value going forward?

ii. Whether the heat value will be updated and if so, on what timeline (e.g., quarterly, annually)?

7.0-CCC-4
Ref: Ex. 7/0/1/ pp. 11, 30

Please confirm that the "Other Supply" does not include any Empress supply transported on the TransCanada Mainline. If this is not confirmed, please further explain.

7.1-CCC-5
Ref: Ex. 7/1/1/pp. 8-9

a) Please confirm that the $17.6M revenue requirement sufficiency as shown in Table 1 is reflected in the cost allocation, rate design and bill impacts set out in the Phase 3 application.

b) Please confirm that none of the Phase 2 deficiency ($8.5M) is reflected in the Phase 3 cost allocation, rate design and bill impacts.

c) Assuming the Phase 2 deficiency is not in the Phase 3 - 2024 revenue requirement (nor the cost allocation and rate design exercise), please further explain how the Phase 2 deficiency will be reflected in base rates at the time that the approved cost allocation/rate design is approved.

d) Please provide the bill impacts resulting from only the updated Phase 3 revenue requirement with no implementation of any cost allocation or rate design changes.

7.1-CCC-6
Ref: Ex. 7/1/3/Attachment 1

a) (P. 1) Please further explain the reason for the methodology change for Load Balancing Transportation to the use of excess peak over annual average demand relative to the methodology previously applied by EGD.

b) (P. 1) Please further explain the reason for the methodology change for Load Balancing Commodity to the use of design day demand less design day deliveries relative to the methodology previously applied by EGD.

c) (P.1) Gas supply administration costs appear to now be recovered from direct purchase customers and treated as other revenue. Please explain the implications for sales service customers of this change in the recovery methodology (i.e., previously these admin costs were allocated to both sales service and direct purchase customers and do not appear to have been treated as other revenue).

d) (P.2) Please further explain the allocation of operational contingency based on "how operational contingency space is used." As part of the response, please explain how this leads to approx. 50% of operational contingency costs being allocated to Rate E01 in the One Zone proposal.

e) (P.4) Please provide support for the continued 60% ex-franchise / 40% in-franchise allocation of Transmission Demand – Albion costs. Please also provide a citation from the proceeding where this allocation was previously approved.

<u>7.3-CCC-7</u>

Ref: Ex. 7/3 / Attachments (Cost Studies)

a) Please confirm that 3,922,421 customers is the total customer count in the cost allocation studies for all rate zone alternatives.

b) Please confirm that, in the harmonized rate class alternatives cost allocation studies, Rate E01 has 3,836,306 customers.

c) Please confirm that, in the current rate zone/rate class alternative cost allocation study, the combined total of Rate 1/01/M1 customers is 3,738,158 customers.

d) Please confirm that the following table, which provides the combined allocated costs for Rate E01 (or 1/01/M1) across all zones in the One Zone, Two Zone (One Dist.) and Current Rate Zone alternatives, is accurate.

		Current Zones/Classes						Alternative - 2 Zones w/ One dist					Proposed			Utility
		EGD	UGL North	UGL South	**Total Rate 1**	Rate 1 %	Per Cust	EO1 North	EO1 South	**EO1 Total**	E01 %	Per Cust	**Total E01**	E01 %	Per Cust	**Total**
Line		Rate	Rate	Rate												
No.	Particulars ($000s)	1	01	M1												
		(f)	(g)	(f)												
	Gas Supply Revenue Requirement															
1	Gas Supply Commodity	664,796	136,498	485,345	**1,286,639**	68.50%	$ 344.19	178,880	1,054,876	$ **1,233,756.06**	65.68%	$ 321.60	**1,234,054**	65.70%	$ 321.68	1,878,311
2	Load Balancing - Transportation	58,367	28,734	-	**87,101**	56.71%	$ 23.30	75,682	7,770	$ **83,451.22**	54.33%	$ 21.75	**83,451**	54.33%	$ 21.75	153,599
3	Load Balancing - Commodity	12,074	2,165	6,847	**21,086**	52.29%	$ 5.64	3,782	16,494	$ **20,275.85**	50.28%	$ 5.29	**20,276**	50.28%	$ 5.29	40,329
4	Transportation Demand	50,444	13,652	316	**64,412**	44.40%	$ 17.23	52,700	18,307	$ **71,007.19**	48.95%	$ 18.51	**71,007**	48.95%		145,074
5	Transportation Commodity	5,048	1,940	34	**7,022**	47.16%	$ 1.88	7,191	231	$ **7,422.25**	49.85%	$ 1.93	**7,422**	49.85%	$ 1.93	14,889
6	Admin	5,795	1,097	3,622	**10,513**	67.86%	$ 2.81	1,882	8,296	$ **10,178.05**	65.70%	$ 2.65	**10,178**	65.70%	$ 2.65	15,492
7	Total Gas Supply Revenue Requirement	796,525	184,086	496,163	**1,476,774**	65.70%	$ 395.05	320,116	1,105,974	$ **1,426,090.62**	63.45%	$ 371.74	**1,426,389**	63.46%	$ 371.81	2,247,693
					-											
	Storage Revenue Requirement				-											
8	Storage Demand - Deliverability	31,816	5,705	18,041	**55,562**	52.29%	$ 14.86	9,964	43,463	$ **53,426.80**	50.28%	$ 13.93	**53,427**	50.28%	$ 13.93	106,266
9	Storage Demand - Space	20,822	4,145	13,097	**38,065**	56.55%	$ 10.18	6,529	28,693	$ **35,221.37**	52.32%	$ 9.18	**35,222**	52.32%	$ 9.18	67,317
10	Storage Demand - Operational Contingency	1,668	329	1,029	**3,026**	52.46%	$ 0.81	531	2,338	$ **2,868.97**	49.73%	$ 0.75	**2,895**	50.19%	$ 0.75	5,769
11	Storage Commodity	3,335	658	2,170	**6,164**	43.60%	$ 1.65	1,125	4,957	$ **6,081.79**	43.02%	$ 1.59	**6,082**	43.03%	$ 1.59	14,136
12	Total Storage Revenue Requirement	57,642	10,838	34,337	**102,817**	53.14%	$ 27.50	18,149	79,450	$ **97,598.93**	50.44%	$ 25.44	**97,627**	50.46%	$ 25.45	193,487
	Transmission Revenue Requirement															
13	Transmission Demand - Dawn Station	2,354	428	1,390	**4,172**	32.37%	$ 1.12	561	3,017	$ **3,578.50**	27.76%	$ 0.93	**4,035**	31.30%	$ 1.05	12,890
14	Transmission Demand - Kirkwall Station	66	-	142	**208**	14.69%	$ 0.06	74	120	$ **194.36**	13.70%	$ 0.05	**191**	13.44%	$ 0.05	1,418
15	Transmission Demand - Parkway Station	9,063	2,775	-	**11,838**	25.71%	$ 3.17	3,263	6,929	$ **10,192.14**	22.14%	$ 2.66	**11,957**	25.98%	$ 3.12	46,034
16	Transmission Demand - Dawn Parkway	51,357	9,376	22,431	**83,164**	36.20%	$ 22.25	12,066	59,299	$ **71,364.82**	31.06%	$ 18.60	**81,374**	35.42%	$ 21.21	229,744
17	Transmission Demand - Albion	5,988	-	-	**5,988**	19.59%	$ 1.60	-	6,396	$ **6,395.56**	20.92%	$ 1.67	**6,396**	20.92%	$ 1.67	30,570
18	Transmission Demand - Panhandle St. Clair	-	-	9,931	**9,931**	18.68%	$ 2.66	-	8,595	$ **8,595.37**	16.17%	$ 2.24	**8,596**	16.17%	$ 2.24	53,148
19	Transmission Commodity	1,510	674	1,293	**3,478**	11.63%	$ 0.93	571	2,777	$ **3,347.72**	11.19%	$ 0.87	**3,347**	11.19%	$ 0.87	29,914
20	Total Transmission Revenue Requirement	70,339	13,254	35,186	**118,779**	29.42%	$ 31.77	16,535	87,134	$ **103,668.47**	25.68%	$ 27.02	**115,895**	28.71%	$ 30.21	403,717
	Distribution Revenue Requirement															
21	Distribution Demand - High Pressure > 4"	73,978	16,326	39,595	**129,899**	41.71%	$ 34.75	125,363	Combined w/ North	$ **125,363.38**	40.26%	$ 32.68	**125,363**	40.26%	$ 32.68	311,407
22	Distribution Demand - High Pressure <= 4"	16,020	5,455	11,264	**32,739**	56.93%	$ 8.76	31,017	Combined w/ North	$ **31,016.62**	53.93%	$ 8.09	**31,017**	53.93%	$ 8.09	57,513
23	Distribution Demand - Low Pressure	85,479	29,063	63,015	**177,557**	58.09%	$ 47.50	167,868	Combined w/ North	$ **167,868.31**	54.92%	$ 43.76	**167,868**	54.92%	$ 43.76	305,683
	Distribution Demand - Specific Allocation		-	-	-				Combined w/ North	$ -						
24	Distribution Demand Specific - DSM Program	59,445	5,543	37,980	**102,968**	68.22%	$ 27.55	109,342	Combined w/ North	$ **109,342.22**	72.45%	$ 28.50	**109,342**	72.45%	$ 28.50	150,928
25	Distribution Demand Specific - DSM Admin	20,109	2,120	13,221	**35,451**	53.84%	$ 9.48	40,146	Combined w/ North	$ **40,146.17**	60.97%	$ 10.46	**40,146**	60.97%	$ 10.46	65,848
26	Distribution Customer - Mains	215,241	50,549	122,510	**388,300**	95.35%	$ 103.87	398,294	Combined w/ North	$ **398,293.55**	97.80%	$ 103.82	**398,294**	97.80%	$ 103.82	407,234
27	Distribution Customer - Services	346,646	70,128	135,934	**552,708**	94.86%	$ 147.86	569,884	Combined w/ North	$ **569,884.12**	97.80%	$ 148.55	**569,884**	97.80%	$ 148.55	582,677
28	Distribution Customer - Meters	111,889	27,768	97,236	**236,892**	80.93%	$ 63.37	233,561	Combined w/ North	$ **233,561.25**	79.79%	$ 60.88	**233,561**	79.79%	$ 60.88	292,702
29	Distribution Customer - Stations	-	1,871	4,031	**5,902**	13.01%	$ 1.58	-	Combined w/ North	$ -	0.00%		-	0.00%		45,350
	Distribution Customer- Specific		-	-	-				Combined w/ North	$ -						
30	Uncollectible Accounts	6,315	1,085	3,361	**10,760**	85.27%	$ 2.88	11,090	Combined w/ North	$ **11,089.88**	87.88%	$ 2.89	**11,090**	87.88%	$ 2.89	12,619
31	Distribution Customer Accounting	70,334	12,169	40,681	**123,184**	93.18%	$ 32.95	126,699	Combined w/ North	$ **126,699.20**	95.84%	$ 33.03	**126,699**	95.84%	$ 33.03	132,203
32	Large Volume Customer Care	-	-	-	-			-	Combined w/ North	$ -	0.00%		-	0.00%		16,856
33	Distribution Commodity	3,134	696	2,292	**6,122**	33.38%	$ 1.64	6,110	Combined w/ North	$ **6,109.85**	33.31%	$ 1.59	**6,110**	33.31%	$ 1.59	18,340
34	Total Distribution Revenue Requirement	1,008,589	222,773	571,121	**1,802,483**	75.12%	$ 482.18			**1,819,375**	75.83%	$ 474.25	**1,819,375**	75.83%	$ 474.25	2,399,359
					-											
35	Total Revenue Requirement	1,933,095	430,951	1,136,808	**3,500,853**	66.76%	$ 936.52			$ **3,446,732.57**	65.72%	$ 898.45	**3,459,286**	65.96%	$ 901.72	5,244,257

e) Please describe the drivers (or differences in the allocation methodology) that result in an additional approximately $10M of "Transmission Demand – Dawn Parkway" costs being allocated to the E01 rate class in the proposed One Zone option relative to the Two Rate Zone (One Dist.) option.

f) Similarly, please explain why additional costs are allocated to the E01 rate class in the proposed One Zone option relative to the Two Rate Zone (One Dist.) option for "Transmission Demand – Dawn Station" and "Transmission Demand – Parkway Station."

g) The total allocated DSM costs (program + admin) and the DSM costs on a per customer basis are higher for Rate E01 in the rate zone options that rely on a harmonized rate class structure relative to the current rate zone/class option. Please provide the detailed DSM budgets that support the allocations.

8.1-CCC-8

Ref: Ex. 8/1/1/p. 5 and Attachment 2

a) Table 2 shows that $3.3 million of delivery revenues are to be recovered through volumetric charges from in-franchise customers. Please describe which cost categories are recovered through volumetric charges.

8.1-CCC-9

Ref: Ex. 8/1/4/p. 6 and Attachment 1

Rate E01 is the only harmonized rate class with more than 1 customer in the class where the monthly customer charge is set at a level that is equal to the customer-related costs. For all other rate classes, the monthly customer charge is set at a level that is significantly below parity with the customer-related costs.

i. Please explain why the monthly customer charge was not set at a level below parity with the customer-related costs for Rate E01 similar to all other rate classes.

ii. Please describe the legacy EGD and Union approaches to the establishment of the monthly customer charge (in the context of recovery of customer-related costs) for the Rate 1, 01 and M1 classes when those were last established. Please provide references (or links) to the corresponding evidence filings.

iii. Please provide an alternative where the monthly customer charge is reduced for Rate E01 and the remaining costs are recovered through the proposed demand charge (similar to the approach taken for the other rate classes). Please provide the resulting rates using this approach for both the One Zone and Two Zone (One Dist.) rate zone alternatives.

iv. Please provide an alternative where the monthly customer charge is reduced for Rate E01 (similar to the approach taken for the other rate classes) and the remaining costs are recovered through a traditional volumetric charge. Please provide the resulting rates using this approach for both the One Zone and Two Zone (One Dist.) rate zone alternatives.

8.2-CCC-10

Ref: Ex. 8/2/1/p. 12

a) Please advise whether the implementation of the service and rate harmonization proposals in two cohorts will cause any rate/bill impacts for general service customers at the time that the second cohort of changes is implemented.

8.2-CCC-11

Ref: Ex. 8/2/2/pp. 3, 6-7
Ex. 8/2/9/Attachments 1 and 8

a) (P.3) With respect to the current treatment of Panhandle/St. Clair transportation costs, please explain what is being recorded in the PGVA (i.e., is it the revenues generated from C1 – St. Clair to Dawn transportation charges recorded as a credit in those accounts)?

b) (PP. 6-7) In the context of the current treatment of the revenues resulting from the C1 – St. Clair to Dawn transportation charges, how are those revenues allocated (e.g., all back to sales service customers, refunded to all in-franchise customers, etc.)?

c) In the context of the proposed treatment of the Panhandle/St. Clair transportation costs and the C1 - St. Clair to Dawn charges and using rate E01 as an example, please:

i. Confirm that the underlying demand-related costs of the Panhandle/St. Clair system are allocated to the class (Exhibit 7, Tab 3, Schedule 1, Attachment 8, Line 18).

ii. Confirm that sales service customers in the class are going to be charged \$0.0229 cents/m^3 related to Panhandle/St. Clair as part of their gas supply commodity charges and this results in a total recovery from those customers of approx. \$2M (Exhibit 8, Tab 2, Schedule 9, Attachment 8, Line 1).

iii. Confirm that the total amount collected through the gas supply commodity charge ($3M) is reallocated back to in-franchise customers with only $0.5M going back to Rate E01 (Exhibit 8, Tab 2, Schedule 9, Attachment 8, Line 1).

iv. Confirm that the result is that Rate E01 customers are allocated an additional $1.5M of Panhandle/St. Clair costs relative to the cost study while the sales service customers in the class are also paying $2M of gas supply charges related to the same cost category (Exhibit 8, Tab 2, Schedule 9, Attachment 1).

d) If the above analysis is not correct, please explain and correct. If correct, please explain why this is appropriate.

8.2-CCC-12
Ref: Ex. 8/2/3/Attachment 5/p. 8

CA Energy Consulting notes that peak demand, although currently not in use in billing GS customers at EGI, offers an advantage of increasing accuracy in matching bills to cost to serve but bears the disadvantages of additional administrative cost and possibly increased bill complexity. We explore these issues below, in an effort to provide EGI with sufficient information to determine whether such a metering and billing strategy would be cost effective.

Please further explain the commentary regarding this being a metering strategy. As part of the response, please discuss whether CA Energy Consulting believes that more advanced metering is needed to implement design day demand-based cost recovery.

8.2-CCC-13
Ref: Ex. 8/2/3/Attachment 1/pp. 43-44
Ex. 8/2/3/Attachment 5/pp. 10, 12-13

a) (Attachment 1 / P. 43-44) Please provide the percentage of total customers that are served by 0.5-inch pipe connections.

b) (Attachment 5 / P. 10) Based on the data available, please explain how CA Energy Consulting knows that the majority of customers that are served by 0.5-inch pipe connections have 200 acfh class meters.

c) (Attachment 5 / P. 10) “While data on the types of connections for customers are not universally available, there is sufficient information to support a rate class boundary decision based on the information from the large quantity of customer consumption data. In brief, the boundary is not determined by connection information, but is chosen such that customers with common connection types - 1/2-inch pipe and 200 or 400 acfh-class meters—generally will be in the Small Demand/Small Volume class using the DDD metric.”

Please further explain whether the rate class boundary was set using consumption/volumetric data or customer connection information.

d) Please explain the linkage between, and provide the conversion calculation for:

i. The 15,000 m^3 annual consumption boundary and the 150 m^3/day design day demand boundary.

ii. The 1,081 m^3 annual consumption and the 10.97 m^3/day design day demand for a small LEGD R1 customer.

iii. The 5,048 m^3 annual consumption and the 51.24 m^3/day design day demand for a large LEGD R1 customer.

iv. The 2,400 m^3 annual consumption and the 24.36 m^3/day design day demand for a small LEGD R1 customer.

e) With respect to the “typical E01 customer” to be used for bill impact presentment purposes in the harmonized rate class and SFVD proposal, please advise whether Enbridge Gas intends to use 24.36 m^3/day as the representative customer and provide rationale. If not, please provide the design day demand for the typical E01 customer that will be used for bill impact presentment purposes.

<u>8.2-CCC-14</u>

Ref: Ex. 8/2/3/Attachment 5/p. 28

a) Please further explain the statement that the SFVD rate design properly handles load factor variation from a cost coverage standpoint.

b) Please further explain the statement regarding the traditional volumetric rate design "requiring a declining block structure for distribution cost recovery that may not be well matched to cost to serve." As part of the response, please explain the problems with a declining block structure in a cost recovery context.

<u>8.2-CCC-15</u>

Ref: Ex. 8/2/3/Attachment 5/pp. 33,

a) With respect to the Toronto-area customer design day demand example at Figure 10, please:

i. Provide the monthly volumes used in the regression

ii. Provide the monthly HDDs used in the regression

iii. Provide the customer's load factor.

b) Please provide the design day HDDs for each weather region/zone/location that is being used in CA Energy Consulting's GS customer-specific design day demand derivation.

<u>8.2-CCC-16</u>

Ref: Ex. 8/2/3/Attachment 5/pp. 29-31, 35

Atlanta Gas Light (AGL), applies a Design Day Demand Charge (DDDC) to all of its residential and commercial customers.

a) Please provide references/links to the original application and decision where the DDDC approach was originally proposed and approved for AGL.

b) Please provide additional information regarding the "bucketing" approach applied by AGL to residential customers. As part of this response, please provide the demand range that is applied to each bucket (i.e., the smallest bucket is between $10m^3$/day to $20m^3$/day, the next bucket is between $20m^3$/day to $30m^3$/day, etc.).

c) Please provide AGL's most recent annual regulatory filing regarding its "bucket demand values."

d) With respect to the AGL's manual review of "exceptions", please describe what the outcome of a manual review might be (e.g., accept the new demand figure, reject it and replace it with the previous figure, etc.).

8.2-CCC-17

Ref: Ex. 8/2/3/pp. 28-31
Ex. 8/2/3/Attachment 5/pp. 28-46

Enbridge Gas stated that CA Energy Consultants derived design day demand for each Enbridge Gas general service customer to facilitate SFVD bill determination.

In order to implement SFVD rate design, Enbridge Gas will need to accommodate changes to its billing system to introduce the design demand billing determinant. Further, SFVD rate design requires a platform to derive design demand for each general service customer and to manage exceptions using automated protocols. Enbridge Gas determined that it will utilize the Azure platform to derive design demands for its general service customers and to manage exceptions.

Subject to OEB approval of the SFVD rate design as part of this Application, Enbridge Gas estimates it will need a lead time of approximately 1 to 2 years following the OEB Decision to make changes to its billing processes and systems, as well as to the Azure platform to facilitate derivation of design demands for general service customers billing processes

a) Please advise whether the GS customer-specific design day demands developed by CA Energy Consultants are going to be implemented for ratemaking purposes or are these billing determinants going to be replaced by GS customer-specific design day demands derived by Enbridge Gas using its Azure platform prior to implementation.

b) Regarding the work completed by CA Energy Consultants in determining each GS customer's specific design day demand for SFVD bill determination, please:

   i. Advise whether the regression methodology (including the specific formula) set out at Exhibit 8, Tab 2, Schedule 3, Attachment 5, page 32 was applied. If not, please provide the regression approach and associated formula for the conversion of monthly volumes to an estimated design day demand.

ii. Provide the calendar year(s) that were used to derive each GS customer's design day demand and explain why those year(s) were used. Please discuss why it is preferable to use a single-year or multiple years of data in this derivation.

iii. Discuss whether: (i) only actual consumption data was used; or (ii) both actual and estimated consumption data was used. Please explain why one approach was selected over the other.

iv. Discuss how any issues with limited historical consumption data for a particular customer were addressed.

v. Discuss whether CA Energy Consultants applied a "bucketing" or "deadbanding" approach for GS customers.

vi. Describe, what, if any, modifications to the regression model were made for customers with uncommon demand patterns. For example, did CA Energy Consultants, through model specifications, address the issue that GS customers with high summer load are being assigned a design day demand that is likely understated. If no modifications were made, please explain why and discuss what CA Energy Consultant's considers to be best practices with respect to deriving customer-specific design day demand for customers with uncommon demand patterns that do not fit well within the model.

vii. Discuss whether CA Energy Consultants also applied the "analytical method", as an alternative, to determine the design day demand for each of Enbridge Gas's GS customers (or only a subset of customers). As a comparative example, please provide the output of the "analytical method" using the same Toronto-area customer reflected in Figure 10 (Exhibit 8, Tab 2, Schedule 3, Attachment 5, p. 33).

c) Regarding Enbridge Gas's proposal to determine GS customer-specific design day demand for SFVD bill determination to be implemented in 2027, please:

i. Advise whether Enbridge Gas proposes to apply the regression approach (including the specific formula) set out at Exhibit 8, Tab 2, Schedule 3, Attachment 5, page 32. If not, please explain and provide the approach (and the specific formula) that Enbridge Gas intends to use to determine GS customer-specific design day demand.

ii. Advise what calendar year(s) will be used to derive each GS customer's design day demand and explain why those year(s) will be used. Please discuss why it is preferable to use a single-year or multiple years of data in this derivation.

iii. Discuss whether: (i) only actual consumption data will be used; or (ii) both actual and estimated consumption data will be used. Please explain why one approach was selected over the other.

iv. Discuss how any issues with limited historical consumption data for a particular customer were addressed.

v. Discuss whether Enbridge Gas intends to apply a "bucketing" or "deadbanding" approach for GS customers at the time of implementation. Please explain why Enbridge Gas is, or is not, applying these approaches.

vi. Describe, what, if any, modifications to the regression model will be made for customers with uncommon demand patterns. For example, does Enbridge Gas intend to address, through model specifications, the issue that GS customers with high summer load are being assigned a design day demand that is likely understated.

vii. Discuss whether Enbridge Gas intends to maintain records regarding customers with uncommon demand patterns to facilitate separating these customers from the bulk of the GS population in the future.

viii. Describe the approach that Enbridge Gas intends to take with respect to addressing "exceptions" in the context of its statement that it plans to "manage exceptions using automated protocols." Please discuss whether this is different from the approach taken by AGL.

ix. Provide examples of the automated protocols that will be used to address "exceptions" or other anomalous estimation results.

d) With respect to updates to GS customer-specific design day demands in the years after the initial implementation, please:

   i. Describe Enbridge Gas's proposal for developing design day demands for new customers and discuss whether additional information will be required to be provided by new connecting customers.

   ii. Advise whether, to implement the annual update, an additional year of consumption data will be included in the regression and the oldest annual data will be removed.

8.2-CCC-18

Ref: Ex. 8/2/3/Attachment 7/p. 21

a) Please confirm that Table 2 at Exhibit 8, Tab 2, Schedule 3, Attachment 7, p. 21 is based on the 150m^3/day design day demand boundary.

b) Assuming the 150m^3/day demand boundary and the 15,000 m^3 annual consumption boundary do not precisely align in terms of customer assignments between Rates E01 and E02, please provide the same information as is provided in Table 2 using the alternative 15,000 m^3 annual consumption boundary that would be applied for the traditional volumetric rate design.

c) Please discuss the implications for the cost allocation studies (i.e., do the cost allocation studies need to be revised) and bill impacts if a harmonized rate class approach with a traditional volumetric rate design is applied.

8.2-CCC-19

Ref: Ex. 8/2/3/Attachment 7/pp. 24-32

a) (P. 24-32) With respect to the bill impact decile analysis in the Phase 3 report, please provide the boundary for each decile (in m^3 or m^3/day depending on how the boundaries were established).

b) (P.29) In the context that legacy EGD Rate 1 is a residential class, please describe what type of residential customers would have moderate annual consumption and extremely high design day demand.

c) (P.29) Please advise whether Table 4 is showing that these 14 legacy EGD Rate 1 customers will experience rate increases of 700% under the SFVD proposal.

d) (P.29) Please further explain the statement that these 14 residential customers "would likely qualify treatment as exceptions under the SFVD rate." As part of the response, please explain how these customers' design day demand (and other customers with unusual consumption patterns) would be calculated by Enbridge Gas.

e) (P.30) Please confirm that "Scenario 7.3.2 – 1 RZ – No Mitigation" refers to Enbridge Gas's no regional adjustment scenario.

f) Please confirm that none of the bill impact analysis provided in the Phase 3 report reflect rate mitigation in the manner proposed by Enbridge Gas and described at Exhibit 8, Tab 3, Schedule 6.

8.2-CCC-20

Ref: Ex. 8/2/3/Attachment 7/pp. 33, 37-39, 55

a) With respect to the pricing information provided in Tables A1.1 to A1.3 and the bill impact information provided in Appendix II, please explain in more detail what is being compared. As part of this response, please provide which rate zone alternative, if any, is being used as the basis for the pricing information.[1] Please also advise whether the bill impact analysis is designed to isolate the impact of only the change in rate design (i.e., from the current rate design to the new rate design) and does not reflect any changes to revenue requirement or cost allocation.

b) With respect to the bill impact information provided in Appendix III, please explain in more detail what the rate zone-specific bill index is being compared against. Please also confirm that this rate zone analysis is based on the SFVD rate design.

c) Assuming Appendix III provides bill impacts for each representative customer by rate zone alternative based on the SFVD rate design, please provide similar bill impact analysis using the traditional volumetric rate design instead.

[1] The pricing information appears to match the One Rate Zone option except for the transportation rate.

d) In Table A3.1b, please confirm that the “Two SAs (One Distribution) with Transmission Adjustments” columns showing East and Central align with Enbridge Gas’s proposal for the North and South Rate Zones under this Rate Zone alternative.

e) Please advise whether the column titled, “Current Rate Zones with Pan/St. Clair Split” is referring to the One Rate Zone option with Panhandle / St. Clair split.

8.2-CCC-21

Ref: **Ex. 8/2/3/Attachment 1**
Ex. 8/2/3/Attachment 7/Appendix I
Ex. 8/2/3/Attachment 8/p. 17
Ex. 8/2/9/Attachment 2
Ex. 8/2/12/Attachment 2
Ex. 8/2/16/Attachment 2

a) For Rate E01 in all rate zone alternatives, please provide tables showing a comparison of the SFVD-derived rates and the equivalent rates using a traditional volumetric rate design (similar to the SFVD and “Vol” pricing information provided at Exhibit 8, Tab 2, Schedule 3, Attachment 7, pp. 37-39).

b) With respect to the current rate zone option, please confirm that the rates set out in Exhibit 8, Tab 2, Schedule 15, Attachment 2 are the proposed 2024 rates under this rate zone alternative.

c) Using the Rate E01 decile analysis at Exhibit 8, Tab 2, Schedule 3, Attachment 8, p. 16, please provide the following information about the average (or typical) customer in each of the 10 deciles in each former rate zone:

i. Monthly volumes for the year(s) analyzed by CA Energy Consultants

ii. Monthly HDDs for the same year(s) and from the same region/zone that the volumes were consumed

iii. The estimated design day demand (i.e., the demand billing determinant)

iv. Load Factor

v. A description of the likely characteristics of the customer (e.g., residential/commercial/institutional, types of installed gas appliances, likely end use, etc.) to the extent that this can be determined.

d) To the extent that the representative customers listed in Tables A3.1a, A3.3a, and A3.5a are different from those requested in part (c) above related to the decile analysis, please provide for each representative customer:

i. Monthly volumes for the year(s) analyzed by CA Energy Consultants

ii. Monthly HDDs for the same year(s) and from the same region/zone that the volumes were consumed

iii. Load Factor

iv. A description of the likely characteristics of the customer (e.g., residential/commercial/institutional, types of installed gas appliances, likely end use, etc.) to the extent that this can be determined.

<u>8.2-CCC-22</u>

Ref: Ex. 8/2/6
Ex. 8/2/2/Attachment 1
Ex. 8/2/9/Attachment 18
Ex. 8/2/9, 12 and 15/Attachment 10

a) Please confirm that all the customers in Rate E62 are natural gas distributors.

b) With respect to the wholesale bundled contract service-related rate mitigation, please confirm that the reduced costs for Rate E62 are funded by customers in Rates E01, E01, E10, E30, and E34.

c) Please confirm that the bill impacts for small Rate 1/01/M1 customers set out in the following table are accurate (with no federal carbon charge included on the total bill). If not, please correct the table.

Small Customer - Rate 01 / 1 / M1	Bill Impact % (Excl. Fed Carbon Charge)	
	Proposed (One Zone)	Proposed Mitigated (One Zone - Rider R)
EGD	0.70%	1.74%
Union		
North East	-19.51%	-18.58%
North West	-4.96%	-3.86%
South	6.42%	2.84%

d) Please confirm that the Rate Mitigation Rider (Rider R) was calculated in the application based on reducing bill impacts, on average, for a legacy rate class to 2% with reference to the total bill impacts inclusive of federal carbon charges.

e) In the context of the elimination of the federal carbon charge, please advise whether Enbridge Gas intends to maintain its Rate Mitigation Rider (Rider R) proposal as filed, which now with the exclusion of federal carbon charge, does not appear to exactly match its upper boundary of 2% bill impacts on average for a legacy rate class. If Enbridge Gas intends to change its proposal to maintain the 2% upper boundary for total bill impacts (to reflect the elimination of the federal carbon charge), please file an updated proposal.

f) Please confirm that the Rate Mitigation Rider (Rider R) is funded through a base rate adjustment, which collects additional revenues from customers in the same rate classes as the customers that will receive the mitigation rider (i.e., Union South general service customers are receiving the mitigation credit from EGD and Union North general service customers in Rates E01 and E02).

g) Please explain why Enbridge Gas appears to have limited the recovery of Rider R-related mitigation costs to customers in the same rate classes as those that receive the Rider R credits. As part of the response, please discuss the reasons for the apparent difference in approach between the wholesale bundled contract services-related rate mitigation (recovered from multiple rate classes and provided to a different rate class) and the Rider R mitigation.

h) Please provide an alternative Rider R mitigation approach that allows for the collection of Rider R funding from all rate classes and generally applies the same boundaries as used in Enbridge Gas's proposal (i.e., seeking to reduce Year 1 bill impacts that are over 2% on average for current rate classes).

i) Please confirm that Enbridge Gas expects that rate mitigation, at some level, would be required for some small volume customers in the Two Rate Zone (One Dist.) (e.g., EGD East – Rate 1) and Current Rate Zone (e.g., Union South – M1) alternatives.

8.2-CCC-23

Ref: Ex. 8/2/9-15/Attachment 1
Ex. 8/2/2/Attachment 1

a) Please advise whether the rate design adjustments (Column G) are related to the rate mitigation proposal for Rate E62 as derived at Exhibit 8, Tab 2, Schedule 2, Attachment 1 (Line 14).

b) For the rate class-specific rate design adjustments (Column G) that are not shown (or alternatively, do not match the base rate adjustments) at Exhibit 8, Tab 2, Schedule 2, Attachment 1 (Line 14) (e.g., Rate E34), please explain what is reflected in those rate design adjustments (and provide references to where those rate design adjustments are derived in the application).

c) Please confirm that the Rider R-related mitigation is not shown in the "Summary of Proposed Revenue Change by Rate Class" schedules.

8.2-CCC-24

Ref: Ex. 8/2/9-14/Attachment 2

a) Please explain how the total delivery demand charge forecast usage for the general service rate classes was derived (Column A).

b) Please explain how the total delivery contract demand charge for the contract rate classes was derived (Column A).

c) With respect to the total delivery demand charge forecast for general service customers, please explain how this level of total demand aligns with the allocators that use design day demand as part of the allocation formula (e.g., "NETFROMSTOR").

8.2-CCC-25

Ref: Ex. 8/2/9-15/Attachment 10

a) Please explain the difference between the Line titled, “Total Bill – Bundled Direct Purchase” and “Bundled Direct Purchase Impact.”

<u>8.4-CCC-26</u>

Ref: Ex. 8/4/2/p. 24

Enbridge Gas noted that the proposal to eliminate consolidated billing is revenue neutral as the Phase 3 2024 Test Year Forecast used to derive the general service monthly customer charges reflects the adjusted customer count.

a) Please confirm that this means that the 1,300 customer meters that were previously billed on a consolidated basis are now treated as 1,300 separate customers for cost allocation and rate design purposes.

<u>8.4-CCC-27</u>

Ref: Ex. 8/4/7/p. 23

a) Please provide the impact, in dollars and percentage, of changes to the cost allocation and rate design for interruptible services relative to the existing costs recovered from interruptible customers.

<u>9.1-CCC-28</u>

Ref: Ex. 9/1/2/pp. 9, 11

a) Please advise whether, currently, load balancing costs (including any true-up between actual and forecast) in the EGD rate zone are recovered through delivery rates and are applied to all customers.

b) Please describe the types of costs that are currently considered load balancing in the EGD rate zone.

c) Please explain which types of load balancing costs are currently considered peaking vs. seasonal supplies in the EGD rate zone.

d) Please advise whether, currently, load balancing costs (including any true-up between actual and forecast) in the Union rate zones are recovered through commodity rates and recovered from only system gas customers.

e) Please describe the types of costs that are currently considered load balancing in the Union rate zones.

f) Please further explain the proposed future recovery of load balancing costs. As part of the response, please discuss the types of costs (and variances on forecast costs) will be recorded in the new load balancing account and advise whether these costs will be recovered through gas supply or delivery rates.

g) Please explain the separation, in terms of the types of cost (and variances on forecast costs) that will be recorded, between the proposed Load Balancing Price Account and the proposed market-based storage account.

h) Please describe the proposed rate design for recovery of the costs recorded in the new market-based storage account.

<u>9.1-CCC-29</u>
Ref: Ex. 9/1/3/p. 4

a) Please provide an illustrative example of the revenue variance calculation that will be performed for a customer that switches classes relative to their forecast rate class. As part of the response, please show whether variances in demand (or consumption if a volumetric rate design is used) relative to forecast is trued-up.