ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit A1, List of Evidence

Question:

a) Please confirm the Application conforms fully to the OEB's EB-2017-0307 MAADs Decision and Rate Order.

b) If not, please list all items with evidentiary references, that deviate from the Decision and Rate Order.

c) Please provide a summary of the basis of any of the listed deviations.

Response

a-c) Confirmed. Please see Exhibit I.CCC.4.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit A1

Question:

Please provide the most recent EGI organization chart down to the Director level.

Response

Please see Exhibit I.CCC.3.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit A1, Tab 5, Schedule 2, Conditions of Service Section 6.4.1: Exhibit A1, Tab 5, Schedule 4.

Preamble:

"Federal Carbon Charge
Pursuant to the Greenhouse Gas Pollution Pricing Act (GGPPA), gas distributors are required to pay to the federal government a fixed carbon charge for use and deliveries of natural gas to customers. This charge is billed based on the amount of natural gas consumed by customers other than industrial emitters who are registered under the GGPPA Output-Based Pricing System (OBPS). For any fixed carbon and OBPS charges that Enbridge must pay to the federal government for its transmission and storage facilities, these charges are included in the "Delivery to You" item on the bill.

Question:

a) Please confirm (with reference) the Decision/Directive to include the Federal Carbon Charge in the "Delivery to You" item of the Customer Bill.

b) Clarify if/how this Directive differs to the presentation of the prior Cap and Trade GHG item.

c) Please provide an estimate of the amounts of the charge (monthly/yearly) for Residential Customers in EGD and Union Rate Zones and compare to the 2017/2018 Cap and Trade charge.

Response

a) On January 11, 2019 Enbridge Gas filled an application with the Board related to the Federal Carbon Pricing Program.[1] Enbridge has requested approval from the Board to add Federal Carbon Charge as a separate line item on customer bills, which will reflect the charge on the customers natural gas use / consumption. Enbridge has also requested approval from the Board to add a Facility Carbon Charge, which will

[1] EB-2018-0187/EB-2018-0205

reflect the charge on company use volumes and costs related to the Output Based Pricing System ("OBPS") for the Company's transmission and storage facilities. Enbridge Gas has proposed that the Facility Carbon Charge would be included in the "Delivery to You" item on the customer bill. At this time, there is no Decision/Directive related to how the federal carbon charge would be shown on the bill. However, the Minister of Energy, Northern Development and Mines encouraged the Board in a letter issued on February 20, 2019 to ensure a transparent process around the implementation of the federal carbon charge on natural gas bills that provided opportunity to consider stakeholder input. Subsequently, on April 3, 2019, the Board issued its procedural order on the federal carbon charge which includes the opportunity for stakeholder comment around the bill presentment matter.

b) See response to a). For clarity, the Board made a decision in Cap and Trade that the customer and facility related costs associated with that program would be included within the "Delivery to You" line item.[2]

c) Please see Attachment 1.

[2] EB-2015-0363 OEB Determination regarding Billing of Cap and Trade Related Costs and Customer Outreach, July 28, 2016, page 5.

ENBRIDGE GAS INC.

Typical Residential Bill Impact of the Proposed Federal Carbon Pricing Program and the 2017/2018 Cap-and-Trade Compliance Plan

Line No.	Particulars ($)	Rate (cents/m^3)	January	February	March	April	May	June	July	August	September	October	November	December	Annual Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n) = sum(b:m)
	EGD Rate Zone														
	Rate 1														
1	Consumption Volumes (m^3)		419	404	354	252	158	69	51	54	58	91	174	316	2,400
2	Proposed Federal Carbon Charge (1)	3.9100	16.38	15.80	13.84	9.85	6.18	2.70	1.99	2.11	2.27	3.56	6.80	12.36	93.84
3	Proposed Facility Carbon Charge (1)	0.0036	0.02	0.01	0.01	0.01	0.01	-	-	-	-	-	0.01	0.01	0.08
4	Total	3.9136	16.40	15.81	13.85	9.86	6.19	2.70	1.99	2.11	2.27	3.56	6.81	12.37	93.92
5	Cap-and-Trade Customer-Related Charge (2)	3.3181	13.90	13.41	11.75	8.36	5.24	2.29	1.69	1.79	1.92	3.02	5.77	10.49	79.63
6	Cap-and-Trade Facility-Related Charge (2)	0.0337	0.14	0.14	0.12	0.08	0.05	0.02	0.02	0.02	0.02	0.03	0.06	0.11	0.81
7	Total	3.3518	14.04	13.55	11.87	8.44	5.29	2.31	1.71	1.81	1.94	3.05	5.83	10.60	80.44
	Union Rate Zones														
	Rate 01 and Rate M1														
8	Consumption Volumes (m^3)		385	403	332	200	114	64	48	46	48	106	158	295	2,200
9	Proposed Federal Carbon Charge (3)	3.9100	15.05	15.74	12.99	7.83	4.47	2.49	1.89	1.81	1.89	4.13	6.19	11.53	86.01
10	Proposed Facility Carbon Charge (3)	0.0084	0.03	0.03	0.03	0.02	0.01	0.01	-	-	-	0.01	0.01	0.02	0.17
11	Total	3.9184	15.08	15.77	13.02	7.85	4.48	2.50	1.89	1.81	1.89	4.14	6.20	11.55	86.18
12	Cap-and-Trade Customer-Related Charge (4)	3.3181	12.77	13.36	11.02	6.64	3.80	2.12	1.61	1.53	1.61	3.50	5.26	9.78	73.00
13	Cap-and-Trade Facility-Related Charge (4)	0.0240	0.09	0.10	0.08	0.05	0.03	0.02	0.01	0.01	0.01	0.03	0.04	0.07	0.54
14	Total	3.3421	12.86	13.46	11.10	6.69	3.83	2.14	1.62	1.54	1.62	3.53	5.30	9.85	73.54

Notes:
(1) EB-2018-0187/EB-2018-0205, Exhibit E, Tab 1, Schedule 1, p.3.
(2) EB-2016-0300, Decision and Rate Order, Appendix D, p. 1.
(3) EB-2018-0187/EB-2018-0205, Exhibit E, Tab 2, Schedule 1, p.3.
(4) EB-2016-0296, Rate Order, Appendix A, p. 1, column (c), lines 13 & 14 and p. 7, column (c), lines 6 & 7.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 1, Schedule 1, Pages 3 and 5, Tables 2 and 3

Question:

Please provide a copy of the Statistics Canada Table 36-10-0106-01 (formerly Can Sim 380-066) GDPPI quarterly for 2017 and 2018

a) Please provide the calculations resulting in the values in Table 3.

b) Please provide the equivalent calculations for 2018.

c) Please provide a version of Table 2 using the 2018 Inflation Factor.

Response

The GDP IPI FDD quarterly index for the years 2017 and 2018 obtained from the Statistics Canada Table 36-10-0106-01 are summarized in tables below for both parts a) and b) of the answer:

a) Annual % Change in GDP IPI FDD for 2017:

Year	Quarter	Index	Year Over Year Change	Annual %	Average % Change
2016	Q1	116.5			
2016	Q2	116.4			
2016	Q3	116.9			
2016	Q4	117.5			
2017	Q1	118.0	1.5	1.29%	
2017	Q2	118.5	2.1	1.80%	
2017	Q3	118.2	1.3	1.11%	
2017	Q4	119.0	1.5	1.28%	1.37%

b) Annual % Change in GDP IPI FDD for year 2018

Year	Quarter	Index	Year Over Year Change	Annual %	Average % Change
2017	Q1	108.0			
2017	Q2	108.5			
2017	Q3	108.3			
2017	Q4	109.0			
2018	Q1	109.4	1.4	1.30%	
2018	Q2	109.9	1.4	1.29%	
2018	Q3	110.6	2.3	2.12%	
2018	Q4	111.1	2.1	1.93%	1.66%

c) The calculated Price Cap Index using the 2018 Inflation factor is shown below:

	Price Cap Index
Inflation factor	1.66%
Less: Productivity Factor	0.00%
Less: Stretch Factor	0.30%
Price Cap Index	1.36%

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 1, Schedule 1, Page 12- AUTVA (Enbridge) and NAC (Union);

Question:

EGD Rate Zones
Exhibit F1, Tab 1, Rate Order, Working Papers, Schedule 10

a) Please show Graphically, for Rate 1 and Rate 6, the average use for the last 10 years and for the forecast period. Please provide a comment on the accuracy of the model and trends.

b) Please provide a status report on the review of Average Use models for EGD as agreed in the EB-2017-102, Settlement at Exhibit N1, Tab 1, Schedule 1, page 8

Union Rate Zones
Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 13.

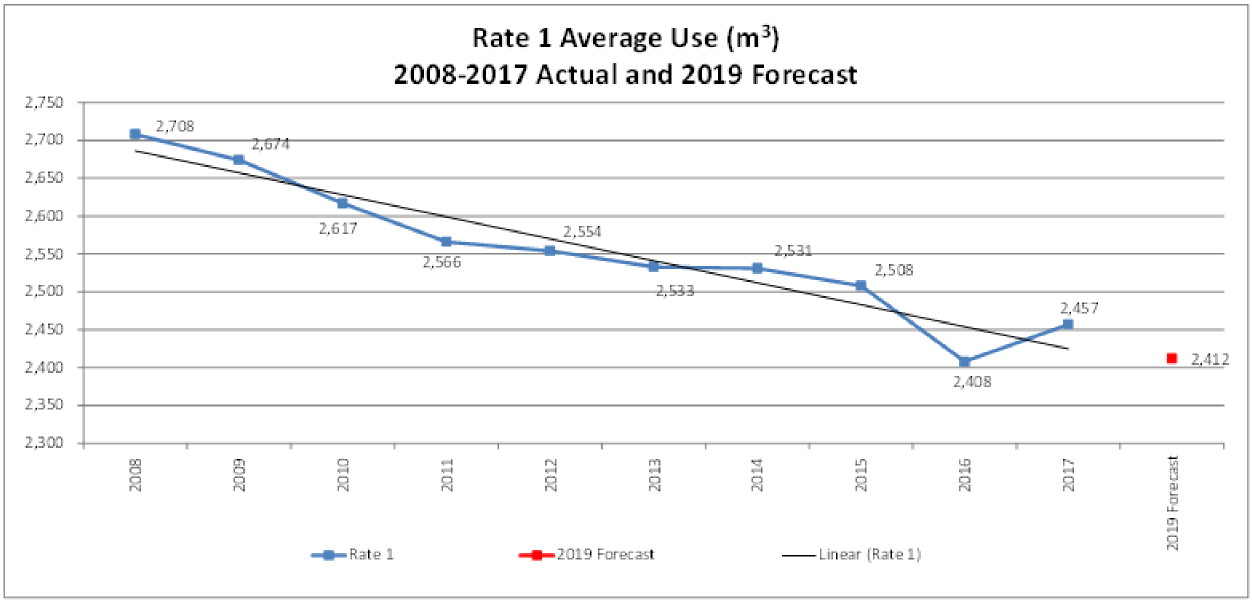
c) Please show Graphically for Rate M1 and M2, the average use for the last 10 years and for the forecast period. Please provide a Comment on the accuracy of the model and trends.

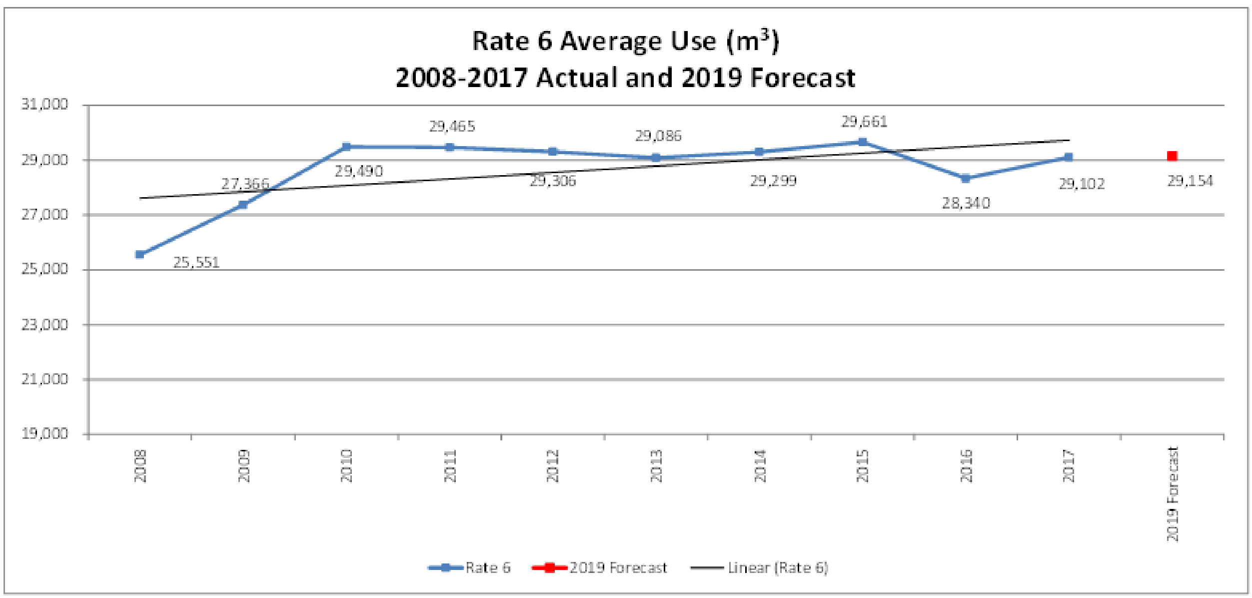
d) Please provide a status report on the review of Average Use models for Union as in the EB-2016-0118 Settlement paragraph 12.

Response

a) The Rate 1 and 6 average uses that are normalized to 2019 Board approved degree days are shown in the charts below.

The 2019 forecast is developed using the data up to 2017. During the last 10 years Rate 1 average use declined 9.3% from 2,708 m3 in 2008 to 2,457 m3 in 2017. Rate 6 in the same period increased 13.9% from 25,551 m3 in 2008 to 29,102 m3 in 2017. For accuracy results, please see Exhibit I.STAFF.5, part a) Table 1, which provides the 10-Year history of Normalized Actual vs. Board-Approved average uses. Out-of-sample average percentage variance over the last 10 years is -0.5% for Rate 1 and 0.5% for Rate 6. The results support the view that the General Service average use forecasting methodology continues to be a reliable predictor for General Service average use.





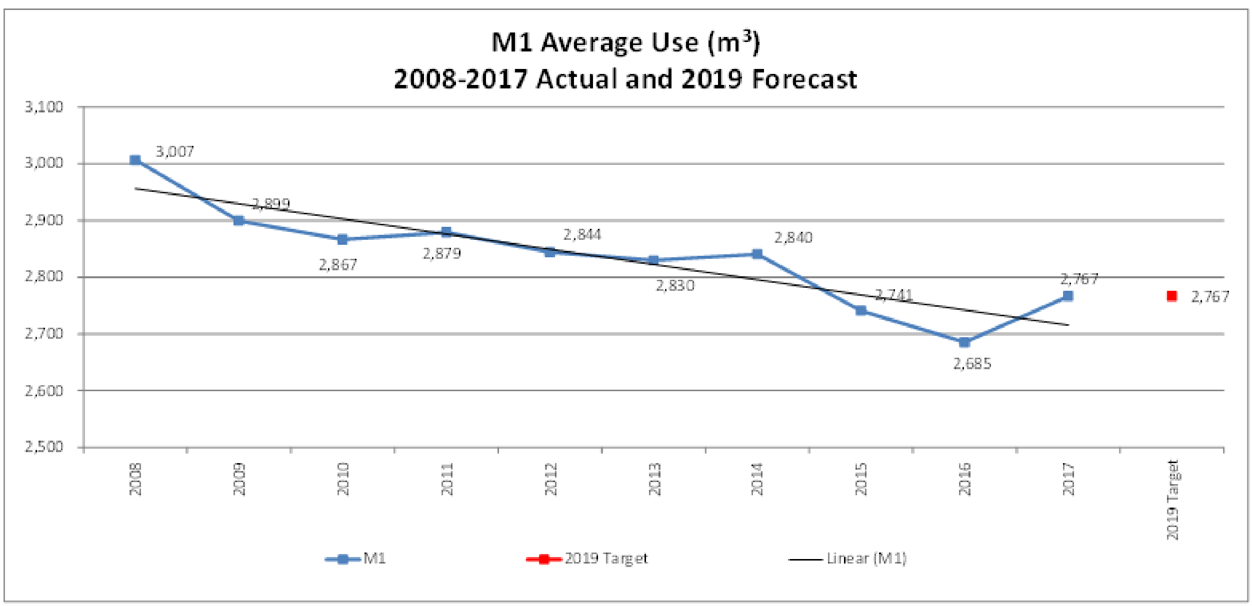
b) As per the Board's Decision and Order in the MAADs and Rate Setting Mechanism proceeding, Enbridge Gas will develop a proposal for the average use methodology for its next rebasing application.[1]

c) The weather normalized average use at the 2019 Board approved normal, for Rate M1 and Rate M2 are shown in the charts below.

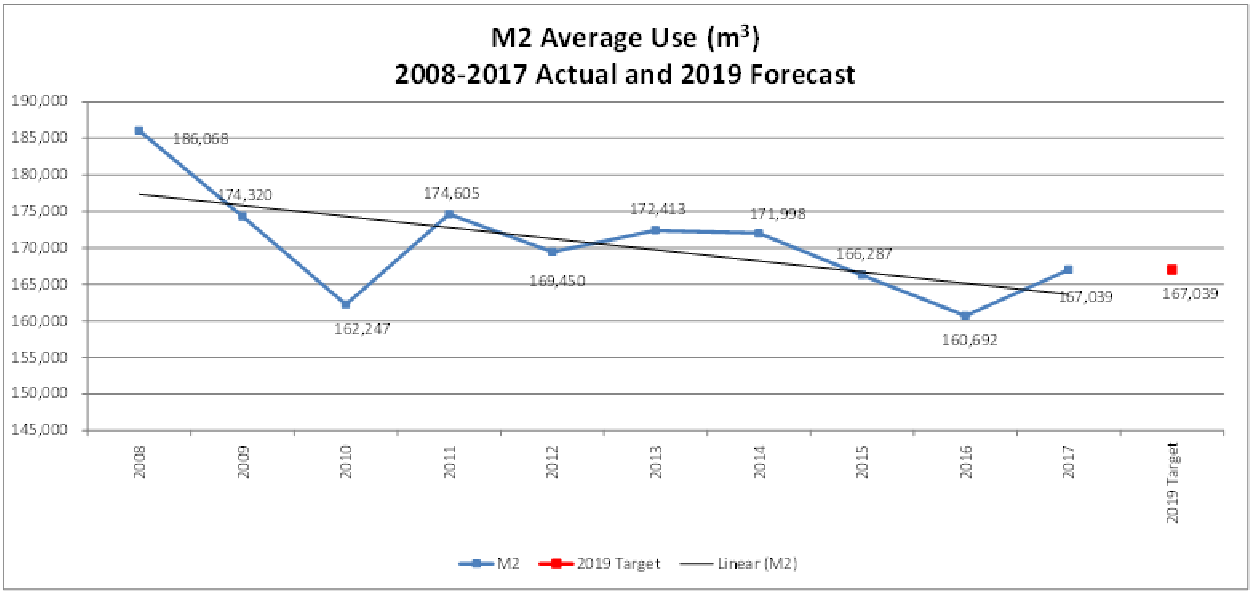
Over the last 10 years, Rate M1 NAC declined 8.0% from 3,007 m3 in 2008 to 2,767 m3 in 2017. Rate M2 NAC for the same period decreased 10.2% from 186,068 m3 in 2008 to 167,039 m3 in 2017.

When adjusting rates each year for changes to NAC, Union applies the most recent actual NAC for each rate class, calculated using the Board-approved 50:50 weather normal for the forecast year. For 2019 rates, 2017 actual NAC calculated using the 2019 weather normal is used for each rate class.

Because of actual customer behavior in each rate class, there has been some variability from year to year in the actual NAC, with an overall declining trend. Enbridge Gas is currently evaluating methodologies regarding NAC forecasting, and will file a proposal with its next rebasing application.



[1] EB-2017-0306/EB-2017-0307 Decision and Order, dated August 30, 2018.



d) Please see the response to part b).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 1, Schedule 1, Page 14, Table 4, Appendices A&B

Question:

a) Please provide a redline comparison of the existing EGDI and Union ESM DAs and new EGDI ESMDA.

b) Please explain in detail the changes to the dead band threshold and sharing for each Rate Zone.

c) Please provide examples of the ESM calculations for 2019 using 0 -300 bps excess earnings

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Response

a) Enbridge Gas's ESMDA is a new deferral account, distinct from the earnings sharing mechanism deferral accounts used prior to 2019 for each of the legacy utilities. It is not an update of the existing EGD and UGL ESMDAs, therefore a redline comparison has not been attached.

   Please see Exhibit I.STAFF.19 for a revised Enbridge Gas ESMDA accounting order.

b) Commencing in 2019, Enbridge Gas will calculate earnings sharing based on the utility results for the amalgamated company. In accordance with the MAADs decision, earnings sharing will be calculated on actual utility results (not normalized), and earnings in excess of 150 basis points above the Board approved ROE will be shared 50/50 between ratepayers and the Company.

   Under EGD's 2014 – 2018 Custom IR plan, if the actual utility ROE, calculated on a weather normalized basis, was greater than the Board approved ROE, the excess earnings were shared 50/50 between ratepayers and EGD.

   Under Union's 2014 – 2018 Price Cap plan, if the difference between the actual (not normalized) utility ROE and the Board approved ROE was greater than 100 basis points, but less than 200 basis points, the excess earnings were shared 50/50 between ratepayers and Union. If the difference between the actual utility ROE and the Board approved ROE exceeded 200 basis points, the excess over 200 basis points was shared 90/10 between ratepayers and Union.

c) The requested information is not relevant to the relief being sought. Enbridge Gas does not have a combined ESM calculation model at this time.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 1, Schedule 1, Page 26; Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 16, pp. 4-5.

Preamble: "*Enbridge Gas proposes a one-time adjustment of ($10.4) million associated with the capital pass through projects ("Projects") that were included in rates as a Y factor during Union's 2014-2018 IRM term. The proposed adjustment represents the difference between the 2018 Project revenue requirement of $127.6 million included in Union's Board-approved 2018 rates and the 2019 forecast Project revenue requirement of $117.2 million."*

Question:

a) Please confirm that the costs of the projects and adjustments are subject to prudence review.

b) When will this review occur?

Response

a) Not confirmed, the one-time adjustment is not subject to a prudence review.

b) Any prudence review of the final capital pass through capital expenditures should take place at rebasing.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 1, Schedule 1, Page 29

Preamble: "*Enbridge Gas has added 30,393 GJ/d of project demands to the allocation of the 2019 project costs and to the derivation of the 2019 Rate M12/C1 Dawn-Parkway demand rate as part of this application. As the revenue of the surplus capacity will be built into 2019 rates, there is no longer a requirement to track the revenue associated with the surplus capacity in the project deferral account.*"

Question:

a) Please provide a schedule with the term(s) and prices realized for the surplus capacity (names other than EGI affiliates omitted).

b) Please provide a Comparison of the annual revenue and average unit costs to the M12/C1 rates.

c) Please provide references for data/calculations.

Response

a) Please see Exhibit I.STAFF.11, part (a).

b) Please see Exhibit I.LPMA.3, part (b).

c) Please see Exhibit I.LPMA.3, part (b), Attachment 1.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 1, Schedule 1, Page 30, Table 11 and Appendix E

Preamble: *"Enbridge Gas proposes to adjust the customer-related cost variance for the Union rate zones in proportion to the current approved revenue, assuming the monthly customer charge revenue is recovered in the first delivery block of the volumetric delivery charges."*

Question:

a) Please provide clarity on the pathway and endpoint for M1 and M2 customer charges over the 5-year period.

b) Please explain how is it appropriate in the context of rate design principles, that by adjusting the first delivery rate block to include the monthly customer charge revenue, the bill impacts are more consistent for each customer within the rate class regardless of annual volumes consumed.

c) Are there similar rate design/customer charge changes contemplated for EGDI Rate zones?

Response

a) Enbridge Gas is not proposing any changes to the level of monthly customer charges for Rate M1 and Rate M2 in 2019.

b) By adjusting the first delivery block to include the monthly charge revenue, such revenue is then recovered from all customers, as all customers consume volumes within the first delivery block. This proposal is similar / analogous to the recovery of the monthly customer charge, which is paid by all customers regardless of volumes consumed. The proposal also addresses the significant bill impacts for certain Rate M1 and Rate 01 customers, which is also a rate design consideration.

c) There are no proposed changes to the EGD rate zone monthly customer charges for general service customers in 2019.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 1, Schedule 1, Page 33 and pages 41-46 Appendix I; Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 11.

Preamble: *"The MAADs Decision requires Enbridge Gas to track actual costs and amounts recovered through rates related to the PDO during the deferred rebasing period for review at the time of rebasing.*
Enbridge Gas proposes to update the allocation of the PDO and PDCI demand-related costs based on the 2019 Dawn-Parkway design day demands and the allocation of the in-franchise compressor fuel costs based on 2019 forecast volumes."

Question:

a) Please provide a schedule that summarizes the total allocation of 2019 PDO and PDCI costs and bill impacts for each of the four EGI rate zones, as provided in the evidence at pages 43/44. Provide explanatory notes.

b) When/how will EGI/Union report on the PDCI volumes and balances?

c) If there are differences between the forecast in rates and actuals, how will these be addressed?

d) Given the utility restructuring and that:*"As of November 1, 2017 the initial Parkway shortfall has been fully eliminated as a result of Dawn to Kirkwall turnback, and therefore Union did not need to take action to manage the shortfall".*
Why should the PDO continue for the next 5 years? Please discuss.

Response

a) Please see Table 1.

Table 1
UNION RATE ZONES
PDO and PDCI Costs and Residential Bill Impacts

Line No.	Particulars	PDO and PDCI Costs Allocation (1) ($000's)	Residential Customer Bill Impact (2) ($)
		(a)	(b)
1	Union North West	1	0.00
2	Union North East	9	0.03
3	Union South	23,861	8.67
4	Union Ex-franchise – EGD	214	0.06
5	Union Ex-franchise – Other	638	
6	Total	24,723	

Notes:
(1) The allocation of PDO and PDCI related costs is provided at Exhibit F1, Tab 2, Working Papers, Schedule 11, p. 1.
(2) Based on a typical residential customer annual consumption of 2,200 m^3 in the Union rate zones and 2,400 m^3 in the EGD rate zone.

b) Enbridge Gas does not report on PDCI volumes and balances.

c -d) The Board determined in the MAADs and Rate-Setting Mechanism Decision and Order that PDO will be reviewed at the time of rebasing.[1]

[1] EB-2017-0306 EB-2017-0307 Decision and Order, September 17, 2018, page 48 and 49.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 1, Schedule 1, Page 40 and Appendix H

Preamble: *"The MAADs Decision requires Enbridge Gas to track actual costs and amounts recovered through rates related to the PDO during the deferred rebasing period for review at the time of rebasing.*
Enbridge Gas proposes to update the allocation of the PDO and PDCI demand-related costs based on the 2019 Dawn-Parkway design day demands and the allocation of the in-franchise compressor fuel costs based on 2019 forecast volumes."

Question:

a) Is the Feasibility Study filed for Board Approval or information?

b) What changes are there to the Connection Policy Guidelines? Please list any major amendments.

c) Are the Policy/Guidelines applicable to all EGI rate zones?

d) What conclusions should existing ratepayers reach from the feasibility analysis regarding cost consequences of infill projects and Community Expansion projects? Please discuss.

Response

a) Enbridge Gas filed the referenced exhibit for information to the Board in compliance with its commitment made in the 2017 ESM Proceeding, EB-2018-0131. In this proceeding, Enbridge Gas committed to file evidence about the refined feasibility analysis approach for residential infill customers.

b) The change to the Connection Policy Guidelines can be found in Exhibit B1, Tab 1, Schedule 1, Appendix H, page 2, paragraph 9.

c) Please see Exhibit I.STAFF.2, part e).

d) The new approach for determining the economic feasibility of infill services is intended to improve the accuracy of project feasibility calculations. Accurate project feasibility ensures that under contributing projects pay an appropriate amount of contribution (“CIAC”) without causing undue burden on existing ratepayers, an objective of the Board’s E.B.O.188 guidelines for determining the economic feasibility of gas distribution system expansion.

Since the Company’s approach to the determination of the economic feasibility requires system expansion projects to achieve a Profitability Index value of 1.0 or greater there is little, if any, opportunity for existing ratepayers to subsidize the expansion of the Company’s gas distribution system with respect to the addition of new customers. The same holds true for community expansion projects, except that such projects may receive financial assistance from the exiting ratepayers as provided for in Bill 32, the Access to Natural Gas Act, 2018 and its accompanying regulation (Ontario Regulation 24/19).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 2, Schedule 1, Page 9 and Table 4

Preamble: "*The Board's ICM materiality threshold calculation results in a 2019 threshold value of $468.513 million for the EGD rate zone and $375.2 million for the combined Union rate zones. The materiality threshold establishes the minimum capital expenditures a utility must fund through base rates. The maximum incremental capital investment eligible for ICM funding is the amount of capital expenditures in the year in excess of the threshold value.*"

Question:

a) Please confirm that per Table 4 the ICM calculation assumes a rate increase for the PCI for 2019 for EGD of 1.07% and Union of 0.72%.

b) Why is EGI proposing a PCI arithmetic average based in the 5-year deferred rebasing period, as opposed to a forecast of expenditures and base rates over the period? Please explain and discuss the options considered.

c) Please explain why a combined consolidated EGI ICM threshold is not more appropriate.

Response

a) The 2019 ICM threshold calculation assumes that, for the EGD rate zone, rates will increase by 1.07% from its 2018 Board Approved rates. For the Union rate zones, the ICM threshold calculation reflects that rates have been increasing at an average of 0.72% since its 2013 Board Approved rates.
Please see Exhibit I.LPMA.12 for the calculation of the average PCI for the Union rate zones.

b) Please refer to:
   - Exhibit B1, Tab 2, Schedule 1, Page 10 and Page 11
   - Report of the OEB EB-2014-0219 "New Policy Options for the Funding of Capital Investments: Supplemental Report" January 22, 2016, page 16

- Decision Order: EB-2017-0306/EB-2017-0307, pages 32, 33

The amalgamation and rate setting mechanism approved by the Board for EGD and Union includes the use of the ICM mechanism for the funding of incremental capital.

The ICM materiality threshold formula estimates the threshold value for multiple years ahead of the base year. The multi-year formula requires that both the growth factor “g” and the PCI factor, be annualized. The proposed annualized PCI is calculated as the arithmetic average since the base year.

c) Please see Exhibit I.VECC.7.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 2, Schedule 1, Pages 12 and 13

Preamble: *"To determine the 2017 revenue from general service rate classes, Enbridge Gas used the actual customer count and held the normalized average consumption/average use ("NAC/AU") per customer constant with the NAC/AU in base rates. If the NAC/AU is not held constant, then any change in NAC/AU would have to be offset by a proportionally similar rate adjustment to keep the revenue per customer constant. Both the EGD and Union rate zones have deferral accounts that record the revenue impact associated with the difference between the forecast normalized average use per customer embedded in rates and the actual normalized average use experienced during the year."*

Question:

a) Please confirm that the approved methodology for average use adjustments to rates includes 3-year averaging.

b) Please explain why average use per customer should be held constant for ICM growth, rather than using a rolling 3-year average.

c) Please provide a revised calculation of the growth factor using an average 3-year rolling average of average use. Compare to Table 5 using the constant/holding average use approach.

Response

a) No, the approved methodology for average use adjustments does not include 3 year averaging for either the EGD or Union Rate Zones. The average use adjustment to rates reflects:

- For the EGD rate zone: Rate 1 and Rate 6 customers, the change from the latest Board-approved average use (2018 Budget) to the 2019 average use forecast was used. The 2019 forecast was determined using the Board approved methodology.

- For the Union rate zones: Rate M1, Rate M2, Rate 01 and Rate 10, the change from the latest Board approved NAC (2018 Target) to the 2019 Target NAC was used. The 2019 target NAC is based on the latest available actual use (from two years ago) that is normalized to the 2019 weather normal. This methodology was approved during the EB-2013-0202 (Union's 2014 to 2018 IRM Settlement Agreement) and as subsequently modified in EB-2014-0271 (Union's 2015 Rates proceeding).

b) The value of the growth factor ("g") is the % difference in distribution revenues between the most current year and the base year. The revenues are calculated maintaining the base rate constant.

Deferral and Variance Accounts are already in place for NAC and AU for the EGD rate zone and Union rate zones and they respectively to true-up any variances from forecast or target. Enbridge Gas is not proposing that those true-up mechanisms change. Therefore, the growth calculation is net of any AU and NAC changes and the difference in revenue year over year would represent the growth in customers only.

c) As noted in part (b) above, the growth factor is calculated net of average use. Any changes in NAC or AU would be trued up through the deferral and variance accounts and would not impact the growth factor.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 2, Schedule 1, Page 18, Table 8, and Exhibit. B1, Tab 2, Schedule 1, Page 24, Table 8

Preamble: The Schedules show the Total Incremental ICM by rate zone for each of the ICM funded requested projects.

Question:

Does EGI propose to update the data and will there be a process for discovery regarding material changes in cost and timing.

Response

Please see Exhibit I.CCC.12.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 2, Schedule 1, Page 31, Table 11

Question:

a) Please confirm that over the 5 years the net ICM annual revenue requirement (costs and revenue) will vary, based on several factors including timing and the dates of in-service additions (ISAs).

b) Does EGI agree that an ISA RR deferral account for ICM projects, is appropriate to protect ratepayers. If not, please explain why not and/or provide alternatives to an ICM RRVA

Response

a) The Company confirms that the annual revenue requirement for each ICM project could vary from forecast for a number of reasons, which could include variances in the project's costs capitalized into service, and variances in the project's in-service timing.

b) Enbridge Gas has requested an Incremental Capital Module (ICM) Deferral Account for each of the EGD and Union rate zones as per Board policy. As indicated at Exhibit B1, Tab 1, Schedule 1, Page 16, and in each of the draft accounting orders found at Exhibit B1, Tab 1, Schedule 1, Appendix A, page 33, and Appendix B, page 34, the purpose of each of the accounts is to capture any variances between the actual revenue requirement of approved ICM projects and the actual ICM revenues collected through ICM rates. Given the scope of the proposed ICM deferral accounts, to compare actual ICM project revenue requirements against actual ICM revenues, the impact of any variances in-service addition amounts or timing (from forecast), each of which impact the actual project revenue requirement, will be one of the impacts captured within the ICM deferral accounts.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 2, Schedule 1, Pages 19 to 27

Question:

a) For each of the proposed ICM projects, please provide the detailed itemized cost estimate including contingency with line by line explanations of differences from the costs approved by the OEB in the LTC proceeding. For each project please provide the current Profitability Index ("PI") and compare it to the PI approved by the OEB in the LTC proceeding. Also please indicate if there have been any changes in the route or schedule of any project from the route and schedule approved by the OEB in the LTC proceeding.

b) For each proposed ICM project where there is a significant difference between the cost, PI and route approved by the OEB in the LTC proceeding and the current cost, PI, and route please explain the meaning of the approvals in the LTC proceeding. For example, should not project cost above what was approved in the LTC proceeding be subject to a prudence review?

c) Please recalculate each ICM proposal using project cost approved by the OEB in the LTC proceeding.

Response

a) Don River Replacement

The table below shows the estimated costs provided in the LTC application and the current cost projections.

Item No.	Description	Cost As Filed in EB-2018-0108	Updated Cost Estimate	Variance
		a	b	b-a
1.0	Material Costs	$710,107	$710,107	$0
2.0	Labour Costs	$17,060,285	$17,060,285	$0
3.0	External & Regulatory Costs	$860,000	$1,433,528	$573,528
4.0	Land Costs	$301,000	$2,264,746	$1,963,746
5.0	Overhead Costs	$759,000	$9,989,358	$9,230,358
6.0	Interest During Construction	$208,255	$209,093	$838
7.0	Contingency Costs	$5,698,892	$3,687,764	($2,011,128)
8.0	Total Project Cost	$25,597,539	$35,354,881	$9,757,342

Variances in estimated costs relative to what was filed in the LTC application can be attributed to an increase in the cost related to the required permanent and temporary working easements for the project and the inclusion of indirect overhead costs. Interest during construction was not included in the costs presented in the LTC application. These costs have been included in the “Cost as Filed in EB-2018-0108” column and Contingency Costs have been reduced by an equivalent amount to maintain the overall cost presented in the LTC application.

The table below shows the estimated schedule provided in the LTC application and the current schedule.

Description	Schedule As Filed in EB-2018-0108	Updated Schedule
Expected LTC Approval	December 2018	November 2018
Reciept of Permits and Approvals	December 2018	April 2019
Commence Construction	January 2019	May 2019
Completion of Construction	September 2019	November 2019
Completion of Reinstatement	October 2019	December 2019
Final Inspection	December 2020	January 2021

The current projected in-service date has changed from October 2019 to December 2019 due to delays in receipt of permits and easements which have caused a delay in construction commencement.

The routing of the proposed facilities has not changed from the route identified in the LTC application.

A DCF analysis was not completed for the Don River Replacement project and therefore no PI calculation is available for this project.

Sudbury Replacement

The table below shows the estimated costs provided in the LTC application and the current cost projections.

Item No.	Description	Cost As Filed in EB-2018-0180	Updated Cost Estimate	Variance
		a	b	b-a
1.0	Materials	$5,379,000	$5,379,000	$0
2.0	Construction & Labour	$58,361,000	$67,261,000	$8,900,000
3.0	Contingencies	$9,561,000	$9,561,000	$0
4.0	Interest During Construction	$756,000	$756,000	$0
5.0	Overheads		$12,300,000	$12,300,000
6.0	Total Project Cost	$74,057,000	$95,257,000	$21,200,000

Variances in estimated costs relative to what was filed in the LTC application can be attributed to the inclusion of indirect overhead costs and an increase in contractor costs due to design changes, inclement weather and construction execution.

The table below shows the estimated schedule provided in the LTC application and the current schedule.

Description	Schedule As Filed in EB-2018-0180	Updated Schedule
OEB Filing	May 2017	May 2017
OEB Decision	September 2017	September 2017
Construction Start	May 2018	April 2018
In Service	November 2018	October 2018

There were no significant changes to the project schedule for the Sudbury Replacement project.

The routing of the proposed facilities did not change from the route identified in the LTC application.

A DCF analysis was not completed for the Sudbury Replacement project and therefore no PI calculation is available for this project.

Kingsville Reinforcement

The table below shows the estimated costs provided in the LTC application and the current cost projections.

Item No.	Description	Cost As Filed in EB-2018-0013	Updated Cost Estimate	Variance
		a	b	b-a
1.0	Materials	$7,725,000	$7,725,000	$0
2.0	Construction & Labour	$82,931,000	$82,931,000	$0
3.0	Contingencies	$13,598,000	$13,598,000	$0
4.0	Interest During Construction	$1,462,000	$1,462,000	$0
5.0	Overheads		$15,700,000	$15,700,000
6.0	Total Project Cost	$105,716,000	$121,416,000	$15,700,000

Variances in estimated costs relative to what was filed in the LTC application can be attributed to the inclusion of indirect overhead costs.

The table below shows the estimated schedule provided in the LTC application and the current schedule.

Description	Schedule As Filed in EB-2018-0013	Updated Schedule
OEB Filing	January 2018	January 2018
OEB Decision	September 2018	September 2018
Clearing	March 2019	March 2019
Construction Start	May 2019	May 2019
In Service	November 2019	November 2019

There have been no changes to the project schedule/in-service date since the original LTC application was filed.

The routing of the proposed facilities has not changed from the route identified in the LTC application.

A revised DCF analysis (per EBO 134) has not been completed. The pre-filed evidence for the Kingsville Reinforcement project showed that the project had a positive NPV of between $341 million and $697 million. The increase in costs due to the inclusion of overheads would not have a significant impact on the NPV of the project.

Stratford Reinforcement

The table below shows the estimated costs provided in the LTC application and the current cost projections.

Item No.	Description	Cost As Filed in EB-2018-0306	Updated Cost Estimate	Variance
		a	b	b-a
1.0	Materials	$2,997,000	$2,997,000	$0
2.0	Construction & Labour	$21,620,000	$21,620,000	$0
3.0	Contingencies	$3,623,000	$3,623,000	$0
4.0	Interest During Construction	$300,000	$300,000	$0
5.0	Total Project Cost	$28,540,000	$28,540,000	$0

There have been no changes to estimated project costs since the LTC was filed. Indirect overhead costs were included in the costs filed in the LTC application.

The table below shows the estimated schedule provided in the LTC application and the current schedule.

Description	Schedule As Filed in EB-2018-0306	Updated Schedule
OEB Filing	November 2018	November 2018
OEB Decision	April 2019	March 2019
Construction Start	May 2019	May 2019
In Service	November 2019	November 2019

There have been no changes to the project schedule/in-service date since the LTC was filed.

The routing of the proposed facilities has not changed from the route identified in the LTC application.

Since there are no changes in estimated project costs the DCF analysis (per EBO 134) for the Stratford Reinforcement project has not been updated since the filing of the LTC application.

b) Enbridge Gas interprets the approval associated with LTC applications, Board findings in the MAADs Decision, and the Board’s ICM Policy as allowing for a prudence review of leave to construct projects and other projects for which ICM treatment is sought at the time of rebasing limited to the difference between forecasted and actual spend.

For example, the Board’s ICM Policy states under section 7.4*:*

> At the time of the next cost of service or Custom IR application, a distributor will need to file calculations showing the actual ACM/ICM amounts to be incorporated into the test year rate base. At that time, the Board will make a determination on the treatment of any difference between forecasted and actual capital spending under the ACM/ICM, if applicable, and the amounts recovered through ACM/ICM rate riders and what should have been recovered in the historical period during the

> preceding Price Cap IR plan term. Where there is a material difference between what was collected based on the approved ACM/ICM rate riders and what should have been recovered as the revenue requirement for the approved ACM/ICM project(s), based on actual amounts, the Board may direct that over- or under-collection be refunded or recovered from the distributor's ratepayers.[1]

c) The table below shows the forecast annual revenue requirement for each of the proposed ICM projects: assuming the capital costs approved for each project in their respective LTC proceedings, and assuming the cost reduction (generally due to the exclusion of indirect overhead and/or IDC) results in a corresponding reduction in the maximum eligible incremental capital of the applicable rate zone (i.e., reduces the ICM amount).

Enbridge Gas notes however, that while these calculations can be made for illustrative purposes, the reclassification/reassignment of certain costs from these projects does not change the total forecast in-service capital for 2019. As such, to the extent that costs apportioned to these projects are reduced, reducing the project specific ICM eligible amount, it may in turn create capacity for another ICM eligible project.

Total Incremental Revenue Requirement by Rate Zone
Using Project Cost Approved by the OEB in LTC

Line No.	Particulars ($000's)	2019	2020	2021	2022	2023
	EGD Rate Zone					
1	Don River Replacement	(26)	335	386	383	380
	Union North Rate Zone					
2	Sudbury Replacement	7,690	7,720	7,617	7,509	7,396
	Union South Rate Zone					
3	Kingsville Reinforcement	(693)	8,859	9,097	9,187	9,245
4	Stratford Reinforcement	(766)	2,146	2,221	2,249	2,267
5	Total Union South Rate Zone	(1,459)	11,005	11,318	11,436	11,512
6	Total Incremental Revenue Requirement	6,205	19,060	19,321	19,328	19,288

[1] Ontario Energy Board, EB-2014-0219, Report of the Board, New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, page 26.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit B1, Tab 2, Schedule 1, Page 32

Question:

Based on the response to EP-16 regarding updated ICM project costs and timing, please update the 2019 ICM Net Revenue Requirement in Table 11 and the Allocation to Rate classes for 2019.

Response

Please see Exhibit I.EP.16, part c) for the incremental revenue requirement by rate zone as updated to reflect the leave to construct project costs approved by the Board. Attachment 1 provides the allocation of 2019 project costs reflected in Exhibit I.EP.16, part c).

EGD RATE ZONE
Allocation of 2019 ICM Project Revenue Requirement
Updated for Exhibit I.EP.17

Line No.	Particulars	Delivery Demand TP > 4" Allocator (1) %	Don River Replacement Project (2) (000's)
		(a)	(b)
	EGD		
1	Rate 1	46%	-
2	Rate 6	41%	-
3	Rate 9	0%	-
4	Rate 100	0%	-
5	Rate 110	2%	-
6	Rate 115	1%	-
7	Rate 125	8%	-
8	Rate 135	0%	-
9	Rate 145	0%	-
10	Rate 170	0%	-
11	Rate 200	1%	-
12	Rate 300	0%	-
13	Total	100%	-

Notes:

(1) EGD extra high pressure mains greater than 4 inch diameter are allocated according to the Board approved cost allocation methodology (EB-2017-0086), Delivery Demand TP > 4 inch allocator, reflecting 2019 forecast peak demand by rate class.

(2) 2019 ICM revenue requirement credit balance associated with the Don River Replacement project in the EGD rate zone will be recovered in 2020.

UNION RATE ZONES
Allocation of 2019 ICM Project Revenue Requirement
Updated for Exhibit I.EP.17

		Union North		Union South			
Line No.	Particulars	Distribution Demand Allocator (1) (%)	Sudbury Replacement Project (2) ($000's)	Other Transmission Allocator (3) ($10^3m^3/d$)	Kingsville Reinforcement Project (4) ($000's)	Stratford Reinforcement Project (4) ($000's)	Total ICM Allocation ($000's)
		(a)	(b)	(c)	(d)	(e)	(f) = (b+d+e)
1	Rate 01	40	3,078	-	-	-	3,078
2	Rate 10	13	1,006	-	-	-	1,006
3	Rate 20	27	2,052	-	-	-	2,052
4	Rate 25	2	185	-	-	-	185
5	Rate 100	18	1,369	-	-	-	1,369
6	Total Union North	100	7,690	-	-	-	7,690
7	Rate M1	-	-	31,974	-	-	-
8	Rate M2	-	-	10,986	-	-	-
9	Rate M4 (F)	-	-	5,860	-	-	-
10	Rate M4 (I)	-	-	-	-	-	-
11	Rate M5 (F)	-	-	87	-	-	-
12	Rate M5 (I)	-	-	-	-	-	-
13	Rate M7 (F)	-	-	2,496	-	-	-
14	Rate M7 (I)	-	-	-	-	-	-
15	Rate M9	-	-	546	-	-	-
16	Rate M10	-	-	4	-	-	-
17	Rate T1 (F)	-	-	2,572	-	-	-
18	Rate T1 (I)	-	-	-	-	-	-
19	Rate T2 (F)	-	-	23,429	-	-	-
20	Rate T2 (I)	-	-	-	-	-	-
21	Rate T3	-	-	2,501	-	-	-
22	Total Union South	-	-	80,456	-	-	-
23	Excess Utility Storage	-	-	-	-	-	-
24	Rate C1 (F)	-	-	-	-	-	-
25	Rate C1 (I)	-	-	-	-	-	-
26	Rate M12	-	-	-	-	-	-
27	Rate M13	-	-	-	-	-	-
28	Rate M16	-	-	-	-	-	-
29	Total Ex-Franchise	-	-	-	-	-	-
30	Total Union	100	7,690	80,456	-	-	7,690

Notes:
(1) Union North distribution demand allocation for joint-use mains in proportion to 2019 forecast peak day and average day demands.
(2) Allocated in proportion to column (a).
(3) Union South other transmission demand allocation in proportion to forecast 2019 Union South in-franchise design day demands.
(4) The 2019 revenue requirement credit for the Kingsville and Stratford Reinforcement projects will be netted with the 2020 revenue requirement in the allocation to rate classes in 2020.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 1, Page 6 and C1, Tab2, Page 41

Preamble: "Examples of this include support for programs such as Renewable Natural Gas, Compressed Natural Gas, and the integration of gas and electric infrastructures using technology like combined heat and power, geothermal loops and hydrogen storage and blending."

Question:

Please confirm that the programs listed except for hydrogen blending are non-utility programs.

Response

As stated on page 41 of EGD rate zone AMP, filed at Exhibit C1, Tab 2, Schedule 1, DSM and hydrogen blending are currently included as rate-regulated activities for the purpose of this Asset Management Plan. The regulatory treatments of the other programs noted in this question vary, and are described below.

RNG:

- With respect to Renewable Natural Gas ("RNG") facilities required to inject RNG into the gas distribution system will be utility assets, whereas any assets created for the purpose of upgrading raw biogas to pipeline quality RNG will be treated as non-utility assets consistent with the OEB's EB-2017-0319 Decision and Order.

Geothermal Energy Services:

- Legacy EGD also submitted a proposal to the Board in 2018 that called for geothermal ground source loops that would displace natural gas consumption to be included as part of utility rate base as a greenhouse gas emission strategy. This proposal included a non-utility element that would apply to situations where the service was provided to those without access to natural gas distribution services. This proposal was part of the EB-2017-0319 submission which was subsequently held in abeyance given the cancellation of the provincial government's Green Energy Fund initiatives.

CNG:

- This business activity has been included as part of EGD’s regulated utility as an ancillary business activity and been subject to the imposition of imputed revenues in the event that the program does not achieve the utility’s regulated rate of return in any particular year.

CHP:

- Enbridge Gas actively supports the adoption of CHP facilities.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 1, Pages 8 to 10

Question:

Were any financial constraints, such as earnings per share or customer rate impacts such as maximum rate increases, used as constraints in the preparation of the USP? If there were, please list them. If not, please explain why not.

Response

The financial constraints mentioned above were not considered as constraints in the preparation of the USP. Please see Exhibit I.CME.1 part (b) for examples of the factors that were taken into consideration when developing the Asset Management Plans for both EGD and UG.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 1, Page 22

Preamble: *"The budgets are reviewed at successively higher levels of management, with modifications made on an iterative basis as required. A final budget for each area is endorsed by the accountable Vice President responsible for each area."*

Question:

Please provide a table listing each level of management that reviews the budget and the types of modifications that each level of management makes.

Response

The process for O&M budget creation begins at the manager level, working closely with Finance. The most detailed review of the budget happens at the management level and each subsequent review/approval is at a higher level. Potential modifications include FTE adjustments and program additions/reductions. Please see the table below:

Level of Management	**Action**	**Description/Modifications**
Manager	Create, Review, Modify	Manager works with Finance to create initial budget.
Director	Review, Modify	Director reviews submission from Manager and makes modifications. Once changes are made the Director approves.
VP	Review, Modify, Final Approval for Functional Area	VP reviews submission from Director and makes modifications. Once changes are made the VP approves.
President	Review, Modify, Final Approval for Entire Company	President reviews submission from VP's and makes modifications. Once changes are made the President provides final approval.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 1, Pages 23 and 27

Preamble: *"The consolidated O&M budget is then consolidated by Finance with the broader Company budget and is reviewed and approved by the Company's Senior Executive management team."*

"The consolidated budget and LRP is then reviewed and approved by the Company's senior executive management team."

Question:

a) Does the Company's Senior Executive management team in the text refers to Enbridge Inc. management or to Enbridge Gas Inc. management team?

b) Please file a copy of the consolidated 2019 budget that was presented by Finance to the Company's Senior Executive Team.

Response

a) The Company's Senior Executive Management Team in the text refers to Enbridge Gas Inc.'s Management Team.

b) The Company declines to provide a copy of the 2019 Budget package given that it has no impact on 2019 rates or this application.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 1, Page 23

Preamble: "*The Company's capital budget process ensures that capital is allocated in a way that maximizes the value of life cycle-based capital while mitigating risk to the lowest practical level.*"

Question:

What is *"life cycle-based capital"* and how is its value maximized?

Response

Life cycle-based capital is the capital spent on assets across its life cycle stages identified as Acquire/Create, Utilize, Maintain, and Renew/Retire. Options to mitigate risk or pursue opportunities are considered at each life cycle stage as short or long term solutions. Value-based decisions are made to manage cost, risk and performance in relation to the specific asset and the total asset portfolio.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 1, Pages 24, 27 and 34

Question:

a) What is LRP and how does it relate to the USP?

b) If the LRP and the USP are related please file the LRP

Response

a) LRP stands for Long Range Plan, which represents the longer term financial forecast, beyond the budget year, typically the latter years of the plan.

   As noted in section 3.1 in the USP, filed at Exhibit C1, Tab 1, Schedule 1, the Budget and LRP is a component of the USP. The budget and LRP balance the need to maintain safe and reliable operations that meet the demands of current and new ratepayers, while ensuring Enbridge Gas's financial viability. The Asset Management Plan underpins the Capital Expenditures for each year of the 10 year plan, which is reflected, along with a portion of the O&M costs, in the LRP, which in turn supports the USP.

b) Enbridge Gas declines to provide the LRP given it is not relevant to the relief requested as part of 2019 rates.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 1, Page 28 and Exhibit C1, Tab 2, Page 89

Question:

a) What is the significance of Lifetime Risk Return on Investment?

b) Please provide a numerical example of the calculation using NPS 30 Don River Replacement Project numbers.

Response

a) Please see Exhibit I.VECC.12.

b)

$$\text{LRROI}=\frac{\text{Discounted Lifetime Risk Reduction}}{\text{Total Net Capital Investment}}$$

Equation 1: LRROI Calculation

$$\text{Discounted Lifetime Risk Reduction}=(\text{Safety Risk Mit}\times\text{Useful Life})+\left(\text{Fin Risk Mit}\times\frac{1-(1+\text{pretax WACC*})^{-\text{useful life}}}{\text{pretax WACC}}\right)+\left(\text{CSAT Risk Mit}\times\frac{1-(1+\text{pretax WACC})^{-\text{useful life}}}{\text{pretax WACC}}\right)$$

**WACC: Weighted Average Cost of Capital*

Equation 2: Discounted Lifetime Risk Reduction

Values for variables used Equation 2 are provided below:

Variables	Values for Project 6423
Safety Risk Mitigation	47,376
Fin Risk Mitigation	114,815
CSAT Risk Mitigation	74,956
Useful Life (Years)	70
Pretax WACC	0.062147

By applying the values in the above table to **Equation 2**, Discounted Lifetime Risk Reduction is $6,325,040. As the Total Net Direct Capital is $26,864,009 [Exhibit C1, Tab 2, Schedule 1, page 699], according to **Equation 1**, the LRROI is 24. The slight discrepancy between the LRROI shown here versus the value published in Exhibit C1, Tab 2, Schedule 1, page 699 is due to a change in the Total Net Direct Capital at the time of the filing.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 1, Schedule 1, Page 57, Figures 12&13

Question:

a) Please clarify if the PI shown in the Figures is based on gross cost or net cost (less CIAC).

b) For Figures 12 and 13 please provide the "Best Fit" Lines and provide the equations.

c) Please explain and discuss the trends in PI for the Project and Rolling Portfolios for Union and EGD.

d) Please provide the historic 2015+ and current approved system expansion projects for EGD and Union with summary data such as location, cost, customer additions etc.

e) Please discuss the outlook for system expansion projects for each rate Zone. Delineate projects using SES and Government support.

f) How much will be invested in SE during the Deferred rebasing period 2020-2025? Please reconcile to the data in the Utility System Plan.

Response

a) The PI shown in figures 12 and 13 are based on net cost (less CIAC).

b) Please see below the best fit lines and the equation for Figures 12 and 13.

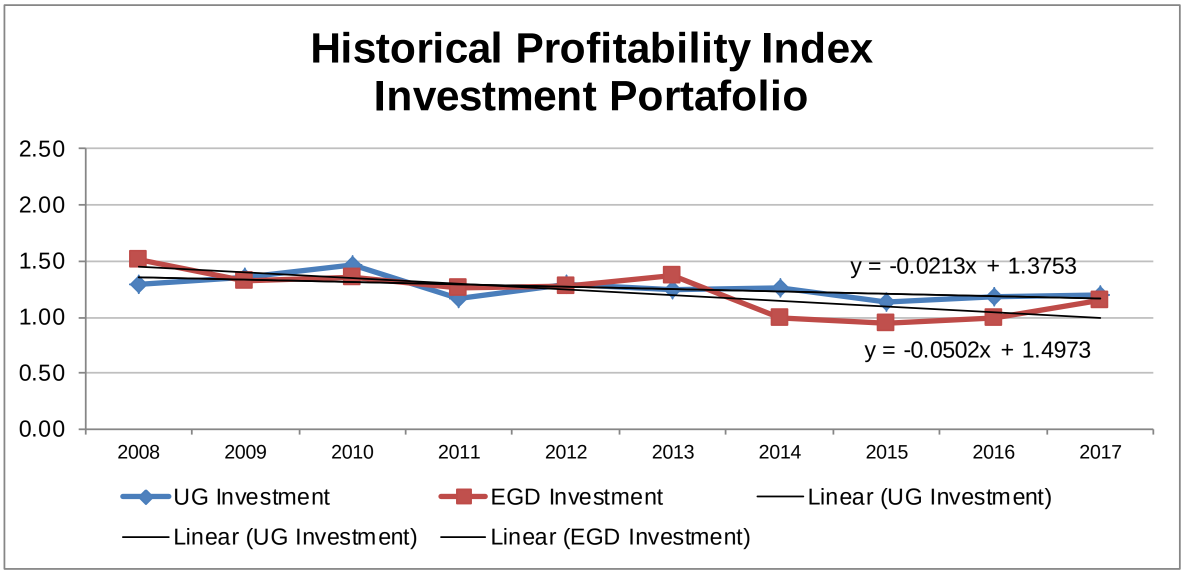

Figure 12

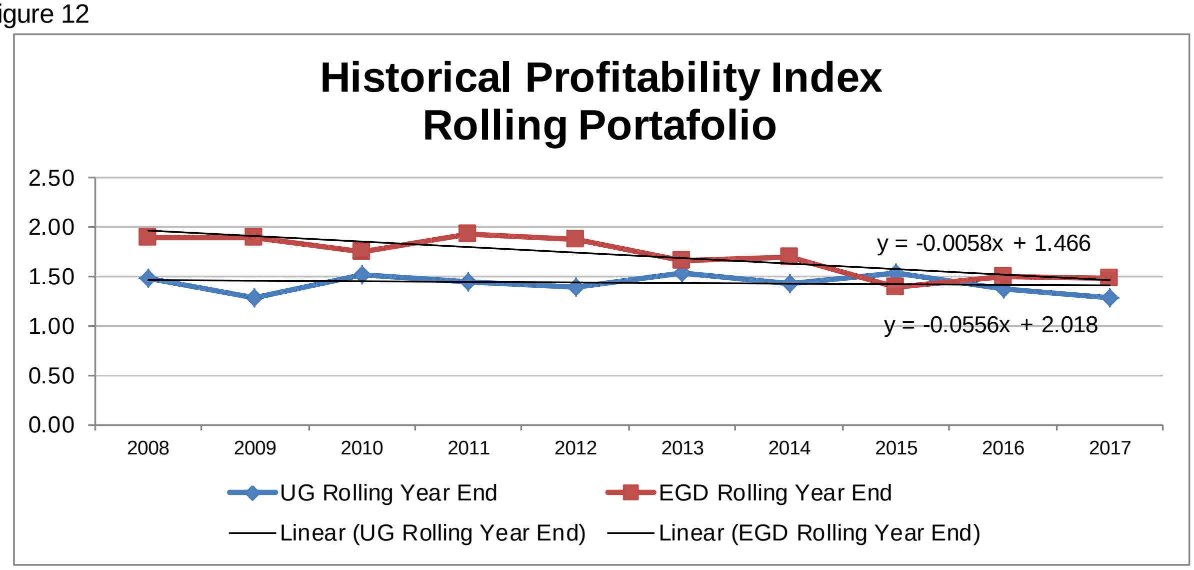

Figure 13

c) Figure 12 shows the Investment Portfolio Trend, where the slope of the best fit line for both the EGD and Union rate zones are negative, which suggests that the PI is trending down over time.

Figure 13 shows the Rolling Project Portfolio Trend, where the slope of best fit lines for the EGD and Union rate zones are negative, which suggests that their portfolio PI is trending downwards.

d) The rolling and investment portfolios include all of the distribution expansion projects completed by the company. These projects could be as simple as a 20 meter NPS 2 plastic main extension to 5 km steel NPS 8 reinforcement project. As such it is not practical to provide a list of all of the projects that are included in the rolling and investment portfolios.

e) Enbridge Gas has and will continue to manage its system expansion projects such that the Profitability Index ("PI") requirements of the Board's E.B.O. 188 economic feasibility guideline are met with respect to each of the Company's rate zones. For projects defined as Community Expansion Projects, the Company will apply the System Expansion Surcharge in compliance with the OEB's EB-2017-0147 Decision and any other relevant decision of the Board. In cases where a community expansion project is to receive financial support either through the former Natural Gas Grant Program or under the auspices of Bill 32, the Access to Natural Gas Act, 2018 and its accompanying regulation (Ontario Regulation 24/19) the funds provided under either of these programs will serve as contributions in aid of construction, effectively reducing the capital cost of these projects such that they achieve a PI of 1.0. Should the requirements of Bill 32 change, the Company will revise its applicable policies so as to accommodate and be in compliance with such changes.

f) To confirm, the deferred rebasing period is 2019 – 2023. As shown on pages 40 and 41, figure 7 and 8 respectively in the USP, filed at Exhibit C1, Tab 1, Schedule 1, system access investment is approximately $622M for EGD and $493M for Union.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 2, Pages 41and 42

Preamble: *"The overall portfolio has an LRROI of 119%. The breakdown by asset class has been summarized in Table 1.9-1. While different asset classes have higher or lower LRROI values, the value of the lifetime risk reduced is greater than the capital investment."*

Question:

a) Please explain the significance of LRROI of 119% for the overall portfolio. What should the OEB conclude from that number?

b) In Table 1.9-1 Storage has the highest LRROI of 284%. Does that mean that Storage is the most profitable asset class? Please show how the 284% number was calculated.

c) In Table 1.9-1 Pipe has the lowest LRROI of 41%. Does that mean that Pipe is the least profitable asset class? Please explain how the 41% number was calculated.

Response

a) Based on an LRROI of 119% for the overall portfolio, the OEB should conclude that the value of Lifetime Risk reduced is greater than the capital investment for such risk reduction. For more details, please refer to section 1.9, page 42 in the EGD rate zone's AMP, filed at Exhibit C1, Tab 2, Schedule 1

b) LRROI is not used to measure profitability. Storage having the highest LRROI means that the ratio of risk mitigation to capital requirements for this asset class is the highest, or per dollar of capital, the storage asset class is able to mitigate the most risk compared to the other asset classes. As described in section 4.2.5, page 89 in the EGD rate zone's AMP, filed at Exhibit C1, Tab 2, Schedule 1, the LRROI was calculated using the equations below:

Lifetime Risk Return on Investment (LRROI) is used to inform optimization where the risk mitigated by a capital investment is normalized by the net direct capital required. LRROI is a measure indicating the efficiency with which risk is reduced across all asset classes. It is calculated using **Equation 1**. The Discounted Lifetime Risk Reduction is calculated using **Equation 2** and represents the present value of the risk reduction over the useful life of the asset. Customer satisfaction and financial risk are discounted over the life of the asset, while safety risk is not, as it is of paramount importance.

$$\text{LRROI}=\frac{\text{Discounted Lifetime Risk Reduction}}{\text{Total Net Capital Investment}}$$

Equation 1: LRROI Calculation

$$\text{Discounted Lifetime Risk Reduction}=(\text{Safety Risk Mit}\times\text{Useful Life})+\left(\text{Fin Risk Mit}\times\frac{1-(1+\text{pretax WACC*})^{-\text{useful life}}}{\text{pretax WACC}}\right)+\left(\text{CSAT Risk Mit}\times\frac{1-(1+\text{pretax WACC})^{-\text{useful life}}}{\text{pretax WACC}}\right)$$

**WACC: Weighted Average Cost of Capital*

Equation 2: Discounted Lifetime Risk Reduction

c) LRROI is not used to measure profitability. Pipe's LRROI of 41% indicates that the capital requirements for the pipe asset class exceed the risk mitigated based on the portfolio of work. Please refer to (b) for the calculation of LRROI.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 2, Page 44, Table 19-3

Question:

Please explain how the Total Overhead numbers were determined.

Response

Please see Exhibit I.STAFF.32, part (c).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 2, Schedule 1, Page 45, Table 1.9-5: ICM-Eligible Capital Projects

Question:

a) Please explain the relationship between the information in this table and the ICM project information in Exhibit B1, Tab 2.

b) Please provide a consolidated schedule showing approved and forecast ICM projects over the 5-year deferred rebasing period with summary data on costs and in-service dates.

Response

a) The information in Table 1.9.5 identifies discrete and material capital projects in the EGD rate zone, and includes the NPS 30 Don River Replacement ICM project and potential future ICM projects. The information in Exhibit B1, Tab 2 discusses the evidence in support of the ICM funding requests and includes the business case summary for the NPS 30 Don River Replacement ICM project.

b) A list of potential ICM projects is filed in Table 6, page 49 at Exhibit C1, Tab 1, Schedule 1.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 2, Page 45, Table 19-5

Question:

The information in the table indicates that the driver for the NPS 20 Don River Relocation project is “third party relocation”. Does Enbridge have a cost sharing agreement with the “third party”. If the answer is yes, what is the sharing ratio? If the answer is no, please explain why not.

Response

Enbridge Gas is currently in discussions with the third party stakeholder to determine what type of cost sharing mechanism and agreement will apply to this third party relocation request.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit C1, Tab 2, Page 58, Figure 3.3-1

Question:

Should the OEB be concerned that 9.1 Monitoring Measurement Risk and Evaluation and 9.2 Internal Audit have been rated as low maturity by KPMG?

Response

In the ISO framework, 9.1 and 9.2 is focused around monitoring of the overall asset management strategy, plans, processes and KPI's as opposed to "asset risk and condition monitoring" which is captured in element 6. These elements typically mature after an organization has gone through several annual cycles and has implemented the defined strategy, organization and processes. The low maturity rating is expected given the time of the assessment.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit D1, Tab 1, Schedule 1, Page 22

Preamble: The Question to Residential customers regarding higher rates for infrastructure replacement was:

"*In considering its five-year investment plan Enbridge Gas Distribution estimates that it will need to increase investments to keep up with aging infrastructure and still maintain the current level of reliability and safety it delivers to its customers. It is estimated that the average residential customer bill will need to increase by 3% or $2 per month over the next 5 years to maintain current levels of safety and reliability. This increase would start in 2019 and apply until 2023. So, by the end of 2023 residential customers will pay $10 more per month compared to what they pay now, to cover these increased capital investments.*"

Question:

a) Please confirm this question relates to Sustainment Capital Investment under the CIR Plan 2020-2025.

b) What information was provided to the respondents as context for the question? Please be specific.

c) Why does the CIR Plan not provide sufficient capital for sustainment? Please reply in detail.

d) Please provide the proposed budgets that underpin this question.

e) Please provide the current level of reliability and the level in 2025 based on measurable parameters.

f) Will there be offsetting OM&A cost reductions from the investment? Please delineate.

Response

a),c),d),e),f) The capital investment plan underpinning the rate impact in the customer engagement was based on a high level estimate at the time of the study and does not reflect the CIR plan for 2020 to 2025.

b) The preamble provided above was read to residential customers as context for this question.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit D1, Tab 1, Schedule 1, Page 24

Preamble: The following question was put to Residential Customers:

"*As you may know, on January 1, 2017 the Ontario government is planning to introduce a Cap and Trade system to help reduce greenhouse gas emissions in Ontario. Customers will pay a cost related to the amount of greenhouse gases they emit, such as from the use of fossil fuels. The government plans to invest these cap and trade proceeds into various initiatives that reduce greenhouse gases such as renewable sources of energy, public transportation, electric vehicle incentives, and energy conservation programs. Initially, the government expects costs to be about $7 per month for each natural gas customer for home heating, but the exact amounts next year and in future years is not yet known. Some estimates have indicated that the cost could increase by roughly 50 percent by 2023.*"

Question:

a) Were Residential Customers aware that the Cap and Trade charge was added to their bills? Please provide data on the level of awareness.

b) Has EGI canvassed its customers following the cancellation of the Cap and Trade and introduction of the Federal Carbon Tax in April 2019? If so please provide the results.

Response

a) The specific question asking if residential customers were aware that the Cap and Trade charge was added to their bills was not asked. Customers were asked if they were aware that starting in 2017 customers would be paying on average more to cover costs associated with Cap and Trade. Residential customers would pay on average $7 more per month – 46% were aware, General Service would pay $36 more per month on average – 36% were aware, Large Volume Customers (various unit rate increases) – 74% were aware, and Rate 6 Business customers would pay an additional 15% increase per month – 31% were aware.

b) No.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit D1, Tab 1, Schedule 1, Pages 25 and 26

Question:

“There are a couple of ways in which Enbridge Gas can help to lower customer costs to offset this cap and trade cost. One way is to offer conservation programs (such rebates and incentives) to encourage customers to make changes to their home to reduce their household natural gas consumption. Another way is for Enbridge to invest in renewable energy sources that will reduce greenhouse gas emissions across the network and offset the amount of cap and trade costs to customers overall.

SOME PEOPLE SAY there is not much more they can do to make their home more energy efficient and therefore they may not be able to lower the cap and trade cost they pay. They are more likely to see savings based on investments Enbridge Gas could make in renewable energy that will reduce the cap and trade costs to customers across the network.

OTHER PEOPLE SAY there is more they can do to make their home more energy efficient and they would prefer to have access to rebates and incentives to help them do that to lower the cap and trade cost they pay rather than rely on investments in renewable energy by Enbridge Gas to lower cap and trade cost across the network.”

a) Which of the above questions was put to residential customers?

b) What information was provided to the respondents as context for the question? Be specific such as relative costs and bill impacts.

c) Given the OEB decision on RNG is the question no longer accurate? Please discuss.

Response

a) The text provided above refers to two separate questions asked in the residential surveys:

Question 9:

There are a couple of ways in which Enbridge Gas can help to lower customer costs to offset this cap and trade cost. One way is to offer conservation programs (such rebates and incentives) to encourage customers to make changes to their home to reduce their household natural gas consumption. Another way is for Enbridge to invest in renewable energy sources that will reduce greenhouse gas emissions across the network and offset the amount of cap and trade costs to customers overall.

Generally speaking, would you prefer to see Enbridge…? (Read list)

Invest in conservation programs to help customer reduce their consumption
Invest in renewable energy sources that will reduce the overall network's consumption
Both
Neither
Don't know (Read) [Anchor]

Question 10:

Some people say [ROTATE STATEMENT 1 AND 2] [STATEMENT 1] there is not much more they can do to make their home more energy efficient and therefore they may not be able to lower the cap and trade cost they pay. They are more likely to see savings based on investments Enbridge Gas could make in renewable energy that will reduce the cap and trade costs to customers across the network. Other people say [STATEMENT 2] there is more they can do to make their home more energy efficient and they would prefer to have access to rebates and incentives to help them do that to lower the cap and trade cost they pay rather than rely on investments in renewable energy by Enbridge Gas to lower cap and trade cost across the network. Which is closer to your point of view? Are you… (Read list)

More likely to see savings based on renewable energy investments across the network

More likely to see savings based on making your home more energy efficient
Don't know (Read) [Anchor]

b) The context provided for each question is detailed in the previous response.

c) Please see Exhibit I.EP.34, part b) and c).

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit D1, Tab 1, Schedule 1, Page 29

Preamble: The following question was put to Residential Customers:

> *"As you may know, Renewable natural gas (RNG), or bio methane gas or biogas, is a type of renewable gas that is carbon neutral, thus it is better for the environment than conventional natural gas. It is a sustainable fuel that is created by converting organic material such as municipal green bin collection waste (ie. vegetable peelings), farm crop residue, gas from water treatment plants and even landfill gas that is captured and cleaned to the same quality level as natural gas. Renewable natural gas could be produced in Ontario and put into the existing natural gas distribution system. It would be compatible with all your natural gas appliances so there would be no lifestyle change for households. Renewable natural gas helps reduce greenhouse gas emissions by displacing conventional natural gas. Investing in renewable natural gas can start with modest levels of blending renewable energy with conventional energy.*
> *Think of this like the 2% blending of ethanol in gasoline. This level of renewable blending is estimated to cost customers approximately $1.60 per month. Over time, it is expected the cost of renewable natural gas will decline, making renewable natural gas less expensive than conventional natural gas in the long-term for customers."*

Question:

a) Please provide the basis of the Calculation of the $1.60 per month.

b) Is this question accurate, given the OEB decision on RNG? Please discuss.

c) Is it still relevant given the Government Policy on RNG? Please discuss.

Response

a) The $1.60 per month RNG price premium was based on 2% RNG blending by volume in EGD's supply gas supply for residential customers, and assumed an average price of $16/GJ for RNG commodity price at the time the analysis was done.

b), c) On November 29, 2018 the province released A Made-in-Ontario Environment Plan, Ontario's new plan to preserve and protect our environment for future generations. On page 33 of the plan the province states: "Require natural gas utilities to implement a voluntary renewable natural gas option for customers."

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ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit D1, Tab 1, Schedule 1, Page 31

Preamble: *"In each of the customer groups, willingness to pay even more for the additional blending of renewable natural gas into the existing natural gas network is low. In terms of residential customers, only about one third (36%) would be willing to pay more (above the base increase detailed in the previous question)."*

Question:

a) Was this result available at the time of the RNG proceeding?

b) If so please provide the reference.

c) Why is EGI bringing this survey regarding RNG into this proceeding? Please be specific regarding the objective(s) for doing so.

Response

a) Yes, the result was available at the time of the RNG proceeding

b) The result can be found on page 31 in the customer engagement report, filed at Exhibit D1, Tab 1, Schedule 1.

c) The customer engagement done by Ipsos Public Affairs and Innovative Research Group (Exhibit D1) is filed in support of Enbridge Gas's USP and AMP planning process. As per the Board's Decision and Procedural Order No. 2 dated April 1, 2019 "customer engagement in this proceeding is only relevant to the USP and AMP planning processes, and therefore is a consideration for the review of the ICMs."

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit D1, Tab 1, Schedule 1, Page 42

Preamble: *"Among Residential customers, more than half (58%) are willing to pay an increase in their bill to fund an investment. About one third (35%) of Residential customers would be willing to pay approximately $3.60 more per month for both maintaining current levels of safety and reliability and to invest in renewable natural gas. Slightly more than one in ten (14%) Residential customers would be willing to pay approximately $1.60 more per month to invest in renewable natural gas exclusively, while one in ten (9%) would be willing to pay approximately $2.00 more per month to maintain existing levels of safety and reliability."*

Question:

a) Please confirm the cited monthly bill impact of $3.60 is split between replacement infrastructure ($2.00) and RNG ($1.60).

b) What is the current comparable Bill impact for DSM/Conservation?

c) Is EGI suggesting to the Board it should charge customers for all three initiatives plus the federal Carbon Tax during the RNG Plan? If provide the monthly residential bill impact.

d) If not, please clarify exactly what EGI is proposing and the estimated bill impacts

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Response

a) Yes, the bill impact of $3.60 is split between replacement infrastructure ($2.00) and RNG ($1.60).

b) The EGD rate zone's Board-Approved 2019 DSM Budget is $66.4M. The amount budgeted for Rate 1: Residential Service customers is $38.6M for 2019.

Based on the budgeted amount of $38.6M, the annual amount a typical Rate 1 residential customer would pay for DSM is $19, which is approximately $1.6 per month.

c, d) Enbridge Gas has been investigating the introduction of a voluntary RNG program that would be designed so as to have minimal bill impacts. This initiative is consistent with and supported by the provincial governments "A Made-in-Ontario Environment Plan" (page 33), which states: "Require natural gas utilities to implement a voluntary renewable natural gas option for customers." The costs associated with the maintenance of a safe and reliable gas distribution are completely unrelated to those of a voluntary RNG program and are legitimate costs recoverable in rates. Enbridge Gas will be required to bill and remit the Federal Carbon Tax based on end user natural gas consumption regardless as to what costs are recoverable in its rates.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Reference: Exhibit D1, Tab 2, Schedule 1, Page 54

Preamble:
- *The three most important outcomes for (Union) residential participants are "pricing" (88% top 3 issue), "safety" (67% top 3 issue) and "reliability" (65% top 3 issue). For business participants it was the exact same order ("pricing", 85% top 3 issue; "safety", 62% top 3 issue; "reliability", 60% top 3 issue).*
- *Roughly three-in-four (74%) residential and two-thirds (65%) of business participants find the price of distributing gas "reasonable". Those residential participants with large bills are less likely to find it reasonable ($120+: 65% vs. $0-79: 79% reasonable).*
- *Nearly all participants are satisfied with Union Gas' performance on safety (residential: 92%; business: 91%) and reliability (residential: 98%; business: 93%).*

Question:

a) Were the respondents asked about paying more for infrastructure replacement, Conservation/DSM and RNG? If not why was this not done? If so please provide the results.

b) Were the Respondents asked about paying the Federal Carbon Tax? If so please provide the result and compare with the comment on Page 65.
"Unpacking "lower cost", most of the codes are general but specific mentions include the delivery charge, showing the carbon tax, and senior discount".

Response

a) Most infrastructure decisions within the plan were driven by asset health and condition or by the need to meet customer demands. These specific choices are technical considerations that don't facilitate customer impact. The utility did collect customer input that informed infrastructure decisions in three ways:

1. As noted in the preamble, customers were asked to rate and rank customer outcomes;
2. Customers were asked about the general approach the utility should take to the pacing of investments; and
3. Customers were asked about the general approach the utility should take to safety standards.

Feedback on all three of these topics was considered in evaluating the portfolio of potential investments.

b) No, the respondents were not asked about the Federal Carbon Tax.