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VIA EMAIL, RESS and COURIER

November 19, 2019

Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Re: EB-2019-0105 - Enbridge Gas Inc. ("Enbridge Gas") – 2018 Disposition of Deferral & Variance Account Balances and 2018 Utility Earnings
Updated Interrogatory Responses

Further to the submission filed by Enbridge on October 28, 2019, enclosed please find updates to the following Interrogatory responses.

Exhibit	Correction
Exhibit I.STAFF.5_Attachment 1	**Corrections to line 1.1 and 1.2.**
Exhibit I.STAFF.9_Attachment 1	**The table within the response was inadvertently cut off. This has been corrected.**

The submission has been filed through the Board's RESS and will be available on the Enbridge website at: www.enbridgegas.com/ratecase.

Please contact the undersigned if you have any questions.

Yours truly,

(Original Signed)

Rakesh Torul
Technical Manager,
Regulatory Applications

cc: David Stevens, Aird and Berlis LLP
EB-2019-0105 Intervenors

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Ref: Harmonization of Deferral Account Disposition Approach Exhibit A / Tab 3 / pp. 3-4
EB-2018-0300/0301 / Decision and Rate Order / May 23, 2019

Preamble:

In the 2016 DSM deferral and variance account disposition proceeding[1], the OEB stated that a common approach to the disposition of deferral and variance accounts should be established by Enbridge Gas Inc. (Enbridge) for its Enbridge Gas Distribution (EGD) and Union Gas Limited (Union) rate zones. In future proceedings, Enbridge is expected to adopt a common approach to the extent practical, and if not, explain the rationale for continuing a different approach.

As part of the current proceeding, Enbridge proposed to dispose of the deferral and variance accounts consistent with the current practices of legacy EGD and Union as follows.

- For the EGD rate zone, Enbridge proposed to dispose of the deferral account balances as a one-time adjustment for both general service and contract rate classes.

- For the Union rate zones, Enbridge proposed to dispose of the deferral account balances prospectively over 6 months for general service customers and as a one-time adjustment for in-franchise contract and ex-franchise rate classes.

Enbridge stated that it is not currently able to administer one-time adjustments for general service customers in the Union rate zones because of limitations in the system used to bill this group of customers. Enbridge further stated that it is in the early stages of integrating internal systems and processes between legacy EGD and Union and is not able to introduce any further commonality to the disposition approaches at this time.

[1] EB-2018-0300/0301

Question(s):

a) Please advise whether it would be possible to dispose of the deferral account balances prospectively over 6 months to general service customers in the EGD rate zone.

b) Please confirm that it is Enbridge's position that one-time adjustments are the most accurate manner in which to refund / recover deferral account balances to / from ratepayers.

c) Please advise whether Enbridge is currently working towards updating its systems to allow one-time adjustments to be applied to general service customers in Union rate zones. If so, please provide expected timelines for that functionality.

Response

a) Yes, it is possible to dispose of the deferral account balances prospectively over six months in the EGD rate zone. However, the balances to be cleared are typically small and do not need to be disposed of over a six month period. A prospective clearance methodology also leads to a variance (actual vs. forecast clearance) that would need to be addressed at the end of the six month prospective clearance period. Introducing a change to the EGD rate zone at this time is unnecessary and would represent a change from what the EGD rate zone's customers have typically experienced.

   An appropriate time to introduce a change to the disposition methodology for either the EGD or Union rate zones is once integrated systems and processes are implemented and a common approach to disposition developed and proposed.

b) Confirmed.

c) Yes, the Union rate zones will be moving to a system for billing its general service customers that will allow one-time adjustments to be applied to customer bills. Enbridge Gas currently estimates the earliest the new billing system for the Union rate zones will begin generating general service customer bills is in mid-2021.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Deferral and Variance Account Balance Summary
Exhibit B / Tab 1 / Appendix A / Schedule 1 / p. 1

Preamble:

Enbridge provided a summary of the actual 2018 deferral and variance account balances restated at April 30, 2019 and the forecast for clearance amounts at January 1, 2020 for the EGD rate zone.

Question(s):

a) For the accounts that Enbridge is seeking to clear as part of this proceeding for the EGD rate zone, please provide an updated version of the summary table that includes: (i) December 31, 2018 balances; (ii) explanations for the differences between the December 31, 2018 balances and the restated balances as of April 30, 2019. In addition, for the accounts where the restated balance as of April 30, 2019 is different from the amount that Enbridge is seeking to clear in January 1, 2020, please explain those differences.

b) Please confirm that the December 31, 2018 balances for the EGD rate zone are consistent with the account balances reported in Enbridge's 2018 RRR filing (2.1.7) and its 2018 audited financial statements. If any differences exist, please explain.

c) Please advise whether there are any deferral and variance accounts that are currently approved for use by Enbridge for the EGD rate zone but have not been listed in the Deferral and Variance Account Balance Summary (with the exception of the QRAM-related deferral accounts, the Demand Side Management (DSM)-related deferral accounts, and the cap and trade-related deferral accounts). If so, please list each account name and the corresponding balance in the account as at December 31, 2018 (including interest). Please also explain the nature of each account and why it is not being brought forward for disposition as part of this proceeding. This should include any accounts that had been opened in previous years but were never disposed.

d) Please advise whether there have been any adjustments made to deferral and variance account balances sought for disposition in the current proceeding that were previously approved by the OEB on a final basis during the current custom IR term. If so, please provide an explanation of the nature and amount of any adjustment and include any supporting documentation. Please also advise how such adjustments have been recorded and what accounts were used to record them.

Response

a) For the accounts requested for clearance, Attachment 1 to this response provides a summary of the December 31, 2018, April 30, 2019, and forecast January 1, 2020 account balances. The notes within Attachment 1 provide explanations for any changes in the principal balances at each of the above mentioned dates.

b) The December 31, 2018 balances are consistent with the account balances reported in Enbridge's 2018 RRR filing (2.1.7), and its 2018 audited financial statements.

c) The following accounts (with the exception of the PGVA which is cleared through the QRAM process, and the Demand Side Management (DSM)-related deferral accounts, and the cap and trade-related deferral accounts) were approved for use by Enbridge during 2018, but were not listed in the Deferral and Variance Account Balance Summary because they had balances of $0 as at December 31, 2018.

- Open Bill Revenue Variance Account (OBRVA) – The purpose of the OBRVA is to track and record the ratepayer share of net revenue for Open Bill Services. The account allows for net annual revenue amounts in excess of $7.389 million to be shared 50/50 with ratepayers, and allows for a credit to Enbridge in the event that net annual revenues are less than $4.889 million, equal to the shortfall between actual net revenues and $4.889 million. No balance was recorded in 2018 as net Open Bill revenue was within the established parameters, and therefore did not require an entry to the OBRVA.
- Ex-Franchise Third Party Billing Services Deferral Account (EFTPBSDA) – The purpose of the EFTPBSDA is to record and track the ratepayer portion of revenues, net of incremental costs, generated from third party billing services provided to ex-franchise parties. The net revenue is to be shared on a 50/50

basis with ratepayers. No balance was recorded in 2018 as EGD did not provide any third party billing services to ex-franchise customers.

- Relocation Mains Variance Account (RLMVA) – The purpose of the RLMVA is to record the cumulative revenue requirement impact of capital spending on mains relocation activities which varies from $12.6 million in each of 2017 and 2018 (which is the forecast capital cost for relocations included in each of the Board approved 2017 and 2018 capital budgets), if the cumulative revenue requirement impact is $5 million or greater. No balance was recorded in 2018 as the spending variance did not have a greater than $5 million revenue requirement impact.
- Replacement Mains Variance Account (RPMVA) – The purpose of the RPMVA is to record the cumulative revenue requirement impact of capital spending on miscellaneous mains replacement activities which varies from $5.1 million in each of 2017 and 2018 (which is the forecast capital cost for miscellaneous replacements included in each of the Board approved 2017 and 2018 capital budgets), if the cumulative revenue requirement impact is $5 million or greater. No balance was recorded in 2018 as the spending variance did not have a greater than $5 million revenue requirement impact.
- Constant Dollar Net Salvage Adjustment Deferral Account (CDNSADA) – The purpose of the CDNSADA was to record and clear the credit to ratepayers that resulted from the adoption of the Constant Dollar Net Salvage (CDNS) approach for determining the net salvage percentages to be included within EGD's depreciation rates. There is no request for disposition of the CDNSADA as part of this proceeding, as the final disposition of the CDNSADA was approved as part of the 2017 ESM hearing, EB-2018-0131. At December 31, 2018 a balance of $6.5 million was recorded in the CDNSADA, and subsequently cleared in January 2019.

d) The TIACDA balance is the only balance for which a clearance amount is being requested, which the Board has previously approved on a final basis. Within EB-2011-0354 the Board approved the recovery of the TIACDA over a 20 year period, commencing in 2013. The final amount recorded in the TIACDA as of the end of 2012 was $88.716 million. That balance has subsequently been adjusted to reflect the recovery of the first six installments (for each of 2013 through 2018) of $4.436 million each (1 / 20 of $88.716 million), which were approved for recovery within the EB-2013 0046, EB-2014-0195, EB-2015-0122, EB-2016-0142, EB-2017-0102, and EB-2018-0131 proceedings.

EGD RATE ZONE
DEFERRAL & VARIANCE ACCOUNT
ACTUAL & FORECAST BALANCES

Line No.	Account Description	Account Acronym	Col. 1 Actual at December 31, 2018 Principal ($000's)	Col. 2 Actual at December 31, 2018 Interest ($000's)	Col. 3 Actual at April 30, 2019 Principal ($000's)	Col. 4 Actual at April 30, 2019 Interest ($000's)	Col. 5 Forecast for clearance at January 1, 2020 Principal ($000's)	Col. 6 Forecast for clearance at January 1, 2020 Interest ($000's)	Col. 7 Apr-19 vs. Dec-18 Principal Variance ($000's)	Col. 8 Jan-20 vs. Apr-19 Principal Variance ($000's)	
	Commodity Related Accounts										
1.	Storage and Transportation D/A	2018 S&TDA	1,946.3	68.9	1,787.7	83.4	1,787.7	109.0	(158.6)	-	1
2.	Transactional Services D/A	2018 TSDA	(1,263.9)	-	(1,304.7)	(10.3)	(1,304.7)	(29.5)	(40.8)	-	2
3.	Unaccounted for Gas V/A	2018 UAFVA	703.2	-	5,616.0	34.6	5,616.0	116.2	4,912.8	-	3
4.	Total commodity related accounts		1,385.6	68.9	6,099.0	107.7	6,099.0	195.7	4,713.4	-	
	Non Commodity Related Accounts										
5.	Average Use True-Up V/A	2018 AUTUVA	(18,790.3)	-	(18,787.8)	(149.2)	(18,787.8)	(422.0)	2.5	-	4
6.	Post-Retirement True-Up V/A	2018 PTUVA	256.6	-	256.6	2.0	256.6	6.0	-	-	
7.	Gas Distribution Access Rule Impact D/A	2018 GDARIDA	117.0	-	117.1	0.9	117.1	2.5	0.1	-	5
8.	Deferred Rebate Account	2018 DRA	981.6	3.6	981.7	(5.1)	981.7	9.3	0.1	-	6
9.	Transition Impact of Accounting Changes D/A	2018/2019 TIACDA	66,537.0	-	62,101.2	-	4,435.8	-	(4,435.8)	(57,665.4)	7
10.	Customer Care CIS Rate Smoothing D/A	2018 CCCISRSDA	(4,901.6)	(33.2)	(4,901.6)	(57.2)	(4,901.6)	(105.2)	-	-	
11.	Customer Care CIS Rate Smoothing D/A	2017 CCCISRSDA	(2,785.3)	(59.7)	(2,785.3)	(13.6)	(2,785.3)	(40.8)	-	-	
12.	Customer Care CIS Rate Smoothing D/A	2016 CCCISRSDA	(779.9)	(14.3)	(779.9)	(3.8)	(779.9)	(11.8)	-	-	
13.	Customer Care CIS Rate Smoothing D/A	2015 CCCISRSDA	1,124.2	20.7	1,124.2	5.5	1,124.2	16.7	-	-	
14.	Customer Care CIS Rate Smoothing D/A	2014 CCCISRSDA	2,927.0	53.8	2,927.0	14.3	2,927.0	43.1	-	-	
15.	Customer Care CIS Rate Smoothing D/A	2013 CCCISRSDA	4,634.9	85.2	4,634.9	22.7	4,634.9	68.3	-	-	
16.	Electric Program Earnings Sharing D/A	2018 EPESDA	(1,210.1)	(3.9)	(1,210.1)	(13.2)	(1,210.1)	(30.8)	-	-	
17.	OEB Cost Assessment V/A	2018 OEBCAVA	2,702.3	29.0	2,702.3	50.5	2,702.3	89.7	-	-	
18.	Dawn Access Costs D/A	2018 DACDA	1,181.4	-	1,173.7	9.3	1,173.7	26.1	(7.7)	-	8
19.	Pension and OPEB Forecast Accrual Vs. Actual Cash Payment Differential V/A	2018 P&OPEBFAVACPDVA	-	(2.2)	-	(2.2)	-	(1.0)	-	-	
20.	Manufactured Gas Plant D/A	2018 MGPDA	888.0	59.0	888.0	66.1	888.0	78.9	-	-	
21.	Earnings Sharing Mechanism Deferral Account	2018 ESMDA	(27,350.0)	-	(27,350.0)	(217.2)	(29,950.0)	(643.0)	-	(2,600.0)	9
22.	Total non commodity Related Accounts		25,532.8	138.0	21,092.0	(290.2)	(39,173.4)	(914.0)	(4,440.8)	(60,265.4)	
23.	Total Deferral and Variance Accounts		26,918.4	206.9	27,191.0	(182.5)	(33,074.4)	(718.3)	272.6	(60,265.4)	

Notes:

1 The change in the April 2019 versus December 2018 balance in the 2018 S&TDA reflects the true up between the estimated year end December 2018 storage and transportation costs, and the final actual 2018 storage and transportation costs.

2 The change in the April 2019 versus December 2018 balance in the 2018 TSDA reflects the true up between the estimated year end December 2018 transactional services results, and the final actual 2018 transactional services results.

3 The change in the April 2019 versus December 2018 balance in the 2018 UAFVA reflects the true up between the December estimated UAF and the actual UAF amount.

4 The change in the April 2019 versus December 2018 balance in the 2018 AUTUVA reflects a minor correction, made in January 2019, to the balance recorded at year end December 2018.

5 The change in the April 2019 versus December 2018 balance in the 2018 GDARIDA reflects the true up between the estimated year end December 2018 gas distribution access rule revenue requirement, and the final actual 2018 gas distribution access rule revenue requirement.

6 The change in the April 2019 versus December 2018 balance of the 2018 DRA was due to backdated billing adjustments, related to prior deferral account clearances, which were processed between January and April 2019.

7 The balance in the 2018 TIACDA was rolled forward into the 2019 TIACDA at the beginning of the year. The change in the April 2019 versus December 2018 balance of the TIACDA was due to the clearance of the 2018 instalment in January 2019, as approved in EB-2018-0131. The balance forecast for clearance reflects 1/20th of the original TIACDA balance, which in EB 2011 0354 was approved for clearance evenly over a 20 year period.

8 The change in the April 2019 versus December 2018 balance in the 2018 DACDA reflects the true up between the estimated year end December 2018 dawn access revenue requirement, and the final actual 2018 dawn access revenue requirement.

9 The variance between the forecast 2018 ESMDA January 1, 2020 balance requested for clearance, and the April 2019 balance, reflects the true up of the 2018 year end estimated earnings sharing provision, to the final calculated amount examined in this proceeding, as discussed at Exhibit B, Tab 2, Pages 1 and 2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Storage and Transportation Deferral Account
Exhibit B / Tab 1 / p. 3
Exhibit B / Tab 1 / Appendix A / Schedule 2
EB-2017-0086 / Exhibit D1 / Tab 2 / Schedule 6

Preamble:

Enbridge provided a detailed breakdown of the $1.8 million debit balance included in the Storage and Transportation Deferral Account at Exhibit B / Tab 1 / Appendix A / Schedule 2.

Question(s):

a) Please confirm that the sum of Line 1 and Line 2 (Column 2) in Exhibit B / Tab 1 / Appendix A / Schedule 2 is meant to reconcile to Line 2 (Column 1) in EB-2017-0086 / Exhibit D1 / Tab 2 / Schedule 6.

b) Please explain the negative costs both forecast and actual related to the Dawn TService (shown in Line 2 / Columns 2 & 4 of Exhibit B / Tab 1 / Appendix A / Schedule 2).

c) Please provide a detailed calculation supporting the actual cap and trade costs incurred (shown in Line 3 / Column 4 of Exhibit B / Tab 1 / Appendix A / Schedule 2).

d) Please explain why the forecast third-party market-based storage value of $20.1 million (shown in Line 4 / Column 2 of Exhibit B / Tab 1 / Appendix A / Schedule 2) does not reconcile to Line 1.4 (Column 1) in EB-2017-0086 / Exhibit D1 / Tab 2 / Schedule 6.

e) Please advise whether there any amounts associated with the disposition of other utilities deferral accounts for 2018 recorded in the Storage and

Transportation Deferral Account. If yes, please provide the amount and details supporting the amount. If not, please explain.

Response

a) Confirmed. The amounts are meant to reconcile in the two schedules noted.

b) The negative amounts for both the forecast and actual Dawn T-service represent the allocation of the Dawn-Parkway capacity that has been used by EGD T-Service customers. The actual negative amounts were invoiced to the T-service customers.

c) Calculation of Cap and Trade Costs

2018 EGD Transportation Throughput Volumes (Jan-June)	176,018,217 GJ
Cap and Trade Rate	$ 0.006/GJ
2018 EGD Transportation Cap and Trade Costs	$ 1,056,109.30

d) The forecast third-party market-based storage amount shown on Line 4 / Column 2 of Exhibit B / Tab 1 / Appendix A / Schedule 2 includes the Chatham D and Demand Dehydration charge.

	$ (millions)
Market Based Storage	18.9
Chatham D	0.1
Demand Dehydration	1.1
	20.1

e) There are no amounts associated with the disposition of other utilities deferral accounts for 2018 recorded in the Storage and Transportation Deferral Account.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Unaccounted For Gas (UAF) Variance Account Exhibit B / Tab 1 / pp. 5-6

Preamble:

Enbridge stated that the OEB approved a 2018 UAF forecast of 106,077 10^3m^3. Due to a clerical error, all subsequent calculations have used an incorrect UAF forecast volume of 106,677 10^3m^3. The gas supply plan and resulting rates were designed based on the higher forecast UAF value and have been used as the benchmark comparator for the UAF variance account. As such, it is appropriate that the UAF forecast volumes remain at the higher value. Using the approved UAF forecast (106,077 10^3m^3) instead of the UAF value of 106,677 10^3m^3, increases the debit balance in the account by $0.096 million.

Enbridge also noted that it was directed to file a report on the issue of UAF for both the legacy EGD and Union rate zones by December 31, 2019.

Question(s):

a) Please provide a reference to the EGD 2018 rates proceeding[2] where both the approved UAF value and the UAF value including the clerical error can be found.

b) Please provide a detailed calculation supporting the $5.6 million principal balance in the account.

c) Please advise when (i.e. in which proceeding) Enbridge intends to file the study on UAF.

[2] EB-2017-0086.

<u>Response</u>

a) Please refer to EB-2017-0086, Exhibit D1, Tab 2, Schedule 4, page 4 for the UAF volumes of 106,077 103 m3 that was proposed for the EGD 2018 rates and approved as part of Decision and Rate Order, EB-2017-0086, dated December 7, 2017.

b) Attachment 1 to this response provides the detailed calculation of the 2018 UAFVA balance.

c) As directed by the Board in the MAAD's decision and Order dated August 30, 2018, Enbridge Gas will file the study on UAF by December 31, 2019. This study will be filed on a standalone basis.

Year 2018 UAFVA Calculation

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Budget UAF (103m3)	17,032.93	18,951.51	16,299.14	11,722.86	6,619.61	3,359.68	2,496.45	2,411.92	2,463.23	3,884.15	8,289.06	13,146.46	106,677.00
PGVA Rate	$ 169.45	$ 169.45	$ 169.45	$ 153.58	$ 153.58	$ 153.58	$ 153.58	$ 153.58	$ 153.58	$ 163.52	$ 163.52	$ 163.52	
Budget UAF Dollar	$ 2,886,162.17	$ 3,211,257.22	$ 2,761,824.66	$ 1,800,338.81	$ 1,016,606.45	$ 515,962.36	$ 383,392.60	$ 370,410.09	$ 378,290.46	$ 635,152.20	$ 1,355,460.16	$ 2,149,761.23	$ 17,464,618.41
Actual UAF (103m3)	19,884.22	16,895.16	14,365.44	13,845.11	7,642.33	4,371.30	3,347.37	3,210.34	3,159.83	5,546.31	10,342.06	13,936.97	116,546.44
PGVA Rate	$ 169.45	$ 169.45	$ 169.45	$ 153.58	$ 153.58	$ 153.58	$ 153.58	$ 153.58	$ 153.58	$ 163.52	$ 163.52	$ 163.52	
	$ 3,369,301.83	$ 2,862,816.79	$ 2,434,166.23	$ 2,126,262.78	$ 1,173,671.38	$ 671,322.19	$ 514,071.82	$ 493,028.03	$ 485,270.50	$ 906,955.45	$ 1,691,175.14	$ 2,279,029.09	$ 19,007,071.22
	$ 483,139.66	$ (348,440.43)	$ (327,658.42)	$ 325,923.97	$ 157,064.92	$ 155,359.82	$ 130,679.22	$ 122,617.94	$ 106,980.04	$ 271,803.24	$ 335,714.98	$ 129,267.85	$ 1,542,452.80
UAF Annual Variance													$ 4,165,162.82
Dec Actual Unbilled True Up													
2018 Damage Adjustment													$ (91,568.46)
Total 2018 UAFVA													$ 5,616,047.16

UAF Annual Varaince Allocation

17%	14%	12%	12%	7%	4%	3%	3%	3%	5%	9%	12%	
4,357.38	3,702.36	3,148.01	3,033.98	1,674.72	957.92	733.53	703.51	692.44	1,215.41	2,266.33	3,054.11	25,539.70
$ 738,340.51	$ 627,350.63	$ 533,417.20	$ 465,943.99	$ 257,195.46	$ 147,111.89	$ 112,652.43	$ 108,040.95	$ 106,340.98	$ 198,747.98	$ 370,599.96	$ 499,420.83	$ 4,165,162.82

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Enbridge noted that the 2018 budget annual use amount for Rate 1 is 2,358 m^3 and for Rate 6 is 28,656 m^3.

Question(s):

a) OEB staff is unable to reconcile the 2018 budgeted annual use amounts provided in the evidence to the Amended Settlement Proposal in EGDs' 2018 rates proceeding[3], dated December 6, 2017, where certain adjustments were made to the 2018 load and average use forecasts. Please provide a reference from the 2018 rates proceeding supporting the 2018 budgeted average use amounts (if available). Otherwise, please provide a supporting calculation.

Response

Please refer to Attachment 1 and Attachment 2 for derivations of the board-approved budget average use per customer for Rates 1 and 6.

The 2018 budget average uses as filed were 2,360.3 m^3 for Rate 1 and 28,656.4 m^3 for Rate 6. As directed in the Amended Settlement Proposal in 2018 Rate Adjustment, the volumetric forecast was reduced by approximately 4.8 10^6m^3, hence the final budgeted average uses were reduced to 2,358.0 m^3 for Rate 1 and 28,656.1 m^3 for Rate 6.

[3] EB-2017-0086.

GENERAL SERVICE RATE 1

2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE

Item.		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Exhibit Reference
1.1	Budget Volumes As filed (m^3)	803,198,093	825,397,790	716,057,956	521,602,693	286,462,839	146,184,059	112,273,290	107,770,833	107,866,513	172,351,918	366,749,480	589,072,524	4,754,987,986	EB-2017-0086, Exhibit C3, Tab 2, Schedule 1
1.2	Volumes Adjustment as per Settlement (m^3)	(803,260)	(825,693)	(716,270)	(521,543)	(286,517)	(146,211)	(112,298)	(107,793)	(107,863)	(172,400)	(366,764)	(589,307)	(4,755,919)	EB-2017-0086, Exhibit N2, Tab 1, Schedule 1, Page 9
1.3	Final Budget Volumes (m^3)	802,394,833	824,572,097	715,341,685	521,081,149	286,176,323	146,037,848	112,160,992	107,663,040	107,758,650	172,179,518	366,382,716	588,483,217	4,750,232,068	1.1 + 1.2
1.4	Customer Meters Budget	2,007,006	2,009,216	2,011,243	2,012,841	2,012,650	2,011,270	2,010,569	2,012,498	2,014,584	2,020,929	2,026,670	2,031,442		EB-2017-0086, Exhibit C3, Tab 2, Schedule 1
1.5	Budget Average Use per Customer (m^3)	400	410	356	259	142	73	56	53	53	85	181	290	2,358	1.3 / 1.4

GENERAL SERVICE RATE 6

2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE

Item.		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Exhibit Reference
1.1	Budget Volumes As filed (m^3)	729,406,650	870,020,004	740,860,231	540,689,268	316,618,208	155,829,375	110,849,892	107,680,034	108,611,393	177,179,748	385,515,813	586,532,132	4,829,792,748	EB-2017-0086, Exhibit C3, Tab 2, Schedule 1
1.2	Volumes Adjustment as per Settlement (m^3)	(5,302)	(6,299)	(5,382)	(3,921)	(2,298)	(1,134)	(807)	(791)	(797)	(1,287)	(2,799)	(4,260)	(35,076)	EB-2017-0086, Exhibit N2, Tab 1, Schedule 1, Page 9
1.3	Final Budget Volumes (m^3)	729,401,348	870,013,705	740,854,849	540,685,347	316,615,910	155,828,241	110,849,085	107,679,243	108,610,596	177,178,461	385,513,014	586,527,872	4,829,757,672	1.1 + 1.2
1.4	Customer Meters Budget	168,893	169,139	169,371	169,049	168,348	166,578	165,889	165,044	164,861	166,287	168,153	169,158		EB-2017-0086, Exhibit C3, Tab 2, Schedule 1
1.5	Budget Average Use per Customer (m^3)	4,319	5,144	4,374	3,198	1,881	935	668	652	659	1,065	2,293	3,467	28,656	1.3 / 1.4

GENERAL SERVICE RATE 1

2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE

Item.		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Exhibit Reference	
1.1	Budget Volumes As filed (m^3)	803,269,356	825,540,316	716,271,745	521,887,745	286,819,155	146,611,638	112,772,132	108,340,938	108,507,881	173,064,549	367,533,374	589,927,681	4,760,546,510	EB-2017-0086, Exhibit C3, Tab 2, Schedule 1	/U
1.2	Volumes Adjustment as per Settlement (m^3)	(874,523)	(968,219)	(930,060)	(806,596)	(642,832)	(573,790)	(611,140)	(677,898)	(749,231)	(885,031)	(1,150,658)	(1,444,464)	(10,314,442)	EB-2017-0086, Exhibit N2, Tab 1, Schedule 1, Page 9	/U
1.3	Final Budget Volumes (m^3)	802,394,833	824,572,097	715,341,685	521,081,149	286,176,323	146,037,848	112,160,992	107,663,040	107,758,650	172,179,518	366,382,716	588,483,217	4,750,232,068	1.1 + 1.2	
1.4	Customer Meters Budget	2,007,006	2,009,216	2,011,243	2,012,841	2,012,650	2,011,270	2,010,569	2,012,498	2,014,584	2,020,929	2,026,670	2,031,442		EB-2017-0086, Exhibit C3, Tab 2, Schedule 1	
1.5	Budget Average Use per Customer (m^3)	400	410	356	259	142	73	56	53	53	85	181	290	2,358.0	1.3 / 1.4	

GENERAL SERVICE RATE 6

2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE

Item.		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Exhibit Reference
1.1	Budget Volumes As filed (m^3)	729,406,650	870,020,004	740,860,231	540,689,268	316,618,208	155,829,375	110,849,892	107,680,034	108,611,393	177,179,748	385,515,813	586,532,132	4,829,792,748	EB-2017-0086, Exhibit C3, Tab 2, Schedule 1
1.2	Volumes Adjustment as per Settlement (m^3)	(5,302)	(6,299)	(5,382)	(3,921)	(2,298)	(1,134)	(807)	(791)	(797)	(1,287)	(2,799)	(4,260)	(35,076)	EB-2017-0086, Exhibit N2, Tab 1, Schedule 1, Page 9
1.3	Final Budget Volumes (m^3)	729,401,348	870,013,705	740,854,849	540,685,347	316,615,910	155,828,241	110,849,085	107,679,243	108,610,596	177,178,461	385,513,014	586,527,872	4,829,757,672	1.1 + 1.2
1.4	Customer Meters Budget	168,893	169,139	169,371	169,049	168,348	166,578	165,889	165,044	164,861	166,287	168,153	169,158		EB-2017-0086, Exhibit C3, Tab 2, Schedule 1
1.5	Budget Average Use per Customer (m^3)	4,319	5,144	4,374	3,198	1,881	935	668	652	659	1,065	2,293	3,467	28,656.1	1.3 / 1.4

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Electric Program Earnings Sharing Deferral Account
Exhibit B / Tab 1 / p. 20

Preamble:

The $1.2 million credit recorded in the 2018 Electric Program Earnings Sharing Deferral Account reflects the ratepayers' 50% share of the net recovery generated by providing conservation and demand management (CDM) activities.

Question(s):

a) Please provide a table showing a detailed breakdown of both the costs and revenues that comprise the net revenue balance in the account for each year 2014-2018.

b) Please advise whether 2018 is the last year that there is expected to be revenues recorded in this account.

Response

a) **Electric Program earnings Sharing Deferral Account ("EPESDA")**

(in $000's)	**2014**	**2015**	**2016**	**2017**	**2018**
Revenue:					
HPNC 1 Program Revenue	214	-	-	-	-
HPNC 2 Program Revenue	1,489	344	-	-	-
Energy Conservation Services	-	-	-	2,315	8,195
	1,703	344	-	2,315	8,195
Costs:					
HPNC 1 Program Costs	160	-	-	-	-
HPNC 2 Program Costs	1,558	226	-	-	-
Energy Conservation Services	-	-	-	1,011	5,861
	1,718	226	-	1,011	5,861
Net Profit / (Loss) prior to Sharing	- 15	118	-	1,304	2,334
50% Sharing	-	59	-	652	1,167
Net Profit / (Loss) post Sharing	**- 15**	**59**	**-**	**652**	**1,167**

Note: The net loss in 2014 resulted in no revenue sharing for that particular year.

b) The IESO Whole Home Pilot program wrapped up in March 2019, as a result Enbridge received homes submissions during Q1 of 2019. The revenue and costs associated with these homes will flow through the 2019 EPESDA and be disposed for through the 2019 Deferral Account clearance proceeding.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Dawn Access Costs Deferral Account
Exhibit B / Tab 1 / p. 24

Preamble:

The $1.2 million debit balance in the account reflects the 2018 revenue requirement associated with the capital spending incurred to accommodate the Dawn Transportation Service (DTS) and heat value changes, which were placed into service in 2017.

Question(s):

a) Please advise whether the tax rule change associated with Bill C-97 (effective November 20, 2018) has any impact on the revenue requirement calculation for the DTS and / or heat value changes. If yes, please confirm that the impact of the tax rule change has been included, in its entirety, in the 2018 revenue requirement calculation for these assets. If not, please explain.

Response

The tax rule change associated with Bill C-97 (effective November 20, 2018) has no impact on the revenue requirement calculation for the DTS and heat value changes. As was indicated in the pre-filed evidence, and within the EB-2018-0131 proceeding, the capital costs associated with systems modifications for DTS and heat value changes, were placed into service effective November 1, 2017, in conjunction with the implementation of Phase 2 of the Dawn Access Settlement. As such, there is no impact from tax rule changes as the capital spending was put into service before Bill C-97 was enacted and effective. Bill C-97 was enacted on June 21, 2019, and allows for accelerated CCA on capital expenditures made and placed into service on or after Nov. 21, 2018. The amount requested in this proceeding represents the 2018 revenue requirement associated with the capital spending was placed into service in 2017.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Manufactured Gas Plant Deferral Account
Exhibit B / Tab 1 / p. 29

Preamble:

The $0.967 million debit balance included in the Manufactured Gas Plant deferral account represents the accumulation of costs incurred since 2006, the year in which the account was first approved.

Question(s):

a) Please provide an excerpt from the decision where the Manufactured Gas Plant deferral account was first approved that discusses this account.

b) Please explain why the $0.967 million debit included in the Manufactured Gas Plant deferral account should be considered recoverable from ratepayers.

Response

a) Attachment 1 to this response provides an excerpt from the Board's Decision and Order from EB-2005-0001, in which it first approved the establishment of the MGPDA.

b) The Company believes that the costs included within the Manufactured Gas Plant Deferral Account are recoverable for ratepayers because, among other things, the costs have been incurred as a requirement of the ongoing operation of the utility in relation to its current or former assets used to serve customers, the costs have been prudently incurred, and no amounts have been included in base rates related to these activities (in fact, Enbridge Gas Distribution was directed to remove costs related to the Cityscape litigation from base rates in the EB-2005-0001 Decision).

All or most of the explanation for why these costs should be recoverable as set out in the pre-filed evidence in EB-2005-0001 (at Exhibit A8, Tab 4, Schedule 1, Page 17) remains applicable:

> The Company remains firmly of the view that all MGP sites were operated and decommissioned in compliance with industry and regulatory standards at all times. In the event that current environmental laws and standards impose liability on the Company for remediation costs and/or related damages, the Company submits that the reasoning and support for the recovery in rates of MGP costs in the United States are equally valid in Canada. If there is liability today, it is because of advancements in the understanding of the environmental impact of the by-products of manufactured coal gas since MGP sites were decommissioned. Recent changes to environmental laws and standards reflect changes in societal attitudes and the public's desire to address environmental issues including those of historical origin. More stringent environmental standards are the result of an enhanced understanding of the impact and risk of certain compounds, not because of past standards unobserved. If liability is imposed upon the Company, it can only be viewed as a necessary part of doing business today given the present climate and knowledge about environmental impacts. Such expenses and costs are therefore appropriately recoverable in rates.

14.14 2006 MANUFACTURED GAS PLANT VARIANCE ACCOUNT

14.14.1 This issue was previously considered by the Board in the RP-2002-0133 proceeding. In that proceeding the Board did not approve the establishment of a 2003 MGPVA on the basis that "… the evidence presented in this proceeding is not adequate to convince the Board that a deferral account of either a generic or specific nature is required at this time". The Board indicated its concern that "… the mere existence of the deferral account may imply an expectation of future recovery by the Company" and noted that "the applicant may reapply in the future for a MGPDA with greater details on the scope, potential costs, and grounds for any ratepayer responsibility for these costs." (RP-2002-0133 Decision par 753-755).

14.14.2 Enbridge noted that a litigant, Cityscape Residential Inc., is once again prosecuting its lawsuit and that there is a substantial probability that a trial will occur in 2006. For this and other reasons the Company is seeking approval for the establishment of a 2006 MGPVA. Enbridge proposed that the 2006 MGPVA record all external costs associated with:

- Responding to all enquiries, demands and court actions relating to former MGP sites;

- All oral and written communications with existing and former third party liability and property insurers of the Company;

- Conducting all necessary historical research and reviews to facilitate the Company's responses to all enquiries, demands, court actions and communications with claimants, third parties and insurers;

- Engaging appropriate experts (for example, environmental, insurance archivists, engineers, etc.) for the purposes of evaluating any alleged contamination that may have resulted from former Manufactured Gas Plant ("MGP") operations, and appropriate steps to remediate/contain/monitor such contamination, if any;

- Engaging legal counsel to respond to all demands and court actions by claimants, and to take appropriate steps in relation to the Company's existing and former third party liability and property insurers; and

- Undertaking appropriate research into the regulatory treatment of costs resulting from former MGP operations in the United States.

14.14.3 The MGPVA would also be used to record any amounts which are payable to any claimant following settlement or trial, including any damages, interest, costs and disbursements and any recoveries from insurers or third parties.

14.14.4 The Company submitted that the establishment of the MGPVA is justified because it meets the four criteria of

- materiality

- protection of the ratepayer and shareholder from benefiting at the expense of the other

- level of uncertainty associated with the forecast amount at risk and

- Company's ability to control the potential outcomes of the legal proceeding.

14.14.5 Intervenors disagreed with the proposal to establish the MGPVA and, if the account were to be established, the range of costs to be recorded. Intervenors also expressed concern that it was not clear whether Enbridge is requesting approval from the Board in principle for the recovery of the recorded costs from ratepayers. The intervenors claimed that there is insufficient and incomplete evidence upon which to grant such approval.

14.14.6 Enbridge clarified that it is requesting approval for the establishment of the variance account for amounts which it has identified specifically in its pre-filed evidence. It confirmed its expectation that the amounts recorded in the variance account would be subject to Board scrutiny in a subsequent proceeding to ensure their prudence before being cleared. Enbridge went on to advance the proposition that a broad range of costs should be recordable in the account, based upon regulated utility practice and precedent in the United States where such costs are considered, as a matter of principle, properly recovered in rates.

14.15 BOARD FINDINGS

14.15.1 It is appropriate to capture the costs incurred in managing and resolving the issues involved in these legacy operations in a deferral account, as requested by the Company.

14.15.2 The extremely complex issue as to whether ratepayers should be responsible for some or all of the possible claims and related costs has yet to be determined, and the creation of this deferral account should not be regarded as predictive of the ultimate resolution of that issue or the disposal of the sums ultimately recorded in the account.

14.15.3 The Board directs that the sum of $770,000, currently included in the O&M budget, be removed from that budget and reflected in the Deferral Account as expenditures are made, pending disposition according to the Board's determination of the underlying issues. The Board approved level of "Other O&M", which has been derived from a cost per customer index, will remain unchanged.

14.16 2006 ONTARIO HEARING COSTS VARIANCE ACCOUNT (2006 OHCVA)

14.16.1 The 2006 OHCVA is a settled item in the 2006 Settlement Proposal. However, some intervenors argued that it appeared that Enbridge was proposing to change the wording of the 2006 OHCVA from what was stipulated in pre-filed evidence, and, in effect agreed to in the Settlement Proposal.

14.16.2 In Exhibit A8 Tab 1 Schedule 1 the 2006 OHCVA is "….to record the variance between actual 2006 rate hearing expense and the budgeted level of $9.95 million as shown in evidence at Exhibit A6 Tab 7 Schedule 4." The Consumers Council of Canada argued that the Board should consider a more defined scope for the deferral account than that which appears in the Settlement Agreement.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Utility Earnings and Earnings Sharing Calculation – Capital Cost Allowance (CCA) Tax Deduction
Exhibit B / Tab 2 / pp. 1-2
Enbridge Letter on CCA Tax Deduction Issue / August 30, 2019
Exhibit C / Tab 1 / Appendix A / Schedule 8
OEB Accounting Direction regarding Bill C-97 / July 25, 2019
EB-2018-0305 / Decision and Order / September 12, 2019

Preamble:

Enbridge noted that for the EGD rate zone, the impact of the change in CCA rules resulting from Bill C-97 is reflected in the earnings sharing calculation.

In the pre-filed evidence, Enbridge stated that its earnings sharing calculation was updated to reflect a revised CCA tax deduction. The revision was made to reflect the impact of the enactment of accelerated CCA provisions contained in Bill C-97, which received Royal Assent on June 21, 2019, and to reflect an updated level of 2018 capital additions to asset pools. The impact of these changes caused a $5.2 million increase in the gross sufficiency to be shared with ratepayers, and a corresponding $2.6 million increase to the earnings sharing amount.

In its letter dated August 30, 2019, Enbridge stated that, in the EGD rate zone, the change in CCA rules is reflected in the utility income tax calculation, which impacts the gross sufficiency and the corresponding amount of earnings sharing payable to ratepayers. The 2018 impact on earnings to be shared with ratepayers related to the CCA rule change is $1.5 million (which reflects 50% of the total impact of the CCA rule change).

The OEB's accounting direction regarding Bill C-97, dated July 25, 2019, states that the OEB expects utilities to record the impacts of the CCA rule changes in the appropriate account for the period November 21, 2018 until the effective date of a utility's next cost-based rate order. For the purposes of increased transparency, the OEB is establishing a separate sub-account of Account 1592 – PILS and Tax Variances – CCA Changes specifically for the purposes of tracking the impact of changes in CCA rules. Natural gas utilities are to create separate sub-accounts within their respective similar accounts to record the same impacts.

In the Decision and Order on Enbridge's 2019 rates application[4], the OEB stated that it is appropriate for Enbridge to follow the OEB's accounting direction set out in its July 25, 2019 letter.

Question(s):

a) Please explain the difference between the $2.6 million impact on the earnings sharing amount discussed in the pre-filed evidence at Exhibit B / Tab 2 / p. 2 and the $1.5 million impact on the earnings sharing amount discussed in the August 30, 2019 letter.

b) Please provide a detailed calculation showing the impact of the CCA rule change for the EGD rate zone in a similar format to what was provided for the Union rate zones at Exhibit C / Tab 1 / Appendix A / Schedule 8.

c) Please advise whether Enbridge agrees that a tax variance account (with a subaccount for CCA rule changes) should be established for the EGD rate zone for 2018 to record the impact of the CCA rule change in accordance with the OEB's July 25, 2019 letter and the OEB's findings in Enbridge's 2019 rates application.

d) Please provide an alternative Earnings Sharing Mechanism (ESM) calculation with the impact of the CCA rule change removed with the assumption that the entirety of the CCA rule change is recorded separately in a tax variance account.

Response

a) The $2.6 million impact on the earnings sharing amount discussed in the pre-filed evidence at Exhibit B, Tab 2, page 2, represents 50% of the change in the 2018 EGD rate zone gross sufficiency calculated at year end, versus the updated 2018 gross sufficiency presented in this proceeding. The change between the year end and updated gross sufficiency amount subject to earnings sharing, was primarily attributable to two distinct updates: a change/increase in the overall level of capital additions subject to CCA (regular or accelerated), and the further impact of accelerated CCA provisions enacted as part of Bill C-97. The combined impact of

[4] EB-2018-0305.

these changes was an increase to the gross sufficiency of $5.2 million, of which 50%, or $2.6 million, was reflected in the updated earnings sharing amount payable to ratepayers. As shown in part b) of this interrogatory, the revenue requirement (or gross sufficiency) impact of Bill C-97 accelerated CCA provisions alone was approximately $3.0 million, 50% of which, or $1.5 million, was reflected within the updated earnings sharing amount.

b) Attachment 1 to this interrogatory provides the detailed calculation of the $3.0 million 2018 revenue requirement impact of Bill C-97 accelerated CCA on the EGD rate zone.

c) The Company will proceed as per the direction in the July 25, 2019 letter from the Board with respect to recording the impact of changes in CCA rules (Accelerated CCA). As there is no established Tax Variance Deferral Account (TVDA) in the EGD rate zone for 2018, the Company proposes to book 100% of the 2018 revenue requirement impact of the Accelerated CCA, a reduction of $3.0 million, as a separate identifiable item within EGI's 2019 TVDA, with disposition to be determined at a later date. However, should the Board determine that a 2018 TVDA is required, the Company will establish one accordingly. The revised Earnings Sharing Mechanism calculation, with 100% of the revenue requirement impact of the Accelerated CCA recorded separately in a TVDA, is provided as Attachment 2 to this interrogatory response. The revised calculation results in an updated 2018 earnings sharing amount of $28.4 million, as compared to the as filed amount of $29.95 million.

d) Attachment 2 to this interrogatory provides an Earnings Sharing Mechanism (ESM) calculation where the $3.0 million 2018 revenue requirement impact of the Bill C-97 CCA rule change is removed, on the assumption that the entire amount is recorded separately in a tax variance account.

EGD RATE ZONE

Calculation of the 2018 Bill C-97 Accelerated CCA Impact

Line No.	Class	Particulars ($000s)	Total Additions Qualifying for Accel. CCA (a)	Accel. CCA Depreciable UCC Balance (b)	Regular CCA Depreciable UCC Balance (c)	Rate (%) (d)	Accelerated CCA (e)	Regular CCA (f)
1	1	Buildings, structures and improvements, services, meters, mains	-	-	-	4%	0.0	0.0
2	1	Non-residential building acquired after March 19, 2007	-	-	-	6%	0.0	0.0
3	2	Mains acquired before 1988	-	-	-	6%	0.0	0.0
4	3	Buildings acquired before 1988	-	-	-	5%	0.0	0.0
5	6	Other buildings	-	-	-	10%	0.0	0.0
6	7	Compression equipment acquired after February 22, 2005	-	-	-	15%	0.0	0.0
7	8	Compression assets, office furniture, equipment	-	-	-	20%	0.0	0.0
8	10	Transportation, computer equipment	1,840.1	2,760.2	920.1	30%	828.0	276.0
9	12	Computer software, small tools	10,859.6	10,859.6	5,429.8	100%	10,859.6	5,429.8
10	13	Leasehold improvements	-	-	-	N/A	0.0	0.0
11	14.1	Intangibles	2.7	4.1	1.4	5%	0.2	0.1
12	14.1	Intangibles (pre 2017)	-	-	-	7%	0.0	0.0
13	17	Roads, sidewalk, parking lot or storage areas	-	-	-	8%	0.0	0.0
14	38	Heavy work equipment	-	-	-	30%	0.0	0.0
15	41	Storage assets	192.0	288.0	96.0	25%	72.0	24.0
16	45	Computers - Hardware acquired after March 22, 2004	-	-	-	45%	0.0	0.0
17	49	Transmission pipeline additions acquired after February 23, 2005	-	-	-	8%	0.0	0.0
18	50	Computers hardware acquired after March 18, 2007	862.7	1,294.1	431.4	55%	711.7	237.2
19	51	Distribution pipelines acquired after March 18, 2007	32,106.2	48,159.3	16,053.1	6%	2,889.6	963.2
20		Total	$ 45,863.3	63,365.2	$ 22,931.7		$ 15,361.1	$ 6,930.3

CCA Variance (e) - (f)	8,430.8
Tax Rate	26.5%
Earnings Impact of Accelerated CCA	2,234.2
Earnings Impact Grossed-up for Taxes	3,039.7
50% to be shared with Ratepayers through earnings sharing	1,519.8

SUMMARY
RETURN ON EQUITY & EARNINGS SHARING DETERMINATION
ENBRIDGE GAS DISTRIBUTION

ONTARIO UTILITY
FOR THE YEAR ENDED DECEMBER 31, 2018

Line No.	Col. 1 Description	Col. 2 Reference	Col. 3 Actual Normalized ($millions) & (%'s)
1.	**Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency**		
2.	Gas Sales		2,495.8
3.	Transportation Revenue		276.3
4.	Transmission, Compr. and Storage Revenue		19.2
5.	Less Cost of Gas		1,566.0
6.	Gas Distribution Margin		1,225.3
7.	Other Revenue		42.3
8.	Other Income		0.2
9.	Total - Other Revenue & Income		42.5
10.	Operations & Maintenance (incl. CC/CIS rate smoothing adj.)		437.5
11.	Depreciation & amortization		294.7
12.	Fixed financing costs		2.2
13.	Municipal & capital taxes		44.9
14.	Total O&M, Depr., & other		779.3
15.	Utility Income before Income Tax	(line 5 + line 9 - line 14)	488.5
16.	Less: Income Taxes		38.1
17.	**Utility Income**		**450.4**
18.	Gross plant		9,594.5
19.	Accumulated depreciation		(3,277.9)
20.	Net plant		6,316.6
21.	Working capital		412.6
22.	**Utility Rate Base**		**6,729.2**
23.	Indicated Return on Rate Base %	(line 17 / line 22)	6.693%
24.	Less: Required Rate of Return %		6.073%
25.	(Deficiency) / Sufficiency %		0.620%
26.	Net Earnings (Deficiency) / Sufficiency	(line 25 x line 22)	41.72
27.	Provision for Income Taxes		15.04
28.	Gross Earnings (Deficiency) / Sufficiency	(line 26 divide by 73.5%)	56.76
29.	**50% Earnings sharing to ratepayers**	(line 28 x 50%)	**28.38**
30.	**Part B) Return on Equity & Revenue (Deficiency) / Sufficiency**		
31.	Utility Income before Income Tax		488.5
32.	Less: Long Term Debt Costs		181.2
33.	Less: Short Term Debt Costs		6.9
34.	Less: Cost of Preferred Capital		2.6
35.	Net Income before Income Taxes		297.8
36.	Less: Income Taxes		38.1
37.	Net Income Applicable to Common Equity	(line 35 - line 36)	259.7
38.	Common Equity		2,422.5
39.	Approved ROE %		9.000%
40.	Achieved Rate of Return on Equity %	(line 37 divide by line 38)	10.721%
41.	Resulting (Deficiency) / Sufficiency in Return on Equity %		1.721%
42.	Net Earnings (Deficiency) / Sufficiency	(line 38 x line 41)	41.70
43.	Provision for Income Taxes		15.03
44.	Gross Earnings (Deficiency) / Sufficiency	(line 42 divide by 73.5%)	56.73
45.	**50% Earnings sharing to ratepayers**	(line 44 x 50%)	**28.37**

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Utility Earnings and Earnings Sharing Calculation – 2018 Capital Expenditures
Exhibit B / Tab 2 / Appendix B / Schedule 4 / p. 4

Preamble:

Enbridge stated that the increased capital spend on Information Technology was primarily due to the implementation cost of EGD's Customer Experience Program of $14.4 million. Enbridge noted that this project aims to make interaction with customers easier, provide seamless customer service experiences, and lower OM&A costs.

Question(s):

a) Please provide further details on how EGD's Customer Experience Program provides an easier and seamless customer service experience.

b) Please provide the original and final capital costs for this project.

c) Please provide the expected OM&A savings resulting from this project.

Response

a) EGD's Customer Experience program encompassed a variety of investments in technology related to customer service. The most direct was a re-build of the myAccount self-serve platform used by over 1 million mass market customers. The goal of the program was to drive down both inbound call volumes and back-office (billing) exception work. By providing a more modern and simplified experience, customers can complete many of the most common transactions traditionally handled in the call centre through myAccount. With myAccount now able to handle transactions ranging from the simple (balance inquiry) to complex (appointment scheduling of a collection account unlock) customers are more likely to self-serve driving down inbound call volumes.

The best example of this more seamless experience can be seen with move in/move out transactions processed in myAccount. In 2016, approximately 30% of moves were completed in myAccount. In 2018 this increased to 42%. By fully integrating with EGD's SAP CIS, over 60% of these transactions were fully automated with no customer call or back-office work to process, reducing EGD's total cost to serve. From a customer satisfaction perspective, EGD's NPS (Net Promoter Score), increased from an average of 11.3 in March/April 2018 (when Qualtrics was implemented) to over 20 by January 2019.

Other investments include a new back-office workflow management system, improved bill estimation logic using advanced analytics, a voice-of-the-customer survey platform (Qualtrics) and a re-designed bill statement.

b) Please refer to the table below for planned vs actual costs.

Year	Business Case	Actual
2018	$8 million	$14.4 million
2019	$24 million	$11.3 million
2020	$5 million	$0

c) The program established a baseline of activity in 2016 to measure savings. Call volumes (live agent) went from 1.61 M in 2016 to 1.34 M in 2018, a 16.9% decrease.

OM&A savings in 2018 come from three areas:

- Reduced call volumes - $4.4 million
- Reduced back-office (billing exception) work - $3.7 million
- Reduced postage with increase in eBill customers - $1.3 million (approximate based on increase in eBill adoption of 6% in 2018)

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Utility Earnings and Earnings Sharing Calculation – Merger-related Costs
Exhibit B / Tab 2 / Appendix D / Schedule 1 / p. 5
EB-2018-0105 / Exhibit B.Staff.16
EB-2018-0105 / Exhibit B.LPMA.13

Preamble:

Enbridge made an adjustment to its utility earnings calculation to remove the EGD / Union amalgamation transaction costs of $0.1 million. However, OEB staff found no direct references to Enbridge Inc. and Spectra Energy merger costs and savings in the current application. OEB staff notes that in Union's 2017 deferral account disposition proceeding[5], there were 2017 costs associated with the merger of Enbridge Inc. and Spectra Energy of $5.6 million (which reflected the utility portion). In addition, there were cost savings of $3.7 million associated with the merger.

Question(s):

a) Please provide the total 2018 merger-related costs and savings for the EGD rate zone (similar to the types of costs and savings provided in Union's 2017 deferral account disposition proceeding). Please also provide a detailed breakdown of these costs and savings.

b) Please indicate whether these merger-related costs and savings have been included in the earnings sharing calculation for the EGD rate zone. If so, please provide rationale supporting the inclusion of these costs and savings in the earnings sharing calculation.

c) If applicable, please explain how the merger-related costs and savings were allocated (including rationale) between the EGD rate zone and the Union rate zones for earnings sharing calculation purposes. Please also provide any

[5] EB-2018-0105.

supporting calculations.

d) If applicable, please provide revised earnings sharing calculations for the EGD rate zone as follows:
   i. Merger-related costs removed
   ii. Merger-related costs and savings removed

Response

a) Please see Table below for the 2018 merger-related costs and savings for the EGD rate zone

$ 000's	2018
Merger-Related Costs	7,622
Merger-Related Savings	(262)

b) Yes, the merger related costs and savings identified in part a) are reflected in the earnings sharing calculation for the EGD rate zone. In preparing for the pending merger/amalgamation of Enbridge Gas Distribution and Union Gas Limited, role redundancies and opportunities for synergy savings were identified. The role reductions and synergies resulted in nominal savings in 2018, as a result of occurring late in the year, but will result in ongoing cost savings for Enbridge Gas Inc. annually, which will be reflected in utility earnings subject to sharing with ratepayers, and in lower costs at the time of rebasing. As the cost savings will flow through utility earnings to the benefit of ratepayers, and will be reflected in rates at the time of rebasing, the costs associated with generating these savings should also flow through utility earnings. This treatment is consistent with the manner in which EGD reflected costs of severances in past years.

c) The merger related costs and savings were not allocated between the EGD Rate Zone and Union Rate Zones. The costs and savings for each rate zone reflect where the underlying role reductions occurred.

d) Please see Attachment 1 for the earnings sharing calculation excluding merger related costs and Attachment 2 for the earnings sharing calculation excluding merger related costs and savings.

SUMMARY
RETURN ON EQUITY & EARNINGS SHARING DETERMINATION
ENBRIDGE GAS DISTRIBUTION

ONTARIO UTILITY
FOR THE YEAR ENDED DECEMBER 31, 2018

	Col. 1	Col. 2	Col. 3
Line No.	Description	Reference	Actual Normalized ($millions) & (%'s)
1.	**Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency**		
2.	Gas Sales	(Ex.B,T2,App.E,S2,P1,Col.1,line 1)	2,498.8
3.	Transportation Revenue	(Ex.B,T2,App.E,S2,P1,Col.1,line 2)	276.3
4.	Transmission, Compr. and Storage Revenue	(Ex.B,T2,App.E,S2,P1,Col.1,line 3)	19.2
5.	Less Cost of Gas	(Ex.B,T2,App.E,S2,P1,Col.1,line 8)	1,566.0
6.	Gas Distribution Margin		1,228.3
7.	Other Revenue	(Ex.B,T2,App.E,S2,P1,Col.1,line 4)	42.3
8.	Other Income	(Ex.B,T2,App.E,S2,P1,Col.1,line 6)	0.2
9.	Total - Other Revenue & Income		42.5
10.	Operations & Maintenance (incl. CC/CIS rate smoothing adj.)	(Ex.B,T2,App.E,S2,P1,Col.1,line 9)	429.9 [1]
11.	Depreciation & amortization	(Ex.B,T2,App.E,S2,P1,Col.1,line 10)	294.7
12.	Fixed financing costs	(Ex.B,T2,App.E,S2,P1,Col.1,line 11)	2.2
13.	Municipal & capital taxes	(Ex.B,T2,App.E,S2,P1,Col.1,line 12)	44.9
14.	Total O&M, Depr., & other		771.7
15.	Utility Income before Income Tax	(line 5 + line 9 - line 14)	499.1
16.	Less: Income Taxes	(Ex.B,T2,App.E,S2,P1,Col.1,line 17)	40.9
17.	**Utility Income**		**458.2**
18.	Gross plant	(Ex.B,T2,App.B,S1,P1,Col.1,line 1)	9,594.5
19.	Accumulated depreciation	(Ex.B,T2,App.B,S1,P1,Col.1,line 2)	(3,277.9)
20.	Net plant		6,316.6
21.	Working capital	(Ex.B,T2,App.B,S1,P1,Col.1,line 11)	412.8
22.	**Utility Rate Base**		**6,729.4**
23.	Indicated Return on Rate Base %	(line 17 / line 22)	6.809%
24.	Less: Required Rate of Return %	(Ex.B,T2,App.E,S1,P1,Col.4,line 6)	6.073%
25.	(Deficiency) / Sufficiency %		0.736%
26.	Net Earnings (Deficiency) / Sufficiency	(line 25 x line 22)	49.53
27.	Provision for Income Taxes		17.86
28.	Gross Earnings (Deficiency) / Sufficiency	(line 26 divide by 73.5%)	67.39
29.	**50% Earnings sharing to ratepayers**	(line 28 x 50%)	**33.70**
30.	**Part B) Return on Equity & Revenue (Deficiency) / Sufficiency**		
31.	Utility Income before Income Tax	(Ex.B,T2,App.E,S2,P1,Col.1,line 16)	499.1
32.	Less: Long Term Debt Costs	(Ex.B,T2,App.E,S1,P1,Col.5,line 1)	181.2
33.	Less: Short Term Debt Costs	(Ex.B,T2,App.E,S1,P1,Col.5,line 2)	6.9
34.	Less: Cost of Preferred Capital	(Ex.B,T2,App.E,S1,P1,Col.5,line 4)	2.6
35.	Net Income before Income Taxes		308.4
36.	Less: Income Taxes	(Ex.B,T2,App.E,S2,P1,Col.1,line 17)	40.9
37.	Net Income Applicable to Common Equity	(line 35 - line 36)	267.5
38.	Common Equity	(Ex.B,T2,App.E,S1,P1,Col.1,line 5)	2,422.6
39.	Approved ROE %		9.000%
40.	Achieved Rate of Return on Equity %	(line 37 divide by line 38)	11.044%
41.	Resulting (Deficiency) / Sufficiency in Return on Equity %		2.044%
42.	Net Earnings (Deficiency) / Sufficiency	(line 38 x line 41)	49.51
43.	Provision for Income Taxes		17.85
44.	Gross Earnings (Deficiency) / Sufficiency	(line 42 divide by 73.5%)	67.36
45.	**50% Earnings sharing to ratepayers**	(line 44 x 50%)	**33.68**

Notes
1. Excludes merger related costs of $7.6 million.

SUMMARY
RETURN ON EQUITY & EARNINGS SHARING DETERMINATION
ENBRIDGE GAS DISTRIBUTION

ONTARIO UTILITY
FOR THE YEAR ENDED DECEMBER 31, 2018

	Col. 1	Col. 2	Col. 3
Line No.	Description	Reference	Actual Normalized ($millions) & (%'s)
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6.	Gas Distribution Margin		1,228.3
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8.	Other Income	(Ex.B,T2,App.E,S2,P1,Col.1,line 6)	0.2
9.	Total - Other Revenue & Income		42.5
10.	Operations & Maintenance (incl. CC/CIS rate smoothing adj.)	(Ex.B,T2,App.E,S2,P1,Col.1,line 9)	430.1 [1]
11.	Depreciation & amortization	(Ex.B,T2,App.E,S2,P1,Col.1,line 10)	294.7
12.	Fixed financing costs	(Ex.B,T2,App.E,S2,P1,Col.1,line 11)	2.2
13.	Municipal & capital taxes	(Ex.B,T2,App.E,S2,P1,Col.1,line 12)	44.9
14.	Total O&M, Depr., & other		771.9
15.	Utility Income before Income Tax	(line 5 + line 9 - line 14)	498.9
16.	Less: Income Taxes	(Ex.B,T2,App.E,S2,P1,Col.1,line 17)	40.8
17.	**Utility Income**		**458.1**
18.	Gross plant	(Ex.B,T2,App.B,S1,P1,Col.1,line 1)	9,594.5
19.	Accumulated depreciation	(Ex.B,T2,App.B,S1,P1,Col.1,line 2)	(3,277.9)
20.	Net plant		6,316.6
21.	Working capital	(Ex.B,T2,App.B,S1,P1,Col.1,line 11)	412.8
22.	**Utility Rate Base**		**6,729.4**
23.	Indicated Return on Rate Base %	(line 17 / line 22)	6.807%
24.	Less: Required Rate of Return %	(Ex.B,T2,App.E,S1,P1,Col.4,line 6)	6.073%
25.	(Deficiency) / Sufficiency %		0.734%
26.	Net Earnings (Deficiency) / Sufficiency	(line 25 x line 22)	49.39
27.	Provision for Income Taxes		17.81
28.	Gross Earnings (Deficiency) / Sufficiency	(line 26 divide by 73.5%)	67.20
29.	**50% Earnings sharing to ratepayers**	(line 28 x 50%)	**33.60**
30.	**Part B) Return on Equity & Revenue (Deficiency) / Sufficiency**		
31.	Utility Income before Income Tax	(Ex.B,T2,App.E,S2,P1,Col.1,line 16)	498.9
32.	Less: Long Term Debt Costs	(Ex.B,T2,App.E,S1,P1,Col.5,line 1)	181.2
33.	Less: Short Term Debt Costs	(Ex.B,T2,App.E,S1,P1,Col.5,line 2)	6.9
34.	Less: Cost of Preferred Capital	(Ex.B,T2,App.E,S1,P1,Col.5,line 4)	2.6
35.	Net Income before Income Taxes		308.2
36.	Less: Income Taxes	(Ex.B,T2,App.E,S2,P1,Col.1,line 17)	40.8
37.	Net Income Applicable to Common Equity	(line 35 - line 36)	267.4
38.	Common Equity	(Ex.B,T2,App.E,S1,P1,Col.1,line 5)	2,422.6
39.	Approved ROE %		9.000%
40.	Achieved Rate of Return on Equity %	(line 37 divide by line 38)	11.039%
41.	Resulting (Deficiency) / Sufficiency in Return on Equity %		2.039%
42.	Net Earnings (Deficiency) / Sufficiency	(line 38 x line 41)	49.39
43.	Provision for Income Taxes		17.81
44.	Gross Earnings (Deficiency) / Sufficiency	(line 42 divide by 73.5%)	67.20
45.	**50% Earnings sharing to ratepayers**	(line 44 x 50%)	**33.60**

Notes
1. Excludes merger related costs and savings of $7.4 million.

ENBRIDGE GAS INC.

Answer to Interrogatory from Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Clearance of 2018 Union South Storage and Transportation Account to
EGD Rate Zone Customers
Exhibit B / Tab 3 / p. 2

Preamble:

Enbridge stated that the 2018 Union South Storage and Transportation account will be disposed to EGD rate zone customers as part of the 2019 deferral account disposition proceeding.

Question(s):

a) Please further explain why a Union rate zone-related deferral account will be disposed to EGD rate zone customers. Please also explain why Enbridge intends to address this issue as part of the 2019 deferral account disposition proceeding (as opposed to the current proceeding).

Response

The 2018 deferral and variance account balances of the Union rate zones allocated to Rate M12, Rate C1 and Rate M16 rate classes will be cleared to all customers taking service under these rate classes, including the EGD rate zone, as part of this proceeding.

The clearance amount will be recorded by the EGD rate zone in its Storage and Transportation Deferral Account in 2019 and disposed of as part of the 2019 Disposition of Deferral and Variance Account Balances proceeding to EGD rate zone customers.

This approach of deferral and variance account disposition is consistent with treatment and timing of account balances by legacy EGD and legacy Union prior to amalgamation.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Deferral and Variance Account Balance Summary
Exhibit C / Tab 1 / Appendix A / Schedule 1 / p. 1

Preamble:

Enbridge requested disposition of gas supply, storage and other deferral accounts. The net balance in the deferral accounts for disposition for the Union rate zones is a $38.3 million credit to ratepayers as at January 1, 2020.

Question(s):

a) Please provide a statement confirming whether the balances proposed for disposition are consistent with the account balances reported in the applicant's 2018 RRR filing (2.7.1) and its 2018 audited financial statements. If not, please provide a reconciliation of the balances.

b) For each account requested for disposition, please provide a continuity schedule for the period commencing from the establishment of the account or from the last approved disposition of the account, whichever is more recent, to the date of the most recent audited actuals. This continuity should show separate itemization of opening balances, new amounts recorded during the period, approved dispositions, other adjustments, interest, and closing balances.

c) Please advise whether there are any deferral and variance accounts that are currently approved for use by Enbridge for the Union rate zones but have not been listed in the Deferral and Variance Account Balance Summary (with the exception of the QRAM-related deferral accounts, DSM-related deferral accounts, and the cap and trade-related deferral accounts). If so, please list each account name and the corresponding balance in the account as at December 31, 2018 (including interest). Please also explain the nature of each account and why it is not being brought forward for disposition as part of this proceeding. This should include any accounts that had been opened in previous years but were never disposed.

d) Were there any adjustments made to deferral and variance account balances that were previously approved by the OEB on a final basis? If so, please provide an explanation of the nature and amount of any adjustment and include any supporting documentation.

Response

a) The balances proposed for disposition are consistent with the account balances reported in Union's 2018 RRR filing and the 2018 audited financial statements with the following exceptions:

   - Certain deferral accounts had true-ups recorded in 2019. For details, please refer to Attachment 1, Column (h).

b) Please see Attachment 1.

c) There are no deferral and variance accounts that were approved for use during 2018, by the Union rate zones, that have not been listed in the Deferral and Variance Account Summary, with the exception of the QRAM-related deferral accounts, DSM-related deferral accounts, and the cap and trade-related deferral accounts.

d) Yes. As discussed in Exhibit C, Tab 1, page 31, included within the 2018 deferral balance there was a $0.153 million credit adjustment to the Parkway West Project Costs deferral account as a result of the assessment authority not reclassifying the Parkway West site from Farmland to Commercial land as anticipated. The property tax component of the revenue requirement that is included in rates assumes a commercial assessed value. The property tax component of the 2016 actual revenue requirement represents the expected amount of property taxes that would be levied for 2016, once the reclassification from Farmland to Commercial land was complete. As of January 2019, the assessment authority had not reclassified the land. As per Section 33 of the Assessment Act, the assessment authority can no longer go back to 2016 for reassessment; therefore the 2016 taxes are now statute-barred. The $0.153 million credit represents the difference between the forecasted property taxes for Commercial assessed value and the actual property taxes for Farmland assessed value.

Deferrals Continuity Schedule ($000's)

No.	Account Number	Account Name	Balance at Dec. 31, 2017	2018 True-up to 2017 Balance	Interest on 2017 Balance	2017 Deferrals Disposition	2018 Activity	2018 Interest on 2018 Balance	Balance at Dec. 31, 2018	2019 True-up to 2018 Balance	2019 Forecasted Interest on 2018 Balance	2018 Total	2018 Filed	Difference
			(a)	(b)	(c)	(d)	(e)	(f)	(g) = (a)+(b)+...+(f)	(h)	(i)	(j) = (g) + (h) + (i)	(k)	(l) = (j) - (k)
1	179-70	Short-Term Storage and Other Balancing Services	1,183	-	22	(1,205)	1,413	7	1,420	-	25	1,445	1,445	-
2	179-108	Unabsorbed Demand Costs (UDC) Variance Account	(4,159)	-	(77)	4,236	(9,712)	(102)	(9,814)	-	(218)	(10,032)	(10,033)	1 [1]
3	179-112	Gas Distribution Access Rule (GDAR) Costs	76	-	1	(77)	-	-	-	-	-	-	-	-
4	179-123	Conservation Demand Management	(245)	-	(5)	250	(1,054)	(8)	(1,062)	-	(24)	(1,086)	(1,085)	(1) [1]
5	179-131	Upstream Transportation Optimization	11,057	-	206	(11,263)	10,273	47	10,320	-	184	10,504	10,503	1 [1]
6	179-132	Deferral Clearing Variance Account	2,590	-	48	(2,638)	(1,736)	(20)	(1,756)	-	(39)	(1,795)	(1,795)	-
7	179-133	Normalized Average Consumption	(2,914)	-	(55)	2,969	(20,322)	(204)	(20,526)	-	(457)	(20,983)	(20,983)	-
8	179-134	Tax Variance	(293)	(38)	(6)	337	(398)	(2)	(400)	(955)	(20)	(1,375)	(1,376)	1 [1]
9	179-135	Unaccounted for Gas (UFG) Volume Variance Account	1	-	(1)	-	1,383	13	1,396	350	36	1,782	1,783	(1) [1]
10	179-136	Parkway West Project Costs	(601)	73	(10)	538	149	7	156	(169)	1	(12)	(11)	(1) [1]
11	179-137	Brantford-Kirkwall/Parkway D Project Costs	(760)	(108)	(16)	884	(824)	(10)	(834)	-	(19)	(853)	(853)	-
12	179-138	Parkway Obligation Rate Variance	(121)	-	(2)	123	-	-	-	288	5	293	293	-
13	179-141	Unaccounted for Gas (UFG) Price Variance Account	164	(61)	2	(105)	2,007	18	2,025	21	46	2,092	2,091	1 [1]
14	179-142	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	(5,735)	(592)	(115)	6,442	(5,824)	(45)	(5,869)	(12)	(131)	(6,012)	(6,012)	-
15	179-143	Unauthorized Overrun Non-Compliance Account	(8)	-	-	8	(5)	-	(5)	-	-	(5)	(5)	-
16	179-144	Lobo D/Bright C/Dawn H Compressor Project Costs	4,130	572	83	(4,785)	(7,148)	(52)	(7,200)	(88)	(161)	(7,449)	(7,449)	-
17	179-149	Burlington-Oakville Project Costs	(3,371)	(106)	(64)	3,541	(3,358)	(25)	(3,383)	(3)	(75)	(3,461)	(3,462)	1 [1]
18	179-151	OEB Cost Assessment Variance Account	1,167	(1,159)	(8)	-	1,203	13	1,216	-	27	1,243	1,243	-
19	179-156	Panhandle Reinforcement Project Costs	59	24	1	(84)	(2,262)	(8)	(2,270)	(79)	(52)	(2,401)	(2,401)	-
20	179-157	Pension and OPEB Forecast Accrual vs Actual Cash	-	-	-	-	-	-	-	(228)	-	(228)	(228)	-

Notes:

1 Rounding.

2 Amounts in the 'Balance at Dec. 31, 2018' column (g) agree with balances reported in the 2018 RRR filing and the 2018 audited financial statements, with the exception of $1 for rounding.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Upstream Transportation Optimization Variance Account
Exhibit C / Tab 1 / pp. 7-8

Preamble:

Enbridge noted that, on an actual basis, it credited $16.84 million in rates in 2018 related to optimization revenues. This is $3.41 million greater than the OEB-approved amount of $13.43 million.

Question(s):

a) Please provide the detailed calculation supporting the actual $16.84 million amount credited in rates.

Response

a) Please see Table 1 below.

Table 1
Calculation of 2018 Gas Supply Optmization Margin in Rates

Line no.	Rate Class	2018 Billing Units (10^3M^3)	Unit Rate (cent/m^3) (1)	Amount ($ 000's)
		(a)	(b)	(c)=(a*b/100)
1	Rate 01	1,030,109	(0.4229)	(4,356)
2	Rate 10	360,440	(0.3906)	(1,408)
3	Rate 20 - Demand (2)	6,296	(4.1642)	(262)
4	Rate 20 - Transportation	64,283	(0.2597)	(167)
5	Rate 25	71,233	(0.2720)	(194)
6	Total Union North	1,532,361		(6,387)
7	Rate M1	2,960,778	(0.2824)	(8,361)
8	Rate M2	634,774	(0.2824)	(1,793)
9	Rate M4	44,094	(0.2824)	(125)
10	Rate M5	6,721	(0.2824)	(19)
11	Rate M7	26,514	(0.2824)	(75)
12	Rate M9	27,915	(0.2824)	(79)
13	Rate M10	410	(0.2824)	(1)
14	Total Union South	3,701,207		(10,452)
15		5,233,568		(16,839)

Notes:
(1) - EB-2017-0087, Rate Order, Working Papers, Schedule 14, p. 2
(2) - Rate 20 Gas Supply Demand Billing Units are shown in 10^3m^3/d.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Short-Term Storage and Other Balancing Services
Exhibit C / Tab 1 / pp. 9-11
Exhibit C / Tab 1 / Appendix A / Schedule 3

Question(s):

a) Please explain the year-over-year reduction from $0.71 million (2017 actual) to $0.14 million (2018 actual) for C1 Off-Peak Storage (Line 1 at Exhibit C / Tab 1 / Appendix A / Schedule 3).

b) Please explain the drivers for the difference between the compressor fuel costs (Line 10 at Exhibit C / Tab 1 / Appendix A / Schedule 3) of $1.20 million (2013 Board Approved) and $0.38 million (2018 actual).

Response

a) The year-over-year reduction for C1 Off-Peak Storage can be attributed to the market value of Off-peak Storage being lower than the prior year, and the availability of Off-Peak Storage to sell.

b) The difference between the compressor fuel costs is driven by the amount of excess in-franchise storage capacity and the amount of non-peak activity relative to the Board Approved activity.

   The Board Approved amount being 11.3 PJ's of Peak Space to sell is much higher than the 7.6 PJ from 2018, and activity from other non-peak short-term services has seen an overall drop. Therefore, with less activity overall versus board approved, a drop in compressor fuel costs is expected.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Conservation Demand Management Deferral Account
Exhibit C / Tab 1 / p. 16

Preamble:

Enbridge stated that the balance in the CDM deferral account is a credit to ratepayers of $1.09 million, which reflects 50% of the net revenue associated with the "Whole Home Pilot Delivery" program.

Question(s):

a) Please provide a table showing a detailed breakdown of both the costs and revenues that comprise the net revenue balance in the account for each year 2014-2018.

b) Please advise whether 2018 is the last year that there is expected to be revenues recorded in this account.

Response

a)

Enbridge Gas Inc.
Legacy Union Gas - CDM Deferral Account
October 9, 2019

Particulars ($000s)	**2014**	**2015**	**2016**	**2017**	**2018**
Revenues	2,581	2,133	-	3,110	11,766
Costs	2,076	1,711	-	2,620	9,658
Net Revenues	505	422	-	490	2,108
Filed Deferral Balance (50% of Net Revenue)	253	211	-	245	1,054

b) The IESO Whole Home Pilot program wrapped up in March 2019, as a result Enbridge received homes submissions during Q1 of 2019. The revenue and costs associated with these homes will flow through the 2019 CDM deferral account and be disposed for through the 2019 Deferral Account clearance proceeding.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Tax Variance Deferral Account and Capital Pass-through Project deferral accounts (tax-related issues)
Exhibit C / Tab 1 / pp. 25-28
Exhibit C / Tab 1 / Appendix A / Schedule 8
Enbridge Letter on CCA Tax Deduction Issue / August 30, 2019
OEB Accounting Direction regarding Bill C-97 / July 25, 2019
EB-2018-0305 / Decision and Order / September 12, 2019

Preamble:

Enbridge noted that for the Union rate zones, 50% of the impact of the change in CCA rules resulting from Bill C-97 is reflected in the Tax Variance deferral account ($0.94 million) (except for capital pass-through projects). For capital pass-through projects, the impact of the change in CCA rules is reflected in the relevant capital pass-through project deferral accounts.

The OEB's accounting direction regarding Bill C-97 states that the OEB expects utilities to record the impacts of the CCA rule changes in the appropriate account for the period November 21, 2018 until the effective date of a utility's next cost-based rate order. For the purposes of increased transparency, the OEB is establishing a separate subaccount of Account 1592 – PILS and Tax Variances – CCA Changes specifically for the purposes of tracking the impact of changes in CCA rules. Natural gas utilities are to create separate sub-accounts within their respective similar accounts to record the same impacts.

In the Decision and Order on Enbridge's 2019 rates application[6], the OEB stated that it is appropriate for Enbridge to follow the OEB's accounting direction set out in its July 25, 2019 letter.

[6] EB-2018-0305.

Question(s):

a) If the entirety of the impact of the CCA rule change for the Union rate zones were to be reflected in the Tax Variance deferral account (except for the impact associated with capital pass-through projects), please confirm that the value to be recorded in the account for the CCA rule change impact would be $1.88 million.

b) Please advise whether Enbridge agrees that a sub-account for CCA rule changes should be established within the Tax Variance deferral account for the Union rate zones for 2018 to record the impact of the CCA rule change (except for the impact associated with capital pass-through projects) in accordance with the OEB's July 25, 2019 letter and the OEB's findings in Enbridge's 2019 rates application.

c) Please confirm that 100% of the impact of the CCA rule change is reflected in the capital pass-through project deferral accounts.

d) Please confirm that the total impact of the CCA rule change related to the capital pass-through projects is $0.31 million.

e) Please explain why the CCA rule change impact is treated differently for the capital additions associated with the capital pass-through projects relative to the capital additions that are not associated with a capital pass-through project.

f) For each capital pass-through project deferral account, please provide the calculation of the CCA rule change impact in a similar format to Exhibit C / Tab 1 / Appendix A / Schedule 8.

Response

a) Confirmed.

b) The Company will proceed as per the direction in the July 25, 2019 letter from the Board with respect to recording the impact of changes in CCA rules (Accelerated CCA), except for the impact associated with capital pass-through projects captured in their respective deferral accounts. The Company proposes to book 100% of the 2018 revenue requirement impact of the Accelerated CCA, a reduction of $1.88 million, as a separate identifiable item in the 2019 Tax Variance Deferral Account (TVDA) for EGI, with disposition to be determined at a later date. However, should the Board determine that the 2018 amount is to be booked in the 2018 TVDA, the

Company will update the description of the TVDA to capture 100% of the revenue requirement impact of Accelerated CCA. The revised Earnings Sharing Mechanism calculation, with 100% of the revenue requirement impact of Accelerated CCA recorded separately in the 2019 TVDA, is provided as Attachment 1 to this interrogatory response. The revised calculation is unchanged from the as filed calculation, with the exception that an updated description for the elimination of accelerated CCA impacts has been included.

c) Confirmed. The impact of the Bill C-97 CCA rule change, in relation to 2018 capital additions associated with capital pass-through projects established in the 2014-2018 period, is reflected in the capital pass-through project deferral accounts. Any 2018 impacts related to capital additions for the Sudbury Replacement Project, which was approved as a capital pass through project in 2019, are reflected in the Tax Variance Deferral Account.

d) Confirmed. The total revenue requirement impact of the Bill C-97 CCA rule change, in relation to 2018 capital additions associated with capital pass-through projects established in the 2014-2018 period, is $0.314 million.

e) Parties agreed in the Board-approved Incentive Regulation (“IR”) Agreement that Union’s 2014-2018 IR term would include Y factor treatment for major capital projects subject to meeting certain eligibility criteria[7]. Capital pass-through projects are major capital additions that the Board has approved for Y factor treatment as part of their respective leave-to-construct applications and are subject to their own variance account treatment. Each respective variance account captures the difference between the actual revenue requirement related to the cost of the project and the revenue requirement included in rates as approved by the Board, with 100% pass-through to customers. Impacts of the CCA rule change reduce the actual revenue requirement in relation to capital additions that are specifically related to capital pass-through projects, and therefore should flow through the respective project variance account at full ratepayer benefit. Capital additions that are not in relation to capital pass-through projects, are not subject to their own variance account treatment and the impacts are therefore be reflected in the amounts captured in the Tax Variance Deferral Account.

f) Please see Attachment 2 for the calculation of the CCA rule change impact on each capital pass-through project in a similar format to Exhibit C, Tab 1, Appendix A,

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[7] EB-2013-0202, 2014-2018 Incentive Regulation, Settlement Agreement, Section 6.6.

Schedule 8. Note, there were no 2018 accelerated CCA impacts on the Brantford-Kirkwall/Parkway D Project.

UNION RATE ZONES
Earnings Sharing Calculation
Calendar Year Ending December 31, 2018

Line No.	Particulars ($000s)	2018 (a)	Non-Utility Storage (b)	Adjustments (c)		2018 Utility (d)=(a)-(b)+(c)
	Operating Revenues					
1	Gas Sales	1,812,564	-	(19,447)	i.	1,793,117
2	Transportation	258,512	(367)	-		258,879
3	Storage	151,772	143,609	-		8,163
4	Other	23,924	-	(6,119)	ii	17,805
5		2,246,773	143,242	(25,566)		2,077,965
	Operating Expenses					
6	Cost of gas	960,481	36,499	(16,839)	i.	907,143
7	Operating and maintenance expenses	461,872	13,451	(1,494)	iii	446,928
8	Depreciation	287,543	10,676	-		276,867
9	Other financing	-	-	998	iv	998
10	Property and other taxes	77,786	1,489	-		76,297
11		1,787,683	62,115	(17,335)		1,708,234
	Other					
12	Gain / (Loss) on sale of assets	(1,803)	(1,824)	-		21
13	Other / Huron Tipperary	-	-	-		-
14	Gain / (Loss) on foreign exchange	3,028	2,282	493	v	1,239
15		1,225	458	493		1,260
16	Earnings before interest and taxes	460,315	81,585	(7,738)		370,991
17	Income taxes					(6,012)
18	Total utility income subject to earnings sharing					377,002
	Less debt and preference share return components					
19	Long-term debt					161,247
20	Unfunded short-term debt					3,226
21	Preferred dividend requirements					2,901
22						167,374
	Less shareholder portions of:					
23	Net short-term storage revenue (after tax)					256
24	Net optimization activity (after tax)					536
25						793
26	Earnings subject to sharing					208,836
27	Common equity					2,166,613
28	Return on equity (line 26 / line 27)					9.64%
29	Benchmark return on equity					9.93%
30	50% earnings sharing % (line 28 - line 29, maximum 1%)					0.00%
31	90% earnings sharing % (if line 30=1%, then line 28 - line 29 - line 30)					0.00%
32	50% earnings sharing $ (line 27 x line 30 x 50%)					-
33	90% earnings sharing $ (line 27 x line 31 x 90%)					-
34	Total earnings sharing $ (line 32 + line 33)					-
35	Pre-tax earnings sharing (line 34 / (1 minus tax rate)					-

Notes:

i	Reclassification of optimization revenue as cost of gas	(16,839)
	Reduction to revenue to reflect the impact of Bill C-97 (accelerated CCA), enacted June 21, 2019:	
	Impact captured in CPT deferral accounts	(314)
	Eliminate 100% of non-CPT CCA impact captured in Tax Variance Deferral Account	(1,880)
	Total Asset CCA Impact	(2,194)
	Elimination for shareholder 50% of HST tax variance impact	(413)
	Total	(19,447)
ii	Demand-side management incentive	
iii	Donations	2,547
	CDM program	(1,054)
		1,494
iv	Facility fees and customer deposit interest	
v	Foreign exchange gain on bank balances	

UNION GAS LIMITED RATE ZONE

Calculation of the 2018 Bill C-97 Accelerated CCA Impact on Capital Pass-through Projects

Line No.	Class	Particulars ($000s)	Total Additions Qualifying for Accel. CCA (a)	Accel. CCA Depreciable UCC Balance (b)	Regular CCA Depreciable UCC Balance (c)	Rate (%) (d)	Accelerated CCA (e)	Regular CCA (f)
		Parkway West Project						
	Class							
1	1	Non-residential building acquired after March 19, 2007	-	-	-	6%	0.0	0.0
2	7	Compression equipment acquired after February 22, 2005	491.3	737.0	245.7	15%	110.5	36.8
3	8	Compression assets, office furniture, equipment	-	-	-	20%	0.0	0.0
4	41	Storage assets	-	-	-	25%	0.0	0.0
5	49	Transmission pipeline additions acquired after February 23, 2005	-	-	-	8%	0.0	0.0
6		Total	$ 491.3	737.0	$ 245.7		$ 110.5	$ 36.8

CCA Variance (e) - (f)	73.7
Tax Rate	26.5%
Earnings Impact of Accelerated CCA	19.5
Earnings Impact Grossed-up for Taxes Captured in the Parkway West Project Costs V/A	26.6

Line No.	Class	Particulars ($000s)	(a)	(b)	(c)	(d)	(e)	(f)
		Lobo C Compressor/Hamilton-Milton Pipeline Project						
	Class							
1	1	Non-residential building acquired after March 19, 2007	99.3	149.0	49.7	6%	8.9	3.0
2	7	Compression equipment acquired after February 22, 2005	-	-	-	15%	0.0	0.0
3	8	Compression assets, office furniture, equipment	-	-	-	20%	0.0	0.0
4	41	Storage assets	-	-	-	25%	0.0	0.0
5	49	Transmission pipeline additions acquired after February 23, 2005	182.0	273.0	91.0	8%	21.8	7.3
6		Total	$ 281.3	422.0	$ 140.7		$ 30.8	$ 10.3

CCA Variance (e) - (f)	20.5
Tax Rate	26.5%
Earnings Impact of Accelerated CCA	5.4
Earnings Impact Grossed-up for Taxes Captured in the Lobo C Compressor/Hamilton-Milton Pipeline Project Costs V/A	7.4

Line No.	Class	Particulars ($000s)	(a)	(b)	(c)	(d)	(e)	(f)
		Lobo D/Bright C/Dawn H Compressor Project						
	Class							
1	1	Non-residential building acquired after March 19, 2007	1,619.7	2,429.6	809.9	6%	145.8	48.6
2	7	Compression equipment acquired after February 22, 2005	3,947.0	5,920.5	1,973.5	15%	888.1	296.0
3	8	Compression assets, office furniture, equipment	-	-	-	20%	0.0	0.0
4	41	Storage assets	-	-	-	25%	0.0	0.0
5	49	Transmission pipeline additions acquired after February 23, 2005	-	-	-	8%	0.0	0.0
6		Total	$ 5,566.7	8,350.1	$ 2,783.4		$ 1,033.8	$ 344.6

CCA Variance (e) - (f)	689.2
Tax Rate	26.5%
Earnings Impact of Accelerated CCA	182.6
Earnings Impact Grossed-up for Taxes Captured in the Lobo D/Bright C/Dawn H Compressor Project Costs V/A	248.5

Line No.	Class	Particulars ($000s)	(a)	(b)	(c)	(d)	(e)	(f)
		Burlington-Oakville Project						
	Class							
1	1	Non-residential building acquired after March 19, 2007	-	-	-	6%	0.0	0.0
2	7	Compression equipment acquired after February 22, 2005	-	-	-	15%	0.0	0.0
3	8	Compression assets, office furniture, equipment	30.3	45.5	15.2	20%	9.1	3.0
4	41	Storage assets	-	-	-	25%	0.0	0.0
5	49	Transmission pipeline additions acquired after February 23, 2005	15.0	22.5	7.5	8%	1.8	0.6
6		Total	$ 45.3	68.0	$ 22.7		$ 10.9	$ 3.6

CCA Variance (e) - (f)	7.3
Tax Rate	26.5%
Earnings Impact of Accelerated CCA	1.9
Earnings Impact Grossed-up for Taxes Captured in the Burlington-Oakville Project Costs V/A	2.6

Line No.	Class	Particulars ($000s)	(a)	(b)	(c)	(d)	(e)	(f)
		Panhandle Reinforcement Project						
	Class							
1	1	Non-residential building acquired after March 19, 2007	-	-	-	6%	0.0	0.0
2	7	Compression equipment acquired after February 22, 2005	-	-	-	15%	0.0	0.0
3	8	Compression assets, office furniture, equipment	69.7	104.6	34.9	20%	20.9	7.0
4	41	Storage assets	141.0	211.5	70.5	25%	52.9	17.6
5	49	Transmission pipeline additions acquired after February 23, 2005	387.3	581.0	193.7	8%	46.5	15.5
6		Total	$ 598.0	897.0	$ 299.0		$ 120.3	$ 40.1

CCA Variance (e) - (f)	80.2
Tax Rate	26.5%
Earnings Impact of Accelerated CCA	21.2
Earnings Impact Grossed-up for Taxes Captured in the Panhandle Reinforcement Project Costs V/A	28.9

Line No.	Class	Particulars ($000s)	(a)	(b)	(c)	(d)	(e)	(f)
		Total Capital Pass-through Projects						
	Class							
1	1	Non-residential building acquired after March 19, 2007	1,719.0	2,578.5	859.5	6%	154.7	51.6
2	7	Compression equipment acquired after February 22, 2005	4,438.3	6,657.5	2,219.2	15%	998.6	332.9
3	8	Compression assets, office furniture, equipment	100.0	150.0	50.0	20%	30.0	10.0
4	41	Storage assets	141.0	211.5	70.5	25%	52.9	17.6
5	49	Transmission pipeline additions acquired after February 23, 2005	584.3	876.5	292.2	8%	70.1	23.4
6		Total	$ 6,982.6	10,473.9	$ 3,491.3		$ 1,306.3	$ 435.4

CCA Variance (e) - (f)	870.9
Tax Rate	26.5%
Earnings Impact of Accelerated CCA	230.8
Total Earnings Impact Grossed-up for Taxes Captured in the Capital Pass-through Project Variance Accounts	314.0

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Unaccounted for Gas (UFG) Volume Variance Account
Exhibit C / Tab 1 / pp. 29-30

Preamble:

Enbridge stated that, for its Union rate zones, based on actual volumes, it recovered $9.25 million in UFG costs in 2018. In comparison, actual UFG costs were $15.98 million.

Question(s):

a) Please provide detailed calculations supporting the 2018 actual UFG costs and the actual 2018 revenues recovered in rates.

Response

a)

Union Gas Limited
2018 Unaccounted for Gas

	2018 Board Approved Rates	2018 Actual Cost Recovery	2018 Actual
UFG %	0.219%	0.219%	0.379%
Throughput (103m3)	32,009,650	35,978,439	35,978,439
UFG Volume (103m3)	70,253	78,963	136,447
Approved Reference Price (WACOG)	$131.025	$131.025	$131.025
2018 UFG Expense	$9,204,874	$10,346,159	$17,877,943
Less: L/T Non-Utility Allocation	$648,023	$922,877	$1,594,712
S/T Excess Utility Allocation	$227,360	$173,815	$300,349
Net 2018 Utility UFG Expense	**$8,329,490**	**$9,249,466**	**$15,982,881**

ENBRIDGE GAS INC.
Answer to Interrogatory from
Ontario Energy Board ("Staff")

Reference:

UFG Price Variance Account, Exhibit C/Tab 1/pp. 43-44

Question:

a) Please provide a detailed calculation supporting the price variance of $34.56/10^3m^3$

Response:

a) Please see Attachment 1 to this response.

Union Gas Limited
UFG Price Deferral
2018

Calc	January	February	March	April	May	June	July	August	September	October	November	December	Total
Regulated UFG - 103m3	10,165.32	10,165.32	10,165.32	10,165.32	10,165.32	10,165.32	10,165.32	10,165.32	10,165.32	10,165.32	10,165.32	10,165.32	121,984
Less: Regulated Exfranchise CSF Collected	- 4,383.00	- 4,383.00	- 4,383.00	- 4,383.00	- 4,383.00	- 4,383.00	- 4,383.00	- 4,383.00	- 4,383.00	- 4,383.00	- 4,383.00	- 4,383.00	52,596
Less: Infranchise CSF Collected	- 892.78	- 892.78	- 892.78	- 892.78	- 892.78	- 892.78	- 892.78	- 892.78	- 892.78	- 892.78	- 892.78	- 892.78	10,713
Total UFG Requirement	4,890	4,890	4,890	4,890	4,890	4,890	4,890	4,890	4,890	4,890	4,890	4,890	58,674
Reference Price - $CDN/103m3	$ 137.182	$ 137.182	$ 137.182	$ 124.098	$ 124.098	$ 124.098	$ 124.098	$ 124.098	$ 124.098	$ 132.809	$ 132.809	$ 132.809	$ 129.55
Total SPGVA Purchases - (103m3)	303,773	506,897	272,421	314,928	298,935	288,545	272,516	301,177	289,348	297,505	301,345	311,334	3,758,725.34
UFG Related Spot Purchase													-
Net SPGVA Purchase (103m3)	303,773	506,897	272,421	314,928	298,935	288,545	272,516	301,177	289,348	297,505	301,345	311,334	3,758,725
Total Cost - SPGVA	$ 41,002,404	$ 89,737,742	$ 39,057,521	$ 42,110,191	$ 37,902,008	$ 40,851,028	$ 40,027,991	$ 42,321,507	$ 41,052,883	$ 45,509,867	$ 53,798,561	$ 82,067,535	$ 595,439,239
UFG Related Spot Purchase Cost			$ -										$ -
Total Portfolio Cost ($CDN/103m3)	$ 41,002,404	$ 89,737,742	$ 39,057,521	$ 42,110,191	$ 37,902,008	$ 40,851,028	$ 40,027,991	$ 42,321,507	$ 41,052,883	$ 45,509,867	$ 53,798,561	$ 82,067,535	$ 595,439,239
Average SPGVA Purchase Cost	$ 134.98	$ 177.03	$ 143.37	$ 133.71	$ 126.79	$ 141.58	$ 146.88	$ 140.52	$ 141.88	$ 152.97	$ 178.53	$ 263.60	158.415
Step 1													
UFG Spot Price Variance Deferral Entry													
Volume - 103m3	2,781.34	2,781.34	2,781.34	2,781.34	2,781.34	2,781.34	2,781.34	2,781.34	2,781.34	2,781.34	2,781.34	2,781.34	33,376
Cost - $CDN/103m3	-$ 40.08	-$ 40.08	-$ 40.08	-$ 40.08	-$ 40.08	-$ 40.08	-$ 40.08	-$ 40.08	-$ 40.08	-$ 40.08	-$ 40.08	-$ 40.08	-$ 40.08
Deferral Amount - $CDN/103m3	-$ 111,475.00	-$ 111,475.00	-$ 111,475.00	-$ 111,475.00	-$ 111,475.00	-$ 111,475.00	-$ 111,475.00	-$ 111,475.00	-$ 111,475.00	-$ 111,475.00	-$ 111,475.00	-$ 111,475.00	-$ 1,337,700.00
Step 2													
Remaining SPGVA Portfolio UFG Price Variance Deferral Entry													
Volume - 103m3	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108	25,298
Cost - $CDN/103m3	$ 2.20	-$ 39.85	-$ 6.19	-$ 9.62	-$ 2.69	-$ 17.48	-$ 22.78	-$ 16.42	-$ 17.78	-$ 20.16	-$ 45.72	-$ 130.79	-$ 27.27
	$ 4,648.51	-$ 84,014.58	-$ 13,049.72	-$ 20,272.03	-$ 5,675.37	-$ 36,846.21	-$ 48,034.88	-$ 34,621.26	-$ 37,488.80	-$ 42,505.69	-$ 96,383.45	-$ 275,730.85	-$ 689,974
	Total												-$ 2,027,674.33

Weighted Average Approach to UFG Price Variance				
	UFG Requirements	**Proration**	**Avg Price Variance**	**Average $ x proratoin**
	(From Table)			
Spot Purchase	33,376	0.568837	$ (40.08)	$ (22.80)
Annual Requirement	25,298	0.431163	$ (27.27)	$ (11.76)
	58,674			**$ (34.56)**

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

UFG Price Variance Account – Allocation Methodology
Exhibit C / Tab 3 / p. 6
EB-2018-0105 / Exhibit A / Tab 3 / p. 8

Preamble:

In the current proceeding, Enbridge proposes to allocate the balance in the UFG Price Variance Account to rate classes based on the actual UFG gas supply purchases made by Enbridge in 2018 for the Union rate zones.

In Union's 2017 deferral account disposition proceeding[7], Union allocated the balances in the UFG Price Variance Account to rate classes in proportion to the 2013 OEB approved allocation of UFG costs to customers for which Union provides fuel.

Question(s):

OEB staff understands that Enbridge is proposing a change to the allocation methodology for the UFG Price Variance Account as part of the current proceeding. Please provide the rationale supporting this change in allocation methodology.

Response

Enbridge Gas is proposing a change to the allocation of the UFG Price Variance Account (179-141) to recognize the portion of the balance related to customers for which Enbridge Gas provides fuel (utility supplied fuel) and the customers who provide fuel in kind (customer supplied fuel).

Enbridge Gas purchases actual UFG volumes for customers for which Enbridge Gas provides fuel and may also purchase actual UFG volumes for customers that provide

[7] EB-2018-0105.

their own fuel when the amount of UFG collected in kind is less than the actual UFG volumes required for these customers.

Enbridge Gas' approved allocation methodology of the price variance account is in proportion to the UFG costs for which the company provides fuel. The approved allocation methodology does not recognize Enbridge Gas may make actual UFG purchases on behalf of customers who provide fuel in kind. In 2017, the balance in the variance account was immaterial (approximately $0.1 million) and did not contribute to material impacts to any rate class.

In 2018, the actual UFG was greater than the actual amount of UFG collected through customer supplied fuel, which required Enbridge Gas to purchase additional UFG volumes on behalf of these customers. Of the total balance of $2.1 million, $0.7 million relates to customers who provide fuel in kind, as shown in Table 1. Given the amount of actual UFG purchased on behalf of customers who provide fuel in kind in 2018, Enbridge Gas has proposed to update the cost allocation to more accurately reflect the actual purchases.

Table 1
2018 UFG Price Variance Account Balance

Line No.	Particulars	Utility Supplied Fuel	Customer Supplied Fuel	Total (1)
		(a)	(b)	(c) = (a + b)
1	Experienced UFG (10^3m^3) (2)	38,503	83,481	121,984
2	Collected UFG in Kind (10^3m^3)	-	63,309	63,309
3	Difference (line 1 - line 2) (10^3m^3)	38,503	20,171	58,674
4	2018 UFG Price Variance Account Balance ($ millions) (3)	(1.372)	(0.719)	(2.091)

Notes:
(1) EB-2019-0105, Exhibit C, Tab 1, Table 14.
(2) Portion of actual UFG volumes related to utility and customer supplied fuel based on total throughput volumes.
(3) Line 3 applied to the UFG price variance of ($34.56)/$10^3m^3$ plus interest.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Parkway West Project Costs Deferral Account
Exhibit A / Tab 3 / p. 5
Exhibit C / Tab 1 / pp. 31-36

Preamble:

Enbridge is seeking interim disposition of the 2018 balance in the Parkway West Project Costs Deferral Account consistent with the approvals granted in the 2016 deferral account disposition proceeding[10] and the 2017 deferral account disposition proceeding[11].

In the 2016 deferral account disposition proceeding, the OEB noted that "all parties agreed that the 2016 balance in the account should be disposed of only on an interim basis to allow the OEB to perform a prudence review of the capital overspend in the future prior to final disposition of the balances in the account[12]."

Enbridge stated that it will seek final disposition of this account as part of a subsequent proceeding when all of the project costs have been incurred and the prudence of the project costs can be assessed.

Question(s):

Please advise when (i.e. in which proceeding) Enbridge intends to file evidence supporting the final disposition of the Parkway West Project Costs Deferral Account.

[10] EB-2017-0091.
[11] EB-2018-0105.
[12] EB-2017-0091.

Response

Enbridge Gas expects that the final prudence review will occur in a future proceeding once capital spending is complete. At this point, Enbridge Gas cannot state with certainty in which proceeding this will take place. Enbridge Gas continues to work with the Town of Milton, its councilors and staff, with respect to Enbridge Gas's application and approval of demolition permits for two residential structures located within the boundary of the Parkway West Compressor facility. As stated in response to

Exhibit I.LPMA.2, $1.454 million is forecast to be spent on the Parkway West Compressor project in 2019. Once Enbridge Gas receives the demolition permit approvals and completes the demolition, it will file evidence seeking final disposition of this account.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Lobo D / Bright C / Dawn H Compressor Project Costs Deferral Account
Exhibit C / Tab 1 / pp. 51-52
Exhibit C / Tab 1 / Appendix A / Schedule 10

Preamble:

Enbridge noted that $0.917 million of the credit balance in the account relates to 2018 revenue generated through the sale of surplus Dawn Parkway system capacity of 30,393 GJ / day associated with the Lobo D / Bright C / Dawn H Compressor project. Enbridge further stated that as of November 2018, the surplus capacity had been deemed to be sold long-term.

Enbridge stated that it also seeking approval of the final disposition of the 2017 revenue recorded in the account, which was approved in an interim basis in Union's 2017 deferral account disposition proceeding[11].

Question(s):

a) Please further explain the statement that the surplus capacity had been deemed to be sold long-term. Please specifically advise whether the capacity has been actually sold on a long-term basis as of November 2018.

b) Please provide the actual average short-term firm daily contract demand plus interruptible average daily throughput volumes for easterly Dawn-Parkway system paths and the actual short-term revenue earned for November and December, 2018.

Response

[11] EB-2018-0105.

a) Based on changes affecting the overall surplus since the time the original schedule was filed in 2015 (i.e. turnback, slight modelling changes, etc.), EGI had surplus Dawn-Parkway capacity of approximately 126 TJ as of November 1, 2018.
As discussed in EB-2018-0305, EGI has sold firm long-term contracts totalling 42,378 GJ/d of Dawn-Parkway capacity starting November 1, 2018 and ending October 31, 2040 at posted M12 rates. As a result, EGI has deemed that the excess capacity of 30,393 GJ/d has been sold long-term. EGI has sold additional long-term M12 contracts beginning November 1, 2019 which will completely utilize the surplus Dawn-Parkway capacity.

b) The table below outlines what columns (a), (b) and (c) of Tab 1, Appendix A, Schedule 10 would be if EGI did not deem the capacity to be sold long-term and instead used short-term revenue and volumes for November and December.

Particulars (000's)	Volume (TJ/d) (a)	Actual Revenue ($) (b)	Project Surplus Allocation (%) (c)=30,393 GJ/d / (a)
November 2018	286	$ 1,320	10.6%
December 2018	352	$ 1,440	8.6%

The volume in column (a) at Exhibit C, Tab 1, Appendix A, Schedule 10, page 2 of 2 is incorrectly showing the volume as GJ/d – this should be TJ/d. The corrected exhibit will be filed with the Board and parties along with these Interrogatory responses.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (“Staff”)

Interrogatory

Reference:

Pension and Other Post-Employment Benefits Variance Account
Exhibit C / Tab 1 / p. 69

Preamble:

On September 14, 2017, the OEB released a report titled, Regulatory Treatment of Pension and Other Post-Employment Benefits (OPEB) Costs (the OEB Report) in which the OEB established a variance tracking account, effective January 1, 2018, to be used by all utilities that are approved to recover their pension and OPEB costs on an accrual basis.

This account is used to track the difference between the forecast accrual amount that is recovered in rates and the actual cash payments made in respect to a utility’s pension and OPEB costs. It will provide ratepayers with an asymmetrical carrying charge on the cumulative differential balance in the account when the cumulative forecast accrual amount exceeds cash payments (i.e. the tracking account is in a credit position).
The OEB Report prescribes the use of the total gross accrual cost as calculated in an actuarial valuation as the default methodology for determining the forecast accrual amount in rates of a given year[13]. However, the OEB Report further indicates:

> If a utility capitalizes a material portion of its total pension and OPEB accrual costs, and there is sufficient incremental value to warrant the added complexity of tracking amounts that are capitalized separately from those that are expensed, any party may propose an enhanced methodology for determining the reference amount (i.e. the forecast accrual amount)[14].

Question(s):

a) Please confirm that for the Union Rate Zone, it is Enbridge’s intention to propose

[13] OEB Report on the Regulatory Treatment of Pension and OPEB Costs / September 14, 2017 / p. 20.
[14] OEB Report on the Regulatory Treatment of Pension and OPEB Costs / September 14, 2017 / p. 20.

the use of an alternate methodology (compared to the default methodology of the OEB Report) for purposes of tracking the forecast accrual amount embedded in rates.

b) The OEB Report indicates that if a utility capitalizes a material portion of its pension and OPEB costs, it may propose an alternate methodology provided that there is sufficient incremental value to warrant the added complexity of tracking amounts that are capitalized separately. Based on the calculation provided in Table 25, please explain why Enbridge believes the use of an alternate methodology is appropriate in this case.

c) As part of its alternate methodology, why is Enbridge only proposing to track the depreciation associated with its pension and OPEB costs that have been capitalized from 2018 and onward, when it actually recovers more than that in the rates in a given year (i.e. it will recover the deprecation associated with the pension and OPEB costs that have been capitalized to date).

d) For 2018, please quantify the depreciation associated with the pension and OPEB costs that have been capitalized to date.

e) Please provide the actuarial valuations that underpin both the total pension and OPEB accrual expense for 2018 (i.e. $47.4 million) and the actual cash payments made for pension and OPEBs for the same period ($26.5 million).

<u>Response</u>

a) The evidence filed at Exhibit C, Tab 1, Pages 69 to 71 forms the substantive basis of the proposed methodology for the Union rate zones. Enbridge Gas proposes to reduce the pension and OPEB costs included in 2013 rates by the amount of pension costs that were capitalized into Regulatory Overheads in 2013 in the Union rate zones. This amount totaling $6.6 million is not being recovered through rates in the Union rate zones and therefore should not be included in the calculation of the variance tracking account.

b) The capitalization amount in 2013 rates equates to 14% or $6.6 million of pension expense. Enbridge Gas is not recovering those costs from ratepayers each year over the term of its deferred rebasing period. This equates to a potential $39.6 million ($6.6 million per year from 2018 to 2023) impact to the cumulative balance in the variance tracking account which is a material amount. As these amounts are not being recovered from ratepayers in the Union rate zones they should not be included in the calculation.

c) Per the Report of the Board in EB-2015-0040, the variance account is effective January 1, 2018 on a prospective basis comparing the accrual expense amount in rates, which is not to change or escalate during an IRM or Custom IR term (except in cases where in a Custom IR term, updated forecasts for subsequent years of the term were approved), versus the cash contributions paid. The accrual pension expense amount in rates for the Union rate zones was determined in the Union Gas 2013 Cost of Service rebasing application, which in accordance with the Board direction became the amount embedded in rates for 2018 as Union was in the midst of an IRM term. Enbridge Gas believes that the calculation of the pension expense should not be impacted by capitalization decisions made prior to 2018. Please see response to part d).

d) Union is unable to quantify the 2018 depreciation associated with the pension and OPEB costs capitalized to date. Regulatory Overheads are calculated on a pooled basis with capitalization amounts from a number of different operational and administrative expenses. These amounts are not tracked in the fixed asset system on a cumulative basis by their source.

e) Please see Attachment 1, Page 1, Table 4 of the excerpt from Union Gas 2013 cost of service filing for the 2013 Forecast of pension and OPEB costs totaling $47.4 million. The supporting actuarial valuations from Towers Watson that underpin the $47.4 million is provided on page 2 and page 3 of Attachment 1. Please see table below.

$ Millions	2013	Reference
Defined Benefit Pension	34.2	Page 2 of attachment 1
Post-Retirement Benefit	7.6	Page 2 of attachment 1
Defined Contribution Pension	5.6	Page 3 of attachment 1
Total	47.4	

The projected 2018 cash contributions $25.6 million is from Mercer estimated projected cash funding for 2018-2021 and is provided in Attachment 2. Several adjustments were made during the year bringing the total to $26.5 million.

Table 4
Comparison of Employee Future Benefit Costs

Line No.	($ millions)	Board-Approved (a)	2007 Actual (b)	2011 Actual (c)	2012 Forecast (d)	2013 Forecast (e)
1	Defined Benefit Pension	$19.3	$21.5	$35.4	$36.2	$34.2
2	Post-Retirement Benefits	8.3	5.4	7.9	8.5	7.6
3	Defined Contribution Pension	2.8	2.8	5.0	5.3	5.6
4	Total	$30.4	$29.7	$48.3	$50.0	$47.4

Defined Benefit Pension

The DB pension costs for 2013 are forecast to be approximately $34.2 million, an increase of $14.9 million from the amount included in Union's approved 2007 rates. The increase in DB costs is the result of a change in the key assumptions used to determine the DB pension expense offset by a decrease due to the change in accounting to U.S. GAAP.

The expense for DB pension and post-retirement benefits for 2012 and 2013 is determined in accordance with U.S. Financial Accounting Standards Board's ASC 715. For years 2007 through 2011, the expense is determined based on Section 3461 of the Canadian Institute of Chartered Accountants ("CICA") Handbook. The change to U.S. GAAP results in a decrease in the net pension cost of $2.8 million. Discussion of the affect of the change in accounting from Canadian GAAP to U.S. GAAP is discussed further at Exhibit A2, Tab 4.

SPECTRA ENERGY TRANSMISSION - CANADA
ESTIMATED 2013 NET BENEFIT COST - ASC 715
CANADIAN REPORTING ("NEW GAAP")

BASE CASE

	Registered Pension Plans	Supplemental Pension Arrangements	Post-Retirement Benefits Other Than Pensions	Total
Pipeline	$ 16,394	$ 2,026	$ 8,687	$ 27,107
Corporate	544	3,902	217	4,663
Empress	1,480	326	454	2,260
Union Gas Limited	31,263	2,657	7,594	41,514
St. Clair Pipelines	259	188	104	551
Spectra Energy Midstream	457	365	256	1,078
All Companies	**$ 50,397**	**$ 9,464**	**$ 17,312**	**$ 77,173**

Note: All amounts are shown in thousands of Canadian dollars.

Key Assumptions:
Discount rate (December 31, 2011):
- Pensions = 4.30% per year
- Post-retirement benefits other than pensions = 4.33% per year

Expected rate of return on asstets from January 1, 2012 to May 31, 2012 = 2.66% (6.50% per year)
Expected rate of return on asstets from June 1, 2012 to December 31, 2012 = 3.74% (6.50% per year)
Rate of salary increases = 3.25% per year
Mortality = 80% of UP94 projected generationally using Scale AA
Health care cost trend rate = 7.5% per year in 2012, grading to 5% per year in 2017 and thereafter

SPECTRA ENERGY TRANSMISSION - CANADA
ESTIMATED CONTRIBUTIONS FOR 2013

	Registered Pension Plans DB	Registered Pension Plans DC	Supplemental Pension Arrangements	Post-Retirement Benefits Other Than Pensions	Total
Pipeline	$ 16,500	$ 2,700	$ 700	$ 2,000	$ 21,900
Corporate	800	0	3,900	230	4,930
Empress	2,100	380	16	32	2,528
Union Gas Limited	55,200	5,500	1,300	3,000	65,000
St. Clair Pipelines	500	130	0	14	644
Spectra Energy Midstream	500	200	150	40	890
All Companies	**$ 75,600**	**$ 8,910**	**$ 6,066**	**$ 5,316**	**$ 95,892**

Notes:

1) *All amounts are shown in thousands of Canadian dollars*
2) The actual contributions in 2013 will depend on the results of the January 1, 2013 actuarial valuations
3) Assumes annual valuations are filed for all pension plans at January 1, 2012 and January 1, 2013
4) Assumes the excess contributions remitted in December 2011 are not treated as a pre-payment
5) Asset experience is reflected to June 30, 2012. Expected rate of return on assets is 6.75% per year thereafter.
6) Reflects the January 1, 2012 actuarial assumptions and assumes no assumption changes at January 1, 2013
7) Assumes that there are no other actuarial experience gains or losses from January 1, 2011 for Ontario registered plans and from January 1, 2012 for the Westcoast Plan.

Appendix E-1
Union Gas Limited - Projected Minimum Cash Funding Requirements (2018 to 2021)
(Reflecting Approved 2017 Funding Strategy, New Harmonized Design where applicable, New Approved Asset Mixes and New Ontario Funding Rules using Quebec rules as a guide)

Projected Contributions ('000s)	Pension Choices Plan	M&S Plan	Bargaining Unit Plan	Centra Salaried Plan	Group One Plan	Group Three Plan	SERP and SEMPL	Total Pensions	PRB Arrangements	Total
2018										
DB Current Service Cost	14,993	675	505	309	79	-	-	16,563	-	16,563
DC Current Service Cost	3,753	-	-	-	-	-	-	3,753	-	3,753
Flex Credits[1]	615	19	-	9	-	-	-	643	-	643
Going Concern Special Payments	-	-	-	-	-	-	-	-	-	-
Solvency Special Payments	-	-	-	-	-	-	-	-	-	-
Benefit Payments	-	-	-	-	-	-	2,097	2,097	2,536	4,633
Total	**19,361**	**694**	**505**	**318**	**79**	-	**2,097**	**23,056**	**2,536**	**25,592**
2019										
DB Current Service Cost	18,351	514	-	-	75	-	-	18,941	-	18,941
DC Current Service Cost	1,503	-	-	-	-	-	-	1,503	-	1,503
Flex Credits[1]	1,221	33	-	17	-	-	-	1,271	-	1,271
Going Concern Special Payments	-	-	-	-	-	-	-	-	-	-
Solvency Special Payments	-	-	-	-	-	-	-	-	-	-
Benefit Payments	-	-	-	-	-	-	2,265	2,265	2,680	4,945
Total	**21,075**	**547**	-	**17**	**75**	-	**2,265**	**23,979**	**2,680**	**26,659**
2020										
DB Current Service Cost	18,324	424	-	-	-	-	-	18,747	-	18,747
DC Current Service Cost	1,947	-	-	-	-	-	-	1,947	-	1,947
Flex Credits[1]	1,191	28	-	15	-	-	-	1,234	-	1,234
Going Concern Special Payments	-	-	-	-	-	-	-	-	-	-
Solvency Special Payments	-	-	-	-	-	-	-	-	-	-
Benefit Payments	-	-	-	-	-	-	2,382	2,382	2,803	5,185
Total	**21,462**	**452**	-	**15**	-	-	**2,382**	**24,310**	**2,803**	**27,113**
2021										
DB Current Service Cost	18,295	349	-	-	-	-	-	18,644	-	18,644
DC Current Service Cost	2,360	-	-	-	-	-	-	2,360	-	2,360
Flex Credits[1]	1,162	23	-	13	-	-	-	1,198	-	1,198
Going Concern Special Payments	-	-	-	-	-	-	-	-	-	-
Solvency Special Payments	-	-	-	-	-	-	-	-	-	-
Benefit Payments	-	-	-	-	-	-	2,507	2,507	2,916	5,423
Total	**21,817**	**372**	-	**13**	-	-	**2,507**	**24,709**	**2,916**	**27,625**

[1] Flex Credits are paid outside of the pension plans

Key Assumptions

Going concern discount rate	6.00% for Pension Choices; 5.00% for all other registered plans
Stabilization provision	17.3% for Pension Choices; 13.0% for all other registered plans
Going concern mortality	100% CPM Private, with improvements based on scale CPM-B
Net expected return on assets	6.75% for Pension Choices; 5.6% for all other funded plans
Average wage index	2.50%

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Utility Earnings and Earnings Sharing Calculation – Merger-related Costs
Exhibit C / Tab 2
EB-2018-0105 / Exhibit B.Staff.16
EB-2018-0105 / Exhibit B.LPMA.13

Preamble:

OEB staff found no direct references to Enbridge Inc. and Spectra Energy merger costs and savings in the current application. OEB staff notes that in Union's 2017 deferral account disposition proceeding[14], there were 2017 costs associated with the merger of Enbridge Inc. and Spectra Energy of $5.6 million (which reflected the utility portion). In addition, there were cost savings of $3.7 million associated with the merger.

Question(s):

a) Please provide the total 2018 merger-related costs and savings for the Union rate zones (similar to the types of costs and savings provided in Union's 2017 deferral account disposition proceeding). Please also provide a detailed breakdown of these costs and savings.

b) Please confirm that these merger-related costs and savings have been included in the earnings sharing calculation for the Union rate zones. If so, please provide rationale supporting the inclusion of these costs and savings in the earnings sharing calculation.

c) Please explain how the merger-related costs and savings were allocated between the EGD rate zone and the Union rate zones for earnings sharing calculation purposes. Please also provide any supporting calculations.

d) Please provide revised earnings sharing calculations for the Union rate zone as

[14] EB-2018-0105.

follows:

i. Merger-related costs removed
ii. Merger-related costs and savings removed

Response

a) Please see the Table below for the 2018 merger-related costs and savings for the Union rate zones.

$ 000's	**2018**
Merger-Related Costs	11,252
Merger-Related Savings	(1,014)

b) Yes, 2018 the merger related costs and savings identified in part a) are reflected in the earnings sharing calculation for the Union rate zones. In preparing for the pending merger/amalgamation of Enbridge Gas Distribution and Union Gas Limited, role redundancies and opportunities for synergy savings were identified. The role reductions and synergies resulted in nominal savings in 2018, as a result of occurring late in the year, but will result in ongoing cost savings for Enbridge Gas Inc. annually, which will be reflected in utility earnings subject to sharing with ratepayers, and in lower costs at the time of rebasing. As the cost savings will flow through utility earnings to the benefit of ratepayers, and will be reflected in rates at the time of rebasing, the costs associated with generating these savings should also flow through utility earnings. This treatment is consistent with the manner in which Union reflected costs of severances in past years.

c) The merger related costs and savings were not allocated between the EGD Rate Zone and Union Rate Zones. The costs and savings for each rate zone reflect where the underlying role reductions occurred.

d) Please see Attachment 1 for the earnings sharing calculation excluding merger related costs and Attachment 2 for the earnings sharing calculation excluding merger related costs and savings.

UNION RATE ZONES
Earnings Sharing Calculation
Calendar Year Ending December 31, 2018

Line No.	Particulars ($000s)	2018 (a)	Non-Utility Storage (b)	Adjustments (c)		2018 Utility (d)=(a)-(b)+(c)
	Operating Revenues					
1	Gas Sales	1,812,564	-	(19,447)	i.	1,793,117
2	Transportation	258,512	(367)	-		258,879
3	Storage	151,772	143,609	-		8,163
4	Other	23,924	-	(6,119)	ii	17,805
5		2,246,773	143,242	(25,566)		2,077,965
	Operating Expenses					
6	Cost of gas	960,481	36,499	(16,839)	i.	907,143
7	Operating and maintenance expenses	461,872	13,451	(12,745)	iii	435,677
8	Depreciation	287,543	10,676	-		276,867
9	Other financing	-	-	998	iv	998
10	Property and other taxes	77,786	1,489	-		76,297
11		1,787,683	62,115	(28,586)		1,696,983
	Other					
12	Gain / (Loss) on sale of assets	(1,803)	(1,824)	-		21
13	Other / Huron Tipperary	-	-	-		-
14	Gain / (Loss) on foreign exchange	3,028	2,282	493	v	1,239
15		1,225	458	493		1,260
16	Earnings before interest and taxes	460,315	81,585	3,513		382,242
17	Income taxes					(3,030)
18	Total utility income subject to earnings sharing					385,272
	Less debt and preference share return components					
19	Long-term debt					161,247
20	Unfunded short-term debt					3,226
21	Preferred dividend requirements					2,901
22						167,374
	Less shareholder portions of:					
23	Net short-term storage revenue (after tax)					256
24	Net optimization activity (after tax)					536
25						793
26	Earnings subject to sharing					217,106
27	Common equity					2,166,613
28	Return on equity (line 26 / line 27)					10.02%
29	Benchmark return on equity					9.93%
30	50% earnings sharing % (line 28 - line 29, maximum 1%)					0.09%
31	90% earnings sharing % (if line 30=1%, then line 28 - line 29 - line 30)					0.00%
32	50% earnings sharing $ (line 27 x line 30 x 50%)					981
33	90% earnings sharing $ (line 27 x line 31 x 90%)					-
34	Total earnings sharing $ (line 32 + line 33)					981
35	Pre-tax earnings sharing (line 34 / (1 minus tax rate)					1,334

Notes:

i	Reclassification of optimization revenue as cost of gas	(16,839)
	Reduction to revenue to reflect the impact of Bill C-97 (accelerated CCA), enacted June 21, 2019:	
	Impact captured in CPT deferral accounts	(314)
	Ratepayer 50% of non-CPT CCA impact captured in Tax Variance	(940)
	Elimination for shareholder 50% of non-CPT CCA impact	(940)
	Total Asset CCA Impact	(2,194)
	Elimination for shareholder 50% of HST tax variance impact	(413)
	Total	(19,447)
ii	Demand-side management incentive	
iii	Donations	2,547
	CDM program	(1,054)
	Elimination of merger-related costs	11,252
		12,745
iv	Facility fees and customer deposit interest	
v	Foreign exchange gain on bank balances	

UNION RATE ZONES
Earnings Sharing Calculation
Calendar Year Ending December 31, 2018

Line No.	Particulars ($000s)	2018 (a)	Non-Utility Storage (b)	Adjustments (c)		2018 Utility (d)=(a)-(b)+(c)
	Operating Revenues					
1	Gas Sales	1,812,564	-	(19,447)	i.	1,793,117
2	Transportation	258,512	(367)	-		258,879
3	Storage	151,772	143,609	-		8,163
4	Other	23,924	-	(6,119)	ii	17,805
5		2,246,773	143,242	(25,566)		2,077,965
	Operating Expenses					
6	Cost of gas	960,481	36,499	(16,839)	i.	907,143
7	Operating and maintenance expenses	461,872	13,451	(11,731)	iii	436,691
8	Depreciation	287,543	10,676	-		276,867
9	Other financing	-	-	998	iv	998
10	Property and other taxes	77,786	1,489	-		76,297
11		1,787,683	62,115	(27,572)		1,697,997
	Other					
12	Gain / (Loss) on sale of assets	(1,803)	(1,824)	-		21
13	Other / Huron Tipperary	-	-	-		-
14	Gain / (Loss) on foreign exchange	3,028	2,282	493	v	1,239
15		1,225	458	493		1,260
16	Earnings before interest and taxes	460,315	81,585	2,499		381,228
17	Income taxes					(3,299)
18	Total utility income subject to earnings sharing					384,527
	Less debt and preference share return components					
19	Long-term debt					161,247
20	Unfunded short-term debt					3,226
21	Preferred dividend requirements					2,901
22						167,374
	Less shareholder portions of:					
23	Net short-term storage revenue (after tax)					256
24	Net optimization activity (after tax)					536
25						793
26	Earnings subject to sharing					216,360
27	Common equity					2,166,613
28	Return on equity (line 26 / line 27)					9.99%
29	Benchmark return on equity					9.93%
30	50% earnings sharing % (line 28 - line 29, maximum 1%)					0.06%
31	90% earnings sharing % (if line 30=1%, then line 28 - line 29 - line 30)					0.00%
32	50% earnings sharing $ (line 27 x line 30 x 50%)					608
33	90% earnings sharing $ (line 27 x line 31 x 90%)					-
34	Total earnings sharing $ (line 32 + line 33)					608
35	Pre-tax earnings sharing (line 34 / (1 minus tax rate)					827

Notes:

i	Reclassification of optimization revenue as cost of gas	(16,839)
	Reduction to revenue to reflect the impact of Bill C-97 (accelerated CCA), enacted June 21, 2019:	
	Impact captured in CPT deferral accounts	(314)
	Ratepayer 50% of non-CPT CCA impact captured in Tax Variance	(940)
	Elimination for shareholder 50% of non-CPT CCA impact	(940)
	Total Asset CCA Impact	(2,194)
	Elimination for shareholder 50% of HST tax variance impact	(413)
	Total	(19,447)
ii	Demand-side management incentive	
iii	Donations	2,547
	CDM program	(1,054)
	Elimination of merger-related costs and savings	10,237
		11,731
iv	Facility fees and customer deposit interest	
v	Foreign exchange gain on bank balances	

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

Interrogatory

Reference:

Utility Earnings and Earnings Sharing Calculation – Tax-related Adjustments
Exhibit C / Tab 2 / p. 4
Exhibit C / Tab 2 / Appendix B / Schedule 1

Preamble:

Enbridge noted that for the Union rate zones it reduced gas sales revenue by $2.19 million to reflect the 2018 revenue requirement impact of the tax rule changes associated with Bill C-97. More specifically, Enbridge stated that the adjustment to gas sales revenue reflects the following reductions:

- $0.31 million associated with the impact of the tax rule change that is reflected in the capital pass-through deferral accounts
- $0.94 million to reflect the ratepayer share (50%) of the impact of the tax rule change that is reflected in the Tax Variance deferral account
- $0.94 million to reflect the shareholder portion (50%) of the impact of the tax rule change that should not be included in the determination of earnings sharing.

Enbridge also reduced gas sales revenue by $0.413 million to reflect the removal of the shareholder portion (50%) of the HST impact (the associated ratepayer share (50%) is recorded in the Tax Variance deferral account).

Question(s):

a) Please further explain the adjustments made to the earnings sharing calculation for the tax rule change associated with Bill C-97. Specifically, please confirm that the utility earnings, prior to the adjustments, includes the entire impact of the tax rule change.

b) Please confirm that no further adjustments to the earnings sharing calculation would be required if the OEB were to order that the entirety of the impact of the tax rule change associated with Bill C-97 is to the benefit of ratepayers.

c) Please advise whether the reduction to gas sales revenue of $0.413 million to reflect the removal of the shareholder portion of the HST impact was made in previous earnings sharing calculations. If not, please explain why this adjustment is appropriate with respect to the 2018 earnings sharing calculation.

d) Please explain why there is no adjustment to the earnings sharing calculation to remove the ratepayer share (50%) of the HST impact that is recorded in the Tax Variance deferral account.

Response

a) Confirmed. Utility earnings, prior to the adjustments to reflect the sharing of tax impacts through the Tax Variance Deferral Account, and impacts captured through the capital pass-through deferral accounts, included (or benefited from) the entire impact of Bill C-97 accelerated CCA rule changes. This was accomplished through inclusion of the full benefit of accelerated CCA in the utility income tax calculation, which resulted in lower utility income taxes and higher utility income, and ultimately a higher revenue sufficiency.

The adjustments to revenue offset the revenue requirement impact of the lower utility taxes, such that the accelerated CCA has no impact on utility results, which is appropriate as the impact of accelerated CCA is to be shared with ratepayers through the Tax Variance Deferral Account or credited to them through the capital pass-through variance accounts.

In normal circumstances, the reduction to revenue for the shareholder portion of tax reduction impacts would be reflected in the overall corporate and utility results through an entry that reduces revenue, with a corresponding increase to a payable to ratepayers in the TVDA, or appropriate capital pass-through deferral account, in the year the benefit is attained. When the entry occurs within the year of the benefit, only the shareholder's 50% of the benefit would then need to be reflected as an elimination reducing utility results (while the ratepayer portion would flow through to utility earnings as normal, as an embedded reduction with revenues). However, because the accelerated CCA measures contained within Bill C-97 were not enacted until June 21, 2019, the ratepayer benefit was not reflected in 2018 results, which is why both the shareholder and ratepayer adjustments need to be made to 2018 results.

Please also see Exhibit I.STAFF.17 b).

b) Confirmed. If the OEB were to order that the entirety of the impact of the tax rule change associated with Bill C-97 was to the benefit of the ratepayer, there would be no change to Union rate zones earnings subject to earnings sharing. The 50% revenue reduction for the shareholder portion of the non-CPT CCA impact would be eliminated, but that amount would be added to elimination of the ratepayer portion of non-CPT CCA impact, the offset to which would be captured in the TVDA (for a total of 100% of the impact).

c) Union has not made the reduction to gas sales revenue for the shareholder portion of the HST impact in prior earnings sharing proceedings, which was an oversight. The elimination of the shareholder portion is appropriate because the 50/50 sharing of tax savings is handled through a deferral account mechanism. Failure to eliminate the shareholder portion would leave it potentially subject to further sharing through the earnings sharing mechanism. The elimination is consistent with the required elimination of the shareholder portion of Upstream Transportation Optimization revenues from utility earnings, which also should not impact utility earnings.

d) As the HST rules and impacts were in place and known in 2018, the adjustment to corporate earnings to reflect recognition of the ratepayer's 50% share of the HST impact in the Tax Variance Deferral Account was recorded in 2018 and was therefore already reflected in the base corporate results upon which the utility earnings calculation was based. Therefore, no further adjustment for the ratepayer share was required. The combination of the elimination of the shareholder 50%, and the recording of the ratepayer 50%, ensures the utility earnings calculation is not impacted by the tax change, which is to be shared 50/50 through a variance account mechanism.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Interrogatory

Reference:

Exhibit A, Tab 3, page 4 of 5

Question(s):

At Exhibit A, Tab 3, page 4, EGI states that the rationale for the continued use of a one-time adjustment includes that the: "[O]ne-time adjustment avoids material mismatches that could occur between cost incurrence and cost recovery due to customer switching between rate classes and changes in customer's consumption volumes from year to year."

(a) Do a material number of customers switch between rate classes on a yearly basis? If so, how many?

(b) Does EGI estimate the impact of different types of recovery windows for those customers that switch rate classes? If so, please provide those estimates.

(c) EGI also states that the use of a prospective recovery disposition from general service customers in the Union rate zones is appropriate as it generally provides alignment between cost incurrence and cost recovery. Does EGI agree that prospective recovery from general service customers in the EGD rate zone would provide that same alignment? If not, why not?

Response

a) No.

b) No.

c) Yes. Please also see the response to Exhibit I.STAFF.1, part a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (“CME”)

Interrogatory

Reference:

Exhibit A, Tab 3, page 4 of 5

Question(s):

At Exhibit A, Tab 3, page 4, EGI states: “A common approach [to disposition of accounts] could be proposed once integrated systems and processes are implemented.”

(a) When does EGI estimate that it will be in a position to integrate such processes such that a common method of disposition will be achievable across all of EGI’s rate zones?

Response

Please see the response at Exhibit I.STAFF.1, part c).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Interrogatory

Reference:

Ref: Exhibit B, Tab 1, page 29 of 29

Question(s):

At Exhibit B, Tab 1, page 29, EGI states: "Most of the amounts recorded within the MGPDA arise from EGD's defense of a lawsuit brought by Cityscape Residential Inc. The Cityscape residential lawsuit was settled and completed in 2018, and that is why the Company is now seeking to clear the current balance in the MGPDA."

(a) Please provide a short description of the other amounts recorded with the MGPDA that do not relate to the Cityscape lawsuit, and what issues relating to the Manufactured Gas Plant legacy operations they were meant to address.

(b) Is EGI aware of any other possible costs that may be dealt with through the MGPDA that have not been captured there yet?

Response

a) Please see Exhibit I.VECC.5 part c) for a breakdown of amounts that comprise the MGPDA balance that is being requested for clearance. The vast majority of costs incurred relate to the Cityscape Residential legal proceeding; however, there are a few smaller legal fees incurred in connection with potential issues related to other former manufactured gas plant properties.

b) EGI has incurred approximately $6,000 in residual Cityscape Residential proceeding legal fees, which have been charged to the MGPDA in 2019, which are not included in the balance requested for clearance. While nothing further has been recorded in the account to date, the Company is aware of the potential for further costs that could be incurred in relation to former manufactured gas plant sites, and it is possible it could receive other enquiries, demands or court actions in the future, should any other third parties come forward relating to former manufactured gas plant sites. Where future costs incurred fit within the scope of the MGPDA, they will be recorded in the account.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Interrogatory

Reference:

Exhibit B, Tab 3, page 3 of 3

Question(s):

At Exhibit B, Tab 3, page 3, EGI states: "The rate base allocator encompasses all facets / aspects of the Company's assets and is the most comprehensive representation of how the costs of providing gas distribution service are allocated and recovered from each customer class."

(a) How are other legal costs allocated to ratepayers? Please explain any differences between that allocation methodology and what is proposed for the MGPDA costs.

Response

(a) In the EGD rate zone, legal costs are part of Administrative and General (A&G) Overheads which are functionalized across all operating and maintenance functions.

Similar to the Company's proposal to clear P&OPEBFAVA balance on the rate base allocator, EGD rate zone does not have a legal cost or A&G allocator. The proposed clearing methodology recognizes that A&G costs are supporting all facets / aspects of the Company's assets in the provision of the gas distribution service to customers. In other words, the three-step cost allocation methodology (functionalization, classification and allocation) of A&G follow the same three-step methodology used for allocation of rate base (i.e., the Company's assets). Consequently, the rate base allocator is the most comprehensive representation of how distribution costs, including A&G, are allocated and recovered from each customer class.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

Interrogatory

Reference:

Exhibit B, Tab 1 Appendix A, Schedule 2

Question(s):

a) Please provide details on the following
   i) Lines 1.1-1.5 The basis of the increases in tolls for Union transportation extract of regulatory decision and increased toll schedule.
   ii) The forecast and actual volumes resulting in $18.2 million lower T-Service costs
   iii) The $1.1 million Cap and Trade costs

b) Please provide details of the Market Storage Costs including
   i) Forecast and actual average unit costs
   ii) The number and range of bids (list names omitted)
   iii) The percentage contracted to affiliates

Response

a)

i. As per the Board-approved accounting order for the Storage and Transportation Deferral Account ("S&TDA"), the purpose of the account is to record the difference between the forecast of Storage and Transportation rates included in the Company's approved rates and the final Storage and Transportation rates.[1]

   The final S&T rates shown on lines 1.1 – 1.5 were approved as part of legacy Union Gas' 2018 rates application, reproduced as Attachment 1.[2]

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[1] EB-2017-0086 Decision and Accounting Order, February 22, 2018, Schedule A, pp. 10 - 11.
[2] EB-2017-0087 Decision and Rate Order, January 18, 2018, Appendix A, pp. 14 – 16.

ii. The forecast volumes are 100,033,128 GJ and the actual volumes are 96,487,908 GJ.

iii. Please refer to Exhibit I.STAFF.3 c).

b)

i. The forecast market storage unit cost is approximately $0.69 CAD/GJ. The actual market storage unit cost is approximately $0.64 CAD/GJ.

ii. Please see the response at Exhibit I.FRPO.3, Attachment 1

iii. 59.1% is contracted with affiliates.

UNION GAS LIMITED
Summary of Changes to Storage and Transportation Rates

Line No.	Particulars ($/GJ)	EB-2017-0351 Approved January 1, 2018 Rate (a)		Rate Change (b)	EB-2017-0087 Approved January 1, 2018 Rate (c)	
	M12 Transportation Service					
	Firm transportation					
	Monthly demand charges:					
1	Dawn to Kirkwall	2.865		0.289	3.154	
2	Dawn to Parkway	3.402		0.314	3.716	
3	Kirkwall to Parkway	0.537		0.024	0.561	
4	F24-T	0.070			0.070	
	M12-X Firm Transportation					
5	Between Dawn, Kirkwall and Parkway	4.239		0.351	4.590	
	Commodity charges:					
6	Easterly	Note (1)			Note (1)	
7	Westerly	Note (1)			Note (1)	
8	Parkway (TCPL / EGT) to Parkway (Cons) / Lisgar	Note (1)			Note (1)	
	Cap-and-Trade Facility-Related Charges:					
9	Dawn to Kirkwall / Parkway (Cons) / Lisgar	0.006			0.006	
10	Dawn to Parkway (TCPL / EGT)	0.006			0.006	
11	Kirkwall to Parkway (Cons) / Lisgar	0.006			0.006	
12	Kirkwall to Parkway (TCPL / EGT)	0.006			0.006	
13	Parkway to Dawn / Kirkwall	0.006			0.006	
14	Kirkwall to Dawn	0.006			0.006	
15	Parkway (TCPL / EGT) to Parkway (Cons) / Lisgar	0.006			0.006	
	Limited Firm/Interruptible					
	Monthly demand charges:					
16	Maximum	8.165		0.753	8.918	
	Commodity charges :					
17	Others	Note (1)			Note (1)	
	Authorized Overrun					
	Transportation commodity charges:					
	Easterly:					
18	Dawn to Kirkwall - Union supplied fuel	Note (1)			Note (1)	
19	Dawn to Parkway - Union supplied fuel	Note (1)			Note (1)	
20	Kirkwall to Parkway - Union supplied fuel	Note (1)			Note (1)	
21	Dawn to Kirkwall - Shipper supplied fuel	0.094	(1)	0.010	0.104	(1)
22	Dawn to Parkway - Shipper supplied fuel	0.112	(1)	0.010	0.122	(1)
23	Kirkwall to Parkway - Shipper supplied fuel	0.018	(1)		0.018	(1)
	M12-X Firm Transportation					
24	Between Dawn, Kirkwall and Parkway - Union supplied fuel	Note (1)			Note (1)	
25	Between Dawn, Kirkwall and Parkway - Shipper supplied fuel:	0.139	(1)	0.012	0.151	(1)
	M13 Transportation of Locally Produced Gas					
26	Monthly fixed charge per customer station	$952.72		4.860	$957.58	
27	Transmission commodity charge to Dawn	0.035			0.035	
28	Commodity charge - Union supplied fuel	0.006			0.006	
29	Commodity charge - Shipper supplied fuel	Note (2)			Note (2)	
30	Cap-and-Trade Facility-Related Charge	0.006			0.006	
31	Authorized Overrun - Union supplied fuel	0.074		0.061	0.135	
32	Authorized Overrun - Shipper supplied fuel	0.069	(2)	0.061	0.130	(2)

Notes:
(1) Monthly fuel rates and fuel and commodity ratios per Schedule "C".
(2) Plus shipper supplied fuel per rate schedule.

UNION GAS LIMITED
Summary of Changes to Storage and Transportation Rates

Line No.	Particulars ($/GJ)	EB-2017-0351 Approved January 1, 2018 Rate (a)	Rate Change (b)	EB-2017-0087 Approved January 1, 2018 Rate (c)
	M16 Storage Transportation Service			
1	Monthly fixed charge per customer station	$1,515.67	7.730	$1,523.40
	Monthly demand charges:			
2	East of Dawn	0.770	0.004	0.774
3	West of Dawn	1.045	1.843	2.888
4	Transmission commodity charge to Dawn	0.035		0.035
	Transportation Fuel Charges to Dawn:			
5	East of Dawn - Union supplied fuel	0.006		0.006
6	West of Dawn - Union supplied fuel	0.006		0.006
7	East of Dawn - Shipper supplied fuel	Note (1)		Note (1)
8	West of Dawn - Shipper supplied fuel	Note (1)		Note (1)
	Transportation Fuel Charges to Pools:			
9	East of Dawn - Union supplied fuel	0.007	(0.001)	0.006
10	West of Dawn - Union supplied fuel	0.016		0.016
11	East of Dawn - Shipper supplied fuel	Note (1)		Note (1)
12	West of Dawn - Shipper supplied fuel	Note (1)		Note (1)
	Cap-and-Trade Facility-Related Charges to Dawn:			
13	East of Dawn - All Shippers	0.006		0.006
14	West of Dawn - All Shippers	0.006		0.006
	Cap-and-Trade Facility-Related Charges to Pool:			
15	East of Dawn - All Shippers	0.006		0.006
16	West of Dawn - All Shippers	0.006		0.006
	Authorized Overrun			
	Transportation Fuel Charges to Dawn:			
17	East of Dawn - Union supplied fuel	0.065	0.001	0.066
18	West of Dawn - Union supplied fuel	0.074	0.061	0.135
19	East of Dawn - Shipper supplied fuel	0.060 (1)		0.060 (1)
20	West of Dawn - Shipper supplied fuel	0.069 (1)	0.061	0.130 (1)
	Transportation Fuel Charges to Pools:			
21	East of Dawn - Union supplied fuel	0.032		0.032
22	West of Dawn - Union supplied fuel	0.050	0.061	0.111
23	East of Dawn - Shipper supplied fuel	0.025 (1)		0.025 (1)
24	West of Dawn - Shipper supplied fuel	0.034 (1)	0.061	0.095 (1)
	C1 - Cross Franchise Transportation Service			
	Transportation service			
	Monthly demand charges:			
25	St. Clair / Bluewater & Dawn	1.045	1.843	2.888
26	Ojibway & Dawn	1.045	1.843	2.888
27	Parkway to Dawn	0.837	0.037	0.874
28	Parkway to Kirkwall	0.837	0.037	0.874
29	Kirkwall to Dawn	1.475	0.067	1.542
30	Dawn to Kirkwall	2.865	0.289	3.154
31	Dawn to Parkway	3.402	0.314	3.716
32	Kirkwall to Parkway	0.537	0.024	0.561
33	Dawn to Dawn-Vector	0.029	0.001	0.030
34	Dawn to Dawn-TCPL	0.138	0.001	0.139
	Commodity charges:			
35	St. Clair / Bluewater & Dawn - Union supplied fuel (Nov. 1 - Mar. 31)	0.009		0.009
36	St. Clair / Bluewater & Dawn - Union supplied fuel (Apr. 1 - Oct. 31)	0.007		0.007
37	Ojibway & Dawn - Union supplied fuel (Nov. 1 - Mar. 31)	0.011		0.011
38	Ojibway & Dawn - Union supplied fuel (Apr. 1 - Oct. 31)	0.016		0.016
39	Parkway to Kirkwall / Dawn - Union supplied fuel (Nov. 1 - Mar. 31)	0.006		0.006
40	Parkway to Kirkwall / Dawn - Union supplied fuel (Apr. 1 - Oct. 31)	0.010	0.001	0.011
41	Kirkwall to Dawn - Union supplied fuel (Nov. 1 - Mar. 31)	0.006		0.006
42	Kirkwall to Dawn - Union supplied fuel (Apr. 1 - Oct. 31)	0.006		0.006
43	Dawn to Kirkwall - Union supplied fuel (Nov. 1 - Mar. 31)	0.027		0.027
44	Dawn to Kirkwall - Union supplied fuel (Apr. 1 - Oct. 31)	0.011		0.011
45	Dawn to Parkway - Union supplied fuel (Nov. 1 - Mar. 31)	0.036	0.001	0.037
46	Dawn to Parkway - Union supplied fuel (Apr. 1 - Oct.31)	0.020	0.001	0.021
47	Kirkwall to Parkway - Union supplied fuel (Nov. 1 - Mar. 31)	0.015		0.015
48	Kirkwall to Parkway - Union supplied fuel (Apr. 1 - Oct.31)	0.014	0.001	0.015

Notes:
(1) Plus shipper supplied fuel per rate schedule.

UNION GAS LIMITED
Summary of Changes to Storage and Transportation Rates

Line No.	Particulars ($/GJ)	EB-2017-0351 Approved January 1, 2018 Rate (a)		Rate Change (b)	EB-2017-0087 Approved January 1, 2018 Rate (c)
	C1 - Cross Franchise Transportation Service				
	Transportation service cont'd				
1	St. Clair / Bluewater & Dawn - Shipper supplied fuel (Nov. 1 - Mar. 31)	Note (1)			Note (1)
2	St. Clair / Bluewater & Dawn - Shipper supplied fuel (Apr. 1 - Oct. 31)	Note (1)			Note (1)
3	Ojibway & Dawn - Shipper supplied fuel (Nov. 1 - Mar. 31)	Note (1)			Note (1)
4	Ojibway & Dawn - Shipper supplied fuel (Apr. 1 - Oct. 31)	Note (1)			Note (1)
5	Parkway to Kirkwall / Dawn - Shipper supplied fuel (Nov. 1 - Mar. 31)	Note (1)			Note (1)
6	Parkway to Kirkwall / Dawn - Shipper supplied fuel (Apr. 1 - Oct. 31)	Note (1)			Note (1)
7	Kirkwall to Dawn - Shipper supplied fuel (Nov. 1 - Mar. 31)	Note (1)			Note (1)
8	Kirkwall to Dawn - Shipper supplied fuel (Apr. 1 - Oct. 31)	Note (1)			Note (1)
9	Dawn to Kirkwall - Shipper supplied fuel (Nov. 1 - Mar. 31)	Note (1)			Note (1)
10	Dawn to Kirkwall - Shipper supplied fuel (Apr. 1 - Oct. 31)	Note (1)			Note (1)
11	Dawn to Parkway - Shipper supplied fuel (Nov. 1 - Mar. 31)	Note (1)			Note (1)
12	Dawn to Parkway - Shipper supplied fuel (Apr. 1 - Oct.31)	Note (1)			Note (1)
13	Kirkwall to Parkway - Shipper supplied fuel (Nov. 1 - Mar. 31)	Note (1)			Note (1)
14	Kirkwall to Parkway - Shipper supplied fuel (Apr. 1 - Oct.31)	Note (1)			Note (1)
15	Dawn to Dawn-Vector - Shipper supplied fuel (Nov. 1 - Mar. 31)	Note (1)			Note (1)
16	Dawn to Dawn-Vector - Shipper supplied fuel (Apr. 1 - Oct . 31)	Note (1)			Note (1)
17	Dawn to Dawn-TCPL - Shipper supplied fuel (Nov. 1 - Mar. 31)	Note (1)			Note (1)
18	Dawn to Dawn-TCPL - Shipper supplied fuel (Apr. 1 - Oct . 31)	Note (1)			Note (1)
19	Dawn(Tecumseh), Dawn(Facilities or TCPL), Dawn (Vector) and Dawn (TSLE)	Note (1)			Note (1)
	Interruptible and Short Term (1 year or less) Firm Transportation:				
20	Maximum	75.00			75.00
	Cap-and-Trade Facility-Related Charges:				
21	St. Clair / Bluewater & Dawn	0.006			0.006
22	Ojibway & Dawn	0.006			0.006
23	Parkway to Dawn	0.006			0.006
24	Parkway to Kirkwall	0.006			0.006
25	Kirkwall to Dawn	0.006			0.006
26	Dawn to Kirkwall / Parkway (Cons) / Lisgar	0.006			0.006
27	Dawn to Parkway (TCPL)	0.006			0.006
28	Kirkwall to Parkway (Cons) / Lisgar	0.006			0.006
29	Kirkwall to Parkway (TCPL)	0.006			0.006
30	Dawn to Dawn-Vector	0.006			0.006
31	Dawn to Dawn-TCPL	0.006			0.006
	Authorized Overrun				
	Firm transportation commodity charges:				
32	St. Clair / Bluewater & Dawn - Union supplied fuel (Nov. 1 - Mar. 31)	0.044		0.060	0.104
33	St. Clair / Bluewater & Dawn - Union supplied fuel (Apr. 1 - Oct. 31)	0.042		0.060	0.102
34	Ojibway & Dawn - Union supplied fuel (Nov. 1 - Mar. 31)	0.045		0.061	0.106
35	Ojibway & Dawn - Union supplied fuel (Apr. 1 - Oct. 31)	0.050		0.061	0.111
36	Parkway to Kirkwall / Dawn - Union supplied fuel (Nov. 1 - Mar. 31)	0.139		0.011	0.150
37	Parkway to Kirkwall / Dawn - Union supplied fuel (Apr. 1 - Oct. 31)	0.144		0.011	0.155
38	Kirkwall to Dawn - Union supplied fuel (Nov. 1 - Mar. 31)	0.054		0.024	0.078
39	Kirkwall to Dawn - Union supplied fuel (Apr. 1 - Oct. 31)	0.054		0.024	0.078
40	Dawn to Kirkwall - Union supplied fuel (Nov. 1 - Mar. 31)	0.143		0.009	0.152
41	Dawn to Kirkwall - Union supplied fuel (Apr. 1 - Oct. 31)	0.127		0.010	0.137
42	Dawn to Parkway - Union supplied fuel (Nov. 1 - Mar. 31)	0.170		0.011	0.181
43	Dawn to Parkway - Union supplied fuel (Apr. 1 - Oct.31)	0.154		0.011	0.165
44	Kirkwall to Parkway - Union supplied fuel (Nov. 1 - Mar. 31)	0.054		0.002	0.056
45	Kirkwall to Parkway - Union supplied fuel (Apr. 1 - Oct.31)	0.054		0.001	0.055
46	St. Clair / Bluewater & Dawn - Shipper supplied fuel (Nov. 1 - Mar. 31)	0.034	(1)	0.061	0.095 (1)
47	St. Clair / Bluewater & Dawn - Shipper supplied fuel (Apr. 1 - Oct. 31)	0.034	(1)	0.061	0.095 (1)
48	Ojibway & Dawn - Shipper supplied fuel (Nov. 1 - Mar. 31)	0.034	(1)	0.061	0.095 (1)
49	Ojibway & Dawn - Shipper supplied fuel (Apr. 1 - Oct. 31)	0.034	(1)	0.061	0.095 (1)
50	Parkway to Kirkwall / Dawn - Shipper supplied fuel (Nov. 1 - Mar. 31)	0.112	(1)	0.010	0.122 (1)
51	Parkway to Kirkwall / Dawn - Shipper supplied fuel (Apr. 1 - Oct. 31)	0.112	(1)	0.010	0.122 (1)
52	Kirkwall to Dawn - Shipper supplied fuel (Nov. 1 - Mar. 31)	0.049	(1)	0.002	0.051 (1)
53	Kirkwall to Dawn - Shipper supplied fuel (Apr. 1 - Oct. 31)	0.049	(1)	0.002	0.051 (1)
54	Dawn to Kirkwall - Shipper supplied fuel (Nov. 1 - Mar. 31)	0.094	(1)	0.010	0.104 (1)
55	Dawn to Kirkwall - Shipper supplied fuel (Apr. 1 - Oct. 31)	0.094	(1)	0.010	0.104 (1)
56	Dawn to Parkway - Shipper supplied fuel (Nov. 1 - Mar. 31)	0.112	(1)	0.010	0.122 (1)
57	Dawn to Parkway - Shipper supplied fuel (Apr. 1 - Oct.31)	0.112	(1)	0.010	0.122 (1)
58	Kirkwall to Parkway - Shipper supplied fuel (Nov. 1 - Mar. 31)	0.018	(1)		0.018 (1)
59	Kirkwall to Parkway - Shipper supplied fuel (Apr. 1 - Oct.31)	0.018	(1)		0.018 (1)
60	Dawn to Dawn-Vector - Shipper supplied fuel (Nov. 1 - Mar. 31)	0.001	(1)		0.001 (1)
61	Dawn to Dawn-Vector - Shipper supplied fuel (Apr. 1 - Oct . 31)	0.001	(1)		0.001 (1)
62	Dawn to Dawn-TCPL - Shipper supplied fuel (Nov. 1 - Mar. 31)	0.005	(1)		0.005 (1)
63	Dawn to Dawn-TCPL - Shipper supplied fuel (Apr. 1 - Oct . 31)	0.005	(1)		0.005 (1)

Notes:
(1) Plus shipper supplied fuel per rate schedule.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

Interrogatory

Reference:

Exhibit B, Tab 1, Page 5, Tables 1 and 2

Preamble:

No significant factors are known to have occurred in 2018 that would have contributed to a higher UAF than recently experienced. As part of the MAAD's Decision and Order dated August 30, 2018 on the amalgamation of Enbridge Gas Distribution and Union Gas (EB-2017-0306), Enbridge Gas Inc. was directed to file a report on the issue of Unaccounted for Gas for both the legacy Union Gas and legacy Enbridge Gas Distribution service areas by December 31, 2019.

Question(s):

a) Please provide UFG volumes and costs from 2013-2018

b) Please provide the status of the UAF Report - consultant and timing of draft.

c) When/how will the report be reviewed?

d) Does the work to date provide light on the causes and variations in UAF? Please discuss.

e) Please provide the metered throughput for each of the historic years 2014-2018.

a) Please provide the metered delivery points and indicate the counter party.

Response

a) Actual UAF Volumes and Costs

Year	Volumes (10^3m3)	Amount ($000s)
2013	97,361	17.899.1
2014	135,380	27,615.0
2015	88,438	18,534.4
2016	133,112	22,368.0
2017	93,077	16,570.7
2018	142,086	19.007.1

b) A consultant has been hired to provide a report addressing each of the following items:
   - Conduct a statistical analysis of annual and monthly trends for unaccounted for gas for legacy Union Gas and legacy Enbridge Gas Distribution;
   - Prepare an analysis of unaccounted for gas causes and identify possible points of gas losses;
   - Review functional capabilities of the measurement system used to produce unaccounted for gas;
   - Determine an industry benchmark of unaccounted for gas levels for companies with legacy Union Gas and legacy Enbridge Gas Distribution profile; and
   - Review current and alternative unaccounted for gas forecasting and allocation methodologies.

c) Please see Exhibit I.STAFF.4 part (c).

d) The consultant's work is at a preliminary date gathering stage. No conclusions regarding causes and variations have been considered to date.

e) Metered Throughput Volumes for EGD.

Year	Volumes (10^6m3)
2014	12,656.5
2015	11,931.8
2016	10,927.1
2017	11,346.5
2018	12,546.0

f) Legacy EGD Metered Delivery Points and Counter Parties

Station	IC Operators	Custody	
Vector-Sombra	Vector & Enbridge (EGD)	Enbridge (EGD)	TCPL = Transcanada Energy
ANR	ANR (Enbridge (EGD)	ANR	ANR = ANR Pipeline Company
Enbridge-Dawn	TCPL & Enbridge (EGD)	TCPL	
All other taps into legacy EGD	TCPL & Enbridge (EGD)	TCPL	
Cornwall	TCPL & Enbridge (EGD)	TCPL	**this location feeds gas into the US via Niagara Gas Transmission

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

Interrogatory

Reference:

Exhibit B, Tab 1, Appendix A, Schedule 4

Question(s):

a) Please provide a graphical representation of Rate 1 and Rate 6 Normalized Average Use per Customer for the historic years 2024-2018.

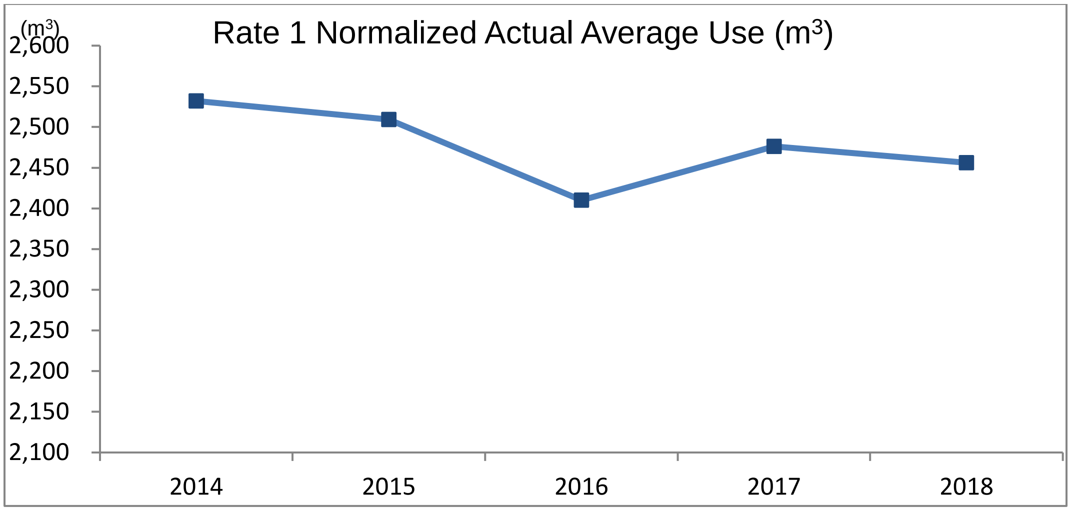
b) Please provide the standard error for 2018.

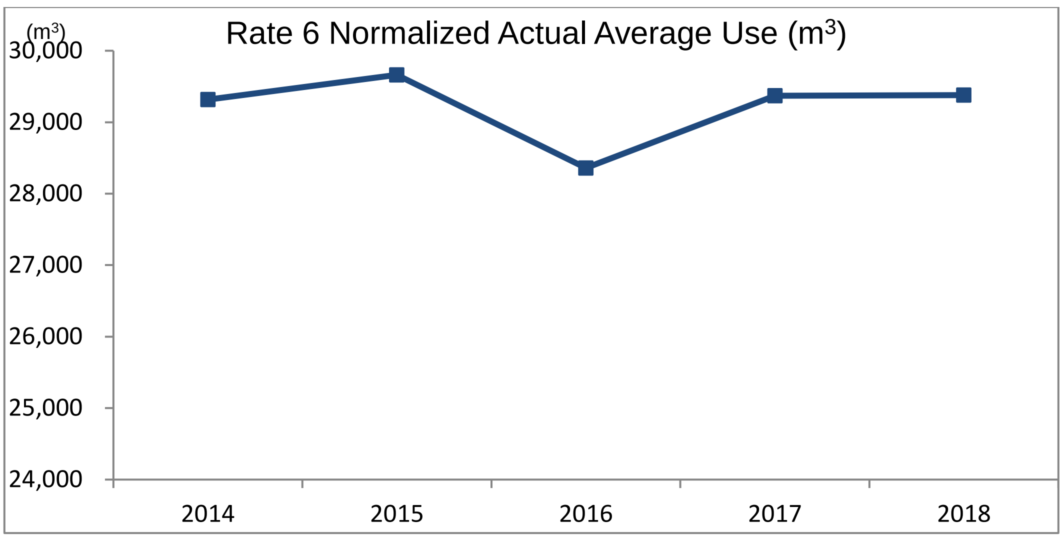
c) Please expand on the basis for the 2018 increase and provide estimates for contributing factors for example - DSM, price, economy and other factors.

d) Did EGD use the 2018 result in its models for 2019? Please provide the forecast results for each class.

Response

a) EGI assumes this question is requesting information for the historic years 2014-2018. Below please find the charts that show 'Actual Normalized Average use' that are normalized to 2018 Board approved degree days for Rate 1 and 6 for the period of 2014 to 2018.





b) Since standard error cannot be calculated for the single point of data, % error for 2018 is provided below. Based on the numbers in the table (refer to EB-2019-0105, Table 1 of Exhibit B, Tab 1, Appendix A, Schedule 4), % error for Rate 1 and Rate 6 average uses are 4.2% and 2.5% respectively.

	2018 Budget Annual Use (m^3)	2018 Normalized Actual Annual use (m^3)	% error (Actual vs Budget)
Rate 1	2,358	2,456	4.2%
Rate 6	28,656	29,377	2.5%

c) Even though contributing factors to higher average use in 2018 cannot be separated and quantified, however, please refer to EB-2019-0105, Exhibit B, Tab 1, Page 9 for the driving factors in general.

In addition to lower actual natural gas prices, higher employment levels and stronger GDP than were forecast, there are quite possible some uncontrollable factors that also lead to higher consumption (customer behavior changes, etc.).

d) No, when 2019 forecast was developed (Q2-2018) 2018 actual data for the full year was not available. The actuals up to 2017 are used to develop the 2019 average use forecast for Rate 1 and Rate 6. Please refer to EB-2018-0305, Exhibit F1, Tab 1, Rate Order, Working Papers, Schedule 10 for the table shows the 2019 forecast for Rate 1 and Rate 6, respectively (2,412 m^3 and 29,154 m^3; normalized to 2019 budget degree days).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

Interrogatory

Reference:

Exhibit B, Tab 1, Page 16 TIACDA; Exhibit B, Tab 3, Appendix A, Schedule 1, Page 3

Preamble:

Enbridge is now requesting recovery of the seventh, or 2019 installment of the Board-Approved TIACDA amount, in the amount of $4.436 million (1/20 of $88.716 million).

Question(s):

a) Confirm that there is a dispute among ratepayers regarding the allocation of the TIACDA.

b) Please provide a schedule that shows for each year, the amounts recovered from each Rate class to date and the proposed 2018 amount.

c) Provide a schedule that shows the over/under collection from each rate class to date and the amount for 2018.

d) Does EGI agree that the allocation dispute should be arbitrated by the Board prior to disposition of the remaining balance?

Response

a) The TIACDA clearance is carried out in accordance with the settlement agreement dated Oct 3, 2012 (EB-2011-0354, Exhibit N1, Tab 1, Schedule 1, Page 33).

b)

	EB-2013-0046 Year 2012 ($000)	EB-2014-0195 Year 2013 ($000)	EB-2015-0122 Year 2014 ($000)	EB-2016-0142 Year 2015 ($000)	EB-2017-0102 Year 2016 ($000)	EB-2018-0131 Year 2017 ($000)	EB-2019-0105 Year 2018 ($000)
Rate Class							
RATE 1	3,005.6	3,076.5	3,072.8	3,034.1	2,985.5	2,900.4	2,909.8
RATE 6	1,274.4	1,227.0	1,228.4	1,267.0	1,288.5	1,214.9	1,241.6
RATE 9	1.1	1.7	1.9	3.3	3.0	0.1	0.0
RATE 100	1.1	0.8	1.0	0.9	0.9	12.5	0.5
RATE 110	42.3	37.7	42.2	35.0	53.5	58.8	53.2
RATE 115	19.1	19.4	16.5	18.4	26.2	24.0	19.5
RATE 125	43.7	39.6	36.2	37.6	47.8	45.1	42.8
RATE 135	4.3	2.0	2.2	2.3	2.6	2.5	2.4
RATE 145	15.2	10.4	12.1	10.7	6.1	5.1	4.4
RATE 170	14.8	10.4	12.6	13.9	8.2	6.6	6.1
RATE 200	12.1	8.5	8.3	11.1	11.8	10.8	11.1
RATE 300	2.0	1.6	1.5	1.5	1.6	1.6	0.3
Rate 332						153.6	143.9
	4,435.8	4,435.8	4,435.8	4,435.8	4,435.8	4,435.8	4,435.8

c) For EGD rate zone, EGI clears TIACDA balances along with other Deferral and Variance Account balances to customers as a one-time billing adjustment based on actual volumes (i.e., 2018 actual volumes for 2018 balances).

As there is no volumetric variability, actual collections (i.e. clearances) equal forecast clearances. Therefore, there is no over/under collection from each rate class.

d) Please see response to part a) above.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

Interrogatory

Reference:

Exhibit B, Tab 2, Appendix A, Schedule 1; and Appendix D, Schedule 2

Question(s):

a) Please provide a version of Schedule 1 that includes the comparable 2017 ESM calculation.

b) Compare the 2018 O&M reduction to the amount proposed in the MAADs IRM proceeding.

c) Please provide details of the change in compensation, headcount and other factors.

d) Please provide the actual 2017 and 2018 ROE and the Board allowed return for each year.

Response

a) Please see attachment 1 to this response which provides a copy of Exhibit B, Tab 2, Appendix A, Schedule 1, updated to include the comparable 2017 ESM calculation, as was provided at Exhibit B, Tab 1, Schedule 2 in EB-2018-0131.

b) & c) Any 2018 O&M budget information presented in the MAADs proceeding was a forecast and not a proposed amount, as stated in the question. In any event, Enbridge Gas is not aware of O&M budget forecasts for EGD in 2018 presented in the MAADs proceeding that were substantially different from the actual amounts that are presented in this proceeding. Enbridge Gas is not able to provide details about differences in compensation, headcount or other factors that might have informed a budget forecast presented in the MAADs proceeding versus the actual results for 2018.

d) The 2017 and 2018 Board Approved ROE's, of 8.78% and 9.00%, can be found in the attachment to the response to part A of this question, at line 39. The 2017 and

2018 Actual Normalized ROE's (before reflecting the impact of earnings sharing), of 10.269% and 10.817%, can be found in the attachment to the response to part A of this question, at line 40.

SUMMARY
RETURN ON EQUITY & EARNINGS SHARING DETERMINATION
EGD RATE ZONE

ONTARIO UTILITY
FOR THE YEARS ENDED DECEMBER 31, 2017 & 2018

Line No.	Col. 1 Description	Col. 2 Reference	Col. 3 2018 Actual Normalized ($millions) & (%'s)	Col. 4 2017 Actual Normalized ($millions) & (%'s
1.	**Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency**			
2.	Gas Sales		2,498.8	2,503.4
3.	Transportation Revenue		276.3	308.2
4.	Transmission, Compr. and Storage Revenue		19.2	19.0
5.	Less Cost of Gas		1,566.0	1,668.0
6.	Gas Distribution Margin		1,228.3	1,162.6
7.	Other Revenue		42.3	42.1
8.	Other Income		0.2	0.3
9.	Total - Other Revenue & Income		42.5	42.4
10.	Operations & Maintenance (incl. CC/CIS rate smoothing adj.)		437.5	431.5
11.	Depreciation & amortization		294.7	301.3
12.	Fixed financing costs		2.2	2.8
13.	Municipal & capital taxes		44.9	44.6
14.	Total O&M, Depr., & other		779.3	780.2
15.	Utility Income before Income Tax	(line 5 + line 9 - line 14)	491.5	424.8
16.	Less: Income Taxes		38.8	1.0
17.	**Utility Income**		**452.7**	**423.8**
18.	Gross plant		9,594.5	9,228.8
19.	Accumulated depreciation		(3,277.9)	(3,126.5)
20.	Net plant		6,316.6	6,102.3
21.	Working capital		412.6	362.9
22.	**Utility Rate Base**		**6,729.2**	**6,465.2**
23.	Indicated Return on Rate Base %	(line 17 / line 22)	6.727%	6.555%
24.	Less: Required Rate of Return %		6.073%	6.019%
25.	(Deficiency) / Sufficiency %		0.654%	0.536%
26.	Net Earnings (Deficiency) / Sufficiency	(line 25 x line 22)	44.01	34.65
27.	Provision for Income Taxes		15.87	12.49
28.	Gross Earnings (Deficiency) / Sufficiency	(line 26 divide by 73.5%)	59.88	47.14
29.	**50% Earnings sharing to ratepayers**	(line 28 x 50%)	**29.94**	**23.57**
30.	**Part B) Return on Equity & Revenue (Deficiency) / Sufficiency**			
31.	Utility Income before Income Tax		491.5	424.8
32.	Less: Long Term Debt Costs		181.2	178.7
33.	Less: Short Term Debt Costs		6.9	3.8
34.	Less: Cost of Preferred Capital		2.6	2.3
35.	Net Income before Income Taxes		300.8	240.0
36.	Less: Income Taxes		38.8	1.0
37.	Net Income Applicable to Common Equity	(line 35 - line 36)	262.0	239.0
38.	Common Equity		2,422.5	2,327.5
39.	Approved ROE %		9.000%	8.780%
40.	Achieved Rate of Return on Equity %	(line 37 divide by line 38)	10.817%	10.269%
41.	Resulting (Deficiency) / Sufficiency in Return on Equity %		1.817%	1.489%
42.	Net Earnings (Deficiency) / Sufficiency	(line 38 x line 41)	44.01	34.64
43.	Provision for Income Taxes		15.87	12.48
44.	Gross Earnings (Deficiency) / Sufficiency	(line 42 divide by 73.5%)	59.88	47.13
45.	**50% Earnings sharing to ratepayers**	(line 44 x 50%)	**29.94**	**23.56**

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

Interrogatory

Reference:

Exhibit B, Tab 2, Appendix B, Schedule 4, Page ¾

Preamble:

The increased spend in Information Technology was primarily due to the implementation cost of EGD's Customer Experience Program of $14.4M. The Program aims to make interaction with customers easier, provide seamless customer service experiences that meets or exceeds our customers' expectations, and lower O&M costs.

Question(s):

a) Please provide the capital and operating costs for each year (including future years) for the CE program.

b) Please provide a summary of the program and the expected benefits to customers.

c) Is the program deployed in the EGD Rate Zone only, or both EGD and Union Rate Zones?

   If the latter, please provide the costs for the Union Rate Zone.

Response

a) Please see Exhibit I.STAFF.10 part (b) for the capital costs for each year (including future years) for the Customer Experience program. There are no operating costs related to the Customer Experience program.

b) Please see Exhibit I.STAFF.10 part (a) and (c).

c) This program is part of the EGD rate zone only, there are no related costs for the Union rate zones.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

Interrogatory

Reference:

Exhibit B, Tab 2, Appendix B, Schedule 4, Page 4

Question(s):

Please explain the reason for the $21 million underspend for service replacements.

Response

Please see the response at Exhibit I.FRPO.6

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

Interrogatory

Reference:

Exhibit B, Tab 2, Appendix F, Page 1

Question(s):

Please explain the reasons for the relatively low call answer service level of 77% and the relatively high call abandon rate of 2.6% in July 2018.

Response

EGD was experiencing lower call volumes throughout the first half of 2018 due to impacts of the Customer Experience program. Decreasing call volumes throughout 2018 resulted in higher than normal service levels for call answer. By mid-2018, staffing levels were being adjusted to achieve cost reductions as part of the program. However, for July specifically, there were two other negative contributing factors in Budget Billing year-end adjustments, and vacation coverage. July 2018 had a higher than anticipated number of customers with adjustments related to Budget Billing. This had the effect of an increase in year-over-year calls which had not happened in any other month in 2018. Vacation activity is also higher in July. These issues combined to negatively impact both call answer and abandon rates for the month.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

Interrogatory

Reference:

Exhibit C, Tab 1, Appendix A, Schedule 2, 179-131 Upstream Transportation Optimization

Question(s):

a) Please explain why the Gas Supply Optimization Margin in Rates is so high and increasing.

b) Please provide the amounts in rates for 2013-2018 and the actual Upstream Exchange Revenue amounts

c) What is the forecast for 2019?

Response

a) The Gas Supply Optimization Margin in Rates is $3.41 million higher than the 2013 Board approved amount. The Gas Supply Optimization Margin in Rates is calculated by multiplying the Board approved unit rates (per EB-2017-0087) by the 2018 billed units. In 2018, billing units were 1,159,218 10^3m^3 higher than 2013 Board approved. This increase is primarily due to higher consumption in the Union South rate zone, in rate classes M1 and M2. The higher consumption is driven in part by growth in number of customers and customers switching back to system gas from direct purchase.

b) See Table 1.

Table 1
2013 – 2018 Gas Supply Optimization in Rates & Exchange Revenues

	2013	2014	2015	2016	2017	2018
Exchange Revenue (Ratepayer Portion)	21,371,933	7,126,736	6,965,490	3,021,872	4,513,193	6,566,684
Gas Supply Optimization Margin in Rates	(15,696,837)	(17,010,234)	(15,565,366)	(14,667,575)	(15,569,780)	(16,839,302)
	5,675,096	(9,883,498)	(8,599,876)	(11,645,703)	(11,056,587)	(10,272,618)

c) The Forecasted 2019 amounts are as follows:

Exchange Revenue (Ratepayer Portion): $6.3 million
Gas Supply Optimization Margin (Rates): $(16.9) million
Total 2019 Forecast: $(10.6) million

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

Interrogatory

Reference:

Exhibit C, Tab 1, Page 9, and Table 3, C1 Off-Peak Storage

Preamble:

Actual 2018 revenues from C1 Off-Peak Storage, Gas Loans and all other Balancing services of $1.739 million were $0.761 million lower than the 2013 Board-approved forecast of $2.500 million.

Question(s):

a) Please provide the C1 forecast volume and price compared to actual

b) Please discuss the reasons for the reduction in revenue relative to forecast.

c) Please provide a Table showing the forecast and actual space and average price since 2014.

d) How does Union produce the forward year forecast? Please describe in detail.

e) Please provide the forecast for 2019

Response

a) EGI does not forecast off-peak and balancing services based on volume and price as the transactions are dependent on other factors such as demand, price and storage availability. Each year will be unique based on factors such as weather, supply, storage balances, etc.

b) EGI does not forecast off-peak and balancing services based on volume and price as the transactions are dependent on other factors such as demand, price and storage availability. Each year will be unique based on factors such as weather, supply, storage balances, etc.

c) Table below shows C1 Off-Peak Storage actual and forecast revenue from 2014 to 2018:

Revenue, $000's	2014	2015	2016	2017	2018
Actual	241	603	2,749	709	141

d) EGI forecasts off-peak and other balancing services by looking at past year's results and applying judgement based on known or expected market conditions.

e) The 2019 C1 off-peak storage Forecast is $0.7 million.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

Interrogatory

Reference:

Exhibit C, Tab 1, Page 20, Table 4, and Page 23, Table 6

Question(s):

a) Please provide a discussion why the 2018 NAC is higher than forecast for each rate class.

b) Please provide for each class a graphical representation of the NAC for 2013-2018. Add the 2019 Forecast.

c) Did the models predict the increase in NAC for Rate 01 and Rate M1? Please provide the 2018 standard error for each class.

d) How was the forecast for 2019 generated?

e) Please provide the 2019 forecasts.

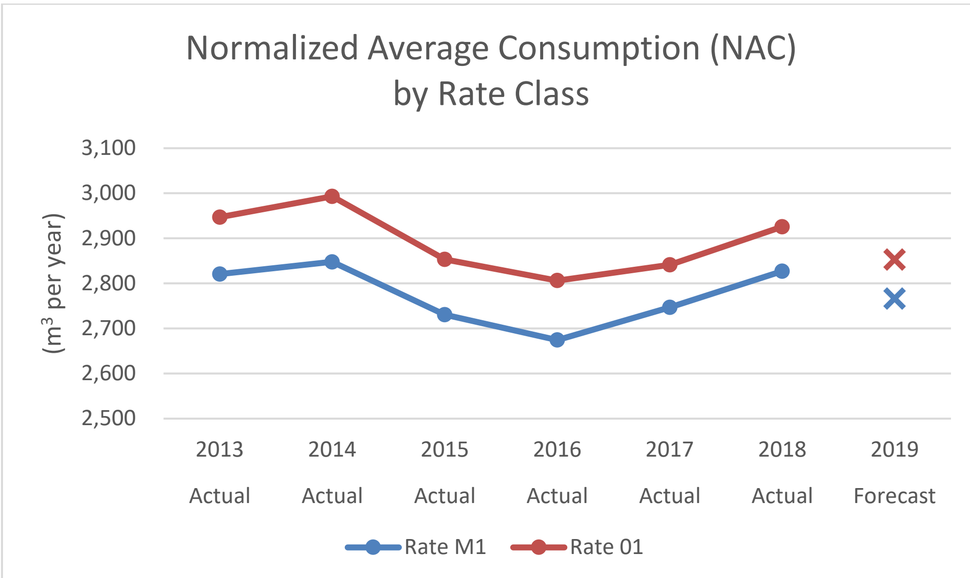
f) Please provide a table that relates the changes in normalized average use per custom (NAC) 2013-2018 to the changes in storage requirements in Table 6.

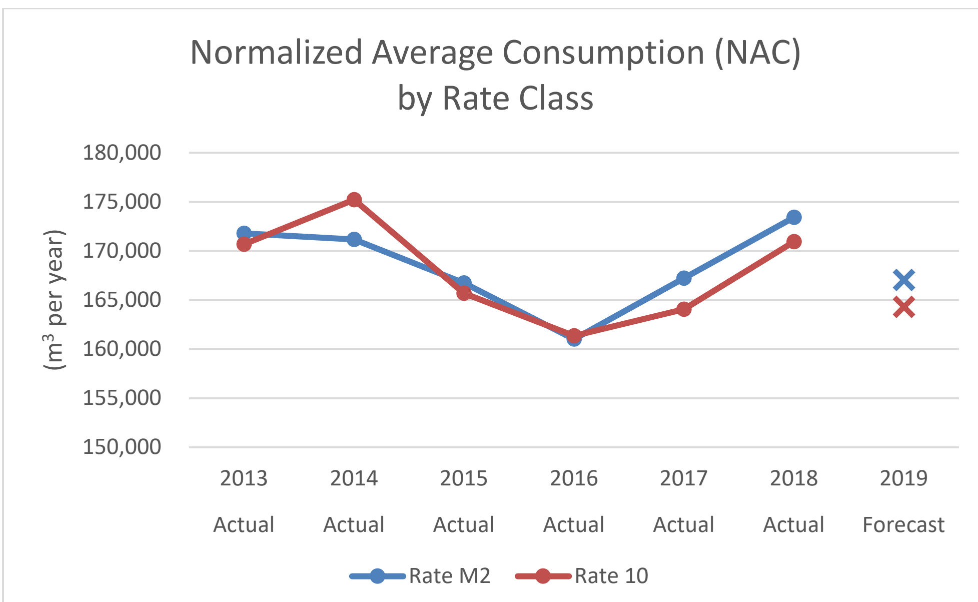
g) Is there a one to one reduction in NAC and storage requirement? Please discuss.

Response

a) The 2018 target (forecast) NAC is based on the 2016 actual NAC. The 2018 actual NAC was higher than 2018 forecast (2016 actual) partly due to higher employment, higher GDP, and lower vacancy rates in 2018 than 2016, and partly due to other customer behavior.

b) The charts below show historical actual NAC for each general service rate class, normalized to the 2018 Board approved weather normal. The 2019 forecast NAC is equal to the 2017 actual NAC, normalized to the 2019 Board approved weather normal (EB-2018-0305, Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 13, Page 1).





c) To determine the 2018 target NAC, EGI uses the 2016 actual NAC for each rate class, weather normalized using the 2018 weather normal. Regression models are not used to determine the target NAC. In all rate classes, the actual NAC declined from 2015 to 2016, and therefore the target NAC also declined from 2017 to 2018. However, actual NAC increased from 2017 to 2018, causing a positive variance.

Calculating a standard error is not applicable. The percentage error for 2018 is shown below:

	Rate M1	Rate M2	Rate 01	Rate 10
2018 Target NAC (m^3)	2,654	159,319	2,771	158,894
2018 Actual NAC (m^3)	2,810	171,248	2,864	167,467
NAC Variance	156	11,929	93	8,573
% Error	5.9%	7.5%	3.4%	5.4%

d) The forecast for 2019 follows the same Board approved methodology as applied previously in each year of the 2014-2018 IRM period. The 2019 NAC forecast was filed as part of EGI's 2019 Rates application (EB-2018-0305, Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 13, Page 1). To determine the 2019 target NAC, EGI uses the 2017 actual NAC for each rate class, weather normalized using the 2019 weather.

e)

2019 Target NAC (m^3)

Rate M1	2,767
Rate M2	167,039
Rate 01	2,853
Rate 10	164,301

f)

Board-approved NAC (m^3)

	Rate M1	Rate M2	Rate 01	Rate 10
2013	2,778	143,867	2,765	157,381
2014	2,751	165,085	2,898	167,443
2015	2,761	169,121	2,901	169,025
2016	2,852	172,693	3,015	177,214
2017	2,738	166,297	2,844	164,329
2018	2,654	159,319	2,771	158,894

% NAC Variance
from 2013 Board approved

	Rate M1	Rate M2	Rate 01	Rate 10
2014	-1%	15%	5%	6%
2015	-1%	18%	5%	7%
2016	3%	20%	9%	13%
2017	-1%	16%	3%	4%
2018	-4%	11%	0%	1%

Change in Storage Space due to NAC
from 2013 Board approved (PJ)

	Rate M1	Rate M2	Rate 01	Rate 10
2014	1.50	-0.50	0.03	0.02
2015	1.12	-1.50	0.20	-0.15
2016	0.47	-1.95	0.10	-0.24
2017	-0.88	-1.89	-0.11	-0.15
2018	0.01	-1.65	-0.23	-0.01

g) The change in storage requirements due to NAC variance is calculated using the aggregate excess methodology, which considers monthly volume variance due to NAC between the Gas Supply Plan and the 2013 Board-approved volumes. The required storage space is related to the profile of winter volumes compared to average daily volume over the year, and not necessarily the calendar year-over-year change in NAC. The tables in part (f) do not show a one to one correlation between annual NAC changes and corresponding changes to storage space.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

Interrogatory

Reference:

Exhibit C, Tab 1, Page 30, Table 8 and Notes

Question(s):

a) Please explain the basis of the $8.329 million in rates.

b) Please provide UFG volumes and costs from 2013-2018.

c) Please provide the status of the UAF/UFG Report - consultant and timing of draft.

d) When/how will the report be reviewed?

e) Does the work to date provide light on the causes and variations in UAF? Please discuss.

f) Please provide the metered throughput for each of the historic years 2014-2018.

g) Please provide the metered delivery points and indicate the counter party.

Response

a) The $8.329 million of UFG costs included in rates pertains to the 2013 Cost of Service (EB-2011-0210) whereas the UFG percentage (0.219%) is applied to the 2013 Board approved throughput to obtain the annual UFG volume (10^3m^3). This UFG volume is then multiplied by the annual weighted average cost to calculate the total Company annual UFG expense. The total UFG cost is reduced by the Board approved excess and non-utility percentages to arrive at the regulated portion of UFG. The table below illustrates how the $8.329 million is derived.

	2018 Board Approved Rates
UFG	
%	0.219%
Throughput (103m3)	32,009,650
UFG Volume (103m3)	70,253
Approved Reference Price (WACOG)	$131.025
2018 UFG Expense	$9,204,874
Less: L/T Non-Utility Allocation	$648,023
S/T Excess Utility Allocation	$227,360
Net 2018 Utility UFG Expense	**$8,329,490**

b)

UFG Continuity				
2013 Board Approved - 2018				
				UFG Expense
Year	**Total Throughput**	**Annual UFG %**	**UFG Volumes (10^3m3)**	**$CDN**
2013 Board Approved	32,009,650	0.219%	70,253	$ 14,729,405
2013	35,592,445	0.320%	113,997	$ 22,631,943
2014	30,577,949	0.318%	97,109	$ 18,429,387
2015	31,306,537	0.174%	54,408	$ 10,531,568
2016	30,835,935	0.427%	131,588	$ 18,510,303
2017	31,800,607	0.342%	108,901	$ 15,707,067
2018	35,978,439	0.350%	126,033	$ 17,877,943

c) Please see the response at Exhibit I.EP.2 b).

d) Please see the response at Exhibit I.EP.2 c).

e) Please see the response at Exhibit I.EP.2 d).

f)

	2014	2015	2016	2017	2018
UFG Throughput Volume (103m3)					
Jan	4,857,543	4,639,029	3,786,927	3,991,971	4,757,740
Feb	3,929,898	4,761,364	3,249,658	3,327,933	3,689,626
Mar	3,678,465	3,874,510	2,697,250	3,868,889	4,094,056
Apr	2,241,840	2,113,926	2,567,456	2,303,289	3,199,743
May	1,544,264	1,754,348	1,972,158	1,853,340	2,184,157
Jun	1,626,820	1,678,986	1,794,136	1,544,655	1,841,883
Jul	1,634,601	1,817,783	2,098,344	1,737,902	1,989,439
Aug	1,759,535	1,744,995	2,226,571	1,820,350	2,095,207
Sep	1,518,448	1,903,635	1,852,340	1,741,234	1,950,282
Oct	1,712,143	2,023,058	1,952,823	2,008,615	2,437,302
Nov	2,692,254	2,372,119	2,680,760	3,229,052	3,691,907
Dec	3,382,136	2,622,783	3,957,514	4,373,377	4,047,096
	30,577,949	31,306,537	30,835,935	31,800,607	35,978,439

g) Legacy Union Gas metered delivery points and counter parties

Station	IC Operators	Custody	
Kirkwall	TCPL & Enbridge (UG)	Enbridge (UG)	
Union-Dawn	TCPL & Enbridge (UG)	TCPL	
Sarnia	TCPL & Enbridge (UG)	TCPL	
Burlington	TCPL & Enbridge (UG)	TCPL	
Hamilton 3	TCPL & Enbridge (UG)	TCPL	
Nanticoke	TCPL & Enbridge (UG)	TCPL	
Ojibway	PEPL & Enbridge (UG)	PEPL	
St Clair	Michcon & Enbridge (UG)	Michcon	
Bluewater	Bluewater & Enbridge (UG)	Bluewater	
Bronte	TCPL & Enbridge (UG)	TCPL	
TCPL Parkway East	TCPL & Enbridge (UG)	Enbridge (UG)	
TCPL Parkway West	TCPL & Enbridge (UG)	Enbridge (UG)	
Enbridge Parkway East	Enbridge (EGD) & Enbridge (UG)	Enbridge (UG)	IC's between legacy EGD & legacy Union Gas
Enbridge Parkway West	Enbridge (EGD) & Enbridge (UG)	Enbridge (UG)	
Lisgar	Enbridge (EGD) & Enbridge (UG)	Enbridge (UG)	
Tecumseh	Enbridge (EGD) & Enbridge (UG)	Enbridge (UG)	
Tecumseh-Sombra	Enbridge (EGD) & Enbridge (UG)	Enbridge (UG)	
Chatham D	Enbridge (EGD) & Enbridge (UG)	Enbridge (UG)	
Enbridge EGT	Enbridge (EGD) & Enbridge (UG)	Enbridge (UG)	
Vector-Dawn	Vector & Enbridge (UG)	Enbridge (UG)	
Vector-Courtright	Vector & Enbridge (UG)	Enbridge (UG)	
All taps into legacy UG North & East Delivery areas	TCPL & Enbridge (UG)	TCPL	

TCPL = Transcanada Energy
Bluewater = Bluewater Gas Storage
Michcon = DTE Energy (Michigan Consolidated)
PEPL = Panhandle Eastern Pipeline Company
Vector = Vector Pipeline
ANR = ANR Pipeline Company

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

Interrogatory

Reference:

Exhibit, C Tab 1, Pages 30 to 61
179-136 Parkway West Project Costs
179-137 Brantford-Kirkwall/Parkway D Project Costs
179-138 Parkway Obligation Rate Variance
179-142 Lobo C Compressor/Hamilton-Milton Pipeline Project Costs
179-144 Lobo D/Bright C/Dawn H Compressor Project Costs

Question(s):

a) For the listed projects please provide a Summary Table that provides
The LTC Approved cost
Changes to approved cost
Planned and actual In-service dates
Planned and actual In-service costs
Incremental Capacity- Planned and Actual
Comments on material changes

b) Has all the incremental capacity been contracted? Please discuss.

c) Please provide a listing of shippers' (including EGD and Union) contracted annual volumes and term and the total capacity.

Response

a) Please see the chart below. For additional detail on the facility projects identified please see Exhibit I.LPMA.2, 4, 5, 6 and 7.

Capital Pass-Through Project	LTC Approved Cost	Planned In-Service Dates	Actual In-Service Dates	Incremental Capacity – Planned and Actual
Parkway West	$219 million	2014-2015	Multi-phased project	LCU compressor
Lobo C Compressor	$159.6 million[1]	Nov. 2016	Nov. 2016	442,770 GJ/d[2]
Hamilton to Milton	$231 million[3]	Nov. 2016	Nov. 18, 2016	See footnote above
Dawn H Compressor	$249.8 million	Nov. 2017	Oct. 2017	456,647 GJ/d[4]
Lobo D Compressor	$144.9 million	Nov. 2017	July 2017	See footnote 4 above
Bright C Compressor	$227.8 million	Nov. 2017	Sept. 2017	See footnote 4 above
Burlington Oakville	$119.5 million	Nov. 2016	Oct 31, 2016	222 TJ/d
Panhandle Reinforcement	$264.5 million	Nov. 7, 2017	Nov. 11, 2017	106 TJ/d[5]

b) As discussed at Exhibit 1.STAFF.22 a), EGI has surplus Dawn Parkway capacity of 126 TJ/d for November 1, 2018. The long-term sale of Dawn Parkway capacity related to the projects listed was more than offset by Dawn Parkway turnback. However, as of November 1, 2019 EGI has sold incremental long-term Dawn Parkway capacity that full utilizes the surplus capacity. This indicates that the incremental capacity that was created has been contracted.

c) As part of the OEB's Storage and Transportation Access Rule (STAR) reporting requirements, EGI files a complete Index of Customers on its website at https://www.uniongas.com/storage-and-transportation/informational-

[1] Adjusted for Settlement Agreement
[2] Combined total for Lobo C compressor and Hamilton to Milton – 2016 Dawn Parkway Expansion project
[3] Adjusted for Settlement Agreement
[4] Combined total for Dawn H, Lobo D and Bright C compressors – 2017 Dawn Parkway Expansion project
[5] Required to provide incremental capacity to Panhandle System and meet forecasted 5-year firm Design Day demand growth

postings/index-of-customers. Please see Attachment 1 for a copy of the Transport Index of Customers for October 1, 2019.

Enbridge Gas Inc. Transport Shippers as of October 1, 2019

Customer Name	Agreement Name	Receipt Point	Delivery Point	Quantity (GJ)	Start Date	Expiry Date	Negotiated Rate indicator	Affiliate
St. Lawrence Gas Company, Inc.	C10076	Parkway	Dawn	10,785	Apr 1, 2007	Mar 31, 2022	N	Y
Greenfield Energy Centre LP	C10083	Dawn	Dawn Vector	92,845	Mar 1, 2008	Oct 31, 2021	N	N
TransCanada PipeLines Limited	C10097	Dawn	Dawn TCPL	500,000	Nov 1, 2010	Oct 31, 2021	N	N
York Energy Centre LP	C10102	Dawn	Parkway	11,654	Apr 1, 2012	Oct 31, 2022	N	N
Bluewater Gas Storage, LLC	C10105	Bluewater	Dawn	-	Nov 1, 2013	Oct 31, 2023	Y	N
Emera Energy Limited Partnership	C10106	Ojibway	Dawn	21,016	Nov 1, 2015	Oct 31, 2020	N	N
Emera Energy Limited Partnership	C10107	Kirkwall	Dawn	73,745	Nov 1, 2015	Oct 31, 2021	N	N
Emera Energy Limited Partnership	C10108	Kirkwall	Dawn	26,335	Apr 1, 2015	Mar 31, 2021	N	N
Seneca Resources Company, LLC	C10109	Kirkwall	Dawn	388,261	Nov 1, 2016	Mar 31, 2023	Y	N
Rover Pipeline LLC	C10113	Ojibway	Dawn	36,927	Nov 1, 2017	Oct 31, 2025	N	N
TransCanada PipeLines Limited	C10114	Parkway	Dawn	516,787	Nov 1, 2017	Oct 31, 2020	N	N
TransCanada PipeLines Limited	C10115	Parkway	Dawn	42,202	Nov 1, 2017	Oct 31, 2022	N	N
BP Canada Energy Group ULC	HUB040E60	Dawn	Parkway	1,277	Nov 1, 2018	Oct 31, 2019	N	N
BP Canada Energy Group ULC	HUB040E61	Dawn	Parkway	3,053	Nov 1, 2018	Oct 31, 2019	N	N
BP Canada Energy Group ULC	HUB040E62	Dawn	Parkway	10,789	Nov 1, 2018	Oct 31, 2019	N	N
Tidal Energy Marketing Inc.	HUB305T0217	Parkway	Kirkwall	79,129	Oct 1, 2019	Oct 31, 2019	Y	N
Ontario Power Generation Inc.	HUB335T0015	Parkway	Dawn	2,650	Nov 6, 2018	Oct 31, 2019	Y	N
Basic Energy Inc.	HUB750T0002	Dawn	Parkway	180	Apr 1, 2019	Oct 31, 2019	Y	N
Basic Energy Inc.	HUB750T0003	Dawn	Parkway	212	May 2, 2019	Oct 31, 2019	Y	N
Energir, L.P. by its General Partner Energir Inc	M12007D	Dawn	Parkway	21,021	Nov 1, 1991	Oct 31, 2019	N	N
1425445 Ontario Limited o/a Utilities Kingston	M12077	Dawn	Parkway	6,322	Apr 1, 2004	Mar 31, 2022	N	N
Stelco Inc.	M12085	Dawn	Parkway	11,087	Sep 16, 2014	Oct 31, 2020	N	N
Energir, L.P. by its General Partner Energir Inc	M12092	Dawn	Parkway	35,000	Nov 1, 2006	Oct 31, 2019	N	N
Energir, L.P. by its General Partner Energir Inc	M12109	Dawn	Parkway	65,000	Nov 1, 2007	Oct 31, 2027	N	N
Goreway Station Partnership by its managing partner Goreway Power Station Holdings ULC	M12110	Dawn	Parkway	140,000	Nov 1, 2007	Oct 31, 2028	N	N
Vermont Gas Systems, Inc.	M12119	Dawn	Parkway	20,000	Nov 1, 2007	Oct 31, 2021	N	N
Greater Toronto Airports Authority	M12120	Dawn	Parkway	7,500	Nov 1, 2007	Oct 31, 2021	N	N
St. Lawrence Gas Company, Inc.	M12126	Dawn	Parkway	10,785	Nov 1, 2008	Mar 31, 2023	N	Y
Thorold CoGen L.P. by its General Partner Northland Power Thorold Cogen GP Inc.	M12129	Dawn	Kirkwall	49,500	Sep 1, 2009	Aug 31, 2029	N	N
Portlands Energy Centre L.P. by its General Partner, Portlands Energy Centre Inc.	M12130	Dawn	Parkway	100,000	Jan 13, 2009	Apr 21, 2029	N	N
Energir, L.P. by its General Partner Energir Inc	M12132	Dawn	Parkway	52,343	Apr 1, 2009	Mar 31, 2022	N	N
Ag Energy Co-operative Ltd.	M12151	Dawn	Parkway	1,247	Nov 1, 2008	Oct 31, 2020	N	N
The Narragansett Electric Company d/b/a National Grid	M12164	Dawn	Parkway	1,081	Nov 1, 2011	Oct 31, 2021	N	N
Connecticut Natural Gas Corporation	M12166	Dawn	Parkway	6,410	Nov 1, 2011	Oct 31, 2021	N	N
Ag Energy Co-operative Ltd.	M12167	Dawn	Parkway	1,900	Nov 1, 2011	Oct 31, 2021	N	N
Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.	M12171	Dawn	Parkway	21,825	Nov 1, 2011	Oct 31, 2021	N	N
Energir, L.P. by its General Partner Energir Inc	M12172	Dawn	Parkway	22,908	Apr 1, 2010	Mar 31, 2022	N	N
Energir, L.P. by its General Partner Energir Inc	M12176	Dawn	Parkway	88,728	Apr 1, 2011	Mar 31, 2021	N	N
Central Hudson Gas & Electric Corporation (a subsidiary of CH Energy Group, Inc.)	M12182	Dawn	Parkway	5,467	Nov 1, 2011	Oct 31, 2021	N	N
York Energy Centre LP	M12184	Dawn	Parkway	76,000	Apr 1, 2012	Oct 31, 2022	N	N
Niagara Mohawk Power Corporation d/b/a National Grid	M12186	Dawn	Parkway	55,123	Nov 1, 2011	Oct 31, 2021	N	N

Enbridge Gas Inc. Transport Shippers as of October 1, 2019

Customer Name	Agreement Name	Receipt Point	Delivery Point	Quantity (GJ)	Start Date	Expiry Date	Negotiated Rate indicator	Affiliate
Vermont Gas Systems, Inc.	M12190	Dawn	Parkway	500	Nov 1, 2010	Oct 31, 2021	N	N
The Brooklyn Union Gas Company d/b/a National Grid NY	M12193	Dawn	Parkway	12,953	Nov 1, 2010	Oct 31, 2021	N	N
KeySpan Gas East Corporation d/b/a National Grid	M12194	Dawn	Parkway	17,162	Nov 1, 2010	Oct 31, 2021	N	N
Central Hudson Gas & Electric Corporation (a subsidiary of CH Energy Group, Inc.)	M12195	Dawn	Parkway	10,792	Nov 1, 2010	Oct 31, 2021	N	N
Boston Gas Company d/b/a National Grid	M12197	Dawn	Parkway	9,282	Nov 1, 2010	Oct 31, 2021	N	N
Colonial Gas Company d/b/a National Grid	M12198	Dawn	Parkway	6,475	Nov 1, 2010	Oct 31, 2021	N	N
Boston Gas Company d/b/a National Grid	M12199	Dawn	Parkway	2,158	Nov 1, 2010	Oct 31, 2021	N	N
Liberty Utilities (EnergyNorth Natural Gas) Corp.	M12200	Dawn	Parkway	4,317	Nov 1, 2010	Oct 31, 2022	N	N
Connecticut Natural Gas Corporation	M12201	Dawn	Parkway	18,077	Nov 1, 2010	Oct 31, 2021	N	N
The Southern Connecticut Gas Company	M12202	Dawn	Parkway	34,950	Nov 1, 2010	Oct 31, 2021	N	N
Yankee Gas Services Company dba Eversource Energy	M12203	Dawn	Parkway	43,116	Nov 1, 2010	Oct 31, 2021	N	N
Bay State Gas Company dba Columbia Gas of Massachusetts	M12204	Dawn	Parkway	27,803	Nov 1, 2010	Oct 31, 2022	N	N
Connecticut Natural Gas Corporation	M12206	Dawn	Parkway	9,170	Nov 1, 2010	Oct 31, 2021	N	N
The Southern Connecticut Gas Company	M12207	Dawn	Parkway	13,970	Nov 1, 2010	Oct 31, 2021	N	N
The Brooklyn Union Gas Company d/b/a National Grid NY	M12208	Dawn	Parkway	30,217	Nov 1, 2010	Oct 31, 2021	N	N
KeySpan Gas East Corporation d/b/a National Grid	M12209	Dawn	Parkway	22,772	Nov 1, 2010	Oct 31, 2021	N	N
Yankee Gas Services Company dba Eversource Energy	M12210	Dawn	Parkway	20,560	Nov 1, 2010	Oct 31, 2021	N	N
Yankee Gas Services Company dba Eversource Energy	M12212	Dawn	Parkway	5,380	Nov 1, 2010	Oct 31, 2021	N	N
The Southern Connecticut Gas Company	M12213	Dawn	Parkway	9,735	Nov 1, 2010	Oct 31, 2021	N	N
Connecticut Natural Gas Corporation	M12214	Dawn	Parkway	6,489	Nov 1, 2010	Oct 31, 2021	N	N
Suncor Energy Products Partnership Produits Suncor Energie, S.E.N.C.	M12217	Dawn	Parkway	9,585	Nov 1, 2011	Oct 31, 2021	N	N
TransCanada PipeLines Limited	M12219	Kirkwall	Parkway	88,497	Nov 1, 2012	Oct 31, 2022	N	N
TransCanada PipeLines Limited	M12220	Kirkwall	Parkway	174,752	Nov 1, 2013	Oct 31, 2023	N	N
Emera Energy Limited Partnership	M12221	Kirkwall	Parkway	36,751	Nov 1, 2012	Oct 31, 2022	N	N
Energir, L.P. by its General Partner Energir Inc	M12222	Dawn	Parkway	257,784	Nov 1, 2015	Oct 31, 2025	N	N
Vermont Gas Systems, Inc.	M12224	Dawn	Parkway	8,100	Nov 1, 2014	Oct 31, 2024	N	N
TransCanada PipeLines Limited	M12230	Kirkwall	Parkway	36,301	Nov 1, 2016	Oct 31, 2031	N	N
Energir, L.P. by its General Partner Energir Inc	M12232	Dawn	Parkway	39,507	Nov 1, 2016	Oct 31, 2031	N	N
Energir, L.P. by its General Partner Energir Inc	M12233	Dawn	Parkway	19,754	Nov 1, 2016	Oct 31, 2031	N	N
Energir, L.P. by its General Partner Energir Inc	M12237	Dawn	Parkway	85,680	Nov 1, 2016	Oct 31, 2031	N	N
Energir, L.P. by its General Partner Energir Inc	M12244	Dawn	Parkway	36,670	Nov 1, 2017	Oct 31, 2032	N	N
TransCanada Energy Ltd.	M12246	Dawn	Parkway	143,775	Nov 1, 2017	Oct 31, 2032	N	N
St. Lawrence Gas Company, Inc.	M12249	Dawn	Parkway	10,412	Nov 1, 2017	Oct 31, 2032	N	Y
1425445 Ontario Limited o/a Utilities Kingston	M12251	Dawn	Parkway	5,000	Nov 1, 2017	Oct 31, 2032	N	N
1425445 Ontario Limited o/a Utilities Kingston	M12252	Kirkwall	Parkway	1,000	Nov 1, 2017	Oct 31, 2032	N	N
The Corporation of the City of Kitchener	M12253	Kirkwall	Parkway	10,000	Nov 1, 2017	Oct 31, 2032	N	N
DTE Energy Trading, Inc.	M12255	Kirkwall	Parkway	73,854	Nov 1, 2017	Oct 31, 2031	N	N
Northern Utilities, Inc.	M12256	Dawn	Parkway	42,962	Nov 1, 2017	Oct 31, 2033	N	N
Enbridge Gas New Brunswick Limited Partnership by its General Partner, Enbridge Gas New Brunswick Inc.	M12270	Dawn	Parkway	2,650	Nov 1, 2018	Oct 31, 2040	N	Y
Boston Gas Company d/b/a National Grid	M12273	Dawn	Parkway	22,332	Nov 1, 2018	Oct 31, 2040	N	N
The Narragansett Electric Company d/b/a National Grid	M12274	Dawn	Parkway	11,349	Nov 1, 2018	Oct 31, 2040	N	N
Heritage Gas Limited	M12276	Dawn	Parkway	3,978	Nov 1, 2018	Oct 31, 2040	N	N

Enbridge Gas Inc. Transport Shippers as of October 1, 2019

Customer Name	Agreement Name	Receipt Point	Delivery Point	Quantity (GJ)	Start Date	Expiry Date	Negotiated Rate indicator	Affiliate
Enbridge Gas New Brunswick Limited Partnership by its General Partner, Enbridge Gas New Brunswick Inc.	M12277	Dawn	Parkway	112	Nov 1, 2018	Oct 31, 2040	N	Y
Liberty Utilities (EnergyNorth Natural Gas) Corp.	M12284	Dawn	Parkway	1,957	Apr 1, 2019	Oct 31, 2040	N	N
TransCanada PipeLines Limited	M12X004	Dawn	Parkway	50,000	Sep 1, 2011	Aug 31, 2022	N	N
TransCanada PipeLines Limited	M12X005	Dawn	Parkway	78,316	Sep 1, 2011	Aug 31, 2022	N	N
TransCanada PipeLines Limited	M12X013	Dawn	Parkway	62,695	Nov 1, 2012	Oct 31, 2023	N	N
1425445 Ontario Limited o/a Utilities Kingston	M12X015	Dawn	Parkway	5,000	Apr 1, 2014	Mar 31, 2024	N	N
Market Hub Partners Canada L.P.	M16004	Dawn	Market Hub Partners - St. Clair Pool	9,000	Jun 1, 2007	May 31, 2022	N	Y
Market Hub Partners Canada L.P.	M16004	Market Hub Partners - St. Clair Pool	Dawn	9,000	Jun 1, 2007	May 31, 2022	N	Y
Enbridge Gas Inc. (In-Franchise Customers - EGD Zone) *		Dawn	Parkway	2,917,173	Jan 1, 2019	Oct 31, 2019	N	Y
Enbridge Gas Inc. (In-Franchise Customers - EGD Zone) **		Dawn	Kirkwall	67,929	Jan 1, 2019	Oct 31, 2019	N	Y
In-Franchise Customers - Union South and North Zones		Dawn	Parkway	2,318,129	Nov 1, 2018	Oct 31, 2019	N	Y

* - comprised of former contract #'s: M12079B, M12080, M12108, M12125, M12188, M12225, M12234, M12250 & M12X006

** - comprised of former contract #'s: M12079A & M12175

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

Interrogatory

Reference:

Exhibit C, Tab 2, Appendix B, Schedule 1, column (d), line 28

Question(s):

Please provide Union's authorized and actual ROE 2013-2018

Response

Please see Table 1 below for the Union rate zones' authorized and actual ROE for 2013-2018.

Table 1
UNION RATE ZONES ROE 2013-2018 (%)

	2013 (1)	2014 (1)	2015 (1)	2016 (1)	2017 (1)	2018 (2)
Actual ROE	10.67	10.69	9.89	9.24	9.16	9.64
Board-Approved ROE	8.93	8.93	8.93	8.93	8.93	8.93

Notes:
(1) EB-2018-0305, Exhibit I.BOMA.38, p. 2.
(2) Exhibit C, Tab 2, Appendix B, Schedule 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

Interrogatory

Reference:

Exhibit C, Tab 2, Appendix A, Schedule 13

Question(s):

a) Compare the 2018 O&M increase to the amount proposed in the MAADs IRM proceeding.

b) Please provide details of the increase in compensation, headcount and other factors

Response

a) The 2018 O&M information presented in the MAADs proceeding was a forecast and not a proposed amount, as stated in the question. The increase is mainly due to increase in compensation and benefits costs and partially offset by variances in other categories such as cost recovery from third parties.

b) The increase in compensation is primarily due to integration related costs – see Exhibit I.STAFF.24.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (“FRPO”)

Interrogatory

Reference:

Exhibit B / Tab 1 / p. 6

Preamble:

EGI’s evidence states: “As part of the MAAD’s Decision and Order dated August 30, 2018 on the amalgamation of Enbridge Gas Distribution and Union Gas (EB-2017-0306), Enbridge Gas Inc. was directed to file a report on the issue of Unaccounted for Gas for both the legacy Union Gas and legacy Enbridge Gas Distribution service areas by December 31, 2019. Among the objectives of the UAF study is an analysis of UAF causes to identify possible points of gas losses and to review functional capabilities of the measurement system used to produce UAF values.”

Question(s):

We would like to understand better what EGI was doing in 2018 to find and mitigate sources of UAF.

Please describe the initiatives undertaken in 2018.

a) What was learned?

b) What material reductions were achieved?

Response

a),b) Please see the response at Exhibit I.EP.2 c), d).

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B / Tab 1 / p. 21

Question(s):

Please provide the background provided by the OEB in billing its assessment.

a) Was the quantum of costs allocated associated in any way with the OEB's needs to hear and determine the merger of the two utilities while regulating the separate utilities?

   i) If so, please provide factors and allocations

   ii) If not, please provide the company's position on why the corporation should not bear some cost responsibility.

Response

a) The OEB's quarterly assessments invoiced to regulated entities during 2018, including the former Enbridge Gas Distribution Inc. and Union Gas Limited (now Enbridge Gas Inc.), which fund the Board's capital and operating expenditures, and are the subject of the OEB Cost Assessment Variance Account, did not to the Company's knowledge include any incremental costs associated with the merger application of the two utilities. In March 2019, the OEB invoiced Enbridge Gas Inc. for its incremental costs associated with the merger proceeding separately and the Company expensed the invoice to O&M.

   Update

   The invoicing of the incremental costs specific to the merger proceeding will not be subject to the 2019 OEB Cost Assessment Variance Account, nor have or will they be requested for incremental recovery in rates. The Company believes the incremental costs of the merger proceeding are appropriately included within the determination of utility results, as they are costs related to a regulatory proceeding, like any other regulatory proceeding costs invoiced above and beyond the quarterly OEB assessment and included within the determination of utility results. To the extent the Company is not in earnings sharing in 2019, the costs will be fully to the account of the Company. If the Company were to be in earnings sharing for 2019, it could then be said that the Company and ratepayers would be sharing the costs 50/50.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B / Tab 1 /Appendix A/ Schedule 2

Preamble:

We would like to understand more about the evaluation process and range of parameters that EGD has received in this process. Specifically, please provide the deliverability parameters or curves that EGD would have seen in RFP process.

Question(s):

Using the Blind RFP process in place at the time for contracts acquired in 2017 for 2018 utilization, please provide EGI third party storage contract parameters and their respective rates without identifying counter-parties.

a) Please provide the results of blind RFP for storage services that were used to contract for 2018 initiated contracts.

Response

In the MAAD's proceeding (EB-2017-0306/EB-2017-0307) Enbridge Gas Distribution provided a matrix of Blind RFP bids received in 2017 for 2018 utilization in Exhibit JT3.16. The requested information was redacted as it was considered commercially sensitive. JT3.16 is provided as attachment 1 to this response.

EGD Storage RFP matrix [1]

EGD defined terms:

**Up to 5 years of service commencing April 1, 2018*

**Firm Injection Schedule: at a minimum, must include the months of May through September*

**Firm Withdrawal Schedule: at a minimum, must include the months of December through March*

**Firm Injection Curve rights: at least 0.75% of MSB per day when inventory is less than 75% full*

**Firm Withdrawal Curve rights: at least 1.2% of MSB per day when inventory is more than 25% full*

Counterparty (BLIND)	***Company A***	***Company B***	***Company C***	***Company C***	***Company C***	***Company C***
offer descriptor (ie 1 of 3)	*1 of 1*	*1 of 1* *Standard LST Service*	*1 of 12*	*2 of 12*	*3 of 12*	*4 of 12*
TERM (years)	3	2-5 Years	1	2	3	1
Start date	4/1/2018	1-Apr-18	1-Apr-18	1-Apr-18	1-Apr-18	1-Apr-18
Inject/Withdrawal Location	Union-Dawn	Union-Dawn	Dawn	Dawn	Dawn	Dawn
MSB (max annual storage balance) units: GJ or MMBtu	2,000,000	Up to 8,000,000 GJ	2,000,000	2,000,000	2,000,000	2,000,000
Heat Value		N/A	mmbtu	mmbtu	mmbtu	mmbtu
Demand Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injection Curve parameters/ratchets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injection period (firm/interruptible)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional/Enhanced terms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal Curve parameters/ratchets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal period (firm/interruptible)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cycling terms (ie unlimited)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nomination Windows	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional/Enhanced terms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
General Terms and Conditions	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional Comments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1 If any above line item is not applicable, please insert N/A

Counterparty (BLIND)	*Company C*	*Company C*	*Company C*	*Company C*	*Company C*	*Company C*
offer descriptor (ie 1 of 3)	*5 of 12*	*6 of 12*	*7 of 12*	*8 of 12*	*9 of 12*	*10 of 12*
TERM (years)	2	3	1	2	3	1
Start date	1-Apr-18	1-Apr-18	1-Apr-18	1-Apr-18	1-Apr-18	1-Apr-18
Inject/Withdrawal Location	Dawn	Dawn	Dawn	Dawn	Dawn	Dawn
MSB (max annual storage balance) units: GJ or MMBtu	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000
Heat Value	mmbtu	mmbtu	mmbtu	mmbtu	mmbtu	mmbtu
Demand Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injection Curve parameters/ratchets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injection period (firm/interruptible)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional/Enhanced terms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal Curve parameters/ratchets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal period (firm/interruptible)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cycling terms (ie unlimited)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nomination Windows	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional/Enhanced terms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
General Terms and Conditions	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional Comments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Counterparty (BLIND)	***Company C***	***Company C***	***Company D***	***Company D***	***Company D***	***Company D***
offer descriptor (ie 1 of 3)	*11 of 12*	*12 of 12*	*1 of 13*	*2 of 13*	*3 of 13*	*4 of 13*
TERM (years)	2	3	1 year	2 year	3 year	4 year
Start date	1-Apr-18	1-Apr-18	1-May-18	1-May-18	1-May-18	1-May-18
Inject/Withdrawal Location	Dawn	Dawn	Dawn	Dawn	Dawn	Dawn
MSB (max annual storage balance) units: GJ or MMBtu	2,000,000	2,000,000	1,000,000 MMBtu	1,000,000 MMBtu	1,000,000 MMBtu	1,000,000 MMBtu
Heat Value	mmbtu	mmbtu	n/a	n/a	n/a	n/a
Demand Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injection Curve parameters/ratchets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injection period (firm/interruptible)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional/Enhanced terms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal Curve parameters/ratchets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal period (firm/interruptible)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cycling terms (ie unlimited)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nomination Windows	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional/Enhanced terms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
General Terms and Conditions	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional Comments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Counterparty (BLIND)	***Company D***	***Company D***	***Company D***	***Company D***	***Company D***	***Company D***
offer descriptor (ie 1 of 3)	*5 of 13*	*6 of 13*	*7 of 13*	*8 of 13*	*9 of 13*	*10 of 13*
TERM (years)	1 year	2 year	3 year	4 year	1 year	2 year
Start date	1-May-18	1-May-18	1-May-18	1-May-18	1-May-18	1-May-18
Inject/Withdrawal Location	Dawn	Dawn	Dawn	Dawn	Dawn	Dawn
MSB (max annual storage balance) units: GJ or MMBtu	2,000,000 MMBtu	2,000,000 MMBtu	2,000,000 MMBtu	2,000,000 MMBtu	3,000,000 MMBtu	3,000,000 MMBtu
Heat Value	n/a	n/a	n/a	n/a	n/a	n/a
Demand Charge per unit	[redacted]					
Commodity Charge per unit						
Fuel Charge per unit						
Transportation Charge per unit						
Injection Curve parameters/ratchets						
Injection period (firm/interruptible)						
Additional/Enhanced terms						
Withdrawal Curve parameters/ratchets						
Withdrawal period (firm/interruptible)						
Cycling terms (ie unlimited)						
Nomination Windows						
Additional/Enhanced terms						
General Terms and Conditions						
Additional Comments						

Counterparty (BLIND)	*Company D*	*Company D*	*Company D*	*Company E*	*Company E*	*Company E*
offer descriptor (ie 1 of 3)	*11 of 13*	*12 of 13*	*13 of 13*	*1 of 6*	*2 of 6*	*3 of 6*
TERM (years)	3 year	4 year	3 year	1 year	3 years	5 years
Start date	1-May-18	1-May-18	1-Apr-18	1-Apr-18	1-Apr-18	1-Apr-18
Inject/Withdrawal Location	Dawn	Dawn	Dawn	Dawn	Dawn	Dawn
MSB (max annual storage balance) units: GJ or MMBtu	3,000,000 MMBtu	3,000,000 MMBtu	1,000,000 MMBtu	3,000,000 mmbtu	3,000,000 mmbtu	3,000,000 mmbtu
Heat Value	n/a	n/a	n/a	Per TransCanada Pipelines	Per TransCanada Pipelines	Per TransCanada Pipelines
Demand Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injection Curve parameters/ratchets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injection period (firm/interruptible)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional/Enhanced terms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal Curve parameters/ratchets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal period (firm/interruptible)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cycling terms (ie unlimited)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nomination Windows	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional/Enhanced terms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
General Terms and Conditions	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional Comments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Counterparty (BLIND)	***Company E***	***Company E***	***Company E***	***Company F***	***Company G***
offer descriptor (ie 1 of 3)	*4 of 6*	*5 of 6*	*6 of 6*	*1 of 1*	*1 of 1*
TERM (years)	1 year	3 years	5 years	1	5 years
Start date	1-Apr-18	1-Apr-18	1-Apr-18	1-Apr-18	April 1, 2018
Inject/Withdrawal Location	Dawn	Dawn	Dawn	Dawn	Injections location: *Company G* Interconnect with Vector/Rover or Nexus. WD location: *Company G*
MSB (max annual storage balance) units: GJ or MMBtu	5,000,000 mmbtu	5,000,000 mmbtu	5,000,000 mmbtu	2.14 Bcf	MSB up to 8 Bcf or equivelent GJ of storage capacity.
Heat Value	Per TransCanada Pipelines	Per TransCanada Pipelines	Per TransCanada Pipelines	N/A	current heat value on injections is approx 1.050
Demand Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commodity Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Charge per unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injection Curve parameters/ratchets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injection period (firm/interruptible)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional/Enhanced terms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal Curve parameters/ratchets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Withdrawal period (firm/interruptible)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cycling terms (ie unlimited)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nomination Windows	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional/Enhanced terms	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
General Terms and Conditions	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Additional Comments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B / Tab 1 /Appendix A/ Schedule 2

Preamble:

We would like to understand better the seasonality of the reported transactional revenue.

Question(s):

Please provide the monthly figures for the reported years.

Response

The table in Attachment 1 outlines the monthly breakdown of the Yearly Transactional Services Revenue totals outlined in Exhibit B, Tab 1, Appendix A, Schedule 3.

EGI Transactional Services Revenue - 2014 to 2018 ($000's)

Year	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2018	Storage Optimization	$ 137	$ 13	$ 7	$ 9	$ -	$ -	$ -	$ 156	$ -	$ -	$ -	$ 102	$ 423.9
2018	Transportation Optimization	$ 5,490	$ 1,205	$ 1,040	$ 941	$ 315	$ 407	$ 472	$ 620	$ 500	$ 295	$ 1,651	$ 1,356	$ 14,292.4
2018	**Gross TS Revenue**	**$ 5,627**	**$ 1,217**	**$ 1,047**	**$ 950**	**$ 315**	**$ 407**	**$ 472**	**$ 777**	**$ 500**	**$ 295**	**$ 1,651**	**$ 1,458**	**$ 14,716.2**
2017	Storage Optimization	$ 20	$ -	$ -	$ 588	$ 422	$ 27	$ 50	$ 70	$ 31	$ 20	$ 3	$ 320	$ 1,550.1
2017	Transportation Optimization	$ 1,780	$ 992	$ 1,566	$ 143	$ 180	$ 307	$ 422	$ 261	$ 260	$ 280	$ 1,053	$ 3,148	$ 10,393.3
2017	**Gross TS Revenue**	**$ 1,800**	**$ 992**	**$ 1,566**	**$ 732**	**$ 603**	**$ 334**	**$ 471**	**$ 331**	**$ 291**	**$ 300**	**$ 1,056**	**$ 3,468**	**$ 11,943.5**
2016	Storage Optimization	$ -	$ 2	$ -	$ 1,170	$ 551	$ 539	$ 630	$ 1,180	$ 970	$ 1,827	$ -	$ 408	$ 7,277.2
2016	Transportation Optimization	$ 1,448	$ 530	$ 501	$ 886	$ 194	$ 423	$ 812	$ 868	$ 1,016	$ 889	$ 100	$ 2,797	$ 10,463.5
2016	**Gross TS Revenue**	**$ 1,448**	**$ 533**	**$ 501**	**$ 2,056**	**$ 745**	**$ 962**	**$ 1,442**	**$ 2,048**	**$ 1,986**	**$ 2,716**	**$ 100**	**$ 3,205**	**$ 17,740.6**
2015	Storage Optimization	$ 1	$ 328	$ 19	$ -	$ -	$ -	$ 1	$ -	$ -	$ 1	$ 1	$ 0	$ 350.6
2015	Transportation Optimization	$ 7,297	$ 8,537	$ 957	$ 67	$ 569	$ 758	$ 1,256	$ 1,028	$ 1,208	$ 236	$ 584	$ 228	$ 22,727.1
2015	**Gross TS Revenue**	**$ 7,298**	**$ 8,865**	**$ 976**	**$ 67**	**$ 569**	**$ 758**	**$ 1,257**	**$ 1,028**	**$ 1,208**	**$ 236**	**$ 585**	**$ 229**	**$ 23,077.8**
2014	Storage Optimization	$ 634	$ 337	$ 84	$ 67	$ 11	$ 11	$ 11	$ 12	$ 12	$ 15	$ 116	$ 393	$ 1,703.4
2014	Transportation Optimization	$ 4,055	$ 4,123	$ 197	$ 113	$ 57	$ 272	$ 242	$ 221	$ 226	$ 183	$ 541	$ 2,681	$ 12,910.3
2014	**Gross TS Revenue**	**$ 4,690**	**$ 4,459**	**$ 281**	**$ 180**	**$ 68**	**$ 284**	**$ 253**	**$ 233**	**$ 237**	**$ 198**	**$ 657**	**$ 3,073**	**$ 14,613.7**

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B / Tab 2 /Appendix B/ Schedule 3

Question(s):

Please provide the monthly percentage targets that EGD used in 2018?

a) Please add any criteria that EGD uses during the shoulder seasons of fall and spring.

Response

As mentioned in EGI 5-year Gas Supply Plan, EB-2019-0137, page 43,

> The inclusion of storage assets in the Plan provides a cost effective, reliable and secure alternative to purchasing commodity when required by customers, which is consistent with the Board's guiding principles. Storage provides the Plan further operational flexibility and aligns with the target to fill storage at November 1, maintain sufficient inventory at February 28 to provide required deliverability from all storage assets, and maintain inventory at March 31 to provide sufficient deliverability to meet peak day demand in March.

Update

EGD does not have monthly percentage targets for storage balances. However, the Company targets to maintain storage levels such that maximum deliverability (or 100% deliverability) could be maintained until the end of February and such that deliverability from storage would be sufficient to meet March peak day (which is basically 50% of maximum deliverability) as late as March 31. Also, the Gas Supply Plan intends to fill storage assets by the end of October, but will operationally execute to a 95% full level to ensure that late season injections can be managed reliably. This approach to manage storage targets was approved by the Board in EB-2014-0276.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B / Tab 2 /Appendix B/ Schedule 4/ Table 1 & p. 4

Question(s):

Given the significant underspend in the System Improvements and Upgrades category, what will the 2020 Revenue Requirement impact be of this quantum of underspend?

a) What factor(s) has (ve) changed in EGI prioritization that results in the $21M underspend in service replacements? Please describe fully including impacts on future expenditures.

Response

a) The System Integrity and Reliability (SIR) portfolio for 2018 was developed using the Enbridge Gas Distribution Asset Management Framework which involved the development of a multi-disciplinary, systematic approach to asset planning. This included the use of condition assessment, risk evaluation and optimization for asset planning to balance cost, risk and performance across the entire capital portfolio. The approach leads to different results compared to when the Board-approved budget was developed several years earlier. As a result, the spend in service replacements was reduced by $21 million.

   The implications of 2018 spending on future spending requirements in 2020 is not at issue in this 2018 ESM proceeding. The Company's capital spending plans for 2019-2028 are set out in the 10-year Asset Management Plan which was filed in the 2019 Rates Application and which reflects the anticipated spend in each Asset Class over the period 2019-2028 (including service replacements which are part of the Pipe Asset Class). The Company has filed an update (Addendum) to the Asset Management Plan in the 2020 Rates Application.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B / Tab 2 /Appendix B/ Schedule 4/ p. 2

Question(s):

How much of the total cost of storage investment was allocated to the non-utility storage?

Please provide the basis for that allocation specifically given the benefits of these expenditures to on-going and reliable storage services from an integrated operation.

Response

The cost of storage investment provided in evidence pertains to core utility storage operations and does not include any allocations to non-utility storage.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B / Tab 2 /Appendix C/ Schedule 1/ p. 5

Preamble:

EGI evidence states: "Property/asset use revenue 3rd party To eliminate asset use revenue (RP-2002-0133) and rental revenue from Tecumseh farm properties considered to be non-utility. (EBRO 464 & 365)

Question(s):

We would like to understand this distinction better

Please produce the specific reference from the Board's decisions in EBRO 464 & 365 which distinguished this income as non-utility.

Response

Please see the attached Reasons for Decision from EBRO 365. Paragraphs 127 – 131 discuss the treatment of costs and revenues related to Tecumseh farm properties.

Rep: OEB
Doc: 11792
Rev: 0

REASONS FOR DECISION

TECUMSEH GAS STORAGE LIMITED 3
October 30, 1981

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E.B.R.O. 365 I & II 4

REASONS FOR DECISION - E.B.R.O. 365-I & II TECUMSEH GAS STORAGE LIMITED 5

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REASONS FOR DECISION 16

in the matter of a rate application under The Ontario Energy Board Act by 17

TECUMSEH GAS STORAGE LIMITED 18

19

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E.B.R.O. 365-I & II

IN THE MATTER OF The Ontario Energy Board Act, R.S.O. 1970, Chapter 312 (now R.S.O. 1980, Chapter 332); 21

AND IN THE MATTER OF an application by Tecumseh Gas Storage Limited for Orders approving rates to be charged by the Company for the storage and transportation of natural gas. 22

BEFORE: H. R. Chatterson, Presiding Member 23

J. R. Dunn, Member 24

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APPENDICES 31

A. Current Rate Schedule SS-1 32

B. Utility Rate Base as at March 31, 1980 33

C. Utility Income 34

D. Revenue Deficiency Determination 35

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REASONS FOR DECISION 36

I. INTRODUCTION 37

1. The Applicant 38

Tecumseh Gas Storage Limited ("Tecumseh", the "Company", or the "Applicant"), provides a gas storage service in southwestern Ontario, the only customer of such service being The Consumers' Gas Company ("Consumers'"). Tecumseh was incorporated on September 24, 1963, to acquire storage leases in the Corunna, Seckerton and Kimball-Colinville natural gas pools in southwestern Ontario from Imperial Oil Limited ("Imperial"), pursuant to an agreement between Imperial and Consumers', and to provide storage facilities for natural gas. In accordance with the agreement, Imperial and Consumers' each acquired and still holds 50 percent of the 600,000 common shares issued by Tecumseh at $10.00 each. A separate long-term agreement was made between Tecumseh and Consumers' for natural gas storage. 39

Approval to inject, store and withdraw natural gas, in these three pools, was granted to Tecumseh by the Ontario Energy Board (the "Board") on December 2, 1963. The Company commenced operation of its 40 natural gas storage facilities in June 1964 and has operated continuously since that date.

Was Page 2. See Image [OEB:11791-0:8]

2. The Application 41

42

Tecumseh has not had a determination of rate base made by the Board nor has the Board assessed the reasonableness of Tecumseh's revenues. After operating for many years with only interim rates approved by the Board, Tecumseh has now made application to have the Board set a rate base and establish a reasonable rate of return thereon.

43

Tecumseh, by application dated January 10, 1978 (the "original application"), applied to the Board for an order or orders approving or fixing just and reasonable rates and other charges for the storage and transportation of natural gas. The original application, filed under section 19 of The Ontario Energy Board Act (the "Act"), also contained a request under sections 15(8) and 19 of the Act for such interim orders as may be necessary to permit Tecumseh to recover cost increases and to earn an appropriate rate of return, pending final disposition of the application.

44

Tecumseh submitted an amending application dated December 17, 1979, whereby it undertook to submit actual financial results for fiscal years ending March 31, 1977, 1978 and 1979 together with forecasted financial statements for 1980. The original application undertook the submission of actual results for fiscal 1977 only.

Was Page 3. See Image [OEB:11791-0:9]

45

A public hearing commenced on April 17, 1978, before Messrs. Chatterson and Clendining at which time counsel for the Applicant sought an adjournment pending completion of certain negotiations for the purchase of a major storage pool. The adjournment was granted and for various reasons the hearing was not reconvened until June 10, 1980.

46

The Applicant claimed a rate base of $46,786,779 and requested an overall rate of return of 11.24 percent which indicated a revenue deficiency of $1,941,600.

47

All evidence was received and testimony taken during six full days of hearing: three day in June 1980 and after an interval of some eight months, three more days in February 1981. During the interim period, historical data for fiscal 1980 became available and was filed in evidence in support of the Applicant's claim. Public hearings were concluded on February 11, 1981, and the Applicant's final argument was received on February 27, 1981.

48

These Reasons for Decision pertain to the determination of a rate base and a reasonable return thereon and the setting of a rate designed to yield the revenue required to permit the Applicant to realize the allowable rate of return.

Was Page 4. See Image [OEB:11791-0:10]

3. Appearances 49

50

The following is a list of appearances:

R. S. Paddon, Q.C. - for Tecumseh Gas Storage P. Y. Atkinson Limited 51

L. Graholm - for the Ontario Energy Board 52

G. J. Hills - representing The Consumers' Gas Company 53

The Applicant drew heavily upon the expertise of Consumers', a major shareholder. The following witnesses called by the Applicant are officials of The Consumers' Gas Company but each has administrative responsibilities as well with respect to Tecumseh. 54

R. B. Carter - Chief Accountant 55

R. J. Craig - Production Engineer 56
Exploration Department

J. I. Cuthill - President, Tecumseh Gas Storage limited and Vice-President, Consumers' 57

K. A. Walker - Manager, Regulatory Accounting 58

The Applicant also called Dr. S. P. Sherwin, Executive Vice-President, Foster Associates Inc., to testify on matters concerning rate base and rate of return. 59

Mr. P. V. Gundy of Gundy and Martin, financial consultants, was called on behalf of Board staff and he testified with respect to evaluation of storage rights, rate base and rate of return. 60

Was Page 5. See Image [OEB:11791-0:11]

There were no other appearances. Consumers', although represented, did not actively participate in the proceedings. There were no other intervenors, nor were there any letters of concern. 61

A verbatim transcript of all of the proceedings was made and a copy is available for public scrutiny at the not considered Board's offices. The Board therefore has not considered it necessary to summarize the evidence or submissions of the various parties in detail. All of the evidence and the submissions were carefully considered by the Board however in deciding the issues. <next page blank> 62

Was Page 7. See Image [OEB:11791-0:12]

II. RATE BASE 63

1. Introduction 64

The Applicant, from the time on its inception some 17 years ago, has operated a gas storage facility and, with Board approval, has charged interim rates for its services that have not been fully investigated as to 65 reasonableness during that period.

The Board in approving or fixing rates is required by the Act, among other things, to determine a rate date and a reasonable return thereon. Section 19 of the Act sets out the processes to be followed in the determination of rate base. Subsections 2, 3, 4, 5 and 6 of that section, to which several references were made during the proceedings, are pertinent and are set out hereunder: 66

"(2) In approving or fixing rates and other charges under subsection 1, the Board shall determine a rate base for the transmitter, distributor or storage company, and shall determine whether the return on the rate base produced or to be produced by such rates and other charges is reasonable. 67

"(3) The rate base to be determined by the Board under subsection 2 shall be the total of, 68

(a) a reasonable allowance for the cost of the property that is used or useful in serving the public, less an amount considered adequate by the Board for depreciation, amortization and depletion; 69

(b) a reasonable allowance for working capital; and 70

Was Page 8. See Image [OEB:11791-0:13]

(c) such other amounts as, in the opinion of the Board, ought to be included. 71

"(4) In determining the reasonable allowance for the cost of the property under clause a of subsection 3, the Board shall ascertain the actual cost of the property to the present owner, but, 72

(a) where the actual cost to the present owner of any of property cannot be ascertained, the Board shall determine a reasonable allowance to be included in the rate base for the cost of that property; and 73

(b) where in the opinion of the Board the actual cost to the present owner of any of the property is more than a reasonable allowance for inclusion in the rate for the cost of that property, the Board shall determine a reasonable allowance to be included in rate base for the cost of the property. 74

"(5) In considering whether the actual cost mentioned in subsection 4 exceeds a reasonable allowance for inclusion in the rate base and in determining the appropriate deductions to be made in respect of any such excess, the Board may consider all matters it considers relevant, including the public benefit resulting from the acquisition of the property, whether the acquisition at the price paid was prudent in the circumstances existing at the time and, where the property was acquired as an operating system or part thereof, the allowance made for its cost in the rate base of the former owner or, if no such rate base had been determined that included an allowance for the cost thereof, the allowance that would have been made therefor in a rate base for the former owner determined in accordance with this section. 75

"(6) Findings of fact on which determinations are made by the Board under subsections 2, 3, 4 and 5 shall be based on the evidence adduced at the hearing." 76

Was Page 9. See Image [OEB:11791-0:14]

77

Consumers' and Imperial are equal shareholders in the ownership of Tecumseh, which has purchased virtually all of the gas storage rights it now holds and certain other facilities from Imperial. The value to be placed upon these storage rights for inclusion in rate base became a major issue during the hearing.

78

As reported by witnesses for the Applicant, several options to the procurement or storage services were considered by Consumers' before proceeding with the establishment of Tecumseh as an operating storage company. One option was to look to TransCanada Pipelines Limited ("TCPL" or "TransCanada") to provide peaking capacity. Mr Cuthill reported that this would not have been a viable option as it would have resulted in a poor pipeline load factor and consequently an "astronomical" cost.

79

A second option, considered and also rejected was the purchase of a gas storage service from a competitor in the gas distribution business. The rates associated with such service, although judged to be too high, were ultimately used as a measure of the reasonableness of the cost of acquiring and developing other storage facilities that were known to be available.

80

After considering all such options, Consumers' decided to join with Imperial in establishing a storage service facility under a separate corporate entity, This launched the first phase of the acquisition and development of storage facilities by Tecumseh in the partially-depleted Corunna, Seckerton and Kimball-Colinville gas fields. Subsequently other options, including the development of the Leepfrog field, were considered. The Leepfrog field lies substantially beneath the waters of Lake Erie and for that and other cost related reasons was rejected in favour of development of the fully-depleted Wilkesport field, which was much closer to Tecumseh's existing facilities and had greater storage capacity.

Was Page 10. See Image [OEB:11791-0:15]

81

2. Valuation of Storage Rights

82

Corunna, Seckerton and Kimball-Colinville Fields

83

Exhibit 64 indicates that Imperial in 1960 decided to enter the gas storage business in Ontario but was prohibited from doing so by the Ontario Government's adoption of a policy whereby only companion with a provincial charter would be allowed to own and operate gas storage reservoirs within the province. This body of evidence, submitted after solicitation by Board counsel, also contained, among other things, several "in-house" memoranda which indicate the nature of the negotiations that took place between Imperial and Consumers'.

84

Neither Tecumseh nor Consumers' was able to provide documentation on rights evaluations. However, Mr. Cuthill, who was employed by Imperial in 1963 and joined Consumers' in mid-1971, and who has been closely associated with the operation of Tecumseh since that time, recalled and testified as to the technique he employed on behalf of Imperial in deriving the value of storage rights. He said:

Was Page 11. See Image [OEB:11791-0:16]

85

"I backed out of the calculation the value that Tecumseh could reasonably expect to pay to acquire the storage leases such that when that value was rolled into the development costs of the pool or the pools, the resulting storage service tariff would be competitive with any other alternative that customer would have to store gas in southwestern Ontario."

86

A firm offer for Imperial's interest in the subject pools was made by Consumers' in February of 1963. This initial offer was for some $7.9 million for all rights and natural gas remaining in place below 235 lbs. per square inch absolute ("psia"). Consumers' valued the gas storage rights at $3.5 million and the value of the gas in place at some $4.4 million.

87

Negotiations continued throughout 1963. Tecumseh was incorporated in September and an agreement between Imperial, Consumers' and Tecumseh was arrived at on November 20, 1963. The agreement stipulates a price to be paid for gas storage leases and gas storage facilities and equipment of $8.2 million. That agreement provides for the free use by Tecumseh of gas remaining in place with a shut-in pressure of 235 lbs. psia, however, title to all such gas remains with Imperial. A second agreement made between Imperial and Tecumseh on December 20, 1963, fixed the price to be paid for storage leases at $7.48 million and the price of storage facilities in place at $0.72 million or $8.20 million in total. The $0.72 million was recorded on the books of the Applicant as various components of "Property, Plant and Equipment" and the balance of the purchase price as "Gas Storage Rights."

Was Page 12. See Image [OEB:11791-0:17]

88

Wilkesport Pool

89

In preparation for the purchase of the Wilkesport storage reservoir from Imperial, Tecumseh had Stone Webster do an evaluation. Their report was completed in March 1976 and concluded that: "Under the assumption that continued increases in gas supply can reasonably be expected, Wilkesport has a value of between $6 million and $9 million for serving the residential heating market." A Stone & Webster memorandum dated August 23, 1976, and filed in evidence, indicated a value of $11.6 million. However as their assumptions with respect to gas supply and peak day capability were considered by Mr. Cuthill to be unrealistic, he subsequently initiated a second study.

90

The second study, dated November 1977, was done by Mr. Craig. In that study he recommended that Tecumseh should tender an offer of $4 million for the Wilkesport storage rights. The study showed that, upon reaching the expected annual _________ volume of 7 Bcf, cost of

Was Page 13. See Image [OEB:11791-0:18]

91

Wilkesport storage service on a stand-alone basis would be 8 to 10 per Mcf higher than the storage cost of Tecumseh's then existing storage operation. It also indicated that for each $2 million increase in the offer price the unit cost would increase by a further 3 per Mcf stored. It pointed out that the Wilkesport Pool could be operated jointly with the then existing Tecumseh service facility and, furthermore, that financial rolling-in of the Wilkesport pool with the existing Tecumseh operation would enable the use of otherwise inapplicable, capital cost allowances, and consequently avoid income taxes during the early years of operation.

92

On January 9, 1978, Tecumseh offered $4.3 million to Imperial for:

93

"(a) A 100% interest in the Petroleum and Natural Gas and Gas Storage Leases comprising the Wilkesport unit together with wells, flowlines and existing residual production facilities.

94

(b) The Petroleum and Natural Gas and Gas Storage Leases adjacent and protective to the Wilkesport unit."

This offer was declined but a subsequent offer, made on March 30, 1978, for $6 million was accepted by Imperial. 95

Mr. Cuthill, was questioned about a rationale to support the $1.7 million increase in the offer. He explained that Consumers' was confronted with an over-supply of gas and was exposed to a take-or-pay provision in its gas supply contract. In those circumstances, he said, availability of the Wilkesport Pool to absorb 9 Bcf of the over-supply meant a one time saving of some 96

Was Page 14. See Image [OEB:11791-0:19]

$2.7 million to Consumers', in unabsorbed demand charges that Consumers' would otherwise have had to pay to TCPL. 97

In addition to the two studies into the economic feasibility of the acquisition of Wilkesport by Tecumseh, other citations were made by Tecumseh to support the reasonableness of the offer. In this context it was noted that the Terminus Pool was purchased in 1974 by Union Gas Limited ("Union") for 30.0 per Mcf of void space, while the comparable cost paid by Tecumseh for Wilkesport in 1979 was 85.7 per Mcf of void space. The increase was said to reflect energy cost escalation. 98

The option of purchasing storage service from Union was explained by Mr. Craig. He stated that while Union's storage rate was expected to be 27.4 per Mcf in 1982-1983, Wilkesport could be fully developed by that time and its cost should then be 28 per Mcf on a stand-alone basis or 20.5 per Mcf on a "rolled in" basis. He estimated that Tecumseh's cost of service during the period 1981 to 1984, without the Wilkesport acquisition, would be in the range of 16 to 18 per Mcf. 99

3. Valuation Issues 100

Mr. Gundy took the position that the Board must determine whether or not the price paid by Tecumseh was appropriate and therefore allowable in rate base. He also questioned whether or not the negotiations between Imperial and Consumers' and between Imperial and Tecumseh were at arm's length. 101

Was Page 15. See Image [OEB:11791-0:20]

Mr. Graholm pointed out that the onus of proof is clearly on the Applicant with respect to the evaluation, and that it was therefore not incumbent upon Board staff or its consultant to provide an evaluation of storage rights. Board staff, however, produced a comparison of storage rights for other pools (Exhibit 96). 102

Mr. Gundy made telephone enquiries regarding the cost of storage rights in the State of Michigan and reported that such costs were much lower than the prices paid by Tecumseh. Mr. Atkinson objected to the nature of such evidence because it could not be tested. 103

Mr. Gundy suggested that an evaluation could be made by capitalizing storage rental payments, but the concept was not pursued. 104

There were no other active respondents to the proceeding. 105

106

Mr. Graholm argued that the Applicant should have sought resolution of the value of rights by bringing an application before the Board under section 21 of the Act. Mr. Cuthill, however, said such a proceeding would have been an expropriation manoeuvre, which was unnecessary as a negotiated settlement evolved.

107

Mr. Gundy noted that each of the two people who negotiated the value of the Wilkesport Pool storage rights, had dual roles. One was an executive of both Tecumseh and Imperial while the other was an executive of both Tecumseh and Consumers'. It was his opinion that negotiations under these circumstances could not have been conducted at arm's length and he said: "I see no evidence that they dealt at arm's length."

Was Page 16. See Image [OEB:11791-0:21]

108

Mr. Graholm argued that in accordance with a rule pertaining to asset valuation for rate making purposes, "the original cost of property purchased by a utility is the cost of the property to the first owner devoting property to public service." He contended that Imperial was in fact the first owner devoting property to public service and that, for purposes of section 19, Imperial should be regarded as the present owner for purposes of determining the cost of property to be included in rate base.

109

The evidence indicates that it was Imperial's policy to expense the cost of storage, petroleum and natural gas rights, and consequently no value for the storage rights was carried on the books of Imperial at the time they were sold to Tecumseh. Mr. Gundy submitted that, since no value was attached to those rights at the point in time when they were dedicated to public service, Imperial made windfall profits of some $13.9 million on the sale of its properties to Tecumseh. His position was that the Board would have to assess the reasonableness of such gains and ensure that windfall profits do not occur to the detriment of the public.

110

Mr. Atkinson argued that the value attached to storage rights in the books of Imperial is irrelevant in that the "present owner" is Tecumseh and it is Tecumseh's costs are relevant in the context of section 19 of the Act. He found it difficult to understand how the rule referred to by Mr. Graholm was applicable here, since there is no reason to conclude that Imperial is a utility or that it first devoted the pools to public service. He concluded that the value to Imperial and hence to Tecumseh was the market value and that Tecumseh's full cost should be allowed in rate base.

Was Page 17. See Image [OEB:11791-0:22]

111

4. The Board's Assessment

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In respect of the valuation of the assets acquired by Tecumseh from Imperial, the question of the relationship between Imperial and Consumers' is paramount.

113

If one disregards the fact that Tecumseh and Consumers' are regulated public utilities, it seems clear to the Board that Imperial would have stood to gain by higher pricing of those assets sold to Tecumseh and would have done so at the expense of Consumers', whose interest would have been in Tecumseh acquiring assets from Imperial at the least possible costs.

When one considers, however, that Tecumseh and Consumers' are regulated public utilities, it becomes clear that the regulatory process would have made higher pricing of those assets sold by Imperial to Tecumseh advantageous for both Imperial and Consumers', as such pricing would in due course likely lead to higher rate base valuation for Tecumseh and Consumers'. 114

Was Page 18. See Image [OEB:11791-0:23]

115

Thus, in the Board's view, the regulatory process enhanced Imperial's interest in higher pricing of its assets for sale to Tecumseh while it lessened, Consumers' incentive to strive for lower pricing.

116

Consequently, it is the Board's opinion in the circumstances of this case that the regulatory process imposed a conflict of interest on Consumers', that Consumers' interests were therefore not totally opposed to Imperial's, and that as a consequence there was not a full arms length relationship between Imperial and Consumers'. The Board has concluded, therefore, that it cannot rely entirely upon the amounts agreed upon between Consumers' and Imperial in the valuation of Tecumseh's assets for rate base purposes.

117

In the view of the Board Consumers' would have recognized this situation and that, in proceeding to a negotiated settlement with Imperial, it was doing so at some risk that the agreed upon values might not stand scrutiny for rate base purposes. It therefore seems to the Board that it was a risk taken knowingly but needlessly, a risk that Consumers' could have avoided by bringing an application to the Board under Section 21 of the Act. In determining a reasonable allowance for properties for inclusion in rate base, the Board has taken into consideration that Consumers' could have declared a conflict of interest and refrained from agreement and could then have applied to the Board under Section 21 of the Act for impartial valuations

Was Page 19. See Image [OEB:11791-0:24]

118

In seeking another basis for valuation, it occurred to the Board that by acting to have some reservoirs designated as gas storage areas, Imperial initiated the commitment of those properties to public service and therefore could be considered to be first to devote them to public service. This would mean that the value of the properties at that time would normally be considered to be the value to be taken for rate base purposes. However, as Imperial, in accordance with its usual practice carried the properties on its books at no value, the Board has had to seek elsewhere for a reasonable basis of valuation for rate base purposes.

119

In respect to valuation of the Corunna, Seckerton and Kimball- Colinville properties, the Board considers the retention of ownership of the gas in place by Imperial, while allowing Tecumseh its free use for cushion gas purposes, yet inflating other asset values to keep the total value unchanged, is but a subterfuge to avoid an evaluation of the gas in place and the recording of such as cushion gas on the books of Tecumseh.

120

In the Board's view, while Tecumseh was ostensibly given free use of the gas in place, in reality through enhancement of the storage rights by the value of the gas in place, Tecumseh paid full value for the gas in place in the guise of storage rights but did not receive title to such gas. Furthermore, this scheme provides for depreciation of the value of the disguised gas in place which otherwise would not be allowed. Now, it is clear that the value of storage rights for a reservoir would be enhanced if there was some gas in place as such gas would otherwise have to be purchased by Tecumseh. The value of the storage rights is not, however, in the Board's view, enhanced by the full value of the gas in place without the transfer of the ownership of such gas. Had the reservoir been empty and Tecumseh purchased gas, equivalent in volume to the gas in place, it would have paid full value but acquired ownership and thus entitlement to any escalation in the value of such gas.

Was Page 20. See Image [OEB:11791-0:25]

121

Since the arrangement provides for Imperial to retain ownership of the gas in place, and so benefit in due course from the escalating value of such gas, while earning a return on it plus depreciation through Tecumseh, and since the value of such gas an estimated by Consumers' would leave exceeded the value of such gas at the time that the reservoirs were designated as gas storage areas, the Board has concluded that the value of the storage rights for the Corunna, Seckerton and Kimball-Colinville reservoirs as claimed by the Applicant for inclusion in rate base, should be reduced by $1,000,000 for the purpose of this proceeding. This rate base reduction should not be taken to preclude further adjustments to the value of such storage rights, which may be considered necessary in subsequent proceedings.

122

With respect to the Wilkesport reservoir, the Board notes that payment of a higher-than-evaluated price was justified by the one time savings to Consumers' by escaping from liabilities arising out of a take or pay obligation with TransCanada. While some of the premium may be considered to represent storage value, the Board is not convinced that the consequential higher value of Tecumsehs rate base, as claimed, is fully warranted as representing the ongoing underlying value of the Wilkesport pool. Furthermore, the Board is not satisfied that the synergistic tax advantage of bringing Wilkesport into the Tecumseh operation, should have a bearing on the basic value of the reservoir. For these reasons, and after taking into account comparable value of other pools and allowing for escalation over time, the Board has determined that the rate has should be reduced by a further $600,000.

Was Page 21. See Image [OEB:11791-0:26]

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5. Other Rate Base Items

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Development Costs of Storage

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In addition to the gas storage rights purchased by Tecumseh, considerable capital expenditures have been made in the development of the storage pools. By March 31, 1980, the end of the test year, these expenditures amounted to some $28.4 million, in addition to the $13.5 million purchase of gas storage rights. The accumulated depreciation on fixed assets plus amortization of storage rights amounted to some $6.3 million at the end of the period, indicating a net book value, excluding land and base pressure gas, of $35.6 million dedicated to the Ontario utility operations. The costs of developing the storage facilites were not seriously challenged. The Applicant submitted that these amounts should be included in rate base. Details of these amounts, together with Board adjustments to rate base may be found in Appendix 'B'.

Was Page 22. See Image [OEB:11791-0:27]

126

Elsewhere in these Reasons for Decision the Board has considered the adequacy of the reserves for depreciation and amortization and found them after adjustment to be acceptable for purposes of this proceeding.

127

Farms

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The Applicant has some $414,217 invested in farms, (including $368,425 in land) and it proposed that the total amount be included in rate base. Tecumseh has been in the practice of purchasing farm land over the storage facilities as it becomes available, and Mr. Cuthill testified as to the intangible value of such land from an operational point of view.

129

Mr. Graholm argued that the investment in farms shows a poor return on investment, and that the Act did not contemplate utility ownership of such lands in fee simple, and that therefore the Board should remove all costs, revenues and expenses relating to farms from the utility operations.

Was Page 23. See Image [OEB:11791-0:28]

130

Mr. Atkinson argued that farm land is functionally related to the storage operation and should be allowed, and that the farm rental income and lease rental savings will increase and raise the apparent return on this rate base item in the future.

131

The Board is of the opinion that any intangible benefits to Tecumseh in its storage operation from owning the farms, on and under which the storage operations are performed, are negligible. Furthermore, as the farms are devoted almost entirely to agricultural purposes and their ownership is not essential to the storage operation, the Board finds that such farms are not used or useful in the storage operation. Consequently, all costs, revenue and expanses relating to farms, as set out in Exhibit 63.12A.1, shall be excluded and an imputed rental cost added.

132

Rights Outside Designated Areas

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Tecumseh holds gas storage leases on certain acreage lying outside the designated storage areas. These have been obtained at a cost of $18,350 and require annual rental payments of some $6,840. Mr. Graholm argued that allowances had already been made for protective acreage surrounding the designated storage areas and therefore those storage rights are not necessary and should be excluded from rate base.

Was Page 24. See Image [OEB:11791-0:29]

134

Mr. Atkinson argued that the rental payments and the capital invested were justified in that extra protection is provided and such rights would be of great value should additional storage pools be discovered adjacent to the designated areas. He also argued that the rights outside the designated area were part of the purchase transaction from Imperial and, in any event, are a minor cost and expense item and should be included in rate bass.

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The Board finds that, as these holdings are adjacent to the designated areas, and the amounts involved are minimal, their inclusion in rate base is acceptable. The Board therefore will not make any adjustments for rights outside the designated areas.

136

Construction Work in Progress

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Mr. Graholm, on enquiring about the status of capital projects at the end of the test year, was advised that two projects totalling $93,391 were not completed until after the year ended. This amount was claimed as a rate base item and depreciation of $1,375 was claimed against such capital plant in the test year. Mr. Graholm submitted that these amounts should be removed. Such removals were agreed to by the witnesses of the Applicant.

Mr. Atkinson argued that these projects are now complete and, since an historical year is used, that the 138
claims should be allowed as being consistent with normalization principles.

Was Page 25. See Image [OEB:11791-0:30]

The Board does not believe that manipulation of the historical data in this manner can be sanctioned and 139
in any event the argument of Mr. Atkinson seems to contradict the testimony of Company witnesses. The Board will therefore disallow the $93,391 in rate base and eliminate the $1,375 of depreciation expense as recommended by Board counsel.

Abandoned Wells 140

The Applicant has reported that, in the development of a storage reservoir, not all wells drilled can be 141
used for storage purposes. A drilled well may miss the reef and, if Imperial is not interested in its further development, then it in abandoned at additional cost to Tecumseh. Some wells drilled by Tecumseh are proven oil producers. These wells are sold to Imperial and the full cost of drilling is recovered by Tecumseh and the rate base reduced accordingly. Others, although of no value as storage wells, may be regarded by Imperial as potential oil producers, in which case Imperial assumes all further costs of drilling and, if oil is not encountered, the abandonment costs too. All drilling costs incurred by Tecumseh in drilling and abandoning wells, which are not recovered from Imperial, are capitalized and appear as a rate base item.

Was Page 26. See Image [OEB:11791-0:31]

Mr. Graholm argued that a well of this latter type, Tecumseh-Seckerton #17, costing $45,837.00 to drill 142
and taken over by Imperial at no cost to it, should be removed from rate base. This particular well, after further drilling, turned out to be a producing oil well, although the prospects at the outset were apparently unknown.

Mr. Atkinson argued that the Company's policy had enabled Tecumseh to save more than $15,000 in 143
abandonment costs for that well, the amount that would have otherwise been added to rate base. He pointed out that at the time the decision was made to transfer the well to Imperial, the prospects as an oil producer were unknown. He also acknowledged that the well in question did eventually become an oil producer.

The Board is of the opinion that the policy an enunciated is a rational policy, which should tend to 144
minimize losses resulting from wells that are drilled but turn out to be of no value to the storage operation. Furthermore, the Board is of the opinion that the eventual status of a potential oil well, transferred by Tecumseh to Imperial, is irrelevant and should not be a factor in retroactively fixing its value. The reasonableness of the policy is obviously dependent upon Tecumseh properly assessing the oil producing capability of any well before entering into an agreement with Imperial.

Was Page 27. See Image [OEB:11791-0:32]

The Board accepts for inclusion in rate base the residual cost of wells abandoned in this manner, for 145
purposes of this hearing. However, the Board directs Tecumseh to address itself to the ongoing appropriateness of such treatment in the depreciation and amortization study which the Board orders.

Allowance for Cash in Working Capital 146

147

In its application Tecumseh proposed that working capital should include an allowance for cash requirements, equivalent to 45 days expenditure on average for operating, maintenance, administration and general expenses, including wage annualization, in the amount of 45/365 of $2,104,153 = $312,787.

148

In response to a Board staff interrogatory, Tecumseh submitted a lead lag study in Exhibit 57. It indicated a cash allowance of $152,300 and was based on the application of component lags, derived from samples taken in 1978 and 1979, to forecasted 1980 figures. It used the same methodology, as that employed by Consumers in preparing the lead lag study, submitted to the Board in E.B.R.O. 369-I.

149

Mr. Atkinson pointed out that, in that case, Consumers' described its lead lag study as a first effort which could be improved upon with further research, and that the Board allowed the traditional allowance of

Was Page 28. See Image [OEB:11791-0:33]

150

45 days, for operating, maintenance, administrative and general expenses, rather than base its decision on that lead lag study.

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In this case, Mr. Walker, relying upon the decision in the Consumers' case, recommended that dependence on a lead lag study should be held in abeyance and the traditional 45 days allowance should be used to determine working cash allowance. He said, however, that if the results of Tecumseh's lead lag study are used, a further allowance should be made for the cash required to be on hand to cover expected requirements, which may exceed the average requirements indicated in the study.

152

Board counsel, contending that Tecumseh is really a division of Consumers', suggested that the Board either award no working cash allowance to Tecumseh or require Tecumseh to negotiate an earlier payment date with Consumer'. Alternatively, he submitted that an amount of $115,900, be adopted as being a more reasonable allowance than Tecumseh's proposal. He said that this amount results from modifications to the lead lag study by Board staff, which modifications were described in his argument.

153

Mr. Atkinson rejected an untrue the suggestion that Tecumseh was a division of Consumers' and contended that there should be an allowance for Tecumseh's cash requirements in working capital, just as for any other regulated company under the Board's jurisdiction. He submitted that the suggestion that Tecumseh negotiate in earlier payment date with Consumers' disregards the time requirements for bill processing and would serve only to transfer the working cash allowance requirement to Consumers', with no overall advantage to the customers of Consumers'.

Was Page 29. See Image [OEB:11791-0:34]

154

Mr. Atkinson submitted that Tecumseh was unable to respond fully to Board counsel's argument, as that argument was lacking in detail, and could not reconcile the adjustments made to the lead lag study by Board staff.

155

He contended that, if there were to be any renegotiation of the date of payment by Consumers', it would be preferable to extend the contractual provision from 20 days to 25 days, in view of the actual time taken from month- end to receipt of income as shown by the study, rather than reduce the receipt lag to accommodate the contractual stipulation of 20 days, and then by a penalty provision encourage Consumers' to pay by the 20th day.

Mr. Atkinson stated in arguments 156

"... that if reference is made to the lead lag study that the revenue lag of 40.2 days be used and the disbursement lag be calculated on the figures shown on Index 80.1.2 (82.1.2) using the comparative figures to those shown on Index 63.19.4 and 5 and using the lag days for operating and maintenance expenses shown on Index 63.19.5 except for the revision of special lease to (73-6) lag days per Index 63.34.2." 157

He also stated: 158

"The Company accepts the revisions on Index 63-19.2 and Index 63.33.2 which would result in working cash allowance for funds held in trust and compressor fuel to be ($9,400) and $nil respectively." 159

Was Page 30. See Image [OEB:11791-0:35]

Mr. Atkinson reiterated his request that the traditional 45 days allowance be used, arguing that such allowance is not antiquated as Board counsel contended for it was allowed to Consumers' in Reasons for Decision in E.B.R.O. 376, dated January 30, 1981. 160

While there may be need for further refinement of the lead lag study, the Board finds the lead lag study provides a more realistic estimate of the actual cash working capital requirement than does the 45 day rule. 161

The Board sees no valid reason for delaying the adoption of the basic lead lag study, pending its further refinement, and subject to certain adjustments will accept its result for the purpose of this proceeding in determining the allowance for cash in the working capital. 162

As there appears to be no sound reason for the time for payment by Consumers' to Tecumseh to the different from the time for payment by Tecumseh to Consumers', the Board rejects its counsel's recommendation and will require Tecumseh to match Consumers' time for payment of 25 days after month-end. This matching maintains the zero lag for compressor fuel established by index 63.33.2 and accepted by Tecumseh. 163

In adjusting the lead lag study the Board will, therefore, be guided by Mr. Atkinson's submission in this respect, noting that it has elsewhere herein rejected its counsel' proposal to exclude the cost of some lease payments. The Board, however, is imputing rental cost for farms and is prorating the capitalized overhead to only those administrative and general expenses listed on Index 82.1.2, before taking the weighted average of the expense lags. 164

Was Page 31. See Image [OEB:11791-0:36]

In respect to Mr. Walker's contention that there is need for a further cash allowance to cover expected requirements which may exceed the average, it is the Board's opinion, as it was in E.B.R.O. 371-1, that the reasonable level of working capital to be allowed, in fairness to both shareholders and customers, is that amount which on the average during the test year will just suffice for that purpose. 165

166

The lead-lag study, adjusted accordingly, indicates an allowance for cash in working capital of $147,600 which the Board accepts for inclusion in rate base.

Allowance for Compressor Fuel Inventory 167

Tecumseh's updated proposal included $534,682 in rate base for the weighted average value of the weighted average volume of 266,068 Mcf of compressor fuel in inventory, based on its forecast for the test year, fiscal 1980. 168

Board counsel observed that, because of variations in fuel purchases and fuel usage, restricting oneself to a particular year may overstate or understate the volume figure that should be used in calculating working capital allowance. He argued that the average volume for the test year is high and that the average volume of 167,561 Mcf for fiscal 1981 is a more accurate portrayal of the current and future situation, as it is calculated using the latest information, including the halving of the volume normally purchased. 169

Was Page 32. See Image [OEB:11791-0:37]

Mr. Atkinson preferred a number of plausible reasons for the halving of the purchase quantity in 1981 and requested the Board to consider that there would have been sound reasons for the "obviously abnormal purchase". He suggested that should the Board wish to deviate from the 1980 test year volumes, it may wish to average the figures available for the last four years. He said that such average is 237,667 mcf, based on upgrading 1981 to a volume of 282,199 Mcf, being the average that would have resulted had the "normal" purchase quantity of 500,000 Mcf been made in 1981. 170

While Tecumseh may have had sound reasons for halving the purchase quantity in 1981, the Board finds no evidence as to why this was done nor any to indicate whether it signifies an ongoing change in the frequency and quantity of fuel purchases. 171

If Tecumseh were to continue to purchase in 250,000 Mcf quantities, then the fiscal year 1981 inventory level would be indicated. If, however, Tecumseh were to revert to purchasing in quantities of 500,000 Mcf, then the fiscal year 1980 inventory level would be indicated. As Tecumseh's intentions are unknown, and as the Board considers the alternatives outlined to be equally likely, the Board will take the average inventory level for the two fiscal years 1980 and 1981 of 216,815 Mcf for the purpose of this proceeding. 172

Was Page 33. See Image [OEB:11791-0:38]

Board counsel submitted that Tecumseh should buy authorized overrun interruptible ("AOI") gas directly from TransCanada or that Consumers' should buy AOI gas from TransCanada at $2.68427 per Mcf for Tecumseh and transfer it to Tecumseh at cost plus 2 cents per Mcf, in similar manner to the way that Consumers' supplies Gazifere d'Hull. He recommended, therefore, that the allowance in working capital for compressor fuel inventory be $2.70427 per Mcf which when multiplied by 167,561 Mcf indicates a value of $453,130. 173

Mr. Atkinson submitted that Tecumseh could not purchase AOI gas directly from TransCanada unless Tecumseh had a contract for the supply of other-than-AOI gas from TransCanada. Such a contract he contended is a prerequisite implied by TransCanada's rate schedule for AOI gas supply. 174

Mr. Atkinson also submitted that Consumers' should not buy AOI gas for Tecumseh because: 175

(a) AOI gas can only be purchased when available and that timing may to soma extent offset its price advantage; 176

(b) it would be thwarting the intention of TCPL rate schedules approved by the National Energy Board; 177

Was Page 34. See Image [OEB:11791-0:39]

(c) it would be giving preferential treatment to Tecumseh not given to other large volume interruptible customers 178

(d) it would not be recovering its cost of service other than product cost beyond 2 cents per Mcf; 179

(e) such purchases would add to Consumers' current surplus supply situation and consequently result in the need for additional short-term storage and/or the incurrence of unabsorbed demand charges, both to the detriment of its Ontario customers; 180

(f) there is no Consumers' rate schedule which would authorize such a sale. 181

Even though Tecumseh might be able to purchase a mixture of AOI and other gas directly from TransCanada, the Board is not satisfied that a proper evaluation with all factors considered would show it to be economically advantageous for Tecumseh to do so. However Tecumseh might investigate, in its own interest, the alternative of purchasing, either directly or through Consumers', AOI gas from TCPL. 182

In the Board's opinion, if Consumers' were to purchase AOI gas ostensibly for Tecumseh, Consumers', in order to avoid discrimination, may have to make such gas available to other interruptible customers on the same basis. 183

There remains the question of the value to be placed on the 216,815 Mcf of fuel gas inventory, The Board thinks the weighted average historical value for the test year is appropriate, noting that such value would be changed but slightly by adjustment for a purchase quantity of 250,000 Mcf. The appropriate value is $534,682 ö 266,068 Mcf or $2.009569 per Mcf which, when applied to the inventory volume of 216,815 Mcf, yields an allowance in working capital for compressor fuel of $435,705. 184

Was Page 35. See Image [OEB:11791-0:40]

Board counsel has pointed out the need for Consumers' to apply for a franchise and certificate under The Municipal Franchises Act in order to supply gas to Tecumseh. That matter in beyond the scope of this proceeding. 185

6. The Approved Rate Base 186

The Applicant has proposed an historical rate base as of fiscal year end March 31, 1980, details of which 187 were got out in Exhibit 83.1.1. The Board finds this acceptable as a starting point to which the afore-mentioned adjustments have been made resulting in an approved rate base of $44,508,671 details of which are summarized in Appendix B. <next page blank>

Was Page 37. See Image [OEB:11791-0:41]

III REVENUES, COSTS AND UTILITY INCOME 188

1. Normalization and Annualization 189

Tecumseh adjusted the costs and revenues for the test year by normalization to reflect contracted rather than actual volumes. 190

Mr. Atkinson submitted that such normalization yields the maximum revenue that Tecumseh can contractually expect. He contended that to normalize to higher than contracted volumes, which might not materialize, would in affect deny Tecumseh the opportunity to earn its allowable rate of return. 191

Board counsel suggested that Tecumseh's proposal to normalize to the contracted volume and assume that all gas is recycled ignores reality. He submitted that the evidence showing volumes stored or to be stored by Tecumseh over several years does not support Tecumseh's claims that the contract level in the normal level and that the closing storage balance is normally zero. He recommended, therefore, that the volumes be normalized to Tecumseh's forecasted 1981 totals as not forth in Exhibit 56.34A.8 and that the affected expenses be adjusted accordingly to the final figures listed hereunder. These were calculated by Board staff, using up-dated expenses and fuel usage graphs. 192

Was Page 38. See Image [OEB:11791-0:42]

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In view of the persistent departure of past, present and projected storage volumes from the contracted levels, the Board thinks that the the total levels projected by Tecumseh are more likely than the contracted levels to represent the levels of storage that are expected to occur over the period during which the storage rates will be in effect. 194

The Board will therefore accept its counsel's recommendation and use forecasted total volumes and the adjusted expenses as set forth above. 195

2. Depreciation and Amortization 196

Tecumseh filed exhibits showing the rates of depreciation and amortization that have been in effect and unchanged since the commencement of Tecumseh's operation in 1964. Based on these rates, Tecumseh proposed to include a provision of $836,564 for both depreciation and amortization in the test year, comprised of $701,617 for depreciation and $134,947 for amortization. 197

Was Page 39. See Image [OEB:11791-0:43]

Tecumseh also showed that the accumulated provision for depreciation, resulting from the application of the depreciation rates, slightly exceeds the accumulated requirement for depreciation as calculated by the 198 formula

199

(Cost less	) (	Expectancy)

200

------------ (Estimated Salvage) (Average Life)

201

Board counsel, noting that Tecumseh's policy and charges for depreciation and amortization were not fully examined in this case, and have not been approved since the commencement of operations, recommended that the Board approve them on an interim basis and direct Tecumseh to file a formal depreciation study to substantiate them in its next case.

202

Mr. Atkinson contended that, even though Tecumseh's witnesses did not object to the suggestion that a depreciation study be done, such a study should not be ordered unless the Board concludes that there is a substantial need for it. He expressed concern that approval of depreciation and amortization costs on an interim basis would result in a conditioned or interim order for storage rates, and sought to avoid such outcome.

203

The Board notes that, while Tecumseh's overall reserve for depreciation and amortization appears to be adequate, the individual rates have never been approved by the Board and Tecumseh's witnesses could neither document the basis on which they were established nor otherwise explain the different rates of depreciation.

Was Page 40. See Image [OEB:11791-0:44]

204

The Board also notes that Tecumseh's auditors, Price Waterhouse & Associates, are of the opinion that the rates for asset depreciation and amortization of gas storage rights should be reviewed and perhaps increased.

205

The Board is not able to assess the adequacy of the depreciation and amortization provisions or reserves from the evidence. On the other hand, the Board has not been given any reason to believe that such provisions or reserves are unreasonable.

206

The Board therefore for the purposes of this proceeding only, accepts the Applicant's annual provisions and accumulated reserves for depreciation and amortization, with adjustments as set out in Appendices B and C. The Board will however, order Tecumseh to file a detailed study in its next rate case to substantiate by asset class, its depreciation and amortization rates and the adequacies of its reserves.

207

3. Utility Income

208

After making several adjustments arising out of the revisions previously referred to, all of which are summarized in Appendix C, the Board finds a utility income of $3,854,224 for the test year. There is no income tax payable.

Was Page 41. See Image [OEB:11791-0:45]

209

IV REASONABLE RATE OF RETURN

210

1. Capital Structure

211

The Applicant proposed a capital structure comprised of only two components -- funded debt and common equity -- based upon book values. The Applicant indicated that the debt ratio was 62.9 percent and the average cost of that debt during the test year was 9.76 percent. These were acceptable to Board counsel.

212

The filed evidence indicated that the funded debt was made up of three debenture issues and a $5 million bank loan. The debentures outstanding at March 31, 1980, represented debt of $23,162,000 and it was reported, none is held by either Imperial or Consumers'. All equity stock outstanding is held in equal shares by Imperial and Consumers'. In view of the foregoing the Board accepts both the capital structure and the average cost of debt as proposed by Tecumseh.

213

2. Return on Equity Submissions

214

The equity component was 37.1 percent of invested capital, and Dr. Sherwin and Mr. Gundy had different advice as to a reasonable rate of return thereon.

215

Dr. Sherwin expressed reservations with respect to the traditional test of the reasonableness of the return on equity when applied to Tecumseh. His evidence was:

Was Page 42. See Image [OEB:11791-0:46]

216

"It would, of course, be possible to test the results of the comparable earnings test by reference to the cost of attracting capital of other Canadian utilities. In my opinion, such a test would here be less useful than it has been in the past in other proceedings."

217

Dr. Sherwin stated in part in his pre-filed testimony:

218

"The risks of a gas storage operation serving only Consumers' Gas are essentially similar to those of Consumers', but are reduced by the existence of two contractual agreements with Consumers': a storage agreement and a "Through-put and Deficiency Agreement". These agreements shift a part of the business and essentially all the financial leverage risks to Consumers'. The equity return requirement is, therefore, less than for Consumers' integrated gas distribution business."

219

Dr. Sherwin accordingly recommended a return on equity of 13.5 to 14.0 percent for Tecumseh, based on a risk premium of 2.0 to 3.25 percentage points over the rate of return of 11.0 to 11.5 percent on "A" rated utility bonds as a datum. He compared this to a return on equity of 15.0 to 16.0 percent for high grade industrials, which corresponds to a risk premium of 3.5 to 5.00 percentage points. As Dr. Sherwin's pre-filed testimony assigned to high grade utilities a risk premium of one half a percentage point lose than for high grade industrials, the corresponding risk premium for high grade utilities is 3.0 to 4.5 percentage points.

220

Mr. Gundy submitted and Mr. Graholm argued that, as the Board has recently fixed an overall rate of return for Consumers' at 10.81 percent and, as Consumers' equity in Tecumseh is consolidated with Consumers' utility operations, the Applicant's equity component of capital should be allowed the overall rate of return approved for Consumers'. Assuming a cost of equity capital of 10.81 percent, as recommended by Mr. Gundy, an overall rate of return of 10.15 percent is indicated for Tecumseh.

Was Page 43. See Image [OEB:11791-0:47]

221

Mr. Atkinson argued that the ownership of Tecumseh equity shares is not relevant and should have nothing to do with the calculation of a fair rate of return for the Applicant. In this respect, Dr. Sherwin explained that:

222

".... the fundamental basis of all rate of return regulations is that the return is designed to be compensating for the risk of business, and the risk of the business has nothing to do with who happens to own it."

223

Mr. Graholm argued that the "happenstance of ownership" does have relevance, pointing out that Consumers' is Tecumseh's only customer; that day- to-day operations are conducted entirely by Consumers'; and that, in effect, Tecumseh is merely a division of Consumers' in which Imperial is a silent partner.

224

The phenomenon of double leverage was discussed and both Mr. Gundy and Dr. Sherwin cited such cases. However, Mr. Gundy, with some reservations agreed with Dr. Sherwin that the financial relationships considered in this application did not involve double leveraging and therefore that concept need not be a concern of the Board in this proceeding.

225

Mr. Gundy also contended that, if the Board were to allow Tecumseh the return on equity recommended by

Was Page 44. See Image [OEB:11791-0:48]

226

Dr. Sherwin, then Consumers' would be unfairly treated as Imperial would enjoy a higher rate of return than would Consumers', since Consumers' would be constrained by the rate of return already established by the Board. Dr. Sherwin and Mr. Atkinson rejected the premise that the Board had limited Consumers' return on its investment in Tecumseh to its overall cost of capital and contended that Consumers' was free to earn what it could on its investment in Tecumseh, so long as its overall return on its rate base did not exceed the allowable limit.

227

3. Conclusions of the Board

228

While Consumers', as Tecumseh's only customer, may cause Tecumseh's day to day operations to be conducted as though Tecumseh were a division of Consumers', such action does not, in the Board's opinion, alter the fact that Tecumseh is a separate corporate entity and entitled to be treated accordingly for regulatory purposes.

229

Furthermore, the Board thinks that ownership in itself cannot be taken to alter the inherent risks of a business and therefore its allowable rate of return. The Board has concluded therefore that its determination of the allowable rate of return for Tecumseh should not depend upon ownership. At the same times the Board believes it must bear in mind the relationship between Tecumseh and its owners in arriving at a decision.

Was Page 45. See Image [OEB:11791-0:49]

230

As previously noted Dr. Sherwin has reduced Tecumseh's risk premium to about two-thirds that for a utility such as Consumers', due to the reduction in Tecumseh's financial and business risks. The Board considers this reduction to be insufficient to reflect fully the decreased financial risk resulting from the through-put and deficiency agreement, together with the reduction in business risk associated with the storage agreement, all of which, to a large degree, has been transferred to Consumers'.

231

On the other hand, Mr. Gundy's recommendation of 10.81 percent return on equity, in the Board's opinion, ignores the risk premium concept, as it pertains to Tecumseh, and could only have validity if Tecumseh had no funded debt. However, in the Board' view the recommendation of Mr. Gundy could provide a datum to which could be added a small risk premium for equity capital that would compensate for the residual business risk and any financial-risk associated with funded debt hold by the investing public. The Board sees no reason why Consumers' return on its equity in Tecumseh cannot be either more or less than Consumers' allowable overall rate of return.

232

After considering all of the pertinent factors and assigning to each an appropriate weighting in accordance with its relevance, the Board concludes that a return on equity of 12.50 percent is reasonable.

Was Page 46. See Image [OEB:11791-0:50]

233

4. The Overall Rate of Return

234

Consequently, the Board finds Tecumseh's allowable overall rate of return is 10.78 percent, calculated as follows:

235

Was Page 47. See Image [OEB:11791-0:51]

236

V REVENUE DEFICIENCY

237

The Board has found that the Applicant's rate base at March 31, 1980, was $44,508,671 and that the Ontario utility income was $3,854,224, which represents an 8.66 percent return on rate base. The overall rate of return found reasonable by the Board is 10.78 percent and in order that the Applicant might realize that rate of return on the above rate base the Board finds that a revenue increase of $943,584 will be required (See Appendix D). <next page blank>

Was Page 49. See Image [OEB:11791-0:52]

238

VI RATE DESIGN

239

1. The Bases of Costing

240

In order to develop the components of a rate structure, the Applicant has done a cost allocation study in which all costs including the requested return are classified as either demand (annual or daily) or commodity costs. Board counsel found the methodology employed to be reasonable and recommended that it be accepted The Board accepts the classification and allocation of costs.

241

The tariff now in effect contains a rate made up of a demand charge based upon the annual turnover, a second demand charge based upon maximum daily through-put, plus a commodity charge based upon volumes handled each month. The proposed rate is a similar in structure.

242

The Applicant, after classifying all costs as fixed or variable, proposed to divide the fixed cost by the contract demand and the variable cost by the contracted volume in deriving the demand and commodity charges respectively.

243

Except for the normalization of volumes and adjustment of expenses as set forth in Section III of these Reasons for Decision, the Board accepts the methodology for the derivation of the rate structure in Imperial units.

Was Page 50. See Image [OEB:11791-0:53]

244

2. Compressor Fuel

245

The Applicant's cost of service analysis indicated that during the test year approximately 18 percent of the total costs, including returns were variable in nature and that those variable costs were primarily (77.5 percent) compressor fuel.

246

The Applicant has submitted that the use of compressor fuel is exceedingly difficult to predict an usage in affected by a number of factors such as storage balances, unplanned injection during the withdrawal cycle, unplanned withdrawals during the injection cycle, and other variations in supply pressure and injection and withdrawal patterns. The Applicant has proposed that the cost of compressor fuel be removed from the commodity charge component of the rate and billed separately from the monthly demand and commodity charge, on an as-used basis.

247

Board counsel, after setting out three options for the recovery of compressor fuel cost, recommended the method presently being used, that is rolling the fuel cost into the commodity component and billing the commodity charge on the basis of injection and withdrawal volumes. He argued that approval of the Applicant's proposal would be an abdication of regulatory responsibility by the Board and that, in any event, the costing methodology of fuel on an "as-used" basis was not clear.

Was Page 51. See Image [OEB:11791-0:54]

248

Mr. Graholm also pointed out that a "fuel ratio" method expressing fuel cost as a ratio of through-put might be considered, but it was his opinion that a meaningful fuel ratio could not be calculated at this time. The Board agrees.

249

Mr. Atkinson argued that the proposal in clear and that fuel would be charged out "as used" at the actual purchase price. He also submitted that a principle of regulation is to set rates enabling the collection of incurred costs during the period in which the rates are in effect, and that the Board in accomplishing this in an equitable manner could not be considered to be abdicating its regulatory responsibility.

250

The Board has some concern that the billing of compressor fuel on an "as used" basis could tend to reduce the motivation of management in their striving to maximize the efficiency of the storage operation. The Board is also of the opinion that compressor fuel volumes can be forecast with sufficient accuracy to permit rolling the fuel cost into the commodity component without more risk of excess revenues or shortfalls than from other forecast errors.

251

Furthermore, the Board foresees rate problems of an administrative nature should the Applicant seek to render a storage service to any customer besides Consumers'.

252

Finally, the Board thinks that allowing charges to be made on an "as used" basis does not constitute setting or fixing rates as the Board is required to do by the Act.

Was Page 52. See Image [OEB:11791-0:55]

253

The Board will therefore require the cost of compressor fuel to be included in the commodity charge.

254

3. Late Payment Penalty

255

Both Tecumseh and Consumers' have exhibited a rather casual attitude to the contractual provision for timely payment. The evidence indicates that Consumers' has not complied with Article 6.02 of the "General Terms and Conditions" attached to the rate schedule, requiring that the monthly storage charges be paid on or before the 20th of each month and, furthermore, that the late payment penalty of 6 percent per annum, as provided for by Article 6.03, is not enforced by Tecumseh.

256

Mr. Graholm suggested that the Board amend Article 6.03 to provide for a late payment penalty of 5 percent to conform with the late payment penalty imposed by Consumers' on its retail customers.

257

Mr. Atkinson argued that such change in not necessary as Tecumseh is satisfied with the clause as now written and that, it any change were to be made it should be an extension of the time allowed for payment.

258

The Board in discussing the lead lag study has extended the period for payment without penalty to the 25th day of the month. The Board is of the opinion that

Was Page 53. See Image [OEB:11791-0:56]

259

a penalty for late payment calculated at 6 percent per annum is unrealistic in view of the current coat of capital. The Board regards the late payment penalty as a charge for service (albeit a deterrent) and directs that a late payment penalty of 5 percent be assessed on any amount of the current bill outstanding after the 25th day of any month, after which a collection procedure could be initiated.

260

4. The Rate Schedule

261

Except as previously noted, the Board will accept the methodology employed in converting costs into rates for purposes of this proceeding.

The Applicant has submitted in evidence Appendix A, the currently effective Rate Schedule SS-1 with terms and conditions attached together with a Storage service Agreement. Certain revisions were proposed by Board counsel and certain modifications are required to be made in accordance with the following. 262

Article 3.02 of the Storage Service Agreement provides for the escalation of rates in the event that certain taxes are imposed an Tecumseh. Mr. Graholm recommended deletion of the clause. Mr. Atkinson acknowledged that any increase in rates as a result of the imposition of taxes would require the approval of the Board and that consequently there is no need to disturb the Storage Service Agreement. The Board agrees that it will not be necessary to delete the subject clause. 263

Was Page 54. See Image [OEB:11791-0:57]

Board counsel also pointed out that Article 2.04 of the Storage Service Agreement provides for deviations from annual turnover volumes and that such volumes will be handled on a best efforts basis, at rates to be agreed upon. The Applicant has handled such volumes at the rate as set out in paragraph 3.A.(b) in Rate Schedule SS-1. 264

Mr. Graholm therefore recommended that that clause of the rate be modified to include such provision as follows: 265

" cents per Mcf of Annual Turnover Volume of excess volume agreed to under Article 2.04 of the (Storage) Service Agreement." 266

As Mr. Atkinson accepted the revision, the Board approves paragraph 3.A.(b) as recommended by Board counsel. 267

Board counsel also observed that the present overrun charge was not applied in certain emergency situations facing Consumers in that the service had been provided on a "best efforts basis" as a force majeure condition was considered to exist. 268

The Board notes that, while a force majeure situation may have existed between Consumers' and TCPL, there did not appear to be a force majeure situation between Consumers' and Tecumseh. In the Board's opinion, in fairness to Imperial, such overrun gas should have been treated as authorized overrun gas in accordance with section 2.05 of the Storage Service Agreement and priced as authorized overrun gas in accordance with section 3.B.(c) of Rate Schedule SS-1. 269

Was Page 55. See Image [OEB:11791-0:58]

With respect to the "Commodity Charges" section of the rate schedule the Board considers that a rate differential at 60 percent of the annual turnover volume is unnecessary, and that a simplified phrasing as proposed by the Applicant and Board counsel is appropriate. 270

The Board points out that the "as used" billing of compressor fuel has been disallowed elsewhere in these Reasons for Decision. The Applicant's proposal with respect to the billing of fuel costs is therefore not acceptable and such costs are to be rolled into the commodity charges. 271

272

The Applicant is expected to proceed immediately with the preparation of a revised rate schedule in both Imperial and SI (metric) units, for final approval by the Board. The Board will be receptive to a hard conversion at this time.

273

The Storage Service Agreement need not be modified or changed in any manner; however, since it is an integral part of the contract for storage service it seems appropriate that a copy be attached to the rate schedule.

Was Page 57. See Image [OEB:11791-0:59]

274

VII COMPLETION OF THE PROCEEDINGS

275

An order shall issue charging the costs and expenses of the Board to the Applicant.

276

The interim orders authorizing the storage service rate the Applicant are hereby affirmed.

277

The Board expects the Applicant to draft an order with rate schedule attached, expressing charges in Imperial and SI units, and incorporating modifications and revisions in conformity with these Reasons for Decision. The Applicant shall file a copy of such draft with the Board Secretary and arrange a meeting with the Board to finalize the order and the rate schedule including its effective date. A Board order shall issue as soon as possible thereafter.

278

DATED at Toronto this 30th day of October, 1981.

ONTARIO ENERGY BOARD

<signed>

H. R. Chatterson

Presiding Member

<signed>

J. R. Dunn

Member

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B / Tab 2 /Appendix D/ Schedule 2

Question(s):

Please provide a more detailed description of the reduction in the Other category and a breakdown to any components that were reduced significantly.

Response

The detailed explanation of the major drivers of the reduction in the Other category is provided in Exhibit B, Tab 2, Appendix D, Schedule 2, page 2, line 18.

Update

The 5-year IR Budget for Other O&M Costs was approved in the 2014-2018 Custom IR Application, EB-2012-0459. In its pre-filed evidence in this application, legacy EGD filed the O&M budget for 2014-2016 using a bottom-up approach to reflect business needs. For 2017 and 2018, the Company did not use a bottom up approach to set the O&M budget, but instead assumed O&M to increase at the average rate of increase in O&M for 2014-2016. Using this assumption, the proposed budget for Other O&M was $256.3 million for 2018.

In its EB-2012-0459 Decision, the Board concluded that Other O&M should be kept to a level which increases at 1% per year, beginning with the 2014 budget. As such, the Other O&M amount for 2018 IR budget was reduced by $19.0 million, which represents the difference between the proposed amount of $256.3 million and the approved amount of $237.3 million for 2018. The $19 million reduction is reflected in the "other" line in the 2018 IR budget, found at Exhibit B, Tab 2, Appendix D, Schedule 2, page 2, line 18. This reflects the fact that EGD acknowledged its overall "Other O&M" budget had to be reduced, but did not determine the specific line items where those reductions might be found.

The 2018 Actual of ($2.3) millions in line 18 (“other”) represents the actual experience during the year. The amounts included in that line relate to miscellaneous adjustments and write-offs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (“FRPO”)

Interrogatory

Reference:

Exhibit B / Tab 2 /Appendix F/ p. 5

Preamble:

We would like to understand better the company’s response to not meeting a Service Quality Indicator.

Question(s):

What did EGI change as a result of not meeting the Board standard?

Response

Exhibit B, Tab 2, Appendix F, page 5 refers to the Service Quality Indicator for Meter Reading Performance Measurement (MRPM). As illustrated below, in 2018 EGI met the OEB approved standard of not exceeding 0.5% on a yearly basis for MRPM.

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Result	0.7%	1.0%	0.7%	0.6%	0.4%	0.4%	0.4%	0.4%	0.5%	0.4%	0.4%	0.4%	0.5%
Yearly Target	0.5%												

The OEB standard of 0.5% annually was met and no changes are required.

Some winter months exceeded 0.5% as severe weather prevented some active meters from being read for four consecutive months or more. For the remainder of 2018, the monthly percentage was at or below the 0.5% target resulting in a yearly total of 0.5%, which meets the OEB approved standard.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p. 2

Question(s):

With more Dawn discretionary purchases in the Union portfolio, how will EGI measure the efficacy of purchasing strategies (e.g., planned vs. spot purchases) between the legacy EGD and Union gas supply plans (e.g., reduction in planned UDC, etc.)?

Response

EGI believes that this question is more appropriately addressed within the Gas Supply Plan proceeding (EB-2019-0137).

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p. 6

Question(s):

Please provide a breakdown of the capacity and cost of UDC budgeted, capacity released and revenue realized by month for each of the North West and East.

Response

Table 1: North West

Line No.		Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
	Budgeted UDC													
1	Capacity (TJ)	64	64	1,551	770	1,220	1,449	1,557	1,564	1,368	1,057	517	79	**11,262**
2	Cost ($000's)	45	45	1,587	736	1,191	1,455	1,573	1,579	1,355	1,018	488	55	**11,128**
	Actual UDC Incurred													
3	Released Capacity (TJ)	-	-	233	933	863	860	1,106	923	935	857	-	-	**6,709**
4	UDC Costs Incurred ($000's)	-	-	345	1,063	944	926	1,165	986	1,032	691	-	-	**7,152**
5	Released Capacity Revenues ($000's)	-	-	141	568	600	386	634	389	362	371	-	-	**3,451**

Table 2: North East

Line No.		Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
	Budgeted UDC													
1	Capacity (TJ)	95	72	2,801	-	0	0	0	-	-	-	77	80	**3,125**
2	Cost ($000's)	49	20	1,726	-	0	0	0	-	-	-	22	22	**1,839**
	Actual UDC Incurred													
3	Released Capacity (TJ)	-	-	19	78	72	72	92	77	78	71	-	-	**559**
4	UDC Costs Incurred ($000's)	-	-	29	89	79	77	97	82	86	58	-	-	**596**
5	Released Capacity Revenues ($000's)	-	-	12	47	50	32	53	32	30	31	-	-	**288**

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p. 7

Preamble:

We would like to understand better the management of asset optimization of the utility.

Question(s):

At the end of 2018, did EGI have two separate departments to optimize the gas supply portfolios of the legacy EGD and Union?

a) How is the company actively pursuing synergies to minimize ratepayer cost in sharing delivery rights or asset capabilities?

Response

At the end of 2018, the two legacy Utilities had not yet amalgamated, and each legacy Utility was optimizing their own gas supply portfolios.

a) The Company has indicated in the Gas Supply Plan proceeding (EB-2019-0137) that it is in the process of preparing a plan for the integration of the gas supply plans of the two legacy utilities. Among other things, this can be expected to look at whether there are opportunities to reduce ratepayer costs.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p. 9-12

Preamble:

We would like to understand better the management of short-term storage and other services of the utility with respect to non-utility operations.

Question(s):

Is the department that sells short-term storage and other service separate and distinct from the non-utility?

a) If not, does the same person provide pricing for:
   i) short-term storage for the utility and non-utility?
   ii) park, loan and other short term services for the utility and non-utility?
   iii) how do they distinguish which entities assets provide the service?

b) Please provide an organization chart that shows the respective utility and non-utility departments.
   i) What barriers are there to inhibit information flow that could lead to conflict of interest? Please describe.
   ii) Please describe the legacy Union Operational Status Traffic Light system.

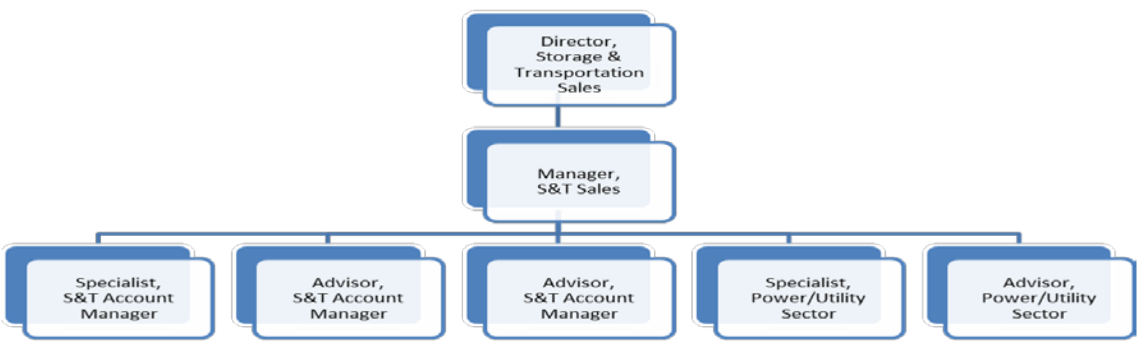
      (1) What department has authority to change the traffic light colour?
      (2) What specific criteria or methodology is used to change the light from green to yellow:
         (a) In the fall for injections?
         (b) In the spring for withdrawals?
      (3) What specific criteria or methodology is used to change the light from green to yellow:
         (a) In the fall for injections?
         (b) In the spring for withdrawals?

<u>Response</u>

Sales of short-term storage and other services are handled by the same department that is responsible for sales of storage to non-utility customers. This department is directly connected to the market and is in the best position to get value from all assets.

a) i) Confirmed
   ii) Confirmed
   iii) Utility storage is comprised of the excess between the 100 PJ available to utility customers as determined in EB-2005-0551, and the amount calculated as required for utility customers based on the aggregate excess calculation in the gas supply planning process each year. All other storage sales are non-utility.

b) As indicated in part a) above, sales of utility and non-utility assets are handled by the same department. The organization chart is provided below.



There are no barriers, nor does EGI believe there is a need to create any, to prevent information flow within the S&T Sales department. For departments outside of S&T Sales, access to information is shared only to the extent that it is required to perform specific job duties. The distribution of any non-public information that could provide a competitive advantage or a conflict of interest to certain groups (e.g. Gas Supply) is prohibited.

i. The legacy Union Operational Status Traffic Light system is an indicator posted on the legacy Union Gas website which informs parties as to the expected operational status of the various Transportation paths, Storage injections and withdrawals and various Distribution areas. It provides a four day projection (current Gas Day plus the next three) and is updated on a regular basis. A green light indicates that all facilities are available and there is no capacity constraints expected. A yellow light indicates that all facilities are available but scheduling reductions are possible. A red light indicates force majeure and firm services are being curtailed.

1) Capacity Planning recommends the changes to the Operational Status indicator and the Director Gas Control and Management provides approval.
2) For both injections and withdrawals, Capacity Planning tracks utilization of storage assets, tracks capability of the assets and forecasts expected upcoming operations. When the forecast of operations exceeds the capability, the light is changed in order to ensure that all firm contractual rights and in-franchise requirements are able to be met.
3) This question is identical to part 2) above.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p. 9-12

Preamble:

We would like to understand better the management of short-term storage and other services of the utility with respect to non-utility operations.

Question(s):

For the past 4 years, please provide the dates that the Operational Status light for storage.

Response

EGI does not believe that this question has any relevance to the disposition of the deferral accounts being requested as a result of this proceeding.

However, in order to be as responsive as possible, the dates requested are provided below.

Dawn to Dawn Storage (i.e., Injections)

- November 6, 2015 – November 27, 2015
- September 29, 2016 – November 25, 2016
- September 14, 2017 – November 5, 2017
- November 30, 2017 – December 10, 2017
- September 24, 2019 - current

Dawn Storage to Dawn (i.e., Withdrawals)

- February 19, 2015 – March 15, 2015
- January 1, 2018 – January 27, 2018

- April 4, 2018 – April 26, 2018

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p. 9-12

Preamble:

We would like to understand better the management of short-term storage and other services of the utility with respect to non-utility operations.

Question(s):

Please produce the webpage describing EGI's park services found at https://www.uniongas.com/storage-and-transportation/services/storage/park

a) Under Receipt and Delivery Points, a bullet states: "Other system points are negotiable with a hyperlink to the Storage & Transportation system map.

    i) Please produce that map.
    ii) Please identify the alternate points for receipt and delivery.
    iii) Please describe how EGI provides this service.

Response

Please see below for a screen capture of the Park service webpage.

a) i) Please see below for the Storage & Transportation system map.

ii) and iii) EGI negotiates each Park transaction individually and will look to accommodate receipt and delivery at any points that customers want. However, the ability to take receipt of gas at, or deliver gas to, points other than Dawn will depend on the transportation capacity available between the point and Dawn, as all park transactions are physically stored at Dawn. Parks are only available if EGI deems that sufficient storage capacity exists to receive and hold the gas for the term being requested.

Park

Looking to take advantage of market spread? Looking for a home for excess supply?

Our parking service permits customers to inject (buy) gas into storage for a defined period of time and withdraw (sell) that same quantity at a future point in time. This allows customers to capture market price spreads (inject low priced gas and sell high priced gas), balance supply or manage delivery commitments on downstream pipelines.

A park can be contracted with either firm or interruptible injections and withdrawals, and there is no requirement to withdraw prior to the end of the contract term. The term is also negotiable to meet your needs.

Service Highlights

- Firm/interruptible withdrawals and injections
- Limited cycling rights - one turn service

Receipt and Delivery Points

- Dawn Hub
- Other system points are negotiable
  Storage & Transportation system map

Pricing and Fuel

- Negotiated demand price
- Fuel included in price
- Customers are billed monthly

Contract

- One to three page hub enhancement agreement to your interruptible hub contract
- Requires executed interruptible hub contract

Contract Term

- From two days to one year

Service Eligibility

- Available to all customers who hold an interruptible hub contract

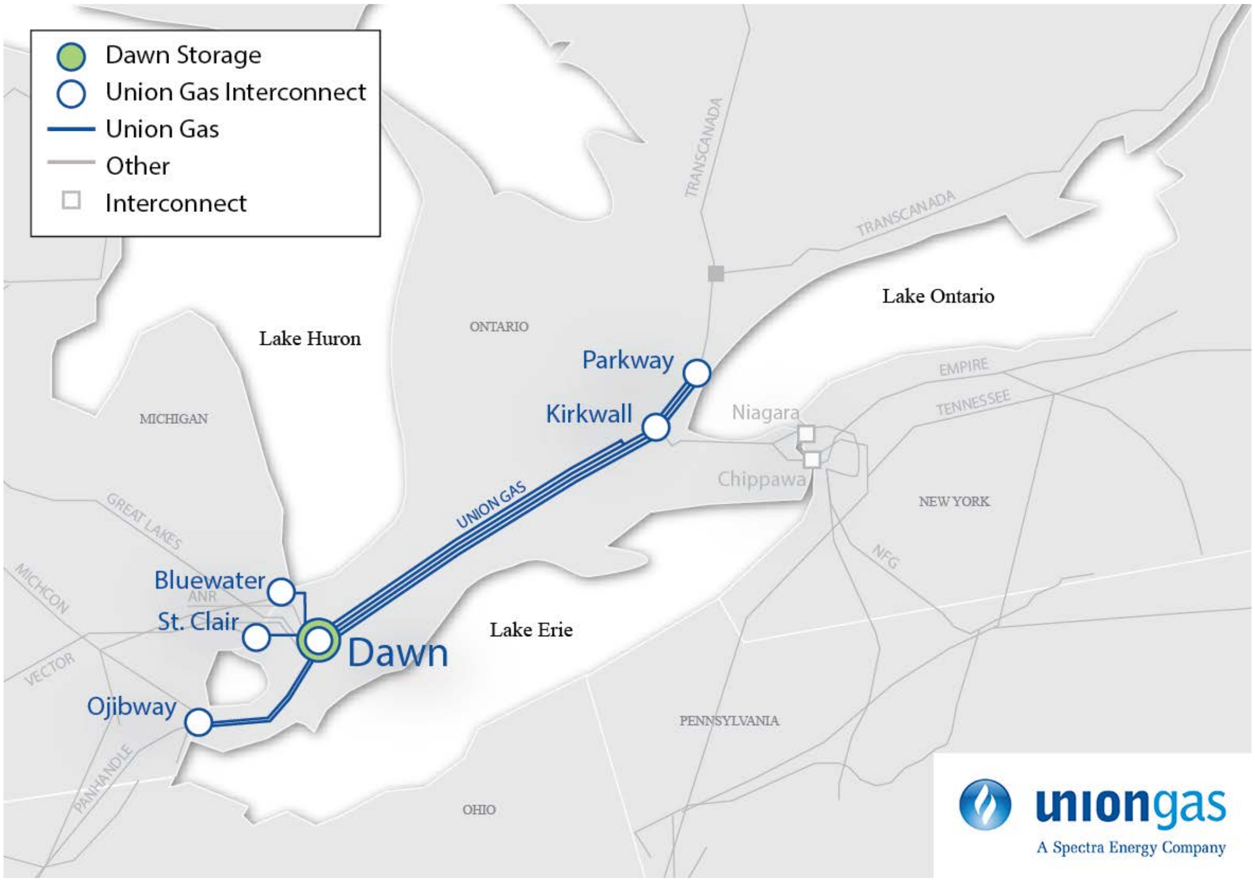
Complementary Services

- C1 transportation and exchanges - provides take away capacity from Dawn Hub to downstream pipelines

How to Request This Service

Contact an account manager or email us below for further information.

Email Us Today


Dawn Storage
Union Gas Interconnect
Union Gas
Other
Interconnect
Lake Huron
ONTARIO
Lake Ontario
TRANSCANADA
TRANSCANADA
Parkway
Kirkwall
Niagara
Chippawa
MICHIGAN
EMPIRE
TENNESSEE
NEW YORK
UNION GAS
GREAT LAKES
NFG
MICHCON
Bluewater
ANR
St. Clair
Dawn
Lake Erie
VECTOR
Ojibway
PENNSYLVANIA
PANHANDLE
OHIO
uniongas
A Spectra Energy Company

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p. 9-12

Preamble:

We would like to understand better the management of short-term storage and other services of the utility with respect to non-utility operations.

Question(s):

For what period is the 2018 storage requirement determined i.e., the 2017/18 gas supply plan, 2018/19 plan or using the 2018 volume forecast and calculating an imputed storage allocation?

a) Using the other timeframes (not the one used for the calculation), what amount of storage would the aggregate excess formula determine as the storage need?

Response

The 2018 storage requirement is using the 2018/19 gas supply plan number which uses demands from April 1 2018-March 31, 2019.

As mentioned in EGI 5-year Gas Supply Plan, EB-2019-0137, page 81, the aggregate excess methodology determines the storage space available to sales service and bundled DP customers. This methodology calculates the difference between forecasted winter demand (November 1 through March 31) and the annual average daily demand for a 151 day period.

The calculation is as follows:

Aggregate Excess = Forecasted Winter Consumption – [(Total Annual Consumption x 151/365)]

Union South T-Service customers select from the following four methodologies to calculate their contracted storage space:

1. Aggregate excess;
2. 15 x Obligated daily contract quantity ("DCQ");
3. Peak hourly consumption x 24 x 4 days; or,
4. Contract demand x 10.

Historical aggregate excess is shown below:

Particulars (PJ)	2017/18	2018/19
Space Allocated for Infranchise Use	100.0	100.0
Infranchise Storage Requirement	93.2	92.4
Excess Utility Space Available for Sale	6.8	7.6

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p. 9-12

Preamble:

EGI evidence states: "During the 2018 injection season, the non-utility storage balance peaked on October 16, 2018 at 88% full with a balance of 98.1 PJ compared to available space of 111.8 PJ."

Question(s):

For the total of 111.8PJ of storage, please provide how much is:

a) Former Union Gas legacy storage

b) Former EGD (Tecumseh) legacy storage

c) Other storage outside of Ontario
    i) For storage outside of Ontario, please describe the assets used, and the ownership of those assets, to move gas to and from Dawn.
    ii) Please provide a detailed description or preferably policy that ensures that former Union or EGD legacy is accountable to the same priority of service as any other contract held by a non-utility or third-party entity.

Response

a) 81.7 PJ

b) 18.3 PJ

c) Total 3rd party contracted storage is 11.8 PJ, of which 4.2 PJ is outside of Ontario (2.1 PJ contracted with Washington 10 and 2.1 PJ contracted with DTE Energy).
    i) For 2018 legacy Union used the St. Clair to Dawn line (100% owned by legacy Union) to move gas to and from Dawn to the DTE Energy storage facility. For

the Washington 10 storage contract, legacy Union injected gas that was transported on the Vector pipeline (owned 60% by Enbridge Inc. and 40% by DTE Energy). For withdrawals, legacy Union contracted an exchange with a 3rd party whereby legacy Union gave gas to the 3rd party at the Washington 10 interconnect with the Vector pipeline, and the 3rd party provided legacy Union with an equivalent volume of gas at Dawn.

ii. Legacy Union in-franchise customers have firm access for up-to 100 PJ of storage (as per EB-2005-0551), and therefore, like all other firm services sold to non-utility customers (including legacy EGD), they are located in the top tier of the Priority of Service schedule. As stated in EB-2017-0306 (the MAAD's proceeding), the amalgamation of the two utilities will not change the price, quality or reliability of the storage services for customers[1]. While the storage contracts sold by legacy Union to legacy EGD ceased to exist upon amalgamation, they have been maintained within the Priority of Service as if the contracts still exist, and will continue to do so for the term of the contracts[2].

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[1] EB-2017-0306, Exhibit B, Tab 1, page 40, line 12
[2] EB-2017-0306, Exhibit B, Tab 1, page 40, lines 14-16

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (“FRPO”)

Interrogatory

Reference:

Exhibit C / Tab 1 / p. 21

Question(s):

Please provide the calculation (data and source) used for the calculation of the storage space needed/allocated to in-franchise customers for the 2017/18 Gas Supply plan.

a) For what period are the space requirements intended to be sufficient for?
   i) Please show the data and calculation for the base storage space and the determined NAC storage space.

b) Please provide the calculation for the deliverability required from that storage as determined in the 2017/18 Gas Supply plan.
   i) How is the cost of deliverability calculated?
   ii) What was the cost allocated for space and deliverability?

Response

a) Please see Exhibit I.FRPO.17.
b)
   i) Please see Attachment 1.

   ii) As per Attachment 1 noted in response to part i) above, the total deliverability cost allocated was a credit of $0.259 million. The remaining components of the costs of storage totaled a credit of $1.665 million.

O&M Cross Charge

PJ of additional gas		(3.03)
Board Approved Cross Charge @ 11.3 PJ	$	3,810,000
O&M Cross Charge @ -3.03 PJ	**$**	**(1,022,923)**

Unaccounted For Gas

Board Approved Volume for 11.3 PJ		56,773
Volume Allocation for -3.03 PJ (56,773 x -3.03/11.3)		(15,243)
Oct 2017 Dawn Reference Price (QRAM)	$	3.549
UFG Costs	**$**	**(54,096)**

Compressor Fuel

Board Approved volume for 11.3 PJ		215,774
Volume allocation for -3.03 PJ (215,774 x -3.03/11.3)		(57,932)
Oct 2017 Dawn Reference Price (QRAM)	$	3.549
Compressor Fuel Costs	**$**	**(205,600)**

Dawn to Parkway Costs

North Additional Storage for Usage (GJ)		(261,713)
Dawn to Parkway Rate	$	0.11185
Dawn to Parkway Toll	$	(29,272)
Dawn to Parkway Fuel Ratio		0.761%
Oct 2017 Dawn Reference Price (QRAM)	$	3.549
Dawn to Parkway Fuel	$	(7,065)
Dawn to Parkway Costs (North General Service)	**$**	**(36,337)**

Inventory Carrying Costs

GJ of additional gas		(3,033,866)
Average Inventory Level (per Inventory Profile)		62%
Oct 2017 Dawn Reference Price (QRAM)	$	3.549
Inventory Carrying Charge		5.18%
Inventory Carrying Costs	**$**	**(345,799)**

Deliverability

GJ of Additional Gas		(3,033,866)
Additional Deliverability (1.8% vs. 1.2%)		0.6%
Board Approved Monthly T1 Rate for Deliverability	$	1.186
		(21,589)
		12

Deliverability Costs	**$**	**(259,068)**
Total Costs	**$**	**(1,923,823)**

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p. 21

Question(s):

Please provide the same data (and source) for the calculation of the storage space needed/allocated to in-franchise customers for the 2018/19 Gas Supply plan.

a) For what period are the space requirements intended to be sufficient for?

b) Please provide the calculation for the deliverability required from that storage as determined in the 2018/19 Gas Supply plan.
   i) How is the cost of deliverability calculated?
   ii) What was the cost allocated? For space and deliverability

Response

a) Please see Exhibit I.FRPO.17.

b)
   i) Please see Exhibit I.FRPO.21, Attachment 2.
   ii) As per Exhibit I.FRPO.21, Attachment 2, the total deliverability cost allocated was a credit of $0.160 million. The remaining components of the costs of storage totaled a credit of $1.026 million.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p. 21

Question(s):

For the purposes of determining the costs of storage space and deliverability for an aggregate excess calculation for 2018, and the resulting deferral account disposition, how are these amounts determined and costed?

Response

Please see Attachment 1 for the detailed Aggregate Excess Impact calculation and Attachment 2 for the calculation details of the total storage cost credit of $1.186 million included in the Normalized Average Consumption deferral account balance.

Volume Change due to Change in Usage (in 10^3m^3)

	Rate M1	Rate M2	Rate 01	Rate 10	Total
Apr-18	(15,753)	27,182	(81)	2,114	13,462
May-18	(8,413)	26,991	(555)	2,908	20,930
Jun-18	(3,927)	20,233	4,247	4,214	24,766
Jul-18	(1,794)	10,383	1,404	2,968	12,960
Aug-18	(4,865)	10,650	(107)	3,352	9,029
Sep-18	(12,369)	16,002	(2,677)	4,339	5,295
Oct-18	(26,288)	30,455	(1,314)	4,731	7,583
Nov-18	(12,537)	26,218	(1,117)	2,875	15,439
Dec-18	(7,442)	7,472	(2,945)	4,674	1,759
Jan-19	(9,471)	(10,159)	(1,336)	3,065	(17,900)
Feb-19	(5,598)	(3,902)	(5,330)	5,651	(9,178)
Mar-19	(16,197)	8,246	994	892	(6,065)
Total	**(124,655)**	**169,772**	**(8,817)**	**41,781**	**78,081**
Convert to PJs (1)	**(4.85)**	**6.60**	**(0.34)**	**1.60**	**3.02**

Aggregate Excess Impact - Volume Change due to change in Usage

	Rate M1	Rate M2	Rate 01	Rate 10	Total
Annual	(124,655)	169,772	(8,817)	41,781	78,081
(/365*151)	(51,570)	70,235	(3,648)	17,285	32,302
Winter	(51,245)	27,876	(9,734)	17,157	(15,945)
Storage Impact (in 10^3m^3)	325	(42,358)	(6,086)	(128)	(48,247)
Convert to GJs	12,633	(1,647,309)	(232,975)	(4,904)	(1,872,554)
Total Aggregate Excess Impact (GJs)	**12,633**	**(1,647,309)**	**(232,975)**	**(4,904)**	**(1,872,554)**
Total Aggregate Excess Impact (PJs)	**0.01**	**(1.65)**	**(0.23)**	**(0.00)**	**(1.87)**

Notes:
(1) Apr. 1/18 heat value conversion rate for M1/M2 = 38.89/1,000,000
Apr. 1/18 heat value conversion rate for 01/10 = 38.28/1,000,000

O&M Cross Charge			
PJ of additional gas		(1.87)	
Board Approved Cross Charge @ 11.3 PJ	$	3,810,000	
O&M Cross Charge @ -1.87 PJ	**$**	**(631,366)**	
Unaccounted For Gas			
Board Approved Volume for 11.3 PJ		56,773	GJ
Volume Allocation for -1.87 PJ (56,773 x -1.87/11.3)		(9,408)	GJ
Oct 2018 Dawn Reference Price (QRAM)	$	3.415	/ GJ
UFG Costs		**(32,129)**	
Compressor Fuel			
Board Approved volume for 11.3 PJ		215,774	GJ
Volume allocation for -1.87 PJ (215,774 x -1.87/11.3)		(35,757)	GJ
Oct 2018 Dawn Reference Price (QRAM)	$	3.415	/ GJ
Compressor Fuel Costs	**$**	**(122,109)**	
Dawn to Parkway Costs			
North Additional Storage for Usage (GJ)		(237,879)	GJ
Dawn to Parkway Rate	$	0.12217	/GJ
Dawn to Parkway Toll	$	(29,062)	
Dawn to Parkway Fuel Ratio		0.775%	
Oct 2018 Dawn Reference Price (QRAM)	$	3.415	/GJ
Dawn to Parkway Fuel	$	(6,298)	
Dawn to Parkway Costs (North General Service)	**$**	**(35,360)**	
Inventory Carrying Costs			
GJ of Additional Gas		(1,872,554)	GJ
Average Inventory Level (per Inventory Profile)		62%	
Oct 2018 Dawn Reference Price (QRAM)	$	3.415	/GJ
Inventory Carrying Charge		5.18%	
Inventory Carrying Costs	**$**	**(205,375)**	
Deliverability			
GJ of Additional Gas		(1,872,554)	GJs
Additional Deliverability (1.8% vs. 1.2%)		0.6%	
Board Approved Monthly T1 Rate for Deliverability	$	1.184	/GJ
		(13,303)	

		12 months
Deliverability Costs	**$**	**(159,632)**
Total Costs	**$**	**(1,185,969)**

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p. 29-30

Question(s):

Please provide the historic actual UFG? What has EGI done to investigate the source of the high incremental UFG?

a) What is the source of the monthly heat value that Union uses for DP customers?

b) Please provide the monthly values for the EDA for the last 4 years.

c) Please describe steps that EGI has undertaken over time to reconcile volume and energy received with TCPL.
   i) Specifically, what has EGI done to verify heat values that are provided by TCPL?

Response

a) The source of the monthly heat value legacy Union Gas uses for DP customers is a "best available" monthly heat value taken from its CARE System.

   Update

   The Heat Values used for DP Billing are the weighted average monthly heat values of gas available for consumption in each delivery area. They are calculated using the unofficial monthly interconnect measurement in GJ and 10^3m^3 for each of the delivery areas.

   In order to meet the invoicing timelines for the DP Invoicing process, heat values for the billing month are required to established at the end of the third business day. All of the interconnect measurement has not been validated as 'official' by the end of the third business day and as such is deemed as ‘best available’. For example, the October 2019 DP invoicing uses a heat values established at the end of November 5, 2019 for the month of October.

b) Please see Attachment 1.

c) TCPL is custody measurer in all North delivery areas for legacy Union Gas (MDA, WDA, NDA, SSMDA, NCDA, EDA) as well as at Union Dawn, Union ECDA and Union CDA. At the North locations, legacy Union has check measurement in place where it validates the volumes reported by TCPL. If any volumes provided by TCPL are considered questionable (i.e. typically outside a 2% difference from legacy Union’s check measurement), then legacy Union investigates. This investigation may involve a review of the TCPL contact or, have Field Technicians confirm that check measurement is good). Legacy Union’s check measurement does not have energy to use as a comparison for the North delivery areas. Legacy Union’s South check measurement is the same as above, but does have energy included (the same comparisons are completed, but include energy as well).

   i. Further to the above, in the South where legacy Union compares volume and energy, the heat value is checked by default when validating energy. In the North delivery areas, legacy Union does not have any way of validating TCPL heat values aside from making sure they fall within a reasonable range of values. Legacy Union does not have gas chromatographs in the Northern areas.

Location	Year	Month	Heat_Value
EDA	2015	9	37.9967
	2015	10	38.467
	2015	11	38.6091
	2015	12	38.5524
	2016	1	38.8181
	2016	2	38.7756
	2016	3	38.5433
	2016	4	38.6375
	2016	5	38.1982
	2016	6	38.1439
	2016	7	37.9307
	2016	8	37.9198
	2016	9	37.8492
	2016	10	38.0558
	2016	11	38.4519
	2016	12	38.7938
	2017	1	38.8432
	2017	2	38.8214
	2017	3	38.7632
	2017	4	38.6619
	2017	5	38.5471
	2017	6	38.1888
	2017	7	38.1167
	2017	8	38.2578
	2017	9	38.1691
	2017	10	38.3456
	2017	11	38.6514
	2017	12	38.7479
	2018	1	38.7811
	2018	2	38.7195
	2018	3	38.7686
	2018	4	38.7327
	2018	5	38.2864
	2018	6	38.4304
	2018	7	38.4401
	2018	8	38.3816
	2018	9	38.3857
	2018	10	38.3843
	2018	11	38.2581
	2018	12	38.815
	2019	1	39.1692
	2019	2	39.1284
	2019	3	39.061
	2019	4	38.937
	2019	5	38.4027
	2019	6	38.4702
	2019	7	38.4208
	2019	8	38.3641
	2019	9	38.4593

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p. 41-42

Preamble:

EGI evidence states: "Exhibit C, Tab 1, Appendix A, Schedule 9 provides the calculation of the Parkway Obligation Rate Variance deferral account balance. The calculation of the deferral account balance is consistent with the 2014 Rates PDO Settlement Framework."

Question(s):

Please provide the expected recording of this evolution in the Board-ordered framework to track the costs and benefits of the PDO framework as outlined in EB-2017-0306.

Response:

In accordance with the MAADs Decision and Order (EB-2017-0306/0307), Enbridge Gas will provide actual costs and amounts recovered through rates related to PDO at the time of rebasing.

> The OEB requires Amalco [Enbridge Gas Inc.] to track actual costs and amounts recovered through rates related to the PDO during the deferred rebasing period. The OEB at the time of rebasing will review the costs and amounts recovered through rates to ensure that ratepayers are not paying twice for the required capacity and the legacy Union Gas is not enhancing earnings contrary to the intent of the PDO settlement agreement.[1]

[1] EB-2017-0306/EB2017-0307, Decision and Order, August 30, 2018, p. 49.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p.44 / Table 14

Preamble:

We would like to understand better the determination of this variance including the volume variance as it relates to the company's ensurance that customer supplied fuel meets actual fuel required?

Question(s):

Did EGD reconcile customer supplied forecasts with actual for a true-up with customers on a regular basis?

Response

Customer supplied fuel does not impact the UFG volume deferral account. The UFG volume deferral account was approved through the EB-2013-0202 Settlement Agreement. The purpose of this account is to capture the difference between the unit cost of UFG recovered in rates approved by the Board and actual UFG costs incurred, in excess of $5.0 million. Please see Exhibit I.FPRO.25 for the explanation of customer supplied fuel.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p.44 / Table 14

Preamble:

We would like to understand better the determination of this variance including the volume variance as it relates to the company's ensurance that customer supplied fuel meets actual fuel required?

Question(s):

Please provide a more detailed calculation of the price variance.

a) Please provide an explanation as to why the quarterly adjustment of fuel provided does not provide for sufficient adjustment to customer supplied volumes over the course of the year?

b) Please provide the aggregate gas recovered by month and each of the aggregated quarterly adjustment to demonstrate the shortfall.

Response

a) Enbridge Gas adjusts the fuel provided in kind by Rate M12 customers through the YCR adjustment. The YCR adjustment is not applicable to customers in Union's other rate classes and does not account for changes between forecast UFG included in rates and actual UFG. There is no true-up for actual UFG. The amount of UFG collected through customer supplied fuel may be less than the actual experienced UFG when the UFG included in rates is lower than the actual UFG as was the case in 2018.

b) As described in part a), there is no quarterly adjustment related to UFG. Please see Exhibit I.STAFF.20.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p. 50

Question(s):

Please provide the comparable deferral account and balance for the legacy EGD franchise.

a) If there is none, please provide EGI's perspective on the efficacy of such a charge moving forward.

Response

The comparable account is a sub-account within legacy EGD's Purchased Gas Variance Account (PGVA). This sub-account records penalty revenues received from interruptible customers who do not comply with the Company's curtailment requirements. Note that PGVA balances are cleared to customers quarterly as part of the Quarterly Rate Adjustment Mechanism (QRAM). There was no curtailment penalty revenue balance in the legacy EGD PGVA for 2018.

Interruptible customers at legacy EGD who do not comply with curtailment orders are subject to unauthorized overrun penalties and to forfeiture / loss of curtailment credits.

Curtailment credits are paid to interruptible customers to compensate them for their demonstrated ability and readiness to switch to an alternative fuel source or to shut down their operations when curtailment orders are issued by the Company.

The combined impact of unauthorized overrun penalties and potential loss of curtailment credits have been effective in achieving compliance with curtailment orders. Hence, the curtailment penalty balance in recent years was either immaterial or nil.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p. 51 and Appendix A, Schedule 10

Preamble:

"By November 2018, the surplus capacity has been deemed to be sold long-term and the revenue credit for November and December 2018 24 is calculated based on the 2018 approved Dawn-Parkway demand rate of $3.716 GJ/m 25 (30,393 GJ/d x 2 x $3.716 GJ/m)."

Question(s):

As of November 1st, what was the total amount of Dawn-Parkway sold Long-Term?

a) What was the total amount of capacity turned back as of Oct. 31/18?

b) What is the net capacity requirement for D-P capacity for the winter of 2018/19?

c) As a result, what is the surplus or deficit as of Nov. 1/18? Please clarify whether this amount includes the "deemed to be sold" capacity of 30 TJ/day.

Response

As of November 1, 2018, the total amount of long-term Dawn-Parkway contracts sold (easterly) was 5,414 TJ/d.

a) As outlined in EB-2018-0305, Exhibit I.FRPO.4 (a), the total amount of Dawn-Parkway capacity turned back in 2018 was 160 TJ/d, which included 70 TJ/d of capacity for TCE Halton Hills as was allowed in the Parkway Delivery Obligation Settlement Agreement (EB-2013-0365).

b) Capacity of the D-P system (easterly) for 2018/2019 was 7,728 TJ/d. In addition, there were deliveries to Parkway of 222 TJ/d. Offsetting the capacity was legacy

Union in-franchise requirements totaling 2,333 TJ/d, ex-franchise contracts sold of 5,414 TJ/d and a fuel requirement of 77 TJ/d. This left a net surplus capacity of 126 TJ/d.

c) As outlined in EB-2018-0305, Exhibit I.STAFF.11 (a) and outlined in part (b) above, as of November 1, 2018 EGI had surplus D-P capacity of 126 TJ/d. This surplus includes all contracts sold including the “deemed to be sold” capacity.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p. 51 and Appendix A, Schedule 10

Preamble:

"By November 2018, the surplus capacity has been deemed to be sold long-term and the revenue credit for November and December 2018 24 is calculated based on the 2018 approved Dawn-Parkway demand rate of $3.716 GJ/m 25 (30,393 GJ/d x 2 x $3.716 GJ/m)."

Question(s):

Please provide the monthly revenue from all D-P capacity sold either through IT or exchange in 2018?

a) For each month, please provide the peak daily commitment to each IT and exchange transactions.

Response

The revenue and average volume for short-term and interruptible Dawn-Parkway activity (including exchanges) has been included in Exhibit C, Tab 1, Appendix A, Schedule 10. The revenue and average volume for November and December 2018 has been provided at Exhibit I.STAFF.22 b).

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 1 / p. 51 and Appendix A, Schedule 10

Preamble:

"By November 2018, the surplus capacity has been deemed to be sold long-term and the revenue credit for November and December 2018 24 is calculated based on the 2018 approved Dawn-Parkway demand rate of $3.716 GJ/m 25 (30,393 GJ/d x 2 x $3.716 GJ/m)."

Question(s):

Please provide the actual revenue generated and percentage of total surplus (columns b and c of Schedule 10)

Response

Please see Exhibit I.STAFF.22 b).

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C/ Tab 1/ Appendix A/ Schedule 3

Question(s):

Please provide the monthly figures for each of the respective categories of revenue.

a) Are the O&M costs for 2018 based on 11.3PJ?
   i) If so, why is this amount appropriate when the actual amount used was 7.6PJ?

Response

The table below outlines the monthly figures detailed by each category found in Exhibit C, Tab 1, Appendix A, Schedule 3.

Revenue ($000's)	2018 Jan	2018 Feb	2018 Mar	2018 Apr	2018 May	2018 Jun	2018 Jul	2018 Aug	2018 Sep	2018 Oct	2018 Nov	2018 Dec	2018 Total
C1 Off-Peak Storage	21	22	22	23	23	29	1	1	1	0	38	-38	**141**
Supplemental Balancing Services	72	82	73	100	110	88	85	71	83	60	138	190	**1,153**
Gas Loans	0	0	0	0	0	0	0	0	0	17	-0	-2	**15**
Enbridge LBA	78	50	2	0	181	26	0	1	0	67	25	0	**430**
C1 ST Firm Peak	413	416	489	210	414	488	429	426	426	427	425	448	**5,011**
Monthly subtotal	**584**	**570**	**586**	**332**	**728**	**631**	**514**	**499**	**510**	**571**	**626**	**599**	**6,750**

a) The 2013 Board approved cost for 11.3PJ was $3,810,000. In 2018, the cost for 7.6PJ was:

   O&M cost = $3,810,000/11.3*7.6 = $2,633,848

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C / Tab 2/ Appendix B/ Schedule 1/ column b

Question(s):

Please provide the values for column b for the years 2014-2018

Response

The table below outlines the column b (Non-Utility Storage) values of past year Earning Sharing Calculations previously filed for the requested timeframe

Earnings Sharing Calculation - Non-Utility Storage
2014-2018

Line No.	Particulars ($000s)	Non-Utility Storage 2014	2015	2016	2017	2018
	Operating Revenues					
1	Gas Sales	-				
2	Transportation	(356)	(469)	(488)	(439)	(367)
3	Storage	74,546	75,794	87,095	119,133	143,609
4	Other	-				
5		74,190	75,325	86,607	118,694	143,242
	Operating Expenses					
6	Cost of gas	1,657	2,221	1,715	23,924	36,499

7	Operating and maintenance expenses	14,020	14,771	13,410	13,450	13,451
8	Depreciation	10,272	11,577	10,679	10,236	10,676
9	Other financing	-				
10	Property and other taxes	1,468	1,620	1,635	1,369	1,489
11		27,417	30,189	27,439	48,979	62,115
	Other					
12	Gain / (Loss) on sale of assets	(901)	(4)	(624)	(210)	(1,824)
13	Other / Huron Tipperary	(1,483)	(691)	-	-	-
14	Gain / (Loss) on foreign exchange	(43)	(18)	39	(47)	2,282
15		(2,428)	(713)	(585)	(257)	458
16	Earnings before interest and taxes	44,346	44,423	58,583	69,457	81,585

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

EB-2018-0105 Exhibit A, Tab 4 and EB-2005-0520 Settlement Agreement, page 13, subsections 3.1, paragraph 2; and, Appendix B –Incremental Transportation Contracting Analysis.

Question(s):

Please provide the Incremental Transport Analysis for the Legacy Union system.

a) Please ensure the Analysis provides Union's consideration of the North Bay Junction Long-term Fixed Price offering.
   i) Please describe the offer including the conversion opportunity and how it was assessed and not bid.

b) Please provide EGI's intent with regard to providing this type of analysis in the 5-Year Gas Supply Plan or Annual Gas Supply Plan.
   i) Please include EGI's perspective on how the Board will discern prudency in the contracting or non-contracting of transportation alternatives.

Response

a) The Incremental Transportation Contracting Analysis is filed in EB-2019-0137, the 5-Year Gas Supply Plan, page 79-80 for Union rate zones.

   In the EB-2005-0520 Settlement Agreement, Union Gas agreed it

   > will provide an Incremental Transport Analysis for any new or extensions to existing upstream transportation contracts with a term of one year or longer that will form part of Union's sales service gas supply arrangements.

Appendix B, page 1 Legacy Union is not required to provide Incremental Transport Analysis in a case where it chose not to contract for the service.

b) As discussed at the EB-2019-0137 Stakeholder Conference on September 23, 2019, EGI intends to file the Incremental Transportation Contracting Analysis as part of the annual filing of the Gas Supply Plan in the same format provided as part of the deferral disposition. This was moved into the 5-Year Gas Supply Plan in an effort to keep information related to gas transportation decisions in one filing which is an intent of the Framework.
    i) EGI has filed this information as part of the 5-Year Gas Supply Plan as it is EGI's interpretation of the Framework direction that this information belonged to that process.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit A, Tab 3, page 2

Question(s):

a) By what date does EGI require a decision in this proceeding in order to implement the disposition of the various account balances effective January I , 2020?

b) If EGI does not receive a decision in this proceeding in time to implement the disposition of the account balances effective January I, 2020 , what effective date does EGI propose?

Response

a) In order to implement rates for January 1, 2020, Enbridge Gas requires a decision no later than November 29, 2019.

b) If rates cannot be implemented by January 1, 2020, Enbridge Gas suggests that the board-approved ESM and DVA amounts be disposed of as part of the next available QRAM (likely April 1, 2020). This approach is consistent with the EGD and Union rate zones past practice of implementing dispositions of various account balances to customers in conjunction with QRAM rate changes.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit C, Tab I, page 33

Question(s):

What is the expected amount of additional capital expenditures in 2019 for the Parkway West project?

Response

There is an expected $1.454 million of capital expenditures in 2019 for the Parkway West project. The expected spend in 2019 relates to the demolition of two residential structures located within the boundary of the Parkway West Compressor facility.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit C, Tab 1, Tables 8 & 14

Question(s):

a) Please confirm the numbers in the following table or provide corrected figures ($millions):

UFG Actual Costs:	$15.983		
UFG Actual Recovery		$9.249	(Exhibit C, Tab 1, page 29)
UFG Volume Variance Recovery		$1.733	(Table 8 for Acct 179-135)
UFG Price Variance Recovery		$2.028	(Table 14 for Acct 179-141)
Total UFG Recovery		$13.010	

b) Please provide a table similar to that shown above, assuming that there was no $5 million threshold for the UFG volume variance account.

c) Please demonstrate mathematically that there is no overlap between the amounts to be recovered through accounts 179-135 and 179-141 with respect to UFG.

d) Please provide the forecasted and actual UFG volumes that underpin the figures in Table 8 and explain how they relate to the utility supplied volumes of 58,674 10^3 m^3 used in Table 14.

Response

a) Confirmed, although the UFG Volume and Price deferral should be treated independently and not combined as these are two separate and distinct deferral accounts with separate and distinct purposes.

   The UFG Volume deferral pertains to volumetric UFG collected in rates and actual volumetric UFG incurred (volume). The UFG Price deferral is used to track the variance in costs between the average cost of gas purchased for UFG requirements, and the approved reference price charged to customers (price).

b)

UFG Volume Deferral			UFG Price Deferral	
UFG Actual Costs	15.983		UFG Experienced (103m3)	121,984
UFG Actual Recovery	9.249		UFG Collected through CSF	63,309
UFG Volume Variance Recovery	6.733		UFG Volumes - Union Supplied	58,674
Total UFG Volume Recovery	**15.983**		Price Variance ($/103m3)	$34.56
			UFG Price Recovery ($ millions)	**$2.028**

c)

Table 8
2018 UFG Variances from Board-approved

Line No.	Particulars ($ millions)	2018 Actual	Recovered in 2018 Rates	Variance
1	Net Utility UFG	15.983	8.329	(7.653)
2	Recovery Variance (1)			(0.920)
3	Total Utility UFG Variance (2)			(6.733)
4	$5M UFG Variance Account Threshold			5.000
5	UFG Volume Variance			(1.733)

Notes:
(1) Board-approved throughput was 32,010 10^6m^3 versus actual throughput of 35,978 10^6m^3.
(2) Board-approved UFG % is 0.219% versus actual UFG % of 0.379% for 2018. Subject to deferral account when in excess of +/- $5 million versus Board-approved.

Calculation of 2018 UFG Price Variance

Line. No.		UFG Volumes (10^3m^3)
1	Experienced UFG (1)	121,984
2	UFG Collected through CSF	63,309
3	UFG Volumes – Utility Supplied (2)	58,674
		Deferral Calculation
4	UFG Volumes – Utility Supplied (10^3m^3) (2)	58,674
5	Price Variance ($/$10^3m^3$) (3)	($34.56)
6	Variance Account Balance ($ millions)	($2.028)

Notes:
(1) Converted using the following heat values (38.95 Jan-Mar) (38.89 Apr-Dec).
(2) UFG Volumes represent gas supply related to actual UFG volumes on behalf of ratepayers who do not provide UFG in kind as part of CSF.
(3) Price variance represents weighted average cost, relative to Board-approved reference prices.

d)

2018 Actual UFG Volumes				**2018 Forecated UFG Volumes**		
%		**0.379%**		%		**0.219%**
Throughput		**35,978,439**		Throughput		**32,009,650**
Excess Utility Throughput	1.68%	**604,438**		Excess Utility Throughput	2.47%	**790,638**
Non Utility Throughput	8.92%	**3,209,277**		Non Utility Throughput	7.04%	**2,253,479**
Utility Throughput		**32,164,724**		Utility Throughput		**28,965,532**
Total UFG Volume (103m3)		**136,447**		Total UFG Volume (103m3)		**70,253**
Excess Utility UFG Volume (103m3)	1.68%	**2,292**		Excess Utility UFG Volume (103m3)	2.47%	**1,735**
Non Utility UFG Volume (103m3)	8.92%	**12,171**		Non Utility UFG Volume (103m3)	7.04%	**4,946**
Utility UFG Volume (103m3)		**121,984**		Utility UFG Volume (103m3)		**63,572**

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit C, Tab 1, page 48

Question(s):

Are there any further capital expenditures expected in 2019 or beyond associated with Lobo C Compressor/Hamilton-Milton? If yes, please explain fully.

Response

There is an expected $0.056 million in capital expenditures for 2019, with a further $0.05 million expected for 2020. The expected spend in 2019 and 2020 relates to post-construction remediation work and restoration commitments to meet environmental and permitting conditions, while 2019 also reflects a final progress payment released to a vendor upon completion.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit C, Tab 1, page 54

Question(s):

Are there any further capital expenditures expected in 2019 or beyond associated with Dawn H/Lobo D/Bright C Compressors? If yes, please explain fully.

Response

There is an expected $8.661 million in capital expenditures for 2019, with nothing further expected in 2020 and beyond. The expected spend in 2019 relates to further clean-up activities not completed in 2018.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit C, Tab 1, page 59

Question(s):

Are there any further capital expenditures expected in 2019 or beyond associated with the Burlington Oakville Pipeline project? If yes, please explain fully.

Response

There are no further capital expenditures expected in 2019 or beyond associated with the Burlington Oakville Pipeline Project.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit C, Tab 1, page 67

Question(s):

What is the forecasted level of additional capital expenditures expected in 2019 and beyond associated with the Panhandle Reinforcement project?

Response

There is an expected $2.222 million in capital expenditures for 2019, with no further capital expenditures expected thereafter. The expected spend in 2019 relates to clean-up activities.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit C, Tab 1, Tables 9, 12, 15, 17, 19, 22

Question(s):

a) Please confirm that the long term debt rate used in Table 9 for the Board Approved required return on line 8 was 4%, as noted on page 34. If this cannot be confirmed, please explain fully.

b) Please confirm that the long term debt rate used in Table 12 for the Board Approved required return on line 8 was 4%, as noted on page 39. If this cannot be confirmed, please explain fully.

c) Please confirm that the long term debt rate used in Table 15 for the Board Approved required return on line 8 was 4.4%, as noted on page 48. If this cannot be confirmed, please explain fully.

d) Please confirm that the long term debt rate used in Table 17 for the Board Approved required return on line 8 was 4%, as noted on page 56. If this cannot be confirmed, please explain fully.

e) Please confirm that the long term debt rate used in Table 19 for the Board Approved required return on line 8 was 4.4%, as noted on page 61. If this cannot be confirmed, please explain fully.

f) Please confirm that the long term debt rate used in Table 22 for the Board Approved required return on line 8 was 4%, as noted on page 68. If this cannot be confirmed, please explain fully.

<u>Response</u>

a) Confirmed.

b) Confirmed.

c) Confirmed.

d) Confirmed.

e) Confirmed.

f) Confirmed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit C, Tab 2

Question(s):

Is the calculation of utility earnings consistent with the methodology used to calculate the earnings in previous years? If not, please explain any differences.

Response

Yes, the calculation of utility earnings is consistent with the methodology used in previous years, with the exception that this year's calculation includes an elimination of the shareholder portion of tax savings that that are to be shared with ratepayers through the Tax Variance Deferral Account. The elimination of the shareholder amount is discussed at Exhibit I.STAFF.25.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit C, Tab 2

Question(s):

a) What was Union's normalized actual return on equity for 2018?

b) Please provide a version of Table 1 that adds a column that shows the total revenue sufficiency for Normalized Actual 2018.

Response

a) Union's weather normalized return on equity for 2018 is 9.34%.

b) Please see Attachment 1 for a version of Table 1 that adds a column showing the actual normalized revenue sufficiency for 2018.

Calculation of Revenue Deficiency/(Sufficiency) from Utility Operations
For the Year Ended December 31

Line No.	Particulars ($ Millions)	Board Approved 2013 (a)	Actual 2017 (b)	Actual 2018 (c)	(Decrease) 2018 vs. 2017 (d) = (c) - (b)	Weather Normalized 2018 (e)	Increase/ (Decrease) 2018 vs. (f) = (e) - (c)
1	Gas sales and distribution revenue	1,448.8	1,857.0	1,793.1		1,793.1	
2	Cost of gas	701.4	1,031.0	907.1		907.1	
3	Weather impact					(8.8)	(8.8)
4	Gas distribution margin	747.4	826.0	886.0	60.0	877.2	(8.8)
5	Transportation	157.0	236.9	258.9	21.9	258.9	-
6	Storage	10.4	7.8	8.2	0.4	8.2	-
7	Other revenue	20.2	17.3	17.8	0.5	17.8	-
8	Expenses	643.8	743.1	799.8	56.7	799.8	-
9	Income taxes	17.1	(5.0)	(6.0)	(1.0)	(8.3)	(2.3)
10	Utility income	274.1	350.0	377.0	27.0	370.5	(6.5)
11	Cost of Capital	272.6	344.9	360.9	16.0	360.9	-
12	Revenue deficiency / (sufficiency) after tax	(1.5)	(5.1)	(16.2)	(11.0)	(9.7)	6.5
13	Provision for income taxes on deficiency / (sufficiency)	(0.5)	(1.8)	(5.8)	(4.0)	(3.5)	2.3
14	Distribution revenue deficiency/(sufficiency)	(2.0)	(7.0)	(22.0)	(15.0)	(13.2)	8.8
15	Shareholder portion of short-term storage revenue	0.5	0.4	0.3	(0.0)	0.3	-
16	Shareholder portion of optimization activity	1.5	0.5	0.7	0.2	0.7	-
							-
17	Total revenue deficiency/(sufficiency)	-	(6.1)	(20.9)	(14.8)	(12.1)	8.8

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association ("LPMA")

Interrogatory

Reference:

Exhibit C, Tab 2, page 2

Question(s):

a) What is the total cost included in the expenses related to the merger of Union Gas and Enbridge Gas Distribution and included in the calculations shown in Table 1?

b) What are the merger savings included in the calculations shown in Table 1?

c) Please provide all the relevant calculations to show the earnings sharing (if any) under each of the two following scenarios (i.e. Exhibit C, Tab 2, Appendix B, Schedule 1 and any supporting schedules required):
   i. the merger related costs are removed from the calculations; and

   ii. both the merger related costs and merger related savings are removed from the calculations.

Response

Please see Exhibit I.STAFF.24.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

Interrogatory

Reference:

[B-1, p.20]

Question(s):

Please provide a full breakdown of the balance of the EGD Electric Program Earnings Sharing Deferral Account, including the underlying calculations to demonstrate that EGI has made use of fully allocated costing.

Response

In responding to this interrogatory, Enbridge Gas determined that the amount in the original calculation of the EPESDA was incorrectly calculated. This response is based on the corrected amount provided in the table below. This correction will be addressed in the 2019 EPESDA.

$ Thousand	**2018**
Revenues	
Marketing & program recoveries	4,558
Other recoveries	3,637
Total Revenues	8,195
Costs	
Staff Costs	150
Other Costs	5,711
	5,861
Net Profit prior to Sharing	2,334
50% sharing to Ratepayers	1,167

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

Interrogatory

Reference:

[B-2-D-2, p.1]

Question(s):

Please explain the drivers of the increase in 2018 'Other OM&A' as compared to 2017.

Response

2018 UTILITY O&M

Line No.	Particulars (in millions)	Actuals 2018	Actuals 2017	Actual Under/(Over)
1	Total Compensation	230.4	223.9	(6.5)
2	Employee Training and Development	3.3	4.2	0.9
3	Materials and Supplies	6.0	5.3	(0.7)
4	Outside Services	95.3	82.5	(12.8)
5	Consulting	3.2	2.6	(0.6)
6	Repairs and Maintenance	1.8	1.7	(0.1)
7	Fleet	3.6	3.1	(0.5)
8	Rents and Leases	4.5	4.9	0.4
9	Telecommunications	0.0	0.0	-
10	Travel and Other Business Expenses	2.1	1.8	(0.3)
11	Memberships	6.4	5.2	(1.2)
12	Claims, Damages and Legal Fees	0.3	0.4	0.1
13	Interest on Security Deposits	0.8	0.6	(0.2)
14	Provision for Uncollectibles	5.6	5.4	(0.2)
15	Natural Gas Vehicles (NGV)	0.5	0.8	0.3
16	Legal Fees	0.8	2.8	2.0
17	Audit Fees	2.1	0.8	(1.3)
18	Other	(2.3)	1.2	3.5
19	Internal Allocations and Recoveries	(14.8)	(14.0)	0.8
20	Capitalization (A&G)	(37.1)	(36.8)	0.3
21	Capitalization	(87.6)	(85.1)	2.5
22	Regulatory Eliminations	(1.0)	(1.7)	(0.7)
23	Other O&M Subtotal	224.0	209.6	-14.4

EXPLANATION OF MAJOR CHANGES
ACTUAL 2018 O&M EXPENSES COMPARED TO ACTUAL 2017 O&M EXPENSES

1 Increase in Total Compensation due to severance costs.

4 Increase in Outside Services mainly due to increase in work done for mains and broken services, and increase in scheduled in-line inspections.

18 Decrease in Other primarily due to Insurance over-accrual from previous years written-off in 2018.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

Interrogatory

Reference:

[C-1, p.25-26]

Question(s):

What would be the balance in the Tax Variance Deferral Account if EGI had credited 100% instead of 50% of the changes resulting from C-97 for the Union Rate Zones?

Response

The principal balance that would have recorded in the UGL Rate Zones Tax Variance Deferral account, had 100% (instead of 50%) of the impact of the Bill C-97 CCA rule change for the Union Rate Zones been reflected in the Tax Variance deferral account (except for the impact associated with capital pass-through projects), would have been a credit of $2.293 million, $1.880 million reflecting 100% of the Bill C-97 CCA impacts, plus $0.413 million reflecting 50% of the HST impact.

Please also see the response to Exhibit I.STAFF.17.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

Interrogatory

Reference:

[C-1, p.64]

Question(s):

Please confirm the 2018 actual 'OEB Cost Assessments', include only the amount related to OEB assessments for its operations, and not cost awards, that may be collected from EGI when the OEB acts as a "cleaning house" for payments.

Response

Confirmed. The actual OEB Cost Assessment amounts, considered in the determination of amounts recorded in the OEB Cost Assessment Variance Account, only include the Board's quarterly invoiced cost assessments to Union rate zones, during 2018, for the recovery of their operating and capital expenditures.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

Interrogatory

Reference:

[C-2, p.4] EGI states: "The revenue requirement impact of accelerated CCA on 2018 capital additions, excluding those associated with capital pass-through projects, a reduction of $1.880 million are to be shared 50/50 with ratepayers through the Tax Variance Deferral Account."

Question(s):

a) Has EGI reflected the 2018 impact of Bill C-97 on its capital pass-through projects, including supporting calculations, anywhere as part of its application (i.e. through the ESM or a DVA)?

b) Please provide the revenue requirement impact, and supporting calculations, of Bill C-97 impact on each capital pass through projects in 2018.

Response

a) The 2018 impact of Bill C-97, on each of the Union rate zone capital pass-through projects (where applicable), has been reflected in the calculation of each project's 2018 actual revenue requirement, which was then compared to each project's 2018 approved revenue requirement included in rates, to determine the amount recorded in each respective project's deferral account. The actual versus approved revenue requirement for each project is included in the Exhibit C, Tab 1, evidence supporting each respective project's deferral account balance. The calculation of the impact of Bill C-97 accelerated CCA, in isolation, for each project was not shown in evidence, as the impact was reflected in the overall revenue requirement calculation for each project. The impact of Bill C-97 was however noted in the Exhibit C, Tab 1 evidence for each project (where applicable), as one of the drivers of the income tax variances.

   The 2018 impact of Bill C-97 accelerated CCA, in relation to the Union rate zones capital pass-through projects, has also been reflected in the calculation of the utility results and earning sharing for the Union rate zones. As noted at Exhibit C, Tab 2, page 4, the impact of Bill C-97 accelerated CCA, inclusive of capital pass-through projects, has been reflected in the determination of utility income taxes, but a corresponding reduction to utility revenues has been made for the grossed-up revenue requirement impact (of $0.314 million), to reflect that the accelerated CCA impact on capital pass-through projects was captured within the respective capital pass-through deferral accounts. As such, the impact of accelerated CCA has no impact on the Union Rate Zone revenue sufficiency or earnings sharing (as the impact was captured through the project deferral accounts).

b) Please see the response to Board Staff interrogatory 17, part f), at Exhibit I.STAFF.17, for supporting calculations of the 2018 Bill C-97 revenue requirement impact on each capital pass-through project. As noted in that response, there were no 2018 accelerated CCA impacts on the Brantford-Kirkwall/Parkway D Project.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit A/T3/pages 4-

Question(s):

a) Enbridge discusses its inability to administer one-time adjustments in the Union rate zone. Does the Company have a timeline for the integration/update of the Union legacy system such that it can provide a consistent means of account dispositions similar to that in the former EGD zone? If yes, please explain when this is targeted for completion and specifically if it is anticipated whether such a system will be in place in time for next year's account/ESM dispositions.

Response

Please see the response at Exhibit I.STAFF.1, part c). Changes to the billing system for general service customers in the Union rate zone is not expected to be in place in time to dispose of balances from the 2019 Deferral and Variance Account Balances and Utility Earnings application.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference:

Exhibit B/T1/Page 7 & Exhibit C/T1/Page 29

Question:

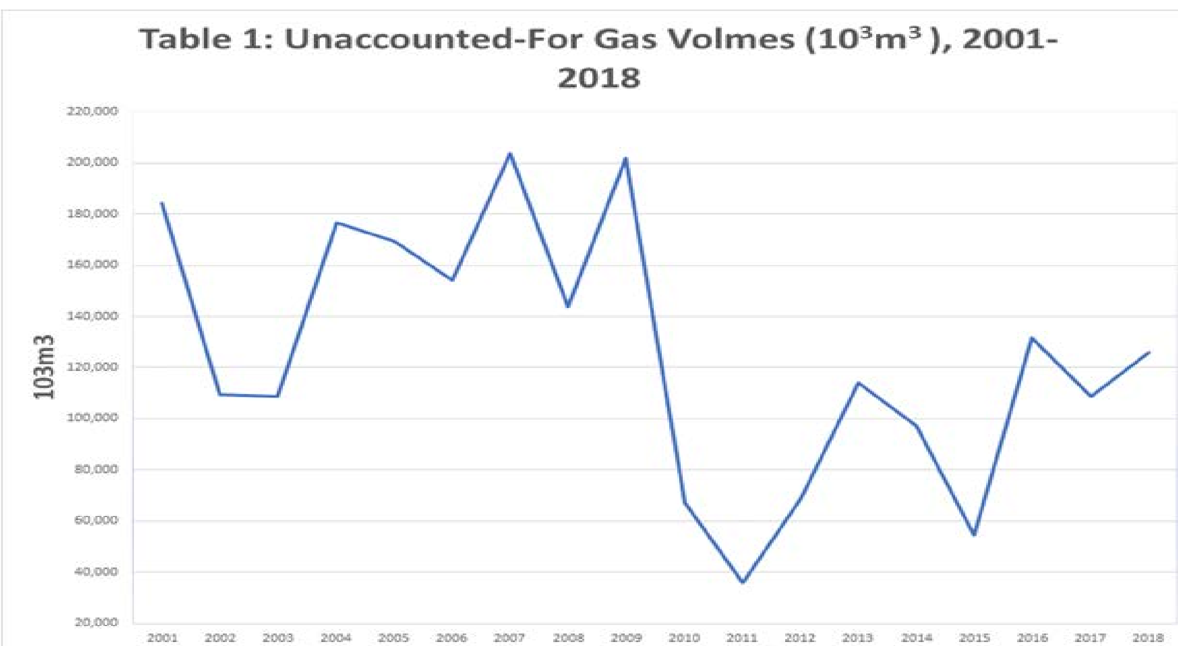
a) If one were to remove the outlier years of 2001 through 2006 or unaccounted for gas volumes (UFG) how would the resulting average UFG compare to the 106,677 103m3 built into rates? (Related to Legacy EGD)

b) Please provide a table similar to Table 1 (UFG 1991-2018) for the Union Rate Zone

Response

a) If 2001-2006 data would have been removed from the estimation period and the data from 2007 to 2016 only would have been used for the forecast; the number of observations would be insufficient to estimate the Board approved regression model.

b) Table 1 below provides UFG volumes for 2001-2018 for Union rate zones. No data is available for 1991-2000.



ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B/T1/page 21 & Exhibit C/T1/page 63-

Question(s):

a) What was the first full year under which the Board's revised cost assessment was charged?

b) Please explain why the Enbridge rate zone uses the 2015-2016 year as the basis for comparison of assessments whereas the Union rate zone uses 2013.

c) Please recalculate the both rates zones on the basis of comparison to the actual assessed costs in the last full year prior to the Board's change in assessment methodology.

Response

a) The Board's revised cost assessment methodology was effective starting April 1, 2016, the start of the Board's fiscal 2016 – 2017 year (which commenced April 1, 2016 and ran through March 31, 2017). As a result, the Board's quarterly invoices to legacy Enbridge Gas Distribution Inc. and Union Gas Limited, and presumably all other regulated entities, dated April 1, 2016, were the first invoices to be issued under the revised cost assessment methodology.

b) Prior to amalgamation, each legacy entity had previously developed their own methodology for determining amounts to be recorded in each of their respective OEB Cost Assessment Variance Accounts, and those methodologies were maintained for calculating 2018 variances, as the Companies were not amalgamated in 2018. For the EGD rate zone, consistent with the determination of amounts previously approved for recovery in relation to 2016 and 2017 OEB cost assessment variances, during 2018 each quarterly assessment received was compared against the actual average quarterly assessment received during the Board's 2015 – 2016 fiscal year, the last year of assessments received under the former methodology. As indicated in evidence at Exhibit B, Tab 1, page 21, the 2015 - 2016 actual average assessment amount was used as the comparator as it was the most recent amount that EGD was expected to accommodate through its Custom Incentive Regulation Mechanism established rates. Further, within the EGD rate zone Customer Incentive Regulation approved annual O&M amounts, no specific OEB cost assessment amounts were identified which could be used for comparison purposes. For the Union rate zones, consistent with the determination of amounts previously calculated in relation to 2016 and 2017 OEB cost assessment variances (which were not recoverable in accordance with the Settlement Agreement and/or Decision in each of Union's 2016 and 2017 Deferral Disposition and Utility Earnings proceedings), during 2018 each quarterly assessment received was compared against the annual amount of $2.5 million, converted to an average quarterly assessment of $0.625 million, which was approved and identified in base 2013 rates.

c) For the EGD rate zone, the $2.702.3 million currently recorded in the OEB Cost Assessment Variance Account reflects a comparison of actual fiscal 2018 quarterly assessed costs against the actual average quarterly assessment received during the Board's 2015 – 2016 fiscal year, the last year of assessments received under the former methodology. If the same methodology was utilized to calculate the amount to be recorded in the Union rate zones OEB Cost Assessment Variance Account for 2018, it would result in a receivable amount of $1.186 million, as compared to the $1.203 million currently recorded in the account. Table 1 below shows the calculation of the variance of $1.186, while table 2 shows the calculation of the requested comparator amount, being the actual average quarterly assessment received by Union Gas Limited during the Board's 2015 – 2016 fiscal year, the last year of assessments received under the former methodology.

Table 1 - Union Rate Zones
OEB Cost Assessment Variance (January 1, 2018 to December 31, 2018)

Date	Actual OEB Cost Assessment	2015/2016 Average OEB Cost Assessment to UGL based on previous CAM	Incremental OEB Cost Assessment
	($ millions)	($ millions)	($ millions)
	(a)	(b)	(c) = (a) – (b)
1-Jan-18	0.886	0.629	0.257
1-Apr-18	0.988	0.629	0.359
1-Jul-18	0.914	0.629	0.285
1-Oct-18	0.914	0.629	0.285
Total	3.703	2.517	1.186

Table 2 - Legacy Union Gas Limited OEB Cost Assessments Under the Board's Old Methodology

OEB Cost Assessment Based on prior CAM	Qtr. # / Invoice Date	Quarterly Assessment	Total for the year	Average/Qtr
		($ millions)	($ millions)	($ millions)
OEB Fiscal 2015/2016	1 (Apr. 1, 2015)	0.590		
	2 (Jul. 1, 2015)	0.590		
	3 (Oct. 1, 2015)	0.589		
	4 (Jan. 1, 2016)	0.747	2.517	0.629

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B/T1/page 21 & Exhibit C/T1/page 63-

Question(s):

a) Are both Cost Assessment accounts subject to the $ 1 million materiality threshold?

b) If the Union rate zone account is subject to a $ 1 million materiality threshold why is the amount sought for disposition not $0.203 million (net of interest costs) rather than $1.203 million?

Response

a) In accordance with the Decision and Order in EB-2018-0105, Union Gas Limited - 2017 Disposition of Deferral Account Balances and 2017 Utility Earnings proceeding, the Board approved of an OEB Cost Assessment Variance Account for the Union rate zones, with a threshold of $1 million, beginning in 2018. The OEB Cost Assessment Variance Account accounting order, approved as part of Enbridge Gas Distribution's 2018 Rate Application, EB-2017-0086, did not include a materiality threshold in the EGD rate zone. However, as part of Enbridge Gas Inc.'s 2019 rate application, in which it proposed to maintain two separate OEB Cost Assessment Variance Accounts, one for each of the EGD rate zone and Union rate zones, a threshold of $1 million was approved for each account commencing in 2019.

b) Please see Natural Gas Rate Application Filing Requirements, Section 2.9.2, "Establishment of New Deferral and Variance Accounts". The $1 million materiality threshold establishes the dollar value at which cost increases (or decreases) have become material enough to warrant consideration for recovery or refund. It does not establish a bar, for which only amounts above the bar are subject to refund or recovery.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Interrogatory

Reference:

Exhibit B/T1/pages 28-

Question(s):

a) Given the resolution of the Cityscape lawsuit is Enbridge now seeking to close the MGPDA? If not please explain why not.

b) Is this the first (and only) disposition ever sought for the MGPDA? If not please provide a summary of all amounts collected from customers from this account.

c) Please provide a breakdown of the costs sought into (1) settlement cost with Cityscape; (2) legal fees; (3) consultant and other fees.

d) Please explain what efforts Enbridge took to mitigate the costs to ratepayers of this action.

Response

a) No, Enbridge Gas is not planning to close the MGPDA. The purpose of the MGPDA is to capture all costs incurred in managing and resolving issues related to the Company's Manufactured Gas Plant ("MGP") legacy operations. This purpose extends beyond the Cityscape litigation.

b) This is the first disposition sought for the MGPDA since its establishment.

c) The following chart breaks down the costs requested for disposition:

Manufactured Gas Plant Deferral Account

	($000's)
External Legal and Consulting Fees - Cityscape Residential proceeding (includes disbursements for consultants/experts for property valuation, environmental evaluation, and insurance coverage review)	615.3
Settlement Funds - Cityscape Residential proceeding	250.0
External Legal Fees - Opinions/Sale of Emma St. Property	16.3
External Legal Fees - Demolition of Trinity Street Regulator Station and Sale of Property	4.6
External Legal Fees - Station A New District Station & Reinforcement	1.8
	888.0
Forecast interest to December 31, 2019	78.9
Total requested for clearance	966.9

d) At every stage of the Cityscape Residential litigation, Enbridge Gas sought to minimize total exposure and costs. Steps taken included the following:

- Vigorous defence of the $50 million claim against Enbridge Gas Distribution.
- Efficient administration of the discovery portion of the proceeding, which covered 1000s of documents (many of which were decades old and hard to locate) and lengthy discovery processes (including follow-ups).
- Appropriate work with expert consultants to assist in preparing positions to minimize liability and exposure.
- Continuous notification to insurers to seek coverage where the costs of the action exceeded applicable levels (the insurance was not responsive to the amount of the settlement).
- Preparation of a motion to dismiss for delay when the plaintiff began pushing the case after several years of inaction (which helped with negotiations for a settlement).
- Negotiation of a prudent settlement that protects against any further exposure or liability, and that does not set any precedent or example that might be used against Enbridge Gas for MGP litigation in the future.