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Enbridge Gas Inc.
P. O. Box 2001
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June 14, 2023

VIA RESS AND EMAIL

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Nancy Marconi:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File No.: EB-2023-0092
2022 Utility Earnings and Disposition of Deferral & Variance Account Balances Application and Evidence

Effective January 1, 2019, Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union) amalgamated to become Enbridge Gas Inc. (Enbridge Gas). Enclosed is the application and evidence submitted by Enbridge Gas addressing 2022 utility earnings and the disposition and recovery of certain 2022 deferral and variance account balances (the Application) for all Enbridge Gas rate zones. Also included is the OEB Scorecard and the IRP Annual Report. No approval is being sought regarding these items.

The Application is supported by evidence which is outlined below:

Exhibit A: Overview and Introduction

Exhibit B: Utility Results and Earnings Sharing

Exhibit C: Enbridge Gas Deferral and Variance Accounts

Exhibit D: EGD Rate Zone Deferral and Variance Accounts

Exhibit E: Union Rate Zones Deferral and Variance Accounts

Exhibit F: Rate Allocation

Exhibit G: OEB Scorecard

Exhibit H: IRP Annual Report

Enbridge Gas proposes to dispose of the approved 2022 deferral and variance account balances with the first QRAM application following the OEB's approval, which is assumed to be January 1, 2024.

In accordance with the OEB's revised Practice Direction on Confidential Filings effective December 17, 2021, Enbridge Gas is requesting confidential treatment of the following exhibit – details of the specific confidential information for which confidential treatment is sought (all of which fits within the OEB's "presumptively confidential" category) are set out below:

Exhibit	**Description of Document**	**Brief Description**	**Basis for Confidentiality Claim**
Exhibit D, Tab 1, Schedule 6	Storage RFP Summary	Contains vendor responses for third party storage information including terms, pricing and injection and withdrawal offers.	Meets categories of information to be treated as confidential from third parties as part of a competitive procurement process. Equivalent information has been treated as confidential in previous proceedings, including the Enbridge Gas 2021 Deferral & Variance Account Balances Application (see EB-2022-0110 Decision on Confidentiality, July 29, 2022).

The above noted submission has been filed electronically through the OEB's RESS and will be made available on Enbridge Gas's website at:
https://www.enbridgegas.com/Regulatory-Proceedings

In the event that you have any questions on the above or would like to discuss in more detail, please do not hesitate to contact me.

Sincerely,

(Original Digitally Signed)

Richard Wathy
Technical Manager, Regulatory Applications

cc.: D. Stevens (Aird & Berlis)

EXHIBIT LIST

A – Overview and Introduction

Exhibit	Tab	Schedule	Contents
A	1		Exhibit List
	2		Application
	3		Overview and Approvals Required

B- Utility Results and Earning Sharing

Exhibit	Tab	Schedule	Contents
B	1		2022 Earnings Sharing Amount and Determination Process
		1	Return on Rate Base & Equity and Earning Sharing Determination
		2	Utility Income
		3	Utility Income Tax
		4	Utility Rate Base and Continuity Schedules
		5	Capital Structure and Cost of Capital
		6	Reconciliation of Audited Income to Corporate
	2	1	Delivery Revenue by Service Type and Rate Class
		2	Total Customers and Revenue by Service Type and Rate Class
		3	Revenue from Regulated Storage and Transportation of Gas
		4	Other Revenue

D - EGD Rate Zone Deferral and Variance Accounts

E – Union Rate Zones Deferral and Variance Accounts

F – Rate Allocation

F – Rate Allocation

G – OEB Scorecard

H – IRP Annual Report

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule. B);

AND IN THE MATTER OF an Application by Enbridge Gas Inc. for an order or orders clearing certain commodity and non-commodity related deferral or variance accounts.

APPLICATION

1. Enbridge Gas Distribution Inc. (referred to in the evidence as EGD, Enbridge Gas or the Company) and Union Gas Limited (referred to in the evidence as Union or the Company) (together the Utilities) were Ontario corporations incorporated under the laws of the Province of Ontario carrying on the business of selling, distributing, transmitting and storing natural gas within the meaning assigned in the *Ontario Energy Board Act*, 1998 (the Act). In the August 30, 2018 EB-2017-0306/0307 Decision and Order (the MAADs Decision), the Ontario Energy Board (OEB) approved the amalgamation of the Utilities, as well as a five-year deferred rebasing term during which a price cap rate-setting model would apply.

2. Effective January 1, 2019 the Utilities amalgamated to become Enbridge Gas Inc. (Enbridge Gas). Following amalgamation, Enbridge Gas has maintained the existing rates zones of EGD and Union (the EGD, Union North West, Union North East and Union South rate zones).[1] Enbridge Gas has also maintained most of the existing deferral and variance accounts for each Rate Zone.

[1] Collectively the Union North West, Union North East and Union South rates zones are referred to as "Union rate zones". Union North West and Union North East are collectively referred to as "Union North".

3. Enbridge Gas, the Applicant, hereby applies to the OEB, pursuant to Section 36 of the *Ontario Energy Board Act*, 1998, for an Order or Orders approving the clearance or disposition of amounts recorded in certain deferral or variance accounts.

1. Earnings Sharing

4. In the MAADs Decision, the OEB approved, among other things, an asymmetrical earnings sharing mechanism (ESM) during the deferred rebasing period, where each year any earnings in excess of 150 basis points over the OEB-approved return on equity (ROE) would be shared 50/50 between the Utilities and ratepayers.

5. In 2022, Enbridge Gas's actual utility earnings did not exceed the OEB-approved ROE by more than 150 basis points. Accordingly, no ESM amount is proposed to be shared with ratepayers.

2. Enbridge Gas Inc.

6. The OEB has approved several deferral and variance accounts that relate to Enbridge Gas as a whole (and not to specific Rate Zone(s)). These accounts are listed at Exhibit C, Tab 1, Schedule 1. Enbridge Gas seeks approval to clear the final balances of certain Enbridge Gas deferral and variance accounts for 2022 as set out at Exhibit C, Tab 1, Schedule 1.

7. Enbridge Gas is not seeking approval to clear the balance in the Accounting Policy Changes Deferral Account (APCDA), in the Covid-19 Emergency Incremental Cost Deferral Account (COVEICDA), in the Incremental Capital Module Deferral Account (ICMDA), in the RNG injection service V/A (RNGISVA) and the amount in the Tax Variance Deferral Account (TVDA) related to integration capital additions. Details on these accounts are presented in this application for information purposes. The balances in these accounts have been brought forward for clearance in EB-2022-0200[2].

[2] EB-2022-0200, Exhibit 9, Tab 2, Schedule 1.

3. EGD Rate Zone

8. As approved in the MAADs Decision and the 2019 Rates Case (EB-2018-0305), Enbridge Gas has maintained substantially the same deferral and variance accounts for the EGD rate zone as during its 2014-2018 Custom IR term.

9. Enbridge Gas seeks approval to clear the final balances of certain EGD rate zone deferral and variance accounts for 2022 as set out at Exhibit C, Tab 1, Schedule 1.

4. Union Rate Zones

10. As approved in the MAADs Decision and the 2019 Rates Case (EB-2018-0305), Enbridge Gas has maintained substantially the same deferral and variance accounts for the Union Rate Zones as during its 2014-2018 IR term.

11. Enbridge Gas seeks approval to clear the interim and final balances of certain Union rate zones deferral and variance accounts for 2022 as set out at Exhibit C, Tab 1, Schedule 1.

5. Relief Requested

12. Enbridge Gas therefore applies to the OEB for such final, interim or other orders as may be necessary or appropriate for the clearance or disposition of the 2022 deferral and variance accounts requested in Exhibit C, Tab 1, Schedule 1. The proposed manner of disposition is described at Exhibit F. Enbridge Gas proposes to clear the balances in these accounts with the first available QRAM application following the OEB’s approval, as early as January 1, 2024.

13. Enbridge Gas requests that certain information included at Exhibit D, Tab 1, Schedule 6 be treated as confidential under the OEB’s Practice Direction on Confidential Filings. Equivalent information has been treated as confidential in prior deferral and variance account clearance proceedings.

14. Enbridge Gas requests that this proceeding be heard in writing.

15. Enbridge Gas further applies to the OEB pursuant to the provisions in the Act and the OEB's *Rules of Practice and Procedure* for such final, interim or other Orders and directions as may be appropriate in relation to the Application and the proper conduct of this proceeding.

16. This Application is supported by written evidence. This evidence may be amended from time to time as required by the OEB, or as circumstances may require.

17. The persons affected by this application are the customers resident or located in the municipalities, police villages and First Nations reserves served by Enbridge Gas, together with those to whom Enbridge Gas sells gas, or on whose behalf Enbridge Gas distributes, transmits or stores gas. It is impractical to set out in this application the names and addresses of such persons because they are too numerous.

18. Enbridge Gas requests that a copy of every document filed with the OEB in this proceeding be served on the Applicant and Applicant's counsel, as follows:

<u>The Applicant</u>:

Mr. Richard Wathy
Technical Manager, Regulatory Applications
Enbridge Gas Inc.

Address for personal service	Enbridge Gas Inc. P. O. Box 2001 50 Keil Drive North Chatham, ON N7M 5M1
Telephone:	519-365-5376
Fax:	(519) 436-4641
Email:	Richard.Wathy@enbridge.com EGIRegulatoryproceedings@enbridge.com

- and –

The Applicant's counsel:

Mr. David Stevens
Aird & Berlis LLP

Address for personal service and mailing address:	Brookfield Place, P.O. Box 754 Suite 1800, 181 Bay Street Toronto, Ontario M5J 2T9
Telephone:	416-863-1500
Fax:	416-863-1515
Email:	dstevens@airdberlis.com

DATED: June 14, 2023, at Chatham, Ontario

ENBRIDGE GAS INC.

[Original digitally signed by]

Richard Wathy
Technical Manager, Regulatory Applications

2022 DEFERRAL ACCOUNT DISPOSITION AND EARNINGS SHARING OVERVIEW AND APPROVALS REQUESTED

1. Enbridge Gas Inc. (Enbridge Gas) is applying to the Ontario Energy Board (OEB) pursuant to section 36 of the *OEB Act* for approval to dispose and recover certain 2022 deferral and variance account final balances for Enbridge Gas, and the Enbridge Gas Distribution (EGD) and Union Gas (Union)[1] rate zones. Enbridge Gas is also presenting the 2022 earnings sharing mechanism (ESM) calculations for the amalgamated utility.

2. The evidence in this Application is organized as follows:
   Exhibit A: Overview and Introduction
   Exhibit B: 2022 Utility Results and Earnings Sharing Amount
   Exhibit C: Enbridge Gas Inc. Deferral and Variance Accounts
   Exhibit D: EGD Rate Zone Deferral and Variance Accounts
   Exhibit E: Union Rate Zones Deferral and Variance Accounts
   Exhibit F: Rate Allocation
   Exhibit G: OEB Scorecard
   Exhibit H: IRP Annual Report

3. Enbridge Gas proposes that the impacts which result from the disposition of 2022 deferral and variance account balances be implemented with the first available QRAM application following the OEB's approval, as early as January 1, 2024, to align with other rate changes implemented through the Quarterly Rate Adjustment Mechanism (QRAM).

1. Relief requested

4. Enbridge Gas seeks approval to clear the final balances of certain Enbridge Gas, EGD rate zone, and Union rate zones 2022 deferral and variance accounts. The

[1] "Union rate zones" collectively refers to Union North West, Union North East and Union South.

balances of the 2022 deferral and variance accounts are set out at Exhibit C, Tab 1, Schedule 1. For ease of reference, a copy of Exhibit C, Tab 1, Schedule 1 is attached at Appendix A to this exhibit.

5. Explanations for the balances in each account are set out at Exhibit C (Enbridge Gas), Exhibit D (EGD rate zone) and Exhibit E (Union rate zones). The evidence also indicates which accounts Enbridge Gas does not seek to clear in this proceeding. The proposed clearance methodology for the accounts being cleared is set out at Exhibit F.

6. In the MAADs Decision (EB-2017-0306/0307), the OEB approved, among other things, an asymmetrical earnings sharing mechanism (ESM) during the 2019-2023 deferred rebasing period, where each year any earnings in excess of 150 basis points over the OEB-approved return on equity (ROE) would be shared 50/50 between Enbridge Gas and ratepayers.

7. Enbridge Gas's actual 2022 utility earnings did not exceed the OEB-approved ROE by more than 150 basis points. Accordingly, no ESM amount is proposed to be shared with ratepayers.

<u>2. Disposition of deferral and variance accounts</u>

8. Integration of the legacy billing systems for EGD and Union Gas enables Enbridge Gas to dispose of balances in the 2022 deferral and variance accounts as a one-time adjustment for all customers. Enbridge Gas proposes to dispose of the 2022 deferral and variance accounts as a one-time adjustment for all general service, in-franchise contract and ex-franchise rate classes.

9. The proposed approach to the one-time adjustment is consistent between the EGD and Union rate zones and, subject to OEB approval as to timing, will be disposed of as part of the January 2024 bills that customers receive in Febraury 2024.

3. Parkway west project costs account interim disposition

10. Enbridge Gas is seeking interim disposition of the 2022 balance in the Parkway West Project Costs Deferral Account (179-136), consistent with the 2016 to 2021 deferral and variance account disposition proceedings. In the 2016 deferral account proceeding, the OEB noted that "all parties agreed that the 2016 balance in the Parkway West Project Costs Account should be disposed of only on an interim basis to allow the OEB to perform a prudence review of the capital overspend prior to final disposition of the balance in the account."[2] The final costs and/or 2024 rate base value for all projects completed since the last rebasing cases for EGD and Union (including the Parkway West project) are being considered and determined in the current EB-2022-0200 rebasing case. Once that determination is made, Enbridge Gas will seek approval of the final disposition of this account as part of a subsequent proceeding (or within this proceeding if timing permits).

[2] EB-2017-0091 Updated Settlement Agreement Proposal, p. 12.

ENBRIDGE GAS
DEFERRAL & VARIANCE ACCOUNT
ACTUAL & FORECAST BALANCES

Line No.	Account Description	Account Acronym		Col. 1 Principal ($000's)	Col. 2 Interest ($000's)	Col. 3 Total ($000's)	Col.4 Reference to Evidence
				Forecast for clearance at January 1, 2024			
	EGD Rate Zone Commodity Related Accounts						
1.	Storage and Transportation D/A	2022 S&TDA		8,074.4	493.3	8,567.7	D-1, Page 2
2.	Transactional Services D/A	2022 TSDA		(31,234.7)	(1,536.0)	(32,770.7)	D-1, Page 4
3.	Unaccounted for Gas V/A	2022 UAFVA		41,400.4	2,179.6	43,580.0	D-1, Page 6
4.	Total Commodity Related Accounts			18,240.1	1,136.9	19,377.0	
	EGD Rate Zone Non Commodity Related Accounts						
5.	Average Use True-Up V/A	2022 AUTUVA		6,904.5	339.5	7,244.0	D-1, Page 10
6.	Gas Distribution Access Rule Impact D/A	2022 GDARIDA		-	-	-	D-1, Page 23
7.	Deferred Rebate Account	2022 DRA		(72.7)	(8.9)	(81.6)	D-1, Page 12
8.	Transition Impact of Accounting Changes D/A	2022 TIACDA		4,435.8	-	4,435.8	D-1, Page 1
9.	Electric Program Earnings Sharing D/A	2022 EPESDA		-	-	-	D-1, Page 23
10.	Open Bill Revenue V/A	2022 OBRVA		-	-	-	D-1, Page 23
11.	Ex-Franchise Third Party Billing Services V/A	2022 EXFTPBSVA		-	-	-	D-1, Page 23
12.	OEB Cost Assessment V/A	2022 OEBCAVA		3,104.8	193.3	3,298.1	D-1, Page 13
13.	Dawn Access Costs D/A	2022 DACDA		1,184.8	58.3	1,243.1	D-1, Page 16
14.	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Di	2022 P&OPEBFAVACPDVA		-	-	-	D-1, Page 23
15.	Total EGD Rate Zone (for clearance)			33,797.3	1,718.9	35,516.2	
	Union Rate Zones Gas Supply Accounts	OEB Account Number					
16.	Upstream Transportation Optimization	179-131	2022	8,899.7	437.6	9,337.3	E-1, Page 6
17.	Spot Gas Variance Account	179-107	2022	-	-	-	E-1, Page 58
18.	Unabsorbed Demand Costs Variance Account	179-108	2022	(5,623.7)	(345.5)	(5,969.2)	E-1, Page 1
19.	Base Service North T-Service TransCanada Capacity	179-153	2022	83.3	5.1	88.4	E-1, Page 52
20.	Total Gas Supply Accounts			3,359.3	97.2	3,456.5	
	Union Rate Zones Storage Accounts						
21.	Short-Term Storage and Other Balancing Services	179-70	2022	4,446.1	215.9	4,662.0	E-1, Page 8
	Union Rate Zones Other Accounts						
22.	Normalized Average Consumption	179-133	2022	8,769.8	564.7	9,334.5	E-1, Page 13
23.	Deferral Clearing Variance Account	179-132	2022	1,978.0	135.1	2,113.1	E-1, Page 21
24.	OEB Cost Assessment Variance Account	179-151	2022	1,254.2	77.8	1,332.0	E-1, Page 49
25.	Unbundled Services Unauthorized Storage Overrun	179-103	2022	-	-	-	E-1, Page 58
26.	Gas Distribution Access Rule Costs	179-112	2022	-	-	-	E-1, Page 58
27.	Conservation Demand Management	179-123	2022	-	-	-	E-1, Page 58
28.	Parkway West Project Costs	179-136	2022	(603.7)	(36.5)	(640.2)	E-1, Page 25
29.	Brantford-Kirkwall/Parkway D Project Costs	179-137	2022	(35.0)	(2.0)	(37.0)	E-1, Page 29
30.	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	179-142	2022	240.0	11.4	251.4	E-1, Page 41
31.	Lobo D/Bright C/Dawn H Compressor Project Costs	179-144	2022	1,315.6	53.8	1,369.4	E-1, Page 44
32.	Burlington-Oakville Project Costs	179-149	2022	(48.0)	(2.9)	(50.9)	E-1, Page 47
33.	Panhandle Reinforcement Project Costs	179-156	2022	(3,149.1)	(188.4)	(3,337.5)	E-1, Page 53
34.	Sudbury Replacement Project	179-162	2022	-	-	-	E-1, Page 58
35.	Parkway Obligation Rate Variance	179-138	2022	(81.0)	(4.0)	(85.0)	E-1, Page 58
36.	Unauthorized Overrun Non-Compliance Account	179-143	2022	(144.9)	(9.8)	(154.7)	E-1, Page 58
37.	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Di	179-157	2022	-	(3,443.7)	(3,443.7)	E-1, Page 56
38.	Unaccounted for Gas Volume Variance Account	179-135	2022	40,046.6	1,969.3	42,015.9	E-1, Page 31
39.	Unaccounted for Gas Price Variance Account	179-141	2022	9,785.0	508.9	10,293.9	E-1, Page 38
40.	Total Other Accounts			59,327.5	(366.4)	58,961.1	
41.	Total Union Rate Zones (for clearance)			67,132.9	(53.4)	67,079.5	
	EGI Accounts						
42.	Earnings Sharing D/A	179-382	2022	-	-	-	C-1, Page 1
43.	Tax Variance - Accelerated CCA - EGI	179-383	2022	(29,236.7)	(1,723.9)	(30,960.6)	C-1, Page 12
44.	IRP Operating Costs Deferral Account	179-385	2022	2,159.4	126.1	2,285.5	C-1, Page 15
45.	IRP Capital Costs Deferral Account	179-386	2022	-	-	-	C-1, Page 1
46.	Green Button Initiative Deferral Account	179-387	2022	-	-	-	
47.	Expansion of Natural Gas Distribution Systems V/A	179-380	2022	-	-	-	C-1, Page 1
48.	Total EGI Accounts (for clearance)			(27,077.3)	(1,597.8)	(28,675.1)	
49.	Total Deferral and Variance Accounts (for clearance)			73,852.9	67.8	73,920.7	
	Not Being Requested for Clearance						
50.	Accounting Policy Changes D/A - Pension - EGI	179-120	2022	160,288.8	-	160,288.8	C-1, Page 2
51.	Accounting Policy Changes D/A - Other - EGI	179-120	2019	(1,749.5)	(156.4)	(1,905.9)	C-1, Page 2
52.	Accounting Policy Changes D/A - Other - EGI	179-120	2020	(14,789.5)	(1,125.8)	(15,915.3)	C-1, Page 2
53.	Accounting Policy Changes D/A - Other - EGI	179-120	2021	(13,864.6)	(990.2)	(14,854.8)	C-1, Page 2
54.	Accounting Policy Changes D/A - Other - EGI	179-120	2022	62,752.5	2,872.2	65,624.7	C-1, Page 2
55.	Tax Variance - Integration Capital Additions - EGI	179-383	2020	(3,736.3)	(249.9)	(3,986.2)	C-1, Page 12
56.	Tax Variance - Integration Capital Additions - EGI	179-383	2021	(10,178.9)	(689.4)	(10,868.2)	C-1, Page 12
57.	Tax Variance - Integration Capital Additions - EGI	179-383	2022	6,882.8	390.5	7,273.3	C-1, Page 12
58.	Incremental Capital Module Deferral Account - EGD	2020 ICMDA	2020	(254.0)	(18.3)	(272.3)	C-1, Page 1
59.	Incremental Capital Module Deferral Account - EGD	2021 ICMDA	2021	175.5	12.5	188.0	C-1, Page 1
60.	Incremental Capital Module Deferral Account - EGD	2022 ICMDA	2022	(6,873.6)	(343.4)	(7,217.0)	C-1, Page 1
61.	Incremental Capital Module Deferral Account - UGL	179-159	2019	(6,869.6)	(603.1)	(7,472.7)	C-1, Page 1
62.	Incremental Capital Module Deferral Account - UGL	179-159	2020	(5,615.4)	(424.6)	(6,040.0)	C-1, Page 1
63.	Incremental Capital Module Deferral Account - UGL	179-159	2021	(14,353.4)	(997.6)	(15,351.0)	C-1, Page 1
64.	Incremental Capital Module Deferral Account - UGL	179-159	2022	(1,719.3)	(102.4)	(1,821.7)	C-1, Page 1
65.	RNG Injection Service V/A	2022 RNGISVA	2022	(159.2)	(7.8)	(167.0)	D-1, Page 23
66.	Impacts Arising from the COVID-19 Emergency D/A - EGI	2020 IACEDA	2020	1,377.5	101.9	1,479.4	C-1, Page 1
67.	Impacts Arising from the COVID-19 Emergency D/A - EGI	2021 IACEDA	2021	34.3	2.4	36.7	C-1, Page 1
68.	Total of Accounts not being requested for clearance			151,348.2	(2,329.6)	149,018.6	

2022 ENBRIDGE GAS INC. EARNINGS SHARING AMOUNT AND DETERMINATION PROCESS

1. For the year ended December 31, 2022, Enbridge Gas Inc. (Enbridge Gas, or the Company) is not in an earnings sharing position, as its achieved return on rate base and return on equity are below the threshold required for sharing. The earnings sharing calculation is shown at Exhibit B, Tab 1, Schedule 1 while supporting schedules that show the calculation of utility rate base, utility income and taxes, and the utility capital structure components, are contained in the balance of the B Exhibits. Exhibit B, Tab 1, Schedule 6 sets out a reconciliation of audited income to corporate income.

2. The earnings sharing amount was determined in accordance with the following prescribed methodology as identified within the EB-2017-0306/0307 OEB Decision and Order, dated August 30, 2018, at pages 28 and 29, and within the EB-2017-0306 pre-filed evidence at Exhibit B, Tab 1, pages 42 and 43:
   - if in any calendar year during the deferred rebasing term, Enbridge Gas's actual utility ROE is more than 150 basis points above the OEB-approved ROE for that year (updated annually by the OEB), then the resultant amount shall be shared equally (i.e., 50/50) between Enbridge Gas and its ratepayers;
   - for the purposes of the ESM, Enbridge Gas shall calculate its earnings using generally accepted accounting principles (GAAP) consistent with its external reporting, including the regulatory rules prescribed by the OEB from time to time;
   - all revenues and costs that would otherwise be included in a cost of service application shall be included in the earnings sharing calculation.

3. While the threshold or benchmark for Enbridge Gas's earnings sharing has changed from that of each legacy utility[1], the general process followed for calculating earnings sharing amounts is consistent with each utilities prior incentive regulation terms.

4. As articulated above, within Exhibit B, Tab 1, Schedule 1, the Company has calculated earnings for sharing in two ways for confirmation purposes.

5. In part A), a return on rate base method is shown, while in part B), a return on equity from a deemed equity embedded within rate base perspective is shown. Column 2 within the exhibit provides references indicating where additional evidence in support of the determination of the amounts in the calculation can be found. Column 3 contains results shown in millions of dollars, or percentages.

<u>1. Part A)</u>

6. The level of utility income, $930.1 million (Line 4) divided by the level of utility rate base, $15,381.4 million (Line 5) generates a utility return on rate base of 6.047% (Line 6).

7. When compared to the Company's required rate of return for ESM determination, of 6.279% (Line 7), as determined within the capital structure required in support of the determined rate base amount (inclusive of the 150 basis point deadband on ROE before earnings sharing is triggered), there is a resulting deficiency of 0.232% (Line 8) on total rate base.

8. As shown in Lines 9 through 11, the deficiency of 0.232% multiplied by the rate base of $15,381.4 million, produces a net under earnings or deficiency of $35.7 million, which from a pre-tax perspective ($35.7 million divided by the reciprocal, 73.5%, of the corporate tax rate which is 26.5%), results in a $48.6 million gross amount of

[1] Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union).

under earnings, and therefore nothing to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

<u>2. Part B) (Confirming the Calculated Earnings Sharing)</u>

9. Net utility income applicable to common equity is first determined.

10. The $959.9 million (Line 14) of utility income before income tax, less utility taxes of $29.8 million (Line 19), produces the $930.1 million of utility income used in part A) above (at Line 4).

11. In order to determine utility net income applicable to a deemed common equity percentage within rate base, all long term debt, short term debt and preference share costs must also be reduced against the part A) $930.1 million utility income.

12. These reductions are shown at Lines 15, 16 and 17 which, along with the utility income tax reduction already mentioned and shown at Line 19, results in a net income applicable to common equity of $526.9 million, shown at Line 20.

13. The $526.9 million, divided by the deemed common equity level of $5,537.3 million (Line 21, calculated as 36% of the $15,381.4 million rate base) produces a return on equity of 9.515% (Line 23). When comparing the 9.515% achieved return on equity to the threshold ROE percentage of 10.160% (Line 22), which is the OEB-approved formula return on equity for 2022 of 8.660% plus the 150 basis point deadband before sharing, there is a deficiency in ROE of 0.645% (Line 24).

14. The 0.645% multiplied by the common equity level of $5,537.3 million (Line 21) produces a net under earnings or deficiency of $35.7 million, which from a pre-tax perspective ($35.7 million divided by the reciprocal, 73.5%, of the corporate tax rate), results in a $48.6 million gross amount of under earnings, and therefore

nothing to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

3. Process Description

15. The calculation of utility earnings and any earnings sharing requirement starts with financial results contained within the Enbridge Gas corporate trial balance. The Company notes that corporate trial balance includes the elimination of transactions between each of the rate zones. This predominantly relates to the elimination of regulated and unregulated storage and transmission revenues that would have been reflected in the Union rate zones, offset by a corresponding elimination of gas costs that would have been reflected for the EGD rate zone. This reflects the fact that from a corporate perspective, EGD rate zone delivery revenues are contributing to the costs of Union rate zones regulated and unregulated storage and transmission services.

16. From there, in order to calculate the utility rate base, income, and capital structure results, and supporting evidence exhibits, various adjustments, regroupings or eliminations are required. This is accomplished by following and applying regulatory rules as prescribed by the OEB and the standards associated with cost of service rate related accounting processes. Examples are:
    - determination of rate base amounts using the average of monthly averages value concept,
    - elimination of corporate interest expense due to the treatment of interest expense as embedded in the capital structure balanced to rate base; and,
    - elimination of corporate income taxes due to the determination of income taxes specific to utility results.

17. In addition, Enbridge Gas has made the appropriate adjustments in relation to non-standard legacy EGD and Union rate regulated items which the OEB has either decided in the past or are required in order to determine an appropriate utility return on equity. Examples are:
    - rate base disallowance from EBRO 473 and 479 Decisions (Mississauga Southern Link project amounts);
    - exclusion of non-utility or unregulated activities;
    - elimination of approved shareholder incentives (such as Demand Side Management incentives, amounts related to Transactional Services, short-term storage, and net optimization incentives, and amounts related to Open Bill program incentives); and
    - elimination of Central Functions Corporate Cost Allocation Methodology (CFCAM) charges that did not pass the 3-prong test.

SUMMARY
RETURN ON RATE BASE & EQUITY & EARNINGS SHARING DETERMINATION
ENBRIDGE GAS INC.

ONTARIO UTILITY
FOR THE YEAR ENDED DECEMBER 31, 2022

Line No.	Col. 1 Description	Col. 2 Reference	Col. 3 Actual
1.	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
			($Millions) & (%'s)
2.	Utility Income before Income Tax	(Ex. B, Tab 1, Sch. 2)	959.9
3.	Less: Income Taxes	(Ex. B, Tab 1, Sch. 3)	29.8
4.	Utility Income		930.1
5.	Utility Rate Base	(Ex. B, Tab 1, Sch. 4)	15,381.4
6.	Indicated Return on Rate Base %	(line 4 / line 5)	6.047%
7.	Less: Required Rate of Return %	(Ex. B, Tab 1, Sch. 5)	6.279%
8.	(Deficiency) / Sufficiency %		-0.232%
9.	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	(35.7)
10.	Provision for Income Taxes		(12.9)
11.	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	(48.6)
12.	50% Earnings sharing to ratepayers	(if line 11 > 1, line 11 x 50%)	-
13.	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
14.	Utility Income before Income Tax	(Ex. B, Tab 1, Sch. 2)	959.9
15.	Less: Long Term Debt Costs	(Ex. B, Tab 1, Sch. 5)	384.9
16.	Less: Short Term Debt Costs	(Ex. B, Tab 1, Sch. 5)	18.4
17.	Less: Cost of Preferred Capital	(Ex. B, Tab 1, Sch. 5)	0.0
18.	Net Income before Income Taxes		556.7
19.	Less: Income Taxes	(Ex. B, Tab 1, Sch. 3)	29.8
20.	Net Income Applicable to Common Equity	(line 18 - line 19)	526.9
21.	Common Equity	(Ex. B, Tab 1, Sch. 5)	5,537.3
22.	Approved ROE (including deadband before earning sharing) %	(Board-approved + 150bp)	10.160%
23.	Achieved Rate of Return on Equity %	(line 20 / line 21)	9.515%
24.	Resulting (Deficiency) / Sufficiency in Return on Equity %		-0.645%
25.	Net Earnings (Deficiency) / Sufficiency	(line 21 x line 24)	(35.7)
26.	Provision for Income Taxes		(12.9)
27.	Gross Earnings (Deficiency) / Sufficiency	(line 25 / 73.5%)	(48.6)
28.	50% Earnings sharing to ratepayers	(if line 27 > 1, line 27 x 50%)	-

EGI UTILITY INCOME
2022 ACTUAL

Line No.		Reference	Col. 1 Corporate (a)	Col. 2 Unregulated Storage (b)	Col. 3 Adjustments (c)		Col. 4 Utility Income (d) = (a)-(b)+(c) ($Millions)
1.	Gas sales and distribution	(Ex. B, Tab 2, Sch. 2)	6,198.6	-	(34.0)	(i)	6,164.5
2.	Transportation	(Ex. B, Tab 2, Sch. 3)	146.2	(0.3)	(0.9)	(ii)	145.7
3.	Storage	(Ex. B, Tab 2, Sch. 3)	179.4	172.4	(0.1)	(iii)	6.9
4.	Other operating revenue	(Ex. B, Tab 2, Sch. 4)	71.8	2.3	(15.9)	(iv)	53.6
5.	Other income	(Ex. B, Tab 2, Sch. 4)	13.0	(0.1)	(15.1)	(viii)	(2.1)
6.	Total operating revenue		6,609.0	174.3	(66.0)		6,368.6
7.	Gas costs		3,678.6	31.7	(16.6)	(i)	3,630.3
8.	Operation and maintenance	(Ex. B, Tab 3, Sch. 1)	1,028.0	15.6	(10.1)	(v)	1,002.3
9.	Depreciation and amortization expense		690.1	14.5	(22.5)	(vi)	653.1
10.	Fixed financing costs		3.5	-	1.1	(vii)	4.6
11.	Municipal and other taxes		120.4	1.9	-		118.5
12.	Cost of service		5,520.6	63.7	(48.2)		5,408.7
13.	Utility income before income taxes						959.9
14.	Income tax expense	(Ex. B, Tab 1, Sch. 3)					29.8
15.	Utility income						930.1

Notes on Adjustments:

(i)	Reclassification of Union rate zone optimization revenue as a cost of gas reduction	(16.6)
	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues	(17.4)
		(34.0)
(ii)	Elimination of the Union rate zone shareholder portion of net optimization activity (before tax)	(0.9)
(iii)	Elimination of the Union rate zone shareholder portion of net short-term storage revenue (before tax)	(0.1)
(iv)	Adjust EGD rate zone OBA costs to reflect EB-2013-0099 approved unit costs agreed to be used for determining net revenue	(4.8)
	Elimination of EGD rate zone Open Bill shareholder incentive	0.3
	Elimination of EGD rate zone shareholder portion of transactional service revenues	(4.8)
	Elimination of demand-side management incentive	(5.8)
	Elimination of EGD rate zone net revenue from ABC T-service, considered to be non-utility	(0.7)
		(15.9)
(v)	Elimination of donations	(1.1)
	Elimination of Central Functions Corporate Allocation Methodology (CFCAM) charges	(8.4)
	Elimination of non-utility costs to support the EGD ABC T-Service program	(0.3)
	Elimination of EB-2021-0204 Assurance of Voluntary Compliance amount	(0.3)
		(10.1)
(vi)	Eliminate amortization of PPD (purchase price discrepancy)	(22.5)
	Eliminate depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479)	(0.0)
		(22.5)
(vii)	Interest on security deposits held during the year and included in elimination of corporate interest exp. Expense incurred to reduce bad debt. The average amount of the security deposit held during the year is applied as a reduction to the allowance for working capital in rate base	1.1
(viii)	Elimination of interest income from investments not included in utility rate base	(0.1)
	Elimination of interest income from affiliates	(3.4)
	Elimination of the revenue indemnification received from Enbridge Inc. related to a non-utility Corporate tax planning Part VI.1 tax transfer to EGI	(11.5)
		(15.1)

CALCULATION OF EGI UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2022 ACTUAL

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	959.9	959.9	
	Add			
2.	Depreciation and amortization	653.1	653.1	
3.	Accrual based pension and OPEB costs	(5.7)	(5.7)	
4.	Other non-deductible items	1.4	1.4	
5.	Total Add Back	648.8	648.8	
6.	Sub-total	1,608.8	1,608.8	
	Deduct			
7.	Capital cost allowance	852.1	852.1	
8.	Items capitalized for regulatory purposes	187.4	187.4	
9.	Amortization of share/debenture issue expense	0.1	0.1	
10.	Amortization of C.D.E. and C.O.G.P.E	0.0	0.0	
11.	Other	1.8	1.8	
12.	Cash based pension and OPEB costs	51.6	51.6	
13.	Total Deduction	1,093.1	1,093.1	
14.	Taxable income	515.7	515.7	
15.	Income tax rates	15.00%	11.50%	
16.	Tax provision excluding interest shield	77.4	59.3	136.7
	Tax shield on interest expense			
17.	Rate base	15,381.3		
18.	Return component of debt	2.62%		
19.	Interest expense	403.3		
20.	Combined tax rate	26.50%		
21.	Income tax credit			(106.9)
22.	Total utility income taxes			29.8

EGI UTILITY RATE BASE
2022 ACTUAL

Line No.		Col. 1 2022 Actual	Col. 2 2021 Actual
		($Millions)	($Millions)
	Property, Plant, and Equipment		
1.	Gross property, plant, and equipment	22,585.9	21,539.8
2.	Accumulated depreciation	(8,320.1)	(8,005.9)
3.	Net property, plant, and equipment	14,265.9	13,533.9
	Allowance for Working Capital		
4.	Materials and supplies	102.6	92.5
5.	ABC receivable	(19.4)	(15.5)
6.	Customer security deposits	(61.0)	(68.9)
7.	Prepaid expenses	6.1	4.7
8.	Balancing gas	59.5	59.5
9.	Gas in storage	1,005.1	594.7
10.	Working cash allowance	22.6	20.9
11.	Total Working Capital	1,115.5	687.7
12.	Utility Rate Base	15,381.4	14,221.6

EGI UTILITY PROPERTY, PLANT, AND EQUIPMENT
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2022 ACTUAL

Line No.		Col. 1 Gross Property, Plant, and Equipment	Col. 2 Accumulated Depreciation	Col. 3 Net Property, Plant, and Equipment
		($Millions)	($Millions)	($Millions)
	EGD Rate Zone			
1.	Underground storage plant	565.3	(159.0)	406.3
2.	Distribution plant	10,180.3	(3,323.1)	6,857.2
3.	General plant	535.5	(363.4)	172.0
4.	Plant held for future use	1.7	(1.5)	0.2
5.	EGD Rate Zone Total	11,282.7	(3,846.9)	7,435.8
	Union Rate Zones			
6.	Intangible plant	1.7	(1.5)	0.2
7.	Local storage plant	33.7	(18.7)	15.0
8.	Underground storage plant	809.6	(351.8)	457.8
9.	Transmission plant	3,919.8	(1,277.0)	2,642.8
10.	Distribution plant - Southern operations	3,843.6	(1,589.5)	2,254.0
11.	Distribution plant - Northern and Eastern operations	2,258.3	(1,037.2)	1,221.1
12.	General plant	436.6	(197.4)	239.3
13.	Union Rate Zones Total	11,303.2	(4,473.1)	6,830.1
14.	EGI Total	22,585.9	(8,320.1)	14,265.9

EGI UTILITY GROSS PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2022 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2021	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2022	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2022	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	EGD Rate Zone Underground Storage Plant							
1.	Land and gas storage rights (450/451)	48.9	0.0	-	48.9	(1.0)	47.9	47.9
2.	Structures and improvements (452)	32.1	3.2	-	35.3	(0.1)	35.2	33.7
3.	Wells (453)	92.4	3.4	-	95.8	-	95.8	93.5
4.	Well equipment (454)	13.4	0.7	-	14.1	-	14.1	15.7
5.	Field Lines (455)	127.7	7.0	-	134.7	-	134.7	129.9
6.	Compressor equipment (456)	196.2	35.3	-	231.5	(0.5)	231.0	201.1
7.	Measuring and regulating equipment (457)	11.2	-	-	11.2	-	11.2	11.2
8.	Base pressure gas (458)	32.4	-	-	32.4	-	32.4	32.4
9.	Sub-Total	554.3	49.7	-	603.9	(1.5)	602.4	565.3
	EGD Rate Zone Distribution Plant							
10.	Renewable Natural Gas (461)	-	5.2	-	5.2	-	5.2	0.6
11.	Land (470)	54.2	43.1	(1.1)	96.2	-	96.2	87.9
12.	Offers to purchase (470)	-	-	-	-	-	-	-
13.	Land rights intangibles (471)	63.8	-	-	63.8	-	63.8	63.8
14.	Structures and improvements (472)	196.0	10.1	(15.9)	190.1	(0.3)	189.8	186.9
15.	Services, house reg & meter install. (473/474)	3,501.0	187.7	(9.3)	3,679.5	-	3,679.5	3,581.1
16.	Mains (475)	4,963.3	296.4	28.8	5,288.4	(2.2)	5,286.2	5,038.1
17.	NGV station compressors (476)	5.2	-	-	5.2	-	5.2	5.2
18.	Measuring and regulating equip. (477)	698.5	13.0	(26.3)	685.2	(0.5)	684.7	688.8
19.	Meters (478)	527.3	39.6	(12.7)	554.2	-	554.2	527.9
20.	Sub-Total	10,009.2	595.1	(36.5)	10,567.9	(3.1)	10,564.8	10,180.3
	EGD Rate Zone General Plant							
21.	Investment in leased assets (101)	11.6	3.6	-	15.3	-	15.3	13.3
22.	Lease improvements (482)	0.1	-	-	0.1	(0.2)	(0.1)	(0.1)
23.	Office furniture and equipment (483)	21.2	6.5	(0.9)	26.9	-	26.9	21.3
24.	Transportation equipment (484)	67.0	6.9	-	73.9	(0.1)	73.8	67.9
25.	NGV conversion kits (484)	2.9	0.1	-	3.1	-	3.1	3.0
26.	Heavy work equipment (485)	23.6	3.2	-	26.8	-	26.8	23.9
27.	Tools and work equipment (486)	61.3	7.8	(17.1)	51.9	-	51.9	51.7
28.	Rental equipment (487)	1.8	1.7	(1.0)	2.5	-	2.5	2.1
29.	NGV rental compressors (487)	3.6	0.5	(0.0)	4.0	-	4.0	3.8
30.	NGV cylinders (484 and 487)	0.6	-	-	0.6	-	0.6	0.6
31.	Communication structures & equip. (488)	1.8	0.1	-	2.0	-	2.0	1.9
32.	Computer equipment (490)	27.8	(0.5)	(26.4)	0.9	-	0.9	22.8
33.	Software Aquired/Developed (491)	239.8	38.6	(48.4)	230.0	-	230.0	218.8
34.	CIS (491)	14.1	(2.0)	-	12.2	-	12.2	12.2
35.	WAMS (489)	92.0	-	-	92.0	-	92.0	92.0
36.	Sub-Total	569.5	66.6	(93.9)	542.2	(0.3)	542.0	535.5

EGI UTILITY GROSS PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2022 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2021 ($Millions)	Col. 2 Additions ($Millions)	Col. 3 Retirements ($Millions)	Col. 4 Closing Balance Dec.2022 ($Millions)	Col. 5 Regulatory Adjustment ($Millions)	Col. 6 Utility Balance Dec.2022 ($Millions)	Col. 7 Average of Monthly Averages ($Millions)
	EGD Rate Zone Plant held for future use							
37.	Inactive services (102)	1.7	-	-	1.7	-	1.7	1.7
38.	EGD Rate Zone Total	11,134.6	711.4	(130.4)	11,715.7	(4.8)	11,710.9	11,282.7
	Union Rate Zones Intangible Plant							
39.	Franchises and consents (401)	1.2	-	-	1.2	-	1.2	1.2
40.	Other intangible plant (402)	0.5	-	-	0.5	-	0.5	0.5
41.	Sub-Total	1.7	-	-	1.7	-	1.7	1.7
	Union Rate Zones Local Storage Plant							
42.	Land (440)	0.0	-	-	0.0	-	0.0	0.0
43.	Structures and improvements (442)	5.9	0.0	(0.1)	5.8	-	5.8	5.9
44.	Gas holders - storage (443)	5.4	0.0	-	5.5	-	5.5	5.4
45.	Gas holders - equipment (443)	20.2	0.0	(0.0)	20.2	-	20.2	20.2
46.	Regulatory Overheads	2.1	0.2	-	2.3	-	2.3	2.2
47.	Sub-Total	33.6	0.3	(0.1)	33.8	-	33.8	33.7
	Union Rate Zones Underground Storage Plant							
48.	Land (450)	9.6	1.4	-	11.0	-	11.0	9.8
49.	Land rights (451)	32.0	0.0	-	32.0	-	32.0	32.0
50.	Structures and improvements (452)	70.2	0.5	(0.0)	70.7	-	70.7	70.2
51.	Wells (453)	49.1	0.1	-	49.2	-	49.2	49.1
52.	Field Lines (455)	51.1	3.2	-	54.3	-	54.3	51.4
53.	Compressor equipment (456)	473.0	6.1	-	479.1	-	479.1	474.0
54.	Measuring and regulating equipment (457)	62.8	0.3	(0.0)	63.1	-	63.1	62.7
55.	Base pressure gas (458)	36.2	-	-	36.2	-	36.2	36.2
56.	Regulatory Overheads	21.7	6.0	-	27.7	-	27.7	24.1
57.	Sub-Total	805.8	17.6	(0.0)	823.4	-	823.4	809.6
	Union Rate Zones Transmission Plant							
58.	Land (460)	84.7	0.9	-	85.7	-	85.7	85.0
59.	Land rights (461)	68.3	0.2	-	68.6	-	68.6	68.4
60.	Structures & improvements (462/463/464)	167.1	1.2	-	168.2	-	168.2	167.2
61.	Mains (465)	2,012.3	58.1	(4.1)	2,066.3	-	2,066.3	2,024.4
62.	Compressor equipment (466)	945.7	13.1	-	958.7	-	958.7	946.7
63.	Measuring & regulating equipment (467)	366.0	53.1	(0.3)	418.8	-	418.8	378.2
64.	Line Pack Gas	7.5	(0.3)	-	7.2	-	7.2	7.3
65.	Regulatory Overheads	231.5	28.8	-	260.4	-	260.4	242.7
66.	Sub-Total	3,883.1	155.2	(4.4)	4,033.9	-	4,033.9	3,919.8

EGI UTILITY GROSS PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2022 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2021	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2022	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2022	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Union Rate Zones Distribution Plant - Southern Operations							
67.	Land (470)	16.7	1.8	-	18.5	-	18.5	17.4
68.	Land rights (471)	9.1	1.8	-	10.9	-	10.9	9.5
69.	Structures and improvements (472)	146.2	9.7	-	155.8	-	155.8	148.6
70.	Services - metallic (473)	130.5	9.2	(0.3)	139.3	-	139.3	132.8
71.	Services - plastic (473)	996.0	44.4	(1.8)	1,038.5	-	1,038.5	1,015.4
72.	Regulators (474)	104.8	12.9	(5.4)	112.2	-	112.2	112.1
73.	House regulators & meter installations (474)	87.2	2.7	-	89.9	-	89.9	87.6
74.	Mains - metallic (475)	684.3	41.2	(0.9)	724.6	-	724.6	699.5
75.	Mains - plastic (475)	750.3	53.9	(0.5)	803.7	-	803.7	768.3
76.	Measuring & regulating equipment (477)	73.4	17.9	-	91.3	-	91.3	77.7
77.	Meters (478)	391.4	31.5	(8.6)	414.3	-	414.3	398.1
78.	Regulator Overheads	355.6	51.0	-	406.6	-	406.6	376.5
79.	Sub-total	3,745.4	277.8	(17.6)	4,005.6	-	4,005.6	3,843.6
	Union Rate Zones Distribution Plant - Northern & Eastern Operations							
80.	Land (470)	5.3	1.1	-	6.3	-	6.3	5.9
81.	Land rights (471)	10.9	0.4	-	11.3	-	11.3	11.1
82.	Structures and improvements (472)	71.4	2.5	-	73.9	-	73.9	71.9
83.	Services - metallic (473)	111.2	2.2	(0.2)	113.2	-	113.2	111.8
84.	Services - plastic (473)	505.8	16.4	(0.8)	521.3	-	521.3	512.2
85.	Regulators (474)	37.7	3.7	(2.0)	39.4	-	39.4	38.3
86.	House regulators & meter installations (474)	42.3	3.6	-	45.9	-	45.9	43.4
87.	Mains - metallic (475)	719.9	76.2	(0.8)	795.3	-	795.3	736.9
88.	Mains - plastic (475)	246.3	5.1	(0.2)	251.2	-	251.2	247.8
89.	Measuring & regulating equipment (477)	155.5	6.3	-	161.8	-	161.8	157.6
90.	Meters (478)	102.2	7.9	(1.3)	108.8	-	108.8	104.1
91.	Regulator Overheads	205.6	32.7	-	238.3	-	238.3	217.2
92.	Sub-total	2,214.1	158.2	(5.3)	2,366.9	-	2,366.9	2,258.3

EGI UTILITY GROSS PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2022 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2021	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2022	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2022	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Union Rate Zones General Plant							
93.	Land (480)	0.5	-	-	0.5	-	0.5	0.5
94.	Structures & improvements (482)	90.0	8.5	-	98.5	-	98.5	90.1
95.	Office furniture and equipment (483)	9.3	0.5	(2.0)	7.8	-	7.8	7.8
96.	Office equipment - computers (483)	113.2	22.7	(35.5)	100.4	-	100.4	124.7
97.	Transportation equipment (484)	65.9	8.0	(5.3)	68.5	-	68.5	69.3
98.	Heavy work equipment (485)	21.0	3.6	(0.8)	23.8	-	23.8	22.3
99.	Tools and work equipment (486)	35.4	2.6	(4.5)	33.4	-	33.4	32.8
100.	NGV fuel equipment (487)	4.5	0.0	-	4.5	-	4.5	4.5
101.	Communication equipment (488)	9.5	0.1	(0.3)	9.3	-	9.3	9.5
102.	Regulatory Overheads	70.3	12.8	(3.8)	79.3	-	79.3	75.1
103.	Sub-total	419.6	58.8	(52.3)	426.1	-	426.1	436.6
104.	Union Rate Zones Total	11,103.3	667.9	(79.7)	11,691.4	-	11,691.4	11,303.2
105.	EGI Total	22,237.9	1,379.3	(210.1)	23,407.1	(4.8)	23,402.3	22,585.9

EGI UTILITY PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2022 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2021	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2022	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2022	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	EGD Rate Zone Underground Storage Plant								
1.	Land and gas storage rights (451)	(27.1)	(0.5)	-	-	(27.6)	-	(27.6)	(27.3)
2.	Structures and improvements (452)	(2.9)	(0.6)	-	-	(3.4)	0.1	(3.4)	(3.1)
3.	Wells (453)	(15.5)	(1.4)	-	-	(16.9)	-	(16.9)	(16.2)
4.	Well equipment (454)	(8.6)	(0.8)	-	-	(9.3)	-	(9.3)	(9.0)
5.	Field Lines (455)	(34.0)	(1.9)	-	-	(35.9)	-	(35.9)	(35.0)
6.	Compressor equipment (456)	(57.7)	(5.3)	-	-	(63.0)	0.3	(62.7)	(60.0)
7.	Measuring and regulating equipment (457)	(8.3)	(0.3)	-	-	(8.6)	-	(8.6)	(8.4)
8.	Sub-Total	(154.0)	(10.8)	-	-	(164.8)	0.3	(164.4)	(159.0)
	EGD Rate Zone Distribution Plant								
9.	Renewable Natural Gas (461)	-	(0.0)	-	-	(0.0)	-	(0.0)	(0.0)
10.	Land rights intangibles (471)	(6.5)	(0.8)	-	-	(7.2)	-	(7.2)	(6.9)
11.	Structures and improvements (472)	(49.2)	(10.9)	15.9	(7.0)	(51.2)	0.3	(50.9)	(49.1)
12.	Services, house reg & meter install. (473/474)	(1,142.4)	(81.2)	9.3	31.8	(1,182.5)	-	(1,182.5)	(1,164.4)
13.	Mains (475)	(1,461.9)	(115.9)	(28.8)	21.4	(1,585.2)	2.2	(1,583.0)	(1,506.1)
14.	NGV station compressors (476)	(3.6)	(0.3)	-	-	(3.9)	-	(3.9)	(3.7)
15.	Measuring and regulating equip. (477)	(257.9)	(16.0)	26.3	0.2	(247.4)	0.5	(246.9)	(252.9)
16.	Meters (478)	(323.0)	(44.1)	12.7	0.0	(354.3)	-	(354.3)	(340.1)
17.	Sub-Total	(3,244.4)	(269.1)	35.5	46.4	(3,431.7)	3.1	(3,428.7)	(3,323.1)
	EGD Rate Zone General Plant								
18.	Investment in leased assets (101)	-	(0.4)	-	-	(0.4)	-	(0.4)	(0.2)
19.	Lease improvements (482)	(0.1)	-	-	-	(0.1)	0.2	0.1	0.1
20.	Office furniture and equipment (483)	(14.8)	(4.4)	0.9	-	(18.3)	-	(18.3)	(15.9)
21.	Transportation equipment (484)	(37.2)	(6.9)	-	-	(44.1)	0.1	(44.1)	(40.5)
22.	NGV conversion kits (484)	0.2	(0.3)	-	-	(0.1)	-	(0.1)	0.0
23.	Heavy work equipment (485)	(6.8)	(0.8)	-	-	(7.5)	-	(7.5)	(7.2)
24.	Tools and work equipment (486)	(24.7)	(2.1)	17.1	-	(9.7)	-	(9.7)	(12.9)
25.	Rental equipment (487)	(1.1)	(0.0)	1.0	-	(0.1)	-	(0.1)	(0.3)
26.	NGV rental compressors (487)	(2.5)	(0.7)	0.0	-	(3.1)	-	(3.1)	(2.8)
27.	NGV cylinders (484 and 487)	(0.5)	(0.0)	-	-	(0.6)	-	(0.6)	(0.5)
28.	Communication structures & equip. (488)	0.1	(0.2)	-	-	(0.1)	-	(0.1)	0.0
29.	Computer equipment (490)	(27.0)	1.0	26.4	-	0.4	-	0.4	(21.6)
30.	Software Aquired/Developed (491)	(218.4)	(29.8)	48.4	-	(199.7)	-	(199.7)	(200.3)
31.	CIS (491)	(21.8)	12.4	-	-	(9.3)	-	(9.3)	(9.3)
32.	WAMS (489)	(47.6)	(9.2)	-	-	(56.8)	-	(56.8)	(52.2)
33.	Sub-Total	(402.1)	(41.3)	93.9	-	(349.5)	0.3	(349.2)	(363.4)

EGI UTILITY PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2022 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2021	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2022	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2022	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	EGD Rate Zone Plant held for future use								
34.	Inactive services (102)	(1.4)	(0.0)	-	-	(1.5)	-	(1.5)	(1.5)
35.	EGD Rate Zone Total	(3,801.9)	(321.3)	129.3	46.4	(3,947.5)	3.7	(3,943.8)	(3,846.9)
	Union Rate Zones Intangible Plant								
36.	Franchises and consents (401)	(1.0)	(0.1)	-	-	(1.0)	-	(1.0)	(1.0)
37.	Other intangible plant (402)	(0.5)	(0.0)	-	-	(0.5)	-	(0.5)	(0.5)
38.	Sub-Total	(1.5)	(0.1)	-	-	(1.5)	-	(1.5)	(1.5)
	Union Rate Zones Local Storage Plant								
39.	Structures and improvements (442)	(2.7)	(0.2)	0.1	-	(2.7)	-	(2.7)	(2.7)
40.	Gas holders - storage (443)	(3.9)	(0.1)	-	-	(4.1)	-	(4.1)	(4.0)
41.	Gas holders - equipment (443)	(11.0)	(0.7)	0.0	-	(11.7)	-	(11.7)	(11.3)
42.	Regulatory Overheads	(0.6)	(0.1)	-	-	(0.6)	-	(0.6)	(0.6)
43.	Sub-Total	(18.2)	(1.1)	0.1	-	(19.1)	-	(19.1)	(18.7)
	Union Rate Zones Underground Storage Plant								
44.	Land rights (451)	(18.8)	(0.7)	-	-	(19.4)	-	(19.4)	(19.1)
45.	Structures and improvements (452)	(43.9)	(1.8)	0.0	-	(45.6)	-	(45.6)	(44.7)
46.	Wells (453)	(34.2)	(1.2)	-	-	(35.4)	-	(35.4)	(34.8)
47.	Field Lines (455)	(29.6)	(1.3)	-	-	(30.9)	-	(30.9)	(30.3)
48.	Compressor equipment (456)	(168.2)	(12.7)	-	0.2	(180.7)	-	(180.7)	(174.5)
49.	Measuring & regulating equipment (457)	(43.0)	(1.9)	0.0	-	(44.9)	-	(44.9)	(44.0)
50.	Regulatory Overheads	(4.1)	(0.7)	-	-	(4.8)	-	(4.8)	(4.4)
51.	Sub-Total	(341.7)	(20.2)	0.0	0.2	(361.8)	-	(361.8)	(351.8)
	Union Rate Zones Transmission Plant								
52.	Land rights (461)	(19.3)	(1.2)	-	-	(20.5)	-	(20.5)	(19.9)
53.	Structures & improvements (462/463/464)	(46.8)	(3.4)	-	-	(50.2)	-	(50.2)	(48.5)
54.	Mains (465)	(697.3)	(40.0)	4.1	0.2	(733.0)	-	(733.0)	(717.1)
55.	Compressor equipment (466)	(324.3)	(30.6)	-	0.0	(354.9)	-	(354.9)	(339.6)
56.	Measuring & regulating equipment (467)	(116.2)	(9.8)	0.3	0.2	(125.5)	-	(125.5)	(121.0)
57.	Regulatory Overheads	(28.0)	(6.0)	-	-	(34.0)	-	(34.0)	(31.0)
58.	Sub-Total	(1,231.9)	(90.9)	4.4	0.4	(1,318.0)	-	(1,318.0)	(1,277.0)

EGI UTILITY PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2022 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2021	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2022	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2022	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Union Rate Zones Distribution Plant - Southern Operations								
59.	Land rights (471)	(2.4)	(0.2)	-	-	(2.6)	-	(2.6)	(2.5)
60.	Structures and improvements (472)	(47.4)	(3.3)	-	-	(50.7)	-	(50.7)	(49.0)
61.	Services - metallic (473)	(108.8)	(3.7)	0.3	2.0	(110.2)	-	(110.2)	(109.8)
62.	Services - plastic (473)	(444.5)	(25.4)	1.8	11.0	(457.1)	-	(457.1)	(452.3)
63.	Regulators (474)	(40.8)	(5.6)	5.4	-	(41.0)	-	(41.0)	(42.1)
64.	House regulators & meter installations (474)	(32.3)	(2.5)	-	0.1	(34.6)	-	(34.6)	(33.4)
65.	Mains - metallic (475)	(375.9)	(19.8)	0.9	1.9	(392.8)	-	(392.8)	(384.5)
66.	Mains - plastic (475)	(300.9)	(17.7)	0.5	0.2	(317.9)	-	(317.9)	(309.6)
67.	Measuring & regulating equipment (477)	(23.6)	(2.8)	-	0.3	(26.1)	-	(26.1)	(24.8)
68.	Meters (478)	(118.0)	(15.2)	8.6	0.0	(124.6)	-	(124.6)	(122.6)
69.	Regulator Overheads	(53.9)	(10.7)	-	-	(64.5)	-	(64.5)	(59.1)
70.	Sub-Total	(1,548.5)	(106.7)	17.6	15.6	(1,622.0)	-	(1,622.0)	(1,589.5)
	Union Rate Zones Distribution Plant - Northern & Eastern Operations								
71.	Land rights intangibles (471)	(4.5)	(0.2)	-	-	(4.7)	-	(4.7)	(4.6)
72.	Structures and improvements (472)	(28.3)	(1.7)	-	-	(30.1)	-	(30.1)	(29.2)
73.	Services - metallic (473)	(81.4)	(3.6)	0.2	0.4	(84.4)	-	(84.4)	(83.1)
74.	Services - plastic (473)	(230.7)	(13.3)	0.8	0.4	(242.8)	-	(242.8)	(237.2)
75.	Regulators (474)	(15.3)	(1.9)	2.0	0.0	(15.3)	-	(15.3)	(15.7)
76.	House regulators & meter installations (474)	(17.7)	(1.3)	-	0.1	(18.8)	-	(18.8)	(18.3)
77.	Mains - metallic (475)	(366.9)	(22.2)	0.8	1.3	(386.9)	-	(386.9)	(377.6)
78.	Mains - plastic (475)	(119.6)	(5.9)	0.2	0.0	(125.3)	-	(125.3)	(122.6)
79.	Measuring & regulating equipment (477)	(82.7)	(5.9)	-	0.1	(88.6)	-	(88.6)	(85.7)
80.	Meters (478)	(28.6)	(4.2)	1.3	(0.0)	(31.5)	-	(31.5)	(30.2)
81.	Regulator Overheads	(30.0)	(6.2)	-	-	(36.2)	-	(36.2)	(33.0)
82.	Sub-Total	(1,005.9)	(66.3)	5.3	2.3	(1,064.5)	-	(1,064.5)	(1,037.2)

EGI UTILITY PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2022 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2021	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2022	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2022	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Union Rate Zones General Plant								
83.	Structures & improvements (482)	(17.3)	(1.8)	-	-	(19.1)	-	(19.1)	(18.2)
84.	Office furniture and equipment (483)	(6.2)	(0.5)	2.0	-	(4.7)	-	(4.7)	(4.8)
85.	Office equipment - computers (483)	(47.1)	(23.6)	35.5	-	(35.2)	-	(35.2)	(57.0)
86.	Transportation equipment (484)	(52.8)	(9.0)	5.3	(0.7)	(57.2)	-	(57.2)	(57.5)
87.	Heavy work equipment (485)	(6.2)	(1.5)	0.8	-	(6.9)	-	(6.9)	(6.9)
88.	Tools and work equipment (486)	(17.2)	(2.2)	4.5	-	(14.9)	-	(14.9)	(14.7)
89.	NGV fuel equipment (487)	(1.6)	(0.2)	-	-	(1.7)	-	(1.7)	(1.6)
90.	Communication equipment (488)	(5.2)	(0.6)	0.3	-	(5.5)	-	(5.5)	(5.5)
91.	Regulatory Overheads	(27.5)	(7.5)	3.8	-	(31.2)	-	(31.2)	(31.0)
92.	Sub-Total	(181.0)	(47.0)	52.3	(0.7)	(176.4)	-	(176.4)	(197.4)
93.	Union Rate Zones Total	(4,328.6)	(332.4)	79.7	17.8	(4,563.5)	-	(4,563.5)	(4,473.1)
94.	EGI Total	(8,130.5)	(653.6)	209.1	64.1	(8,511.0)	3.7	(8,507.3)	(8,320.1)

EGI WORKING CAPITAL COMPONENTS
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2022 ACTUAL

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
Line No.		Materials and Supplies	ABC Receivable	Customer Security Deposits	Prepaid Expenses	Balancing Gas	Gas in Storage	Working Cash Allowance	Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	January 1	91.4	(10.0)	(65.1)	(0.8)	59.5	895.1	22.6	992.6
2.	January 31	94.0	(9.4)	(63.5)	(10.4)	59.5	759.9	22.6	852.6
3.	February	96.4	(18.5)	(62.7)	(1.6)	59.5	561.3	22.6	657.0
4.	March	97.9	(37.7)	(61.5)	2.9	59.5	397.2	22.6	481.0
5.	April	97.8	(32.0)	(61.5)	6.2	59.5	362.0	22.6	454.6
6.	May	103.8	(34.9)	(61.4)	6.4	59.5	479.5	22.6	575.5
7.	June	105.5	(37.9)	(61.1)	10.9	59.5	657.1	22.6	756.6
8.	July	107.2	(23.5)	(60.1)	6.7	59.5	1,155.8	22.6	1,268.1
9.	August	112.3	(14.1)	(59.2)	12.5	59.5	1,418.2	22.6	1,551.8
10.	September	112.9	(14.5)	(59.2)	16.6	59.5	1,614.3	22.6	1,752.1
11.	October	114.8	0.4	(59.3)	13.8	59.5	1,799.6	22.6	1,951.4
12.	November	95.2	3.4	(59.5)	9.4	59.5	1,697.0	22.6	1,827.6
13.	December	96.2	(18.5)	(59.9)	(0.1)	59.5	1,422.9	22.6	1,522.7
14.	Avg. of monthly avgs.	102.6	(19.4)	(61.0)	6.1	59.5	1,005.1	22.6	1,115.5

EGI SUMMARY OF CAPITAL STRUCTURE & COST OF CAPITAL
2022 ACTUAL

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5 (Col. 1x Col. 3)
		Utility Capital Structure				
Line No.		Principal	Component	Cost Rate	Return Component	Interest & Return
		($Millions)	%	%	%	($Millions)
1.	Long and Medium-Term Debt	9,049.8	58.84	4.25	2.502	384.9
2.	Short-Term Debt	794.3	5.16	2.31	0.119	18.4
3.	Total Debt	9,844.1	64.00		2.622	403.3
4.	Preference Shares	-	-	-	-	-
5.	Common Equity	5,537.3	36.00	10.16	3.658	562.6
6.	Total Rate Base	15,381.4	100.00		6.279	965.9

CALCULATION OF COST RATES
FOR EGI CAPITAL STRUCTURE COMPONENTS
2022 ACTUAL

Line No.			Col. 1 Average of Monthly Averages	Col. 2	Col. 3 Carrying Cost
			($Millions)		($Millions)
	Long and Medium-Term Debt				
1.	Debt Summary		9,375.3		394.6
2.	Unamortized Finance Costs		(97.7)		-
3.	(Profit)/Loss on Redemption		-		-
4.			9,277.6		394.6
5.	Percentage Allocation of Debt to Unregulated	2.46%	(227.8)		(9.7)
6.	Net Regulated Long and Medium-Term Debt		9,049.8		384.9
7.	Calculated Cost Rate			4.25%	
	Short-Term Debt				
8.	Calculated Cost Rate			2.31%	
	Preference Shares				
9.	Preference Share Summary		-		-
10.	Unamortized Finance Costs		-		-
11.	(Profit)/Loss on Redemption		-		-
12.			-		-
13.	Calculated Cost Rate			0.00%	
	Common Equity				
14.	Board Formula ROE			8.66%	
15.	Threshold before earnings sharing			1.50%	
16.	ROE for earnings sharing determination			10.16%	

EGI SUMMARY STATEMENT OF PRINCIPAL
AND CARRYING COST OF
TERM DEBT
2022 ACTUAL

Line No.	Coupon Rate	Maturity Date	Col. 1 Average of Monthly Averages Principal ($Millions)	Col. 2 Effective Cost Rate	Col. 3 Carrying Cost ($Millions)
Medium Term Notes					
1.	4.20%	June 2, 2044	250.0	4.24%	10.6
2.	4.20%	June 2, 2044	250.0	4.27%	10.7
3.	6.05%	September 2, 2038	300.0	6.10%	18.3
4.	4.88%	June 21, 2041	300.0	4.92%	14.8
5.	5.20%	July 23, 2040	250.0	5.27%	13.2
6.	3.79%	July 10, 2023	250.0	3.87%	9.7
7.	2.81%	June 1, 2026	250.0	2.87%	7.2
8.	3.80%	June 1, 2046	250.0	3.84%	9.6
9.	2.88%	November 22, 2027	250.0	2.95%	7.4
10.	3.59%	November 22, 2047	250.0	3.64%	9.1
11.	3.19%	September 17, 2025	200.0	3.26%	6.5
12.	5.46%	September 11, 2036	165.0	5.49%	9.1
13.	8.65%	November 10, 2025	125.0	8.77%	11.0
14.	4.85%	April 25, 2022	36.5	4.91%	1.8
15.	8.85%	October 2, 2025	20.0	8.97%	1.8
16.	7.60%	October 29, 2026	100.0	8.09%	8.1
17.	6.65%	November 3, 2027	100.0	6.71%	6.7
18.	6.10%	May 19, 2028	100.0	6.16%	6.2
19.	6.05%	July 5, 2023	100.0	6.38%	6.4
20.	6.90%	November 15, 2032	150.0	6.95%	10.4
21.	6.16%	December 16, 2033	150.0	6.18%	9.3
22.	5.21%	February 25, 2036	300.0	5.18%	15.5
23.	4.95%	November 22, 2050	200.0	4.99%	10.0
24.	4.95%	November 22, 2050	100.0	4.73%	4.7
25.	4.50%	November 23, 2043	200.0	4.20%	8.4
26.	3.15%	August 22, 2024	215.0	3.24%	7.0
27.	4.00%	August 22, 2044	215.0	3.89%	8.4
28.	4.00%	August 22, 2044	170.0	4.44%	7.5
29.	3.31%	September 11, 2025	400.0	3.62%	14.5
30.	2.50%	August 5, 2026	300.0	3.42%	10.3
31.	3.51%	November 29, 2047	300.0	3.53%	10.6
32.	2.37%	August 9, 2029	400.0	3.23%	12.9
33.	3.01%	August 9, 2049	300.0	3.03%	9.1
34.	2.90%	April 1, 2030	600.0	3.41%	20.4
35.	3.65%	April 1, 2050	600.0	3.67%	22.0
36.	2.35%	September 1, 2031	475.0	2.94%	14.0
37.	3.20%	September 1, 2051	425.0	3.22%	13.7
38.	4.15%	August 17, 2032	121.9	3.15%	3.8
39.	4.55%	August 17, 2052	121.9	4.52%	5.5
40.			9,290.3		386.2
Long-Term Debentures					
41.	9.85%	December 2, 2024	85.0	9.910%	8.4
42.			85.0		8.4
43.	Total Term Debt		9,375.3		394.6

EGI UNAMORTIZED DEBT DISCOUNT AND EXPENSE
AVERAGE OF MONTHLY AVERAGES

Line No.		Col. 1 Unamortized Debt Discount and Expense
		($Millions)
1.	January 1	118.3
2.	January 31	116.8
3.	February	115.6
4.	March	114.3
5.	April	113.1
6.	May	111.9
7.	June	110.7
8.	July	109.5
9.	August	72.6
10.	September	72.2
11.	October	71.3
12.	November	70.4
13.	December	69.5
14.	Average of Monthly Averages	97.7

RECONCILIATION OF AUDITED EGI INCOME (PER FINANCIAL STATEMENTS)
TO CORPORATE INCOME FOR UTILITY INCOME DETERMINATION PURPOSES
2022 ACTUAL

Line No.	($ millions)	Col. 1 Audited Income (as per Financial Statements)	Col. 2 Corporate Income (as per Utility Income Schedule)	Col. 3 Variance	Col. 4 Reference
	Operating Revenues				
1.	Gas sales and distribution	5,613.7	6,198.6		
2.	Storage, transportation and other	994.5	-		
3.	Transportation	-	146.2		
4.	Storage	-	179.4		
5.	Other operating revenue	-	71.8		
6.	Other Income	79.2	13.0		
7.	Total operating revenue	6,687.4	6,609.0	(78.4)	(a)
	Operating Expenses				
8.	Gas Costs	3,678.6	3,678.6	0.0	
9.	Operation and maintenance	1,226.9	1,028.0	(198.9)	(b)
10.	Depreciation and amortization expense	690.1	690.1	(0.0)	
11.	Fixed financing costs	-	3.5	3.5	(c)
12.	Municipal and other taxes	-	120.4	120.4	(d)
13.	Cost of service	5,595.6	5,520.6	(75.0)	
14.	Income before interest and income taxes	1,091.8	1,088.4	(3.4)	
15.	Interest and financing expenses	423.1	-	(423.1)	(e)
16.	Income before income taxes	668.7	1,088.4	419.7	
17.	Income taxes	68.6	-	(68.6)	(f)
18.	Net Income	600.1	1,088.4	488.3	

Col. 2 - Corporate income as reported in Exhibit B, Tab 1, Schedule 2, Column 1

a)	Audited Total Operating Revenue	6,687.4
	Reclassify pension related other revenue to O&M	(66.6)
	Reclassify EGD rate zone Open Bill and ABC T-service O&M against program revenues in other revenue	(12.2)
	Reclassify other expenses out of other income to O&M	0.4
	Corporate Total Operating Revenue	6,609.0
b)	Audited Operation and Maintenance	1,226.9
	Reclassify pension related other revenue to O&M	(66.6)
	Reclassify Municipal & Property Taxes out of O&M	(120.4)
	Reclassify EGD rate zone Open Bill and ABC T-service O&M against program revenues in other revenue	(12.2)
	Reclassify other expenses out of other income to O&M	0.4
	Corporate Operation and Maintenance	1,028.0
c)	Audited Fixed Financing Costs	-
	Reclassify fixed financing costs from interest and financing expenses	3.5
	Corporate Fixed Financing Costs	3.5
d)	Audited Municipal and Other Taxes	-
	Reclassify Municipal and other taxes included within O&M costs	120.4
	Corporate Municipal and Other Taxes	120.4
e)	Audited Interest and Financing expenses	423.1
	Reclassify fixed financing costs from interest and financing expenses	(3.5)
	Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure	(419.6)
	Corporate Interest and Financing expenses	0.0
f)	Audited Income Taxes	68.6
	Elimination of corporate income taxes which will be calculated on a utility stand-alone basis	(68.6)
	Corporate Income Taxes	-

DELIVERY REVENUE BY SERVICE TYPE, RATE CLASS AND SERVICE CLASS
ENBRIDGE GAS INC.

FOR THE YEAR ENDED DECEMBER 31, 2022

Line No.		Col. 1 Sales	Col. 2 ABC-T	Col. 3 ABC-Unbundled	Col. 4 Bundled-T	Col. 5 T-Service	Col. 6 Total
		Revenues ($ Millions)					
1	General Service						
2	Rate 1	982.7	15.0	0.0	0.1	0.0	997.8
3	Rate 6	319.0	82.8	0.0	31.7	0.0	433.6
4	Rate 9	(0.0)	-	0.0	-	0.0	(0.0)
5	Total EGD Rate Zone	1,301.7	97.8	0.0	31.8	0.0	1,431.4
6	Rate M1	500.6	18.5	0.0	1.7	0.0	520.7
7	Rate M2	38.2	26.4	0.0	16.5	0.0	81.2
8	Rate 01	188.2	8.2	0.0	1.0	0.0	197.4
9	Rate 10	11.6	6.9	0.0	5.0	0.3	23.8
10	Total Union Rate Zones	738.6	59.9	0.0	24.1	0.3	823.0
11	Total General Service	2,040.3	157.7	0.0	56.0	0.3	2,254.4
12	Wholesale - Utility						
13	Rate M9	0.7	0.0	0.0	1.3	0.0	1.9
14	Rate M10	0.0	0.0	0.0	0.0	0.0	0.0
15	Total Wholesale - Utility	0.7	0.0	0.0	1.3	0.0	2.0
16	Contract Sales						
17	Rate 100	0.7	0.4	0.0	1.2	0.0	2.3
18	Rate 110	3.6	5.5	0.0	27.3	0.0	36.5
19	Rate 115	0.0	0.0	0.0	6.8	0.0	6.9
20	Rate 125	0.0	0.0	0.0	0.0	12.2	12.2
21	Rate 135	0.2	0.3	0.0	1.1	0.0	1.6
22	Rate 145	0.1	0.2	0.0	1.4	0.0	1.7
23	Rate 170	0.1	0.2	0.0	3.2	0.0	3.5
24	Rate 200	3.3	0.0	0.0	1.5	0.0	4.8
25	Rate 300	0.0	0.0	0.0	0.0	0.1	0.1
26	Rate 315	0.0	0.0	0.0	0.0	0.0	0.0
27	Total EGD Rate Zone	8.0	6.7	0.0	42.6	12.3	69.6
28	Rate M4	4.7	2.8	0.0	27.6	0.0	35.1
29	Rate M7	2.6	1.2	0.0	23.3	0.0	27.0
30	Rate 20	0.9	0.1	0.0	3.1	23.7	27.8
31	Rate 100	0.0	0.0	0.0	0.0	11.9	11.9
32	Rate T-1	0.0	0.0	0.0	0.0	14.3	14.3
33	Rate T-2	0.0	0.0	0.0	0.0	80.8	80.8
34	Rate T-3	0.0	0.0	0.0	0.0	7.5	7.5
35	Rate M5	0.2	0.2	0.0	2.3	0.0	2.7
36	Rate 25	2.4	0.0	0.0	0.0	3.7	6.1
37	Rate 30	0.0	0.0	0.0	0.0	0.0	0.0
38	Total Union Rate Zones	10.8	4.4	0.0	56.3	141.9	213.4
39	Total Contract Sales	18.8	11.1	0.0	98.9	154.2	282.9
40	Subtotal	2,059.8	168.8	0.0	156.2	154.5	2,539.3
41	Accounting Adjustments:						
42	EGI Tax Variance						(29.9)
43	EGI Accounting Policy Change						(2.8)
44	EGD Average Use / Normalized Average Consumption						3.5
45	EGD Dawn Access COS (DACDA)						1.2
46	EGD Incremental Capital Module						(6.9)
47	EGD LRAM						0.1
48	EGD Febderal Carbon Program						0.9
49	EGD Greenhouse Gas Emissions Administration						0.1
50	Union Average Use / Normalized Average Consumption						6.4
51	Union Incremental Capital Module						(2.0)
52	Union Capital Pass-through						(2.9)
53	Union Parkway Obligation						(0.1)
54	Union LRAM						0.8
55	Union Federal Carbon Program						2.0
56	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues						(17.4)
57	Total Utility Revenue						2,492.0

DELIVERY REVENUE BY SERVICE TYPE, RATE CLASS AND SERVICE CLASS
ENBRIDGE GAS INC.

FOR THE YEAR ENDED DECEMBER 31, 2021

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
		Revenues ($ Millions)					
Line No.		Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
1	General Service						
2	Rate 1	920.6	16.4	0.0	(0.0)	0.0	937.0
3	Rate 6	288.5	78.0	0.0	28.4	0.0	394.9
4	Rate 9	0.0	0.0	0.0	0.0	0.0	0.0
5	Total EGD Rate Zone	1,209.1	94.4	0.0	28.4	0.0	1,331.8
6	Rate M1	463.7	16.9	0.0	1.4	0.0	482.0
7	Rate M2	33.0	20.7	0.0	14.2	0.0	67.9
8	Rate 01	173.9	7.4	0.0	0.9	0.0	182.2
9	Rate 10	10.5	5.8	0.0	4.4	0.2	21.0
10	Total Union Rate Zones	681.1	50.9	0.0	20.9	0.2	753.1
11	Total General Service	1,890.2	145.3	0.0	49.3	0.2	2,084.9
12	Wholesale - Utility						
13	Rate M9	0.7	0.0	0.0	1.0	0.0	1.7
14	Rate M10	0.0	0.0	0.0	0.0	0.0	0.0
15	Total Wholesale - Utility	0.7	0.0	0.0	1.0	0.0	1.7
16	Contract Sales						
17	Rate 100	0.6	0.3	0.0	1.1	0.0	2.0
18	Rate 110	2.6	4.6	0.0	24.0	0.0	31.2
19	Rate 115	0.0	0.0	0.0	5.4	0.0	5.4
20	Rate 125	0.0	0.0	0.0	0.0	11.9	11.9
21	Rate 135	0.2	0.2	0.0	1.2	0.0	1.5
22	Rate 145	0.0	0.1	0.0	1.5	0.0	1.7
23	Rate 170	0.1	0.2	0.0	2.6	0.0	2.9
24	Rate 200	3.2	0.0	0.0	1.6	0.0	4.9
25	Rate 300	0.0	0.0	0.0	0.0	0.1	0.1
26	Rate 315	0.0	0.0	0.0	0.0	0.0	0.0
27	Total EGD Rate Zone	6.7	5.4	0.0	37.4	11.9	61.5
28	Rate M4	4.0	2.3	0.0	26.5	0.0	32.8
29	Rate M7	2.3	0.5	0.0	20.7	0.0	23.4
30	Rate 20	0.8	0.1	0.0	3.0	20.7	24.7
31	Rate 100	0.0	0.0	0.0	0.0	11.5	11.5
32	Rate T-1	0.0	0.0	0.0	0.0	13.9	13.9
33	Rate T-2	0.0	0.0	0.0	0.0	75.9	75.9
34	Rate T-3	0.0	0.0	0.0	0.0	7.2	7.2
35	Rate M5	0.2	0.2	0.0	2.2	0.0	2.5
36	Rate 25	2.7	0.0	0.0	0.4	2.7	5.8
37	Rate 30	0.0	0.0	0.0	0.0	0.0	0.0
38	Total Union Rate Zones	9.9	3.1	0.0	52.8	131.9	197.7
39	Total Contract Sales	16.6	8.5	0.0	90.3	143.9	259.2
40	Subtotal	1,907.5	153.8	0.0	140.6	144.1	2,345.9
41	Accounting Adjustments:						
42	EGI Tax Variance						(18.0)
43	EGI Accounting Policy Change						(16.2)
44	EGD Average Use / Normalized Average Consumption						9.9
45	EGD Dawn Access COS (DACDA)						2.0
46	EGD Incremental Capital Module						0.2
47	EGD LRAM						0.0
48	EGD Febderal Carbon Program						0.7
49	EGD Greenhouse Gas Emissions Administration						0.1
50	Union Average Use / Normalized Average Consumption						16.0
51	Union Incremental Capital Module						(14.0)
52	Union Capital Pass-through						(4.4)
53	Union LRAM						0.7
54	Union Federal Carbon Program						1.5
55	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues						(17.2)
	Total Utility Revenue						2,307.3

CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
ENBRIDGE GAS INC.

FOR THE YEAR ENDED DECEMBER 31, 2021

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		Customer Meters			Throughput Volumes (10^3M^3)			Revenues ($ Millions)		
Line No.		Sales	T-Service	Total	Sales	T-Service	Total	Sales	T-Service	Total
1	General Service									
2	Rate 1	2,064,173	34,054	2,098,227	4,665,992	82,730	4,748,722	1,749.7	18.5	1,768.3
3	Rate 6	147,546	22,416	169,962	2,740,101	1,698,331	4,438,432	775.8	144.3	920.1
4	Rate 9	2	0	2	3	0	3	0.0	0.0	0.0
5	**Total EGD Rate Zone**	**2,211,721**	**56,470**	**2,268,191**	**7,406,097**	**1,781,061**	**9,187,158**	**2,525.6**	**162.8**	**2,688.3**
6	Rate M1	1,140,908	29,855	1,170,763	2,728,007	169,080	2,897,087	853.1	18.3	871.4
7	Rate M2	4,749	3,206	7,955	526,743	587,121	1,113,864	109.2	35.0	144.2
8	Rate 01	351,562	10,059	361,621	871,182	58,759	929,941	364.2	12.8	377.1
9	Rate 10	1,369	878	2,247	148,728	163,067	311,794	40.9	20.0	60.9
10	**Total Union Rate Zones**	**1,498,588**	**43,998**	**1,542,586**	**4,274,660**	**978,026**	**5,252,686**	**1,367.4**	**86.1**	**1,453.5**
11	**Total General Service**	**3,710,309**	**100,468**	**3,810,777**	**11,680,756**	**2,759,087**	**14,439,844**	**3,893.0**	**248.9**	**4,141.9**
12	Wholesale - Utility									
13	Rate M9	1	3	4	15,903	74,193	90,096	3.0	1.0	4.0
14	Rate M10	2	0	2	320	0	320	0.1	0.0	0.1
15	**Total Wholesale - Utility**	**3**	**3**	**6**	**16,223**	**74,193**	**90,415**	**3.1**	**1.0**	**4.1**
16	Contract Sales									
17	Rate 100	6	10	16	12,899	21,095	33,994	2.9	1.8	4.7
18	Rate 110	110	305	415	83,260	1,018,629	1,101,890	16.6	40.4	57.0
19	Rate 115	2	15	17	1,002	386,695	387,697	0.2	8.2	8.3
20	Rate 125	0	4	4	0	707,660	707,660	0.0	11.9	11.9
21	Rate 135	7	35	42	2,624	60,488	63,112	0.6	1.6	2.2
22	Rate 145	5	15	20	0	24,785	24,785	0.0	1.9	1.9
23	Rate 170	1	22	23	6,302	249,399	255,701	1.1	1.2	2.3
24	Rate 200	1	0	1	137,779	54,230	192,010	27.8	2.4	30.2
25	Rate 300	0	2	2	0	269	269	0.0	0.1	0.1
26	Rate 315	0	0	0	0	0	0	0.0	0.0	0.0
27	**Total EGD Rate Zone**	**132**	**408**	**540**	**243,868**	**2,523,251**	**2,767,118**	**49.2**	**69.4**	**118.6**
28	Rate M4	37	190	227	56,304	554,504	610,808	12.0	28.8	40.8
29	Rate M7	5	56	61	31,987	654,366	686,353	6.7	21.2	27.9
30	Rate 20	5	54	59	8,464	629,136	637,600	2.9	30.6	33.5
31	Rate 100	0	12	12	0	958,587	958,587	0.0	11.5	11.5
32	Rate T-1	0	39	39	0	453,007	453,007	0.0	13.9	13.9
33	Rate T-2	0	25	25	0	4,700,474	4,700,474	0.0	76.0	76.0
34	Rate T-3	0	1	1	0	241,187	241,187	0.0	7.2	7.2
35	Rate M5	4	34	38	4,043	59,468	63,511	0.8	2.3	3.1
36	Rate 25	37	30	67	79,188	64,709	143,898	15.6	3.1	18.8
37	Rate 30	0	0	0	0	0	0	0.0	0.0	0.0
38	**Total Union Rate Zones**	**88**	**441**	**529**	**179,987**	**8,315,439**	**8,495,425**	**38.0**	**194.7**	**232.7**
39	**Total Contract Sales**	**220**	**849**	**1,069**	**423,854**	**10,838,690**	**11,262,544**	**87.2**	**264.1**	**351.3**
40	**Subtotal**	**3,710,532**	**101,320**	**3,811,852**	**12,120,833**	**13,671,970**	**25,792,803**	**3,983.3**	**514.0**	**4,497.3**
41	**Accounting Adjustments:**									
42	EGI Tax Variance									(18.0)
43	EGI Accounting Policy Change									(16.2)
44	EGD Average Use / Normalized Average Consumption									15.4
45	EGD Dawn Access COS (DACDA)									2.0
46	EGD Incremental Capital Module									0.2
47	EGD LRAM									0.0
48	EGD Federal Carbon Program									0.7
49	EGD Greenhouse Gas Emissions Administration									0.1
50	EGD Transactional Services Revenue									12.0
51	Union Average Use / Normalized Average Consumption									19.0
52	Union Incremental Capital Module									(14.0)
53	Union Capital Pass-through									(4.4)
54	Union LRAM									0.7
55	Union Federal Carbon Program									1.5
56	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues									(17.2)
57	Miscellaneous									1.4
58	**Total Utility Revenue**									**4,480.6**

WEATHER NORMALIZED CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
ENBRIDGE GAS INC.

FOR THE YEAR ENDED DECEMBER 31, 2021

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		Customer Meters			Throughput Volumes (10^3M^3)			Revenues ($ Millions)		
Line No.		Sales	T-Service	Total	Sales	T-Service	Total	Sales	T-Service	Total
1	General Service									
2	Rate 1	2,064,173	34,054	2,098,227	4,930,993	86,477	5,017,470	1,810.6	18.9	1,829.5
3	Rate 6	147,546	22,416	169,962	2,899,533	1,806,248	4,705,781	807.3	152.6	959.9
4	Rate 9	2	0	2	3	0	3	0.0	0.0	0.0
5	**Total EGD Rate Zone**	**2,211,721**	**56,470**	**2,268,191**	**7,830,529**	**1,892,725**	**9,723,254**	**2,617.9**	**171.6**	**2,789.5**
6	Rate M1	1,140,908	29,855	1,170,763	2,901,101	179,808	3,080,909	881.4	18.7	900.1
7	Rate M2	4,749	3,206	7,955	559,108	623,195	1,182,303	114.6	36.8	151.4
8	Rate 01	351,562	10,059	361,621	935,043	63,066	998,109	381.5	13.4	395.0
9	Rate 10	1,369	878	2,247	157,870	173,090	330,960	43.0	21.1	64.1
10	**Total Union Rate Zones**	**1,498,588**	**43,998**	**1,542,586**	**4,553,121**	**1,039,160**	**5,592,281**	**1,420.5**	**90.1**	**1,510.6**
11	**Total General Service**	**3,710,309**	**100,468**	**3,810,777**	**12,383,650**	**2,931,885**	**15,315,535**	**4,038.4**	**261.6**	**4,300.1**
12	Wholesale - Utility									
13	Rate M9	1	3	4	15,903	74,193	90,096	3.0	1.0	4.0
14	Rate M10	2	0	2	320	0	320	0.1	0.0	0.1
15	**Total Wholesale - Utility**	**3**	**3**	**6**	**16,223**	**74,193**	**90,415**	**3.1**	**1.0**	**4.1**
16	Contract Sales									
17	Rate 100	6	10	16	12,899	21,095	33,994	2.9	1.8	4.7
18	Rate 110	110	305	415	83,587	1,020,335	1,103,922	16.7	40.4	57.1
19	Rate 115	2	15	17	1,011	386,733	387,744	0.2	8.2	8.4
20	Rate 125	0	4	4	0	707,660	707,660	0.0	11.9	11.9
21	Rate 135	7	35	42	2,624	60,488	63,112	0.6	1.6	2.2
22	Rate 145	5	15	20	29	24,912	24,941	0.0	1.9	1.9
23	Rate 170	1	22	23	6,302	250,441	256,744	1.1	1.3	2.3
24	Rate 200	1	0	1	145,763	54,230	199,994	29.1	2.4	31.5
25	Rate 300	0	2	2	0	269	269	0.0	0.1	0.1
26	Rate 315	0	0	0	0	0	0	0.0	0.0	0.0
27	**Total EGD Rate Zone**	**132**	**408**	**540**	**252,216**	**2,526,164**	**2,778,379**	**50.5**	**69.5**	**120.0**
28	Rate M4	37	190	227	56,304	554,504	610,808	12.0	28.8	40.8
29	Rate M7	5	56	61	31,987	654,366	686,353	6.7	21.2	27.9
30	Rate 20	5	54	59	8,464	629,136	637,600	2.9	30.6	33.5
31	Rate 100	0	12	12	0	958,587	958,587	0.0	11.5	11.5
32	Rate T-1	0	39	39	0	453,007	453,007	0.0	13.9	13.9
33	Rate T-2	0	25	25	0	4,700,474	4,700,474	0.0	76.0	76.0
34	Rate T-3	0	1	1	0	241,187	241,187	0.0	7.2	7.2
35	Rate M5	4	34	38	4,043	59,468	63,511	0.8	2.3	3.1
36	Rate 25	37	30	67	79,188	64,709	143,898	15.6	3.1	18.8
37	Rate 30	0	0	0	0	0	0	0.0	0.0	0.0
38	**Total Union Rate Zones**	**88**	**441**	**529**	**179,987**	**8,315,439**	**8,495,425**	**38.0**	**194.7**	**232.7**
39	**Total Contract Sales**	**220**	**849**	**1,069**	**432,202**	**10,841,602**	**11,273,805**	**88.5**	**264.1**	**352.7**
40	**Subtotal**	**3,710,532**	**101,320**	**3,811,852**	**12,832,075**	**13,847,680**	**26,679,755**	**4,130.0**	**526.8**	**4,656.8**
41	**Accounting Adjustments:**									
42	EGI Tax Variance									(18.0)
43	EGI Accounting Policy Change									(16.2)
44	EGD Average Use / Normalized Average Consumption									15.4
45	EGD Dawn Access COS (DACDA)									2.0
46	EGD Incremental Capital Module									0.2
47	EGD LRAM									0.0
48	EGD Federal Carbon Program									0.7
49	EGD Greenhouse Gas Emissions Administration									0.1
50	EGD Transactional Services Revenue									12.0
51	Union Average Use / Normalized Average Consumption									19.0
52	Union Incremental Capital Module									(14.0)
53	Union Capital Pass-through									(4.4)
54	Union LRAM									0.7
55	Union Federal Carbon Program									1.5
56	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues									(17.2)
57	Miscellaneous									1.4
58	**Total Utility Revenue**									**4,640.1**

CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
ENBRIDGE GAS INC.

FOR THE YEAR ENDED DECEMBER 31, 2020

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		Customer Meters			Throughput Volumes (10^3M^3)			Revenues ($ Millions)		
Line No.		Sales	T-Service	Total	Sales	T-Service	Total	Sales	T-Service	Total
1	General Service									
2	Rate 1	2,020,078	44,454	2,064,531	4,789,664	104,740	4,894,404	1,618.2	28.4	1,646.6
3	Rate 6	145,283	23,801	169,084	2,810,280	1,840,046	4,650,326	663.4	187.5	850.9
4	Rate 9	2	0	2	127	0	127	0.0	0.0	0.0
5	**Total EGD Rate Zone**	**2,165,363**	**68,254**	**2,233,617**	**7,600,071**	**1,944,786**	**9,544,857**	**2,281.6**	**215.9**	**2,497.5**
6	Rate M1	1,128,040	35,176	1,163,216	2,815,940	187,938	3,003,878	772.5	19.9	792.4
7	Rate M2	4,324	3,571	7,895	571,025	633,316	1,204,341	99.3	35.6	134.8
8	Rate 01	347,480	12,515	359,995	913,225	69,511	982,736	340.3	14.5	354.8
9	Rate 10	1,156	982	2,138	155,265	187,391	342,656	37.1	21.9	58.9
10	**Total Union Rate Zones**	**1,481,000**	**52,244**	**1,533,244**	**4,455,454**	**1,078,157**	**5,533,611**	**1,249.1**	**91.9**	**1,341.0**
11	**Total General Service**	**3,646,363**	**120,498**	**3,766,861**	**12,055,525**	**3,022,943**	**15,078,468**	**3,530.7**	**307.8**	**3,838.5**
12	Wholesale - Utility									
13	Rate M9	1	3	4	16,236	72,529	88,765	2.5	0.9	3.5
14	Rate M10	2	0	2	360	0	360	0.1	0.0	0.1
15	**Total Wholesale - Utility**	**3**	**3**	**6**	**16,596**	**72,529**	**89,125**	**2.6**	**0.9**	**3.5**
16	Contract Sales									
17	Rate 100	2	7	9	9,142	10,969	20,111	1.8	1.2	3.0
18	Rate 110	57	279	335	71,781	909,360	981,141	9.6	36.4	45.9
19	Rate 115	1	19	20	728	377,311	378,039	0.2	7.6	7.8
20	Rate 125	4	0	4	0	523,436	523,436	0.0	11.4	11.4
21	Rate 135	5	36	40	1,785	63,502	65,287	0.4	1.6	2.0
22	Rate 145	3	19	22	628	22,768	23,396	0.3	1.3	1.6
23	Rate 170	3	18	21	4,843	242,587	247,430	0.6	0.7	1.4
24	Rate 200	1	0	1	137,358	52,115	189,473	23.1	2.4	25.5
25	Rate 300	2	0	2	0	262	262	0.0	0.1	0.1
26	Rate 315		0	0		0	0		0.0	0.0
27	**Total EGD Rate Zone**	**77**	**377**	**454**	**226,265**	**2,202,309**	**2,428,574**	**36.0**	**62.6**	**98.7**
28	Rate M4	35	201	236	56,325	565,055	621,380	9.9	28.1	38.0
29	Rate M7	4	49	53	28,488	589,884	618,372	4.7	17.1	21.8
30	Rate 20 Storage	0	0	0	0	0	0	0.0	2.5	2.5
31	Rate 20 Transportation	4	53	57	9,423	769,053	778,476	3.1	27.5	30.6
32	Rate 100 Storage	0	0	0	0	0	0	0.0	0.0	0.0
33	Rate 100 Transportation	0	12	12	0	996,605	996,605	0.0	11.3	11.3
34	Rate T-1 Storage	0	0	0	0	0	0	0.0	1.4	1.4
35	Rate T-1 Transportation	0	39	39	0	430,312	430,312	0.0	12.2	12.2
36	Rate T-2 Storage	0	0	0	0	0	0	0.0	7.2	7.2
37	Rate T-2 Transportation	0	25	25	0	4,017,975	4,017,975	0.0	66.9	66.9
38	Rate T-3 Storage	0	0	0	0	0	0	0.0	1.4	1.4
39	Rate T-3 Transportation	0	1	1	0	264,209	264,209	0.0	5.8	5.8
40	Rate M5	5	33	38	2,712	59,105	61,817	0.4	2.1	2.6
41	Rate 25	38	26	64	29,990	62,848	92,838	5.0	2.8	7.8
42	Rate 30	0	0	0	0	0	0	0.0	0.0	0.0
43	**Total Union Rate Zones**	**86**	**439**	**525**	**126,938**	**7,755,045**	**7,881,983**	**23.1**	**186.2**	**209.4**
44	**Total Contract Sales**	**163**	**816**	**979**	**353,203**	**9,957,354**	**10,310,557**	**59.2**	**248.8**	**308.0**
45	**Subtotal**	**3,646,529**	**121,318**	**3,767,846**	**12,425,324**	**13,052,825**	**25,478,150**	**3,592.5**	**557.6**	**4,150.1**
46	**Accounting Adjustments:**									
47	EGI Tax Variance									(13.4)
48	EGI Accounting Policy Change									(14.0)
49	EGD Average Use/ Normalized Average Consumption									(4.6)
50	EGD Dawn Access Cost									2.1
51	EGD Incremental Capital Module									(0.3)
52	EGD Transactional Services Revenue									12.0
53	EGD LRAM									0.0
54	EGD Federal Carbon Program									0.6
55	EGD Greenhouse Gas Emissions Administration									0.2
56	EGD Reverse 2019 Gas Supply Plan Cost Consequences reversed									(3.9)
57	EGD Elimination of 2019 Gas Supply Plan Cost Consequences reversal									3.9
58	Union Average Use/ Normalized Average Consumption									7.2
59	Union Parkway Obligation Rate Variance									0.0
60	Union Incremental Capital Module									(5.6)
61	Union Capital Pass-through									(1.1)
62	Union LRAM									1.4
63	Union Federal Carbon Program									1.2
64	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues									(17.7)
66	Miscellaneous									0.7
67	**Total Utility Revenue**									**4,118.8**

WEATHER NORMALIZED CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
ENBRIDGE GAS INC.

FOR THE YEAR ENDED DECEMBER 31, 2020

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		Customer Meters			Throughput Volumes (10^3M^3)			Revenues ($ Millions)		
Line No.		Sales	T-Service	Total	Sales	T-Service	Total	Sales	T-Service	Total
1	General Service									
2	Rate 1	2,020,078	44,454	2,064,531	4,925,067	107,556	5,032,623	1,650.3	28.7	1,679.0
3	Rate 6	145,283	23,801	169,084	2,919,935	1,887,608	4,807,543	686.1	190.5	876.6
4	Rate 9	2	0	2	127	0	127	0.0	0.0	0.0
5	**Total EGD Rate Zone**	**2,165,363**	**68,254**	**2,233,617**	**7,845,129**	**1,995,164**	**9,840,293**	**2,336.4**	**219.2**	**2,555.6**
6	Rate M1	1,128,040	35,176	1,163,216	2,966,369	197,978	3,164,348	801.4	20.3	821.7
7	Rate M2	4,324	3,571	7,895	595,912	660,918	1,256,830	104.1	36.9	141.0
8	Rate 01	347,480	12,515	359,995	954,899	72,683	1,027,582	352.7	15.0	367.6
9	Rate 10	1,156	982	2,138	160,473	193,677	354,151	38.4	22.6	61.0
10	**Total Union Rate Zones**	**1,481,000**	**52,244**	**1,533,244**	**4,677,654**	**1,125,257**	**5,802,911**	**1,296.5**	**94.8**	**1,391.3**
11	**Total General Service**	**3,646,363**	**120,498**	**3,766,861**	**12,522,783**	**3,120,421**	**15,643,204**	**3,632.9**	**314.0**	**3,946.9**
12	Wholesale - Utility									
13	Rate M9	1	3	4	16,236	72,529	88,765	2.5	0.9	3.5
14	Rate M10	2	0	2	360	0	360	0.1	0.0	0.1
15	**Total Wholesale - Utility**	**3**	**3**	**6**	**16,596**	**72,529**	**89,125**	**2.6**	**0.9**	**3.5**
16	Contract Sales									
17	Rate 100	2	7	9	9,142	10,969	20,111	1.8	1.2	3.0
18	Rate 110	57	279	335	71,936	910,575	982,511	9.6	36.4	46.0
19	Rate 115	1	19	20	730	377,426	378,156	0.2	7.6	7.8
20	Rate 125	4	0	4	0	523,436	523,436	0.0	11.4	11.4
21	Rate 135	5	36	40	1,785	63,502	65,287	0.4	1.6	2.0
22	Rate 145	3	19	22	628	22,937	23,565	0.3	1.3	1.6
23	Rate 170	3	18	21	4,847	243,184	248,031	0.6	0.7	1.4
24	Rate 200	1	0	1	142,758	52,433	195,190	24.0	2.4	26.4
25	Rate 300	2	0	2	0	262	262	0.0	0.1	0.1
26	Rate 315		0	0		0	0		0.0	0.0
27	**Total EGD Rate Zone**	**77**	**377**	**454**	**231,825**	**2,204,724**	**2,436,549**	**36.9**	**62.7**	**99.6**
28	Rate M4	35	201	236	56,325	565,055	621,380	9.9	28.1	38.0
29	Rate M7	4	49	53	28,488	589,884	618,372	4.7	17.1	21.8
30	Rate 20 Storage	0	0	0	0	0	0	0.0	2.5	2.5
31	Rate 20 Transportation	4	53	57	9,423	769,053	778,476	3.1	27.5	30.6
32	Rate 100 Storage	0	0	0	0	0	0	0.0	0.0	0.0
33	Rate 100 Transportation	0	12	12	0	996,605	996,605	0.0	11.3	11.3
34	Rate T-1 Storage	0	0	0	0	0	0	0.0	1.4	1.4
35	Rate T-1 Transportation	0	39	39	0	430,312	430,312	0.0	12.2	12.2
36	Rate T-2 Storage	0	0	0	0	0	0	0.0	7.2	7.2
37	Rate T-2 Transportation	0	25	25	0	4,017,975	4,017,975	0.0	66.9	66.9
38	Rate T-3 Storage	0	0	0	0	0	0	0.0	1.4	1.4
39	Rate T-3 Transportation	0	1	1	0	264,209	264,209	0.0	5.8	5.8
40	Rate M5	5	33	38	2,712	59,105	61,817	0.4	2.1	2.6
41	Rate 25	38	26	64	29,990	62,848	92,838	5.0	2.8	7.8
42	Rate 30	0	0	0	0	0	0	0.0	0.0	0.0
43	**Total Union Rate Zones**	**86**	**439**	**525**	**126,938**	**7,755,045**	**7,881,983**	**23.1**	**186.2**	**209.4**
44	**Total Contract Sales**	**163**	**816**	**979**	**358,763**	**9,959,769**	**10,318,532**	**60.1**	**248.9**	**309.0**
45	**Subtotal**	**3,646,529**	**121,318**	**3,767,846**	**12,898,142**	**13,152,718**	**26,050,861**	**3,695.6**	**563.8**	**4,259.4**
46	**Accounting Adjustments:**									
47	EGI Tax Variance									(13.4)
	EGI Elimination of 2018 Tax Variance									0.0
48	EGI Accounting Policy Change									(14.0)
49	EGD Average Use/ Normalized Average Consumption									(4.6)
50	EGD Dawn Access Cost									2.1
51	EGD Incremental Capital Module									(0.3)
	EGD Elimination of 2018 Earnings Sharing Adjustment									0.0
52	EGD Transactional Services Revenue									12.0
53	EGD LRAM									0.0
54	EGD Federal Carbon Program									0.6
55	EGD Greenhouse Gas Emissions Administration									0.2
56	EGD Reverse 2019 Gas Supply Plan Cost Consequences									(3.9)
57	EGD Elimination of 2019 Gas Supply Plan Cost Consequences reversal									3.9
58	Union Average Use/ Normalized Average Consumption									7.2
59	Union Parkway Obligation Rate Variance									0.0
60	Union Incremental Capital Module									(5.6)
61	Union Capital Pass-through									(1.1)
62	Union LRAM									1.4
63	Union Federal Carbon Program									1.2
64	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues									(17.7)
66	Miscellaneous									0.7
67	**Total Utility Revenue**									**4,224.3**

EGI REVENUE FROM REGULATED STORAGE
& TRANSPORTATION OF GAS
2022 ACTUAL

Line No.	Particulars ($000s)	2020 Actual	2021 Actual	2022 Actual
	Revenue from Regulated Storage Services:			
1	C1 Off-Peak Storage	1,002	433	138
2	Supplemental Balancing Services	1,016	640	1,053
3	Gas Loans	1	1	(1)
4	C1 Short Term Firm Peak Storage	2,715	1,536	2,108
5	Short Term Storage and Balancing Services Deferral	907	3,577	3,732
6	Rate 325: Transmission, Compression, & Storage	1,988	2,169	2,303
7	Less: Elimination of charges between EGD and Union rate zones	(2,000)	(2,226)	(2,344)
8	Total Regulated Storage Revenue Net of Deferral	5,630	$ 6,130	$ 6,988
	Revenue from Regulated Transportation Services:			
9	M12 Transportation	206,677	206,637	213,050
10	M12-X Transportation	21,335	21,527	20,769
11	C1 Long Term Transportation	20,882	19,934	21,023
12	Rate 332: Gas Transmission	17,804	18,107	18,313
13	C1 Short Term Transportation	5,698	7,226	8,365
14	Gross Exchange Revenue	999	1,729	1,127
15	Rate 331: Gas Transmission	259	165	170
16	Rate 401: RNG Injection Service	0	0	111
16	M13 Local Production	122	157	173
17	M16 Transportation	1,089	926	986
18	M17 transportation	109	545	511
19	S&T:Transportation Carbon Facility Collection	1,931	2,692	4,196
20	Other S&T Revenue	1,580	1,440	1,407
21	Less: Elimination of charges between EGD and Union rate zones	(136,155)	(138,489)	(144,576)
22	Total Regulated Transportation Revenue Net of Deferral	142,330	$ 142,597	$ 145,627

EGI UTILITY OTHER REVENUE AND OTHER INCOME
2022 ACTUALS

Line No.	Particulars	Col. 1 2021 Utility Revenue ($Millions)	Col. 2 2022 Utility Revenue ($Millions)
1.	Late Payment Penalties	19.9	20.9
2.	Account Opening Charges	11.1	9.8
3.	Other Billing Revenue	3.2	9.7
4.	Customer Billing Revenue	34.1	40.4
5.	Open Bill Revenue	5.4	5.4
6.	Distributor Consolidated Billing and Direct Purchase Administration Charges	2.3	2.3
7.	Mid Market Transactions	1.2	1.4
8.	CNG Rental Revenue	1.8	1.6
9.	Other Operating Revenue	4.2	2.6
10.	Total Other Revenue	49.1	53.6
11.	Other Income (1)	0.9	(2.1)
12.	Total Other Revenue and Other Income	50.0	51.5

Notes:
(1) Includes Gain(Loss) on foreign exchange and Gain(Loss) on disposition of assets

UTILITY O&M

1. This evidence explains the drivers in the Utility Operating and Maintenance (O&M) expense change from 2021 to 2022.

2. Table 1 presents 2022 O&M expenses relative to the prior year. Appendix A is provided as required and agreed to by Enbridge Gas. As in 2021, Enbridge Gas provided an appendix reconciling 2022 O&M results presented in the format of Table 1 compared to formats previous to 2019. This appendix is only provided to satisfy a previous commitment and is not used for any internal analysis or other purpose. Enbridge Gas requests approval to not provided the Appendix A reconciliation going forward after this proceeding.

3. Overall, O&M expenses increased by $81.7 million primarily due to increases in Corporate Shared Services (CSS), Outside Services, Admin Expenses, and Miscellaneous Expenses. These increases were partially offset by decreases primarily in Integration-Related Costs, increased capitalization recovery on Non-CSS, Donations and Memberships and Compensations and Benefits.

Table 1

UTILITY O&M

Line No.	Col. 1 Expense Categories	Col. 2 2021 Actual ($M)	Col. 3 2022 Actual ($M)	Col. 4 $ change	Col. 5 % change
1	Compensation and Benefits	404.3	398.9	(5.5)	(1.4%)
2	Employee Related Services and Development	1.5	2.1	0.6	38.2%
3	Materials and Supplies	32.5	31.7	(0.7)	(2.3%)
4	Outside Services	232.1	271.3	39.1	16.9%
5	Transportation Related Repairs and Maintenance	5.7	7.4	1.7	30.8%
6	Vehicle Related Repairs and Maintenance	19.8	19.9	0.1	0.7%
7	Rents and Leases	11.1	12.6	1.5	13.6%
8	Telecommunications	0.2	0.2	(0.0)	(7.2%)
9	Travel and Entertainment	3.7	8.1	4.4	119.6%
10	Donations and Memberships	11.3	3.6	(7.8)	(68.9%)
11	Admin Expenses	(4.1)	2.9	7.0	(171.1%)
12	Allocations & Recoveries	(16.5)	(12.1)	4.4	(26.6%)
13	Corporate Shared Services (CSS)	218.1	285.2	67.1	30.8%
14	DSM	132.1	132.1	(0.0)	(0.0%)
15	Integration-Related Costs	49.8	30.8	(19.1)	(38.3%)
16	Miscellaneous Expense	9.8	16.4	6.6	67.9%
17	Capitalization on Non-CSS	(172.7)	(183.1)	(10.3)	6.0%
18	O&M Subtotal before Eliminations	938.7	1,028.0	89.4	9.5%
19	Donations	(3.6)	(1.1)	2.5	(68.3%)

Table 1 (continued)

UTILITY O&M

Line No.	Col. 1 Expense Categories	Col. 2 2021 Actual ($M)	Col. 3 2022 Actual ($M)	Col. 4 $ change	Col. 5 % change
20	CDM Program	0.0	0.0	0.0	
21	ABC T-service Program	(0.3)	(0.3)	0.0	0.0%
22	CF utility adjustment		(8.4)	(8.4)	
23	Other Eliminations	(0.1)	(0.3)	(0.2)	150.0%
24	Unregulated Adjustments	(14.1)	(15.6)	(1.6)	11.1%
25	Total Unregulated/Non-Utility Eliminations	(18.1)	(25.7)	(7.7)	42.3%
26	Total Net Utility O&M Expense	920.6	1002.3	81.7	8.9%

4. CSS costs (Line 13) include business functions such as Legal, Finance, Human Resources and Technology Information Services (TIS) that serve business units across the Enbridge enterprise. Costs are charged to the individual business units based on appropriate cost allocation in relation to the services received.

5. CSS costs were $67.1 million higher than the prior year primarily due to: a higher share price and stronger Enbridge Inc. performance that has resulted in higher LTIP and STIP, higher legislative benefit costs resulting from a year over year change in maximum contribution levels, higher TIS costs related to additional mandated cybersecurity costs and incremental sustainment costs related to the addition of 1.6 million customers to the CIS system in 2021. These variances were partially offset by higher overhead capitalization of CSS costs, lower pension costs and a decrease in insurance premium costs.

6. As noted above in Table 1 Line 22, Enbridge Gas eliminated from utility O&M $8.4 million in Central Function (CF) costs that were determined to not pass the

OEB Three Prong Test. As discussed in EB-2022-0200, Exhibit 4, Tab 4, Schedule 3, Enbridge Gas accepted the findings of Guidehouse in Attachment 3 which identified 2022 Budgeted costs that do not meet either Prong 1 or Prong 2 requirements of the OEB Three Prong Test. Enbridge Gas extended these findings to 2022 actuals. These costs were identified in the following CF categories: Corporate Development Office (CDO), Aviation, and Depreciation (related to Aviation and TIS assets). Please refer to Table 3, Note 2 for further details of the adjustments.

7. Outside services (Line 4) increased $39.1 million over the prior year primarily due to an increase in integrity spending as a result of a higher number of inspections resulting from risk modelling enhancements and also addressing the backlog of work created by COVID-19 impacts, higher locates costs due to higher contract prices as a result of tight labour conditions, higher regional spend due to catching up on work previously deferred due to pandemic restrictions (ex. customer facing work such as meter exchanges and inspections) and a return to typical annual levels of work, offset by lower third-party contract costs as a result of the CIS platform integration. The Vertex platform (which was the Union Gas CIS system) was decommissioned in June 2021 and customers were integrated onto the existing SAP CIS platform, which was already being utilized for EGD customers.

8. Admin Expenses (Line 11) increased $7.0 million primarily due to two drivers. First, the transfer of Union Gas Low-Income Energy Assistance Program (LEAP) amounts to the Admin Expenses category from the Donation and memberships category in 2022. And secondly, plant damages recoveries accounting changes were made to align with US GAAP ASC 606 accounting standards and has no impact on net income, presentation only.

9. Miscellaneous Expense (Line 16) increased $6.6 million over the prior year primarily due to increase in bad debt resulting from an increase in sales, changes in market conditions such as inflation, COVID-19, and no disconnections, as well as other economic factors.

10. Compensations and Benefits decreased by $5.5 million over the prior year primarily due to: lower pension cost and lower STIP (which is based on business unit performance/scorecards) resulting from a decrease in Enbridge Gas performance compared to 2021. These decreases were partially offset by increases in merit, higher FTEs, higher LTIP related to a higher share price and higher legislative benefit costs resulting from a year over year change in maximum contribution levels.

11. Donations and memberships (Lines 10 and 19) (after elimination of donations not deducted for utility purposes) decreased by $5.3 million over the prior year primarily due to transfer of Union Gas Low-Income Energy Assistance Program (LEAP) amounts to the Admin Expenses category, as discussed above. Sponsorships costs fluctuate in response to the timing of community needs and sponsorship opportunities.

12. Integration-related costs (Line 15) decreased by $19.1 million as integration initiatives start to wind-down in 2022, with 2023 being the final year of integration.

<u>1. 2022 Overhead Capitalization</u>

13. The following section describes total overhead capitalization for both CSS (included in Line 13) and non-CSS cost categories (Line 17).

14. Overhead capitalization applies to all expense categories except integration-related costs, which are fully expensed. Total overhead capitalization was $35.5 million more than the prior year (Table 2).

15. Non-CSS overhead capitalization increased by $10.3 million driven by the increases in O&M expenses noted in the previous section.

16. CSS overhead capitalization increased by $25.1 million from the prior year driven by the increases in CSS expenses noted in the previous section

Table 2

Total Overhead Capitalization Impact on O&M

Line No.	Categories	2021 Actual ($M)	2022 Actual ($M)	2022-2021 Variance ($M)
1	CSS-related Capitalization	(61.6)	(86.7)	(25.1)
2	Capitalization on Non-CSS	(172.7)	(183.1)	(10.3)
3	Total Overhead Capitalization	(234.3)	(269.7)	(35.5)

17. Similar to 2021 Filing, inbound allocations and outbound recoveries are no longer relevant for 2022 as all CSS costs are inbound to Enbridge Gas. Affiliates are similarly allocated their charges directly through Enbridge Inc. and not through Enbridge Gas. Table 3 summarizes the Total Corporate allocation, the CSS capitalization applied, and Total Net CSS. Variance explanations are as noted in previous sections.

Table 3

Central Functions Cost Allocations and CSS

Line No.	Categories	2021 ($M)	2022 ($M)	2021-2022 Variance ($M)
1	CF Cost Allocations (1)	279.7	371.9	92.2
2	Less: Utility CF Adjustment (2)		(8.4)	(8.4)
3	Utility CF Cost Allocations	279.7	363.5	83.8
4	Less: Capitalization of CSS (1)	(61.6)	(86.7)	(25.1)
5	Net Utility CSS	218.1	276.8	58.7

Note 1: Gross CF Cost Allocations ($371.9) less Capitalization of CSS ($86.7) = Net Corporate Shared Services - line 13 - Table 1 ($285.2).
Note 2: Utility CF Adjustment pertains to CF costs determined to not pass OEB Three-prong test and therefore eliminated from Utility results (Aviation $1.9 + Corporate Development Office (CDO) $1.9 + Depreciation (Aviation and TIS) $6.6 – Other $2.0 = $8.4).

RECONCILIATION OF UTILITY O&M SCHEDULE
2021 & 2022 Results

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
		2021 ACTUAL				2022 ACTUAL				2021-2022	2021-2022
Line No.	Expense Categories ($M)	2021 Previous Format	Central Functions Costs	DSM & Integration Costs	**2021 Revised**	2022 Previous Format	Central Functions Costs	DSM & Integration Costs	**2022 Revised**	$ change	% change
1	Compensation and Benefits	514.2	(78.3)	(31.6)	404.3	493.8	(69.6)	(25.3)	398.9	(5.4)	-1.3%
2	Employee Related Services and Development	5.1	(3.1)	(0.5)	1.5	6.2	(3.3)	(0.8)	2.1	0.6	38.2%
3	Materials and Supplies	97.7	(7.9)	(57.3)	32.5	52.2	(1.7)	(18.8)	31.7	(0.7)	-2.3%
4	Outside Services	364.0	(39.3)	(92.6)	232.1	440.0	(50.8)	(117.9)	271.3	39.1	16.9%
5	Transportation Related Repairs and Maintenance	9.2	(3.5)	(0.0)	5.7	9.4	(2.0)	(0.0)	7.4	1.7	30.8%
6	Vehicle Related Repairs and Maintenance	19.9	(0.0)	(0.1)	19.8	20.0	(0.0)	(0.0)	19.9	0.1	0.7%
7	Rents and Leases	12.5	(1.4)	0.0	11.1	14.9	(2.3)	-	12.6	1.5	13.6%
8	Telecommunications	2.5	(2.3)		0.2	0.2	-	(0.0)	0.2	(0.0)	-7.2%
9	Travel and Entertainment	4.1	(0.3)	(0.1)	3.7	9.6	(1.0)	(0.6)	8.1	4.4	119.6%
10	Donations and Memberships	12.4	(0.3)	(0.7)	11.3	4.7	(0.3)	(0.8)	3.6	(7.7)	-68.0%
11	Admin Expenses	(4.7)	(1.2)	1.7	(4.1)	0.0	(0.2)	3.1	2.9	7.0	-171.1%
12	Allocations & Recoveries	126.2	(142.1)	(0.7)	(16.5)	230.6	(242.2)	(0.5)	(12.1)	4.4	-26.6%
13	Corporate Shared Services (CSS)	0.0	218.1		218.1	-	285.2		285.2	67.1	30.8%
14	DSM	0.0		132.1	132.1	-		132.1	132.1	(0.0)	0.0%
15	Integration-Related Costs	0.0		49.8	49.8	(0.0)	1.3	29.5	30.8	(19.0)	- 38.1
16	Miscellaneous O&M Expense	9.8			9.8	16.2	0.1		16.4	6.6	%
17	Capitalization on non-CSS	(234.3)	61.5		(172.7)	(269.7)	86.7		(183.1)	(10.4)	67.9
18	O&M Subtotal before Eliminations	938.7	(0.0)	0.0	938.7	1028.0	(0.0)	0.0	1028.0	89.4	9.5% %
											6.0%
19	Donations	(3.6)			(3.6)	(1.1)			(1.1)	2.5	-68.3%
20	CDM Program	0.0			0.0	0.0			0.0	0.0	0.0%
21	ABC T-service Program	(0.3)			(0.3)	(0.3)			(0.3)	0.0	0.0%
22	CF utility adjustment					(8.4)			(8.4)	(8.4)	100.0
23	Other Eliminations	(0.1)			(0.1)	(0.3)			(0.3)	(0.2)	%
24	Unregulated Adjustments	(14.1)			(14.1)	(15.6)			(15.6)	(1.5)	150.0
25	Total Unregulated/Non-Utility Eliminations	(18.1)			(18.1)	(25.7)			(25.7)	(7.6)	42.0%
											10.9%
26	Total Net Utility O&M Expense	920.6			920.6	1002.3			1002.3	81.7	8.9%

UTILITY CAPITAL EXPENDITURES

1. The purpose of this evidence is to provide information on Enbridge Gas' 2022 utility capital expenditures within the EGD and Union rate zones.

Table 1
Summary of Capital Expenditures 2022 Actual
($millions)

	Col 1	Col 2	Col 3
	EGD	UG	TOTAL EGI
Distribution Plant	531.8	468.4	1,000.2
Transmission Plant	-	197.5	197.5
General & Other Plant	103.7	36.3	140.0
Underground Storage Plant	82.5	16.9	99.5
	718.0	719.1	1,437.1

2. The dollars presented are annual capital expenditures and are comparable to the presentation in the Asset Management Plan. Capital expenditures in ICM applications are presented on an in-service basis.

3. Tables 2 and 3 show the regulated expenditures by Asset Class for each of the rate zones. Further commentary regarding the year over year changes in capital expenditures are described by Asset Class in the narrative following Tables 2 and 3.

Table 2
EGD Rate Zone by Asset Class
($millions)

	Asset Class	2021	2022	Variance
A	Compression Stations	26.8	73.4	46.6
B	Customer Connections	172.0	183.8	11.8
C	Distribution Pipe	151.0	205.2	54.1
D	Distribution Stations	43.4	54.8	11.4
E	Fleet & Equipment	15.3	15.0	(0.3)
F	Growth - Distribution System Reinforcement	13.4	10.2	(3.2)
G	Real Estate & Workplace Services	40.2	46.5	6.3
H	Technology Information Services (TIS)	12.7	18.2	5.5
I	Transmission Pipe and Underground Storage	32.7	9.1	(23.6)
J	Utilization	34.8	44.6	9.9
K	EA Fixed Overhead	19.5	22.2	2.7
L	Capitalized Overheads	-	-	-
M	Integration Capital	44.8	24.0	(20.8)
N	Community Expansion	13.5	9.3	(4.2)
O	Other	10.1	1.6	(8.5)
	Total Capital Expenditures	630.4	718.0	87.6

Table 3
UG Rate Zone by Asset Class
($millions)

	Asset Class	2021	2022	Variance
A	Compression Stations	15.5	33.4	17.9
B	Customer Connections	88.7	113.2	24.5
C	Distribution Pipe	296.1	272.3	(23.8)
D	Distribution Stations	47.8	42.3	(5.5)
E	Fleet & Equipment	11.4	15.5	4.1
F	Growth - Distribution System Reinforcement	35.1	59.2	24.1
G	Real Estate & Workplace Services	30.3	17.9	(12.4)
H	Technology Information Services (TIS)	10.1	9.9	(0.3)
I	Transmission Pipe and Underground Storage	46.8	87.7	40.9
J	Utilization	45.9	53.7	7.9
K	EA Fixed Overhead	5.9	4.8	(1.1)
L	Capitalized Overheads	-	-	-
M	Integration Capital	42.7	4.7	(38.0)
N	Community Expansion	3.8	4.9	1.1
O	Other	0.3	(0.5)	(0.8)
	Total Capital Expenditures	680.4	719.1	38.7

1. Descriptions of Asset Classes and Year over Year Variances

4. Effective January 2021, Enbridge Gas is allocating capitalized overheads to projects based on the total pool of overheads and the total direct capital spend by rate zone. As a result, capitalized overheads are being reflected within the asset classes and will no longer be shown as a separate asset class. This is consistent with the presentation of overheads in the Asset Management Plan and ICM applications (as of 2021).

a) Compression Stations

- Enbridge Gas (Union rate zone) uses compressors to move natural gas throughout the natural gas transmission system by compressing natural gas into transmission pipelines designed for high pressure and flow. Compressors are also used for both rate zones to move gas in and out of underground storage reservoirs by providing a significant pressure increase at the expense of flow.

- Dehydration facilities are also included in the compression asset category. Dehydration facilities remove moisture from natural gas to ensure that the natural gas entering the transmission system meets the contractual standard of moisture content, and to avoid operational problems related to high moisture content. Enbridge Gas operates one liquified natural gas (LNG) facility, the LNG facility serves to provide reserve capacity and balance operational loads during peak periods.
- The EGD rate zone increased due primarily to the continuation of the SCOR Meter Area Upgrade Phase 2 project ($19.8M) and the Dawn to Corunna Replacement project ($37.8 million).
- The Union rate zone increased due to a turbine failure at Parkway C ($12.5 million). In addition, inflationary rates for labor and materials contributed to the increased cost to project work.

b) Customer Connections

- This asset class includes the addition of new customers based on new housing or business starts, customers converting to natural gas from another fuel source and equipment and service upgrades to accommodate load growth of existing customers. General customer growth costs include materials and installation of mains and services to attach new customers as well as the costs associated with the meter and regulator installation at the customers site.
- For both rate zones, there was an increase in customer connections in 2022 compared to 2021. In addition, the average cost for customer connection increased for both rate zones due to the inflation pressures for labor and materials.

c) <u>Distribution Pipe</u>

- This asset class includes the maintenance, replacement, and renewal of pipelines and piping components (such as valves and fittings) used to transport natural gas within the distribution system or to end-use customers. It includes steel and plastic pipe, as well as services to customers.
- The EGD rate zone increased due to the continuation of NPS 20 Lake Shore Replacement Cherry to Bathurst vintage steel replacement ($45.4 million) and advanced focus on Integrity work in 2022 compared to 2021.
- The Union rate zone decreased due to the completion of ICM projects executed in 2021 (London Lines ($41.9 million) and West portion of the Windsor Lines ($30.5 million) offset by increases to Integrity work in 2022 compared to 2021.

d) <u>Distribution Stations</u>

- These assets are typically above grade facilities designed to reduce the operating pressure of natural gas pipeline systems through pressure control and over pressure protection. These facilities are used to transmit and/or distribute natural gas to reduced operating pressure pipeline systems which supply natural gas to cities and towns.
- The EGD rate zone increased due to inflationary pressures for labor and materials and the execution of Brampton Gate Rebuild ($9.9 million) and Lisgar Gate ($0.9 million).
- The Union rate zone decreased due to the pacing of station replacements and rebuilds to compensate for the inflationary pressures for labor and materials in other asset classes.

e) Fleet & Equipment

- The Fleet, Equipment and Tools asset class includes the vehicles, trailers, heavy equipment and tools owned by Enbridge Gas to support its business needs.
- The EGD rate zone did not experience a significant variance from 2021 to 2022.
- The Union rate zone increased due to supply chain challenges associated with delivery delays ($0.6 million) and an increase in vehicle purchases across regions to align with company policy that was not met due to supply chain delays ($2.3 million).
- In addition, both rate zones' vehicles, equipment, and tools cost increased due to shortages and inflation rates.

f) Growth – Distribution System Reinforcement

- The Growth asset class includes reinforcements driven by customer and load growth.
- The EGD rate zone decreased due to the completion of the Royal Windsor Reinforcement project ($2.1 million) in 2021 and fewer projects in 2022.
- The Union rate zone increased due to large reinforcement projects executed in 2022: Geraldton NPS 6 ($8.1 million) and Ingersoll Transmission Station ($10.7 million).
- In addition, both rate zones' labor and materials cost increased due to inflation.

g) Real Estate and Workplace Services

- The Real Estate and Workplace Services (REWS) asset class includes properties (buildings and land) and furnishings.
- There is a base spend for each rate zone that supports building repairs and acquisition of furnishings. Variances are driven by the specific land

purchases and building renovations that occur in a given year. Land acquisitions are driven by market availability and are aligned with the long-term strategies described in the Asset Management Plan.

- The EGD rate zone increased due to the execution of the Brockville Operations Centre ($6.5 million).
- The Union rate zone decreased due to the pacing of 50 Keil Renovation to compensate for the inflationary pressures for labor and materials in other asset classes. In addition, development project approvals have delayed the progression of the execution of the London Building.

h) Technology Information Services

- The Technology Information Services (TIS) asset class includes:
  - General Hardware (Laptops/Desktops and Desktop sustainment equipment, networks, servers and security);
  - Specialized Hardware (to support specific business needs such as meter reading equipment, call center network devices);
  - Software assets consisting of packaged applications, developed applications, and application infrastructure software; and
  - Communications assets including mobile phones and field devices (such as GPS devices, push-to-talk radios, leak survey field technology, and truck modems).
- The EGD rate zone increased due to the execution of Green Button ($0.7M), Chatbot Enhancements & Migration to KoreAI 2022 ($0.8 million), MyAccount Enhancements ($1.1 million), GDS OT Cyber Security Integrity ($0.8 million), ConTrax Program ($1.0 million) in 2022.
- The Union rate zone did not experience a significant variance from 2021 to 2022.

i) Transmission Pipe and Underground Storage

- This asset class includes the pipelines that form the backbone of the gas transmission system as well as the underground storage reservoirs in St. Clair Township near Sarnia, Crowland Township in Welland, and in Chatham-Kent.
- The EGD rate zone decreased due to the completion of large replacement and improvement projects in 2021: MOP remediation at Wilksport & Wilksport and Ladysmith Interconnect ($10.3 million) and the LWLK Well Debris Filter ($2.5 million) and fewer overall projects in 2022. There were also fewer land acquisitions in 2022 compared to 2021.
- The UG rate zone increased due to the Panhandle Regional Expansion Project ($33.3 million) and Dawn to Cuthbert NPS 42 Replacement ($18.7 million).

j) Utilization

- The utilization asset class includes measurement & regulation systems at customer premises, below ground and internal piping systems after the meter, and customer-owned systems[1].
- Both rate zones increased to align pacing with the integrated policy for Government Inspection Program. In addition, both rate zones' labor and material costs increased for Meter Exchanges due to material shortages and inflation.

k) EA Fixed Overheads

- The EA fixed overhead asset class includes cost for Alliance partner overheads and district contractor pre-work costs. The increase is in the

[1] For customer owned systems that are downstream of the meter, the asset class is accountable for inspection at the time of initial installation and after re-introduction of gas. Maintenance and remediation of these assets are the responsibility of the customer.

EGD rate zone is due to a one-time fuel surcharge in 2022. The decrease in the Union rate zone is due to the timing of payments.

l) Capitalized Overheads

- As set out above, effective January 2021, Enbridge Gas is allocating capitalized overheads to projects based on the total pool of overheads and the total direct capital spend by rate zone. As a result, capitalized overheads are being reflected within the asset classes and will no longer shown as a separate asset class. This is consistent with the presentation of overheads in the Asset Management Plan and ICM applications (as of 2021).
- Total combined capitalized overheadsincreased by $32.4 million which includes a $8.6M increase to IDC as a result of increases to the OEB prescribed rate. The indirect overhead increases of $34.2 million are explained in Exhibit B, Tab 3, Schedule 1.

m) Integration Capital

- Integration capital includes expenditures required to integrate the two legacy companies. Enbridge Gas continues to evaluate projects to determine if they meet the criteria of integration capital: a one time incremental cost related to the amalgamation of the legacy utilities. Projects can be newly identified to address integration needs, or they may be driven by a need to replace an asset due to obsolescence. In either case, the project is classified as integration as it is driving a harmonized solution that adds value to the integrated utility. It is important to note that the work being addressed through some integration projects would have been required for either or both rate zones in the absence of amalgamation (because of factors such as obsolescence or growth), but the projects are nonetheless included as integration capital because the project is done for the amalgamated utility. An example of work related to integration expenditures would be the integration of the customer billing systems. These expenditures are excluded when calculating the thresholds for ICM capital.

- The decrease in the EGD rate zone is due to lower spend on the GTA West site as compared to 2021 as a result of purchasing land in advance of project construction.
- The decrease in the UG rate zone is due to the completion of the CIS Integration project in 2021 and lower spend on the Cost of Gas project in 2022 compared to 2021.

n) Community Expansion

- Community expansion provides natural gas services to communities not currently using natural gas. In response to the Ontario Energy Board's (OEB) initiative to address the Government of Ontario's desire to expand natural gas distribution systems to communities that currently do not have access to natural gas, Enbridge Gas has filed proposals with the OEB designed to facilitate enhanced access to natural gas for non-served rural, remote and First Nation communities, and businesses in Ontario.
- In the EGD rate zone, the decrease in spend is primarily related to lower spend on the Scugog Island project due to construction completion, offset by the start of design work for the Community Expansion Phase 2 projects.
- In the Union rate zone, the increase in spend is related to start of design work for the Community Expansion Phase 2 projects.

5. Tables 4 and 5 show the Asset Classes with storage spend for each rate zone and the allocation of costs between the regulated and unregulated segments of Enbridge Gas's storage operations. Both the EGD and Union rate zones have OEB approved policies and methodologies for unregulated storage allocations. Allocations are maintained at the individual asset level and updated annually to reflect additions and retirements to the assets. The allocations are applied to storage based capital projects in order to separate the regulated and unregulated costs. Regulated projects include indirect overhead allocations.

Table 4
EGD Rate Zone Storage by Asset Class 2022 Actual
($millions)

	Asset Class	Regulated	Unregulated
A	Compression Stations	73.4	1.0
B	Transmission Pipe and Underground Storage	9.1	13.5
	Total Capital Expenditures	82.5	14.5

6. EGD Rate Zone Compression Stations – significant projects related to EGD's regulated assets include Dawn to Corunna Replacement ($37.8 million), Corunna (SCOR) Meter Area Upgrade Phase 2 ($19.8 million), SCOR:60004-Fdn-Blk-Replace ($1.7 million), SCOR:810001 IDC-Replace ($1.5 million), SCOR:100MOD HdrValves-Replace ($1.3 million) and SCOR:62209-PSV-013-Incr Cap ($1.3 million).

7. EGD Rate Zone Transmission Pipe and Underground Storage – significant projects related to EGD's regulated assets include 2021 LAD MSand PL Upgrade ($1.6 million), NPS 16 WLK Trans Retrofit ($1.4 million), NPS 16 WLK Gathering Retrofit ($1.3 million) and PMKC:TKC68H New HWell ($1.0 million). Significant

unregulated projects include strategic land purchases ($2.4 million), PCOR:TC8 A1 Obs Well-Drill ($1.3 million) and various projects ($6.2 million) related to the 2021/2022 Storage Enhancement project (EB-2021-0079) which will increase the maximum operating pressure of the Corunna and Ladysmith pools. The Storage Enhancement projects are being executed in 2 phases in order to meet the growing market demand for incremental storage space.

Table 5
UG Rate Zone Storage by Asset Class
($millions)

	Asset Class	Regulated	Unregulated
A	Compression Stations	33.39	3.23
B	Transmission Pipe and Underground Storage	87.66	26.13
	Total Capital Expenditures	121.1	29.4

8. UG Rate Zone Compression Stations – significant projects related to UG's regulated assets include Parkway Plant C Turbine Failure ($12.5 million), Bright A2 Gas Generator Midlife Overhaul ($3.3 million), Lobo B Yard Suction Valve Replacement (OBV 1305) ($3.2 million), Dawn to Corunna Replacement (Dawn Tie-in) ($1.5 million), Dawn:5985 CV Piping & Improvements ($1.3 million) and Bright B Boiler Upgrade ($1.2 million). Unregulated projects include the Dawn Dehy Plant – Process Tank Replacement ($1.3 million).

9. UG Rate Zone Transmission Pipe and Underground Storage – significant projects related to UG's regulated assets include the Panhandle Regional Expansion Project ($33.3 million), Dawn to Cuthbert NPS 42 Replacement ($18.7 million), Dawn to Cuthbert ECDA to ILI Retrofit NPS 34 ($4.6 million), Dawn to Cuthbert ECDA to ILI Retrofit NPS 26 ($3.1 million), Trafalgar NPS 26 Line Lowering ($6.3 million) and Trafalgar NPS 34 Hamiton-Milton-Centre Rd Class Location Replacement

($6.3 million). The SE 21/22 LCOR:Payne Tie-In, Payne DP and NPS 24 Tie In Stn projects ($24.9 million) are unregulated projects and part of the 2nd phase of the Storage Enhancement project (EB-2021-0079) described in paragraph 7.

ENBRIDGE GAS

SUMMARY OF CAPITAL COST ALLOWANCE (CCA)

			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col 8	Col. 9	Col. 10	Col. 11
Line No.		Particulars ($000s)	UCC at Prior Year Filing EB-2022-0110	True-up from Filing to Tax Return	UCC At Beginning of Year	Total Additions	Total Additions Qualifying for Accel. CCA	Less: Lessor of Cost or Proceeds	Eligible CCA Additions**	Depreciable UCC Balance	Rate (%)	CCA FY2022	Ending UCC
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Class												
1.	1	Buildings, structures and improvements, services, meters, mains	2,206,746.7	-	2,206,746.7	-	-	-	-	2,206,746.7	4%	88,269.9	2,118,476.9
2.	1	Non-residential building acquired after March 19, 2007	140,204.4	(625.3)	139,579.1	24,119.1	24,119.1	-	36,178.6	175,757.7	6%	10,528.2	153,170.0
3.	2	Mains acquired before 1988	152,488.9	-	152,488.9	-	-	-	-	152,488.9	6%	9,149.3	143,339.5
4.	3	Buildings acquired before 1988	2,847.0	-	2,847.0	-	-	-	-	2,847.0	5%	142.4	2,704.7
5.	6	Other buildings	70.5	-	70.5	-	-	-	-	70.5	10%	7.0	63.4
6.	7	Compression equipment acquired after February 22, 2005	421,057.3	(1,746.6)	419,310.7	18,981.3	18,981.3	-	28,472.0	447,782.6	15%	67,167.4	371,124.6
7.	8	Compression assets, office furniture, equipment	165,420.1	6,635.1	172,055.2	90,158.5	90,158.5	-	135,237.8	307,293.0	20%	61,445.8	200,767.9
8.	10	Transportation, computer equipment	24,928.3	2,731.0	27,659.3	21,228.8	21,228.8	(864.3)	31,411.0	58,206.0	30%	17,430.4	30,593.4
9.	12	Computer software, small tools	1,521.5	(1,521.5)	-	43,997.0	43,553.6	-	43,775.3	43,775.3	100%	43,216.9	780.1
10.	13	Leasehold improvements	351.7	-	351.7	-	-	-	-	351.7	0%	212.1	139.6
11.	14.1	Intangibles	12,638.2	(4.9)	12,633.3	891.2	891.2	-	1,336.8	13,970.1	5%	698.5	12,826.0
12.	14.1	Intangibles (pre 2017)	43,522.7	(19.0)	43,503.7	-	-	-	-	43,503.7	7%	3,045.3	40,458.5
13.	17	Roads, sidewalk, parking lot or storage areas	462.4	-	462.4	-	-	-	-	462.4	8%	37.0	425.4
14.	38	Heavy work equipment	9,072.7	1,548.6	10,621.4	6,785.9	6,785.9	-	10,178.8	20,800.1	30%	6,228.8	11,178.4
15.	41	Storage assets	78,076.1	(5,944.6)	72,131.5	42,761.2	39,628.5	-	61,009.0	133,140.6	25%	33,285.1	81,607.6
16.	45	Computers - Hardware acquired after March 22, 2004	3.4	-	3.4	-	-	-	-	3.4	45%	1.6	1.9
17.	49	Transmission pipeline additions acquired after February 23, 2005	758,627.8	(214.1)	758,413.7	65,474.3	65,474.3	-	98,211.5	856,625.2	8%	68,530.0	755,358.0
18.	50	Computers hardware acquired after March 18, 2007	14,221.8	(5,782.4)	8,439.3	16,205.6	15,698.0	-	23,800.9	32,240.2	55%	17,678.2	6,966.8
19.	51	Distribution pipelines acquired after March 18, 2007	5,724,879.9	(14,187.9)	5,710,692.0	923,232.9	923,232.9	(7,651.4)	1,381,023.7	7,084,064.3	6%	425,043.9	6,201,229.7
20.	Total		9,757,141.6	(19,131.6)	9,738,009.9	1,253,835.9	1,249,752.1	(8,515.7)	1,850,635.4	11,580,129.6		852,117.7	10,131,212.4

ACCOUNTS NOT BEING REQUESTED FOR CLEARANCE

1. The Company is not seeking clearance of the following accounts in this proceeding. For the following accounts, Enbridge Gas will carry the balances forward and seek clearance in appropriate future proceedings:
   - Accounting Policy Changes Deferral Account - EGI
   - Tax Variance Deferral Account – Integration-related Balances - EGI
   - Impacts Arising from the COVID-19 Emergency Deferral Account - EGI
   - Incremental Capital Module Deferral Account - EGD Rate Zone
   - Incremental Capital Module Deferral Account - Union Rate Zones
   - Renewable Natural Gas Injection Service Variance Account – EGD Rate Zone

2. The following accounts of Enbridge Gas have zero balances and are therefore not requested for clearance:
   - IRP Capital Costs Deferral Account - EGI
   - Earnings Sharing Mechanism Deferral Account - EGI
   - Expansion of Natural Gas Distribution Systems Variance Account – EGI
   - Green Button Initiative Deferral Account - EGI

ENBRIDGE GAS – ACCOUNTING POLICY CHANGES DEFERRAL ACCOUNT (APCDA) (No. 179-381)

1. On August 30, 2018 the OEB issued its Decision and Order for the amalgamation and rate setting mechanism (the MAADs Decision) approving the amalgamation of Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union) and the rate-setting framework[1]. In its Decision, the OEB established a deferral account to record the impact of any accounting changes required as a result of amalgamation that affect the revenue requirement.[2] The OEB approved wording of the accounting order for the Accounting Policy Changes Deferral Account (APCDA) effective January 1, 2019 in its Decision and Order on Enbridge Gas' 2019 Rates application[3].

2. As per the EB-2020-0134 Decision on Settlement Proposal, as part of the settlement proposal, parties agreed to defer the review, allocation and disposition of all balances in the APCDA until the end of Enbridge Gas's deferred rebasing term (2023). Parties noted that they required more information regarding the treatment of the balances and the extent of rate harmonization post-rebasing before approval of the balances and the disposition methodology can be considered[4].

3. The Company continues to track the annual revenue requirement impact of accounting policy changes made as of the amalgamation date, January 1, 2019, as well as any further accounting policy changes adopted since that time. The cumulative balance of the APCDA as of December 31, 2022 is a receivable of $192.638 million, driven by the revenue requirement impact of six accounting changes arising from (and since) amalgamation, which are detailed in the table below. The table categorizes each of the accounting policy changes, provides the cumulative opening balance as of the beginning of the period, details the current

[1] EB-2017-0306/0307, MAAD's Decision and Order dated August 30, 2018; The Decision and Order was later amended by the OEB on September 17, 2018 with no material changes.
[2] EB-2017-0306/0307, MAAD's Decision and Order dated August 30, 2018, p. 47.
[3] EB-2018-0305, 2019 Rates Final Rate Order dated October 24, 2019, Appendix I, p. 7.
[4] EB-2020-0134, Decision on Setlement Proposal dated January 25, 2021, pp. 4-5.

period revenue requirement impact being added to the cumulative balance, and finally provides the ending cumulative balance as of the end of the current period. The details of each item within the table below are described further in the remaining evidence presented.

4. Please refer to Exhibit C, Tab 1, Schedule 2 for the detailed 2022 revenue requirement calculation of the items presented above.

Table 1
Revenue Requirement
($millions)

	Capitalization vs Expense	Interest During Construction	Depreciation Expense	Overhead Capitalization	Amortized Gas Supply Storage and Transportation Costs	**Subtotal**	Pension Expense	**Total**
Balance at December 31, 2021	(4.410)	1.349	(16.056)	(11.288)	-	**(30.404)**	169.432	**139.027**
Impact to 2022 revenue requirement:								
Expense	(8.853)	0.093	(2.749)	9.412	62.155	**60.057**	(9.143)	**50.914**
Cost of capital	0.413	0.007	1.150	0.861	-	**2.432**	-	**2.432**
Income tax	(0.210)	(0.848)	(0.804)	2.124	-	**0.263**	-	**0.263**
Total	**(8.6495)**	**(0.7477)**	**(2.4031)**	**12.3979**	**62.155**	**62.753**	**(9.143)**	**53.610**
Balance at December 31, 2022	**(13.059)**	**0.601**	**(18.459)**	**1.110**	**62.155**	**32.348**	**160.289**	**192.638**

1. Capitalization vs Expense

5. Capitalization policies differed between EGD and Union with respect to whether the following items were capitalized or expensed as incurred:

	Union Policy	EGD Policy	EGI Policy
• Verification of Maximum Operating Pressure Program (“MOP”); • Customer Assets Programs (Low Pressure Delivery Meter Set and Farm Tap Programs); • Distribution Integrity Technology; • Distribution Records Management Program; and,	Expensed as incurred	Capitalized	Expensed as incurred
• Integrity Digs resulting from integrity inspections	Expensed as incurred	Capitalized	Capitalize

6. Upon amalgamation, it was necessary for Enbridge Gas to align its capitalization policies where differences existed between legacy EGD and legacy Union. The policy alignment resulted in a net impact in 2022 between UGL and EGD Rate Zones of:
   - Lower O&M expense of approximately $8.902 million, offset by higher capitalization; and,
   - Gross revenue requirement decrease, or sufficiency of $8.650 million.

2. Interest During Construction

7. Interest During Construction (IDC) is a cost of constructing an asset which is included in the cost of property plant and equipment capitalized.[5] IDC is recovered in rates through depreciation expense, along with a return on rate base over the life of the asset. Both Union and EGD capitalized IDC in accordance with US GAAP, however, IDC calculation was different in the legacy utilities, as seen below:

[5] ASC 835-20-05-1.

	Union Policy	EGD Policy	EGI Policy
Threshold	IDC is only calculated on projects with capital spend of $1 million or greater, and that have a duration of greater than 12 months	No threshold – applied to all capital projects regardless of size and duration	No Threshold – applied to all capital projects regardless of size and duration
Rate	OEB prescribed interest rate for CWIP	Weighted average cost of debt (WACD)	OEB prescribed interest rate for CWIP

8. Upon amalgamation, it was necessary for Enbridge Gas to align its accounting treatment of IDC. The policy alignment resulted in the following for 2022:
    - Total 2022 net gross revenue requirement decrease, or sufficiency of $0.748 million.

3. Depreciation Expense

9. Depreciation rates for Union and EGD are based on depreciation studies that were approved by the OEB in prior proceedings. The respective depreciation studies for each EGD and Union Rate Zones continue to be used by Enbridge Gas.

10. Upon amalgamation, it was necessary for Enbridge Gas to align the depreciation policies of legacy EGD and legacy Union Gas with respect to how depreciation on assets is calculated.

Union Policy	EGD Policy	EGI Policy
Half year of depreciation in the first and last year of service, regardless of month the asset went into service	Begin depreciation the month after the asset goes into service, and stops the month after retirement	Begin depreciation the month after the asset goes into service, and stops the month after retirement

11. Since many projects go into service late in the year, the EGD/Enbridge Gas policy would typically result in a lower first year depreciation expense than following the Union policy.

12. The policy alignment resulted in an impact in 2022 specific only to the UGL Rate Zone of:
    - A decrease in depreciation expense of approximately $2.749 million; and,
    - A gross revenue requirement decrease, or sufficiency of $2.403 million.

4. Overhead Capitalization

13. Following amalgamation, the Company sought to harmonize its overhead capitalization methodology and retained Ernst and Young (EY) to carry out the study. EY's assessment was informed by historical legacy approaches, the amalgamated structure, US GAAP, the OEB's Uniform System of Accounts, and Enbridge's Enterprise Capitalization Policy. Recommendations of the study were implemented in January 2020. The study grouped costs into Operations Costs, Business Costs, Support Costs, and Pension and Benefits, each with their own capitalization treatment to more directly link with causal determinants of cost.

14. Prior to this harmonization, capitalized overheads in the legacy EGD approach were determined by the application of Departmental Labour Costs (DLC) rates and Administrative & General (A&G) rates to support costs for capital work in field operations and business support operations, as well as administrative functions that support the overall business. In legacy UG, annual updates were carried out for support groups where capitalization rates were derived from time spent on capital activity.

15. The APCDA isolates the impact of the overhead capitalization policy change. The calculation takes the annual O&M spend with the new harmonized rates and subtracts from it O&M spend using the legacy rates to determine the APCDA impact.

During 2022, the policy change results in an increase in O&M and offsetting decrease in capitalized overheads, with the revenue requirement impact recorded in the APCDA. The net impact (inclusive of a 2021 true-up) between UGL and EGD Rate Zones was:

- Higher net OM&A expenses of $8.575 million (offset by lower capitalization of overheads); and,
- A gross revenue requirement increase, or deficiency of $12.398 million

5. Amortized Gas Supply Storage and Transportation Costs

16. As described in Enbridge Gas' 2024 Rebasing Application[6], Enbridge Gas contracts with third parties for market-based storage and transportation capacity to transport gas to and from storage. Storage mainly facilitates the load balancing of Enbridge Gas's heat-sensitive customer base, but also allows annual transportation contracts to be utilized more effectively and lowers commodity costs to customers by injecting lower-priced supply during the summer, which is withdrawn to meet demand during the winter, when prices for supply are higher. These services are considered a component of the gas supply portfolio, and costs incurred are recovered through monthly gas supply rates charged to customers.

17. Enbridge Gas has historically expensed these costs in the EGD rate zone over the five-month winter period from November 1 to March 31 (which crosses over Enbridge Gas calendar fiscal years), while similar costs in the Union rate zones are expensed as incurred and accrued monthly over the calendar year. In the EGD rate zone, these monthly invoiced charges are initially accrued monthly and recognized as a prepaid cost when invoiced and accumulated monthly as part of total gas in storage inventory on the balance sheet. The charges are recorded as gas costs on the income statement over the five-month heating season period, beginning in November and ending in March, such that at the end of March, the balance in gas in storage inventory is zero.

[6] EB-2022-0200 Exhibit 9 Tab 2 Schedule 1, pp. 14-17.

18. In 2022, Enbridge Gas implemented financial system harmonization for recognition of gas costs in the general ledger. This system implementation aligned the expense recognition process for the monthly accrued charges based on calendar year recognition in line with the approach for the Union rate zones.

Union Policy	EGD Policy	EGI Policy
Costs expensed as incurred and accrued monthly over calendar year.	Costs expensed over the five-month winter period from November 1 to March 31.	Costs expensed as incurred and accrued monthly over calendar year.

19. The accrued balance ($62.155 million) at the end of 2022 in gas in storage (representing the inventory that would have been amortized from January 1 to March 31 in 2023), has been transferred to the APCDA resulting in no amounts being required to be amortized to gas cost expense in 2023.

20. The amount transferred to the APCDA represents costs incurred by Enbridge Gas in providing service to customers and does not reflect any change to the total annual revenue requirement of Enbridge Gas to provide gas supply storage and transportation service. The change in the accounting treatment does recognize a one-time transition to allow for consistent recovery of these gas supply storage and transportation costs for Enbridge Gas.

6. Pension Expense – Unamortized Actuarial Gains/Losses and Prior Service Costs

21. Prior to December 31, 2018, Union recorded actuarial gains/losses and past service costs (Actuarial Losses) in Accumulated Other Comprehensive Income (AOCI) and amortized the balance over the expected average remaining service life (EARSL) of employees in accordance with ASC 715-30-35-24. This amortization expense was part of pension cost that was recognized annually and included in the forecast that underpinned rates. As a result of the Enbridge Inc. (EI) and Spectra merger (the

Merger) on February 27, 2017, EI recorded the acquisition of Union through a purchase price allocation (PPA) in accordance with ASC 805. As a result, Union's pension assets were adjusted on EI's books to fair value and the unamortized Actuarial Losses of $250 million were reclassified from AOCI to Goodwill. These adjustments were not required to be pushed down[7] and were not pushed down to the Union stand alone financial statements. Therefore, this adjustment did not impact Union financial statements or accounting at the time of the merger.

22. Approximately $39 million of Actuarial Losses were amortized between February 27, 2017 and December 31, 2018, resulting in a balance of $211 million remaining in Union's AOCI at amalgamation (the Amalgamation) (January 1, 2019).

23. Upon amalgamation, US GAAP required the PPA recorded by Enbridge Inc. related to Union to be pushed down into the combined financial statements of Enbridge Gas.[8] This resulted in the remaining unamortized Actuarial Losses on Union's balance sheet to be reclassified from AOCI to Goodwill.

24. Although this appears to be a balance sheet reclassification only, the adjustment would have a significant impact on Enbridge Gas if not for regulatory accounting. AOCI is amortized as an annual expense whereas Goodwill is not. As such, this treatment would result in stranding the balance in Goodwill that would never be

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[7] *Pushdown accounting* refers to establishing a new basis of accounting in the separate financial statements of the acquired entity (or acquiree) after it is acquired. The acquisition adjustments recorded by the acquirer in a business combination under ASC Topic 805 are pushed down to the acquiree's separate financial statements.

[8] In accordance with *ASC 805-50-30-5*:*"When accounting for a transfer of assets or exchange of shares between entities under common control, the entity that receives the net assets or the equity interests shall initially measure the recognized assets and liabilities transferred at their carrying amounts in the accounts of the transferring entity at the date of transfer. If the carrying amounts of the assets and liabilities transferred differ from the historical cost of the parent of the entities under common control, for example, because pushdown accounting had not been applied, then the financial statements of the receiving entity shall reflect the transferred assets and liabilities at the historical cost of the parent of the entities under common control."*

expensed. This is an accounting change that occurred only because of the amalgamation. Otherwise, Union would have continued to amortize Actuarial Losses as pension expense, just as it had done in the past.

25. The change in accounting policy has not altered the fact that Union has incurred the Actuarial Losses and should recover these costs over time, as is currently approved by the OEB. As noted previously, the balances represent the accumulation of Actuarial Losses incurred in relation to the pension assets that Enbridge Gas needs to continue to fund through cash contributions to the pension plans. Enbridge Gas's funding requirements do not change simply because the accounting treatment has changed. Therefore, continued recovery in rates through the deferred rebasing period is appropriate and is consistent with the OEB's approved approach for utilities. As noted in the *"Report of the Ontario Energy Board – Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs – EB-2015-0040,"* accrual based accounting for pensions under ASC 715 would result in a match to actual cash contributions by the end of the life of the plans.

26. Accordingly, Enbridge Gas adjusted the opening balance sheet at January 1, 2019, to record the $211 million balance previously recognized as AOCI in the financial records of Enbridge Gas as a regulatory asset (within the APCDA). Enbridge Gas continues to draw down the regulatory asset by amortizing this balance as part of pension expense resulting in a regulatory asset balance of $160.289 million recognized in the APCDA at December 31, 2022. By continuing to follow this approach, Enbridge Gas ensures that its results during the deferred rebasing period reflect the accrual based pension expense recognized annually through amortization of the noted balance.

27. As noted in the EB-2020-0134 Interrogatory Response to LPMA[9], the amortization of actuarial gains/losses and past service costs is a component of accrual-based pension expense. Base rates for both the EGD and Union rate zones include a provision for accrual-based pension expenses as part of O&M. As communicated previously, commencing in 2019, the amortization of the unamortized actuarial gains/losses and past service costs through a drawdown of the pension balance in the APCDA results in the amortization continuing to form part of Enbridge Gas's overall pension expense, consistent to amortization that would have occurred prior to amalgamation.

28. Enbridge Gas proposes to continue the annual amortization and inclusion as part of the accrual based pension costs recognized as part of O&M expense (consistent with the amortization of actuarial gains/losses and past service costs incurred after the Enbridge/Spectra merger in 2017). This proposal will draw down the balance in the APCDA throughout the deferred rebasing period and will result in the recognition of annual pension expenses consistent with amounts that would have been recognized had the accounting change not been required (i.e. utility earnings are not impacted).

29. As indicated in 2019, 2020, and 2021, in a continuing effort to manage the impact to ratepayers, Enbridge Gas is continuing with this approach throughout the deferred rebasing period and has proposed a methodology for disposal of the residual balance in the APCDA related to pension costs at December 31, 2023, as part of rebasing[10].

[9] EB-2020-0134, Exhibit I.LPMA.4, p. 2.
[10] EB-2022-0200 Exhibit 9, Tab 2, Schedule 1.

ENBRIDGE GAS - TAX VARIANCE DEFERRAL ACCOUNT

1. Establishment of the Enbridge Gas Inc. - Tax Variance Deferral Account was approved in the OEB's 2019 Rates (EB-2018-0305) Final Rate Order[1]. The purpose of this account is to record 50% of the revenue requirement impact of any tax rate changes, versus the tax rates included in rates that affect Enbridge Gas. In accordance with the OEB's July 25, 2019 letter, *Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance*, also accumulated in this account is 100% of the revenue requirement impact of any changes in Capital Cost Allowance (CCA) that are not reflected in base rates. This includes impacts related to Bill C-97 CCA rule changes, which became effective November 21, 2018, as well as any future CCA changes instituted by relevant regulatory or taxation bodies. Tax rate and CCA rule change impacts recorded in the account will, however, exclude tax rate and rule change impacts that are captured through other deferral account mechanisms (i.e., through the Incremental Capital Module Deferral Account and respective Capital Pass-through Project Deferral Accounts).

2. The balance in the Enbridge Gas Tax Variance Deferral Account at the end of 2022 is comprised of the following:

[1] EB-2018-0305, Final Rate Order dated October 24, 2019, Appendix I, p.10.

Table 1
Details of TVDA Balances

	Amount ($ millions)
2021 True up to T2 Filing balance [2]	1.195
2022 Non-integration related balance[3]	28.042
Subtotal	29.237
2020 Integration related balance[4]	3.736
2021 Integration related balance[5]	10.179
2022 Integration related balance[6]	(6.883)
Subtotal	7.032
Total Balance	36.269

3. As noted above, the balance requested for clearance within this proceeding is a credit of $29.237 million, plus forecast interest of $1.724 million, for a total of $30.961 million. Of the principal balance in the account, $1.195 million relates to a true-up of the 2021 accelerated CCA impact which reflects the impact of a variance between the 2021 qualifying additions captured in the 2021 Enbridge Gas Tax Variance Deferral Account examined in the EB-2022-0110 proceeding, and the final 2021 qualifying additions supporting Enbridge Gas's 2021 tax filing. The 2022 balance of $28.042 million relates to the 2022 accelerated CCA impact on non-integration related assets and additions. The accelerated CCA impacts of Bill C-97 were the only tax rate changes that impacted 2022.

4. As noted in the account description, the Tax Variance Deferral Account does not include the accelerated CCA impacts related to capital pass-through and incremental capital module projects, which have been reflected in the determination of variances recorded in deferral accounts associated with those respective projects.

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[2] Seeking approval to dispose of balance in this proceeding.
[3] Seeking approval to dispose of balance in this proceeding.
[4] Balance to be carried forward through end of 2023 per direction in EB-2021-0149 Settlement Decision.
[5] Balance to be carried forward through end of 2023 in line with decision on 2020 integration related balance.
[6] Balance to be carried forward through end of 2023 in line with decision on 2020 integration related balance.

5. Consistent with the OEB's EB-2021-0149 Decision and Order, dated January 27, 2021, the Tax Variance Deferral Account balance also includes the balances above that relate to accelerated CCA impacts of capital additions related to amalgamation/integration capital projects. Please see Exhibit C, Tab 1, Schedule 3 for continuity schedules supporting the calculation and accumulation of the 2020, 2021, and 2022 accelerated CCA impacts of capital additions related to amalgamation/integration capital projects. As per the direction in the Decision and Order, Enbridge Gas will hold these cumulative balances in the account through 2023 and has proposed disposition within Enbridge Gas's 2024 rebasing application[7].

<u>1. Income Tax - Bill C-97 (Accelerated CCA) - Calculation</u>

6. To calculate the annual income tax (or earnings) impact of accelerated CCA, Enbridge Gas has maintained a continuity of the 2018 – 2022 total annual capital additions which have qualified for accelerated CCA, and then removed the annual additions related to capital pass-through and incremental capital module. For the remaining qualifying additions, the cumulative annual CCA has been calculated utilizing the accelerated rates and compared against the cumulative annual CCA calculated at the non-accelerated rates. The annual income tax (or earnings) impact of the variance between the two methodologies was then grossed-up for taxes to determine the annual revenue requirement impact. These annual impacts, representing 100% of the revenue requirement impact, have been recorded each year in the Enbridge Gas Inc. – Tax Variance Deferral Account. Please see Exhibit C, Tab 1, Schedule 3 for continuity schedules supporting the calculation of the 2022 accelerated CCA impact.

[7] EB-2022-0200 Exhibit 9, Tab 2, Schedule 1.

ENBRIDGE GAS – INTEGRATED RESOURCE PLANNNING OPERATING COSTS DEFERRAL ACCOUNT

1. On July 22, 2021, the OEB released its Decision and Order (EB-2020-0091) for Enbridge Gas' Integrated Resource Planning (IRP) Proposal. In this Decision, the OEB approved the establishment of an IRP Operating Costs Deferral Account for all IRP operations, maintenance, and administrations costs, and a separate IRP Capital Costs Deferral Account for IRP project plan costs.

2. On August 12, 2021, Enbridge Gas filed its draft accounting orders for the IRP Operating Costs Deferral Account and IRP Capital Cost Deferral Account. On September 2, 2021, the OEB found that the draft accounting orders were consistent with the Decision and Order and approved the accounts as filed.

3. The purpose of the IRP Operating Costs Deferral Account, as established in the OEB's EB-2020-0091 Decision and Order, is to record incremental IRP general administrative costs, as well as incremental operating and maintenance costs and ongoing evaluation costs for approved IRP Plans. Operating costs associated with approved IRP Plans would also include all enabling payments to service providers, made as part of the IRP Plans.

4. The balance in the 2022 IRP Operating Costs Deferral Account that is being requested for clearance within this proceeding is a debit of $2.159 million, plus forecast interest of $0.126 million, for a total debit of $2.285 million. This amount is attributable to incremental Enbridge Gas staff salaries including expenses for IRP related work performed in 2022, the implementation of IRP alternatives to defer a project in Kingston and non-labour costs such as consulting and legal costs. The OEB in its IRP Decision approved "incremental IRP administrative costs required to meet the increased workload related to IRP"[1] … 'be treated as expenses and recorded in this account [operating costs deferral account]."[2]

[1] EB-2020-0091, Decision and Order, p. 71.
[2] Ibid, p. 75.

5. Table 1 provides details and a breakdown of the expenditures included in the 2022 IRP Operational Deferral Account.

Table 1
Details of Expenditures – IRP

	Item	Description	Millions ($)
1	Incremental FTE's	Salaries and expenses	$1.773
2	East Kingston Creekford Rd Project	Project costs	$0.080
3	Posterity Group	Model enhancement costs	$0.169
4	Posterity Group	IRP Pilot costs	$0.028
5	Guidehouse	Jurisdictional Scan	$0.015
6	Guidehouse	DCF+ Study	$0.094
7	TOTAL		$2.159

1. Incremental Full Time Equivalent's and expenses:

6. In 2022, there was 13.5 Full Time Equivalent (FTE) additions and employee expenses associated with IRP, all of which are accounted for in the 2022 IRP Operating Costs Deferral Account. This is in addition to the 3 FTE IRP roles that are already captured in O&M. These 13.5 FTE roles perform IRP work that is incremental to what was performed by the organization prior to the IRP Decision.[3]

7. The incremental work that has arisen for the organization because of implementing the OEB's IRP Decision includes:
   - Binary screening and technical evaluations of facility projects in the Asset Management Plan and optimization of the AMP to include IRP Plans;
   - Economic analysis of those projects with a technically feasible IRPA(s);

[3] EB-2020-0091.

- Support the technical and economic evaluation of ETEE and demand response IRPAs, as well as design and, once approved, support the delivery and ongoing evaluation of IRP Plans, including Pilot Projects;
- Development and implementation of regional, geo-targeted and pilot specific IRP stakeholder engagement activities, as well as an increased level of direct engagement with a number of key IRP stakeholders; and
- Regulatory support for IRP Plans, and for traditional Leave-to-Construct (LTC) proceedings.

8. To ensure that IRP is considered and supported within the Community Engagement; Distribution Optimization Engineering (DOE); Asset Management; Demand Side Management (DSM); Regulatory; and Finance departments, IRP resources have been hired directly into their respective teams. These FTE's work closely with and under the guidance and oversight of the IRP team. This ensures a strong, ongoing, focus remains on the coordination and implementation of integrated resource planning across the organization.

9. Table 2 provides a description of the roles and responsibilities of the incremental IRP FTE's included in the 2022 IRP Operating Costs Deferral Account. The work completed as of the end of 2022 is outlined in the 2022 IRP Annual Report included as Exhibit H, Tab 1.

Table 2
Description of FTE Additions – IRP

Role	Number of FTEs	DEPT	Responsibilities
Senior Advisor / Advisor	2	Community Engagement	Manage, support and execute on the overall development and implementation of the stakeholder engagement components for IRP regional, geotargeted, and pilot specific engagements, including (1) planning and implementation of engagements, (2) gathering and incorporating stakeholder feedback from and into regional stakeholder plans, including for pilots projects, (3) Supporting the creation of IRP stakeholder specific communications materials, including website, webinars, invites, etc., and (4) assisting with the response to incoming stakeholder inquiries.
Senior Advisor / Engineer	2	Distribution Optimization Engineering (DOE)	Perform technical evaluations on projects that pass binary screening in the AMP, including: (1) model how each IRPA option, or combination of options, impacts the project needs and design to support IRP technical feasibility evaluations (2) support the development of IRP Plans, including pilot projects, by completing the system modeling required to understand the projects' needs and design, . (3) Lead the analysis of hourly data gathered from control groups and IRPA participants (where AMI is available) to support Enbridge Gas's ongoing development of design hour reduction assumptions for IRPAs.
Supervisor	1	Distribution Optimization Engineering (DOE)	Provide leadership and support for the DOE technical leads' work noted above. Provide technical expertise to the broader group of internal IRP resources as well as in external engagements.
Advisor	2	IRP	Support the development and filing of the annual IRP Report. Support the IRP Technical Working Group. Support IRP stakeholder and Indigenous engagement activities, including the IRP web/digital plans. Support the technical evaluations of facilities projects / IRP alternatives. Develop evidence for regulatory filings/proceedings related to IRP projects. Support the implementation of IRP Plans, including two pilot projects. Project manage internal activities associated with IRP Plans and LTC applications.
Specialist II	1	Asset Management	Liaison between Asset Class Managers and Integrated Resource Planning to complete binary screening of facility projects in the Asset Management Plan. Ensure adherence to stipulated timelines to support the consideration of IRPAs as part of the AMP process. Liaise with Asset Management Governance, Regulatory, and Public Affairs and Communications to ensure regulatory and stakeholder expectations around IRP are met during annual optimization/decision reporting activities. Support IRP Plan and traditional infrastructure proceedings to ensure compliance with the criteria set out in the IRP Decision[4]. Support Asset Management team in ongoing alignment of Asset Investment Strategies and Integrated Resource Planning strategies.

4 EB-2020-0091.

Table 2
Description of FTE Additions – IRP

Role	Number of FTEs	DEPT	Responsibilities
Senior Advisor	1	DSM	Support the technical and economic evaluation of ETEE and demand response IRPAs, as well as design and, once approved, support the delivery and ongoing evaluation of IRP Plans, including Pilot projects
Senior Advisor	2	Regulatory	Provides guidance specific to interpretation of the IRP Framework[5] for various departments within Enbridge Gas. Participate in project-specific discussions regarding Integrated Resource Planning considerations. For each Project where Enbridge Gas is required to apply to the OEB for LTC approval, review various aspects of integrated resource planning (including the conclusions drawn from the Binary Screening Criteria assessment, IRP alternatives assessment, etc.,) throughout the OEB proceeding including during evidence development, the development of responses to interrogatories, in oral or written argument, etc. Participate in discussions regarding preparations for IRP Technical Working Group meetings and responses to requests from the IRP Technical Working Group. Review, support and provide input to the development of the IRP Annual Report and deferral account applications. Manage Applications to the OEB for IRP Pilot Projects and all future IRP Plan approvals (including management of all aspects of the regulatory proceeding). Support Conditions of Approval reporting to the OEB as applicable to IRP Pilot Projects and IRP Plan Projects.
Specialist / Senior Advisor	2	Finance	Participate as core Enbridge Gas representatives on the IRP Technical Working Group, specific to the Discounted Cash Flow (DCF+) methodology. Prepare the IRP DCF+ Supplemental Guide and support associated regulatory review activities. Partner with internal business units in evaluating IRP projects at various stages including identification, due-diligence, assessment, approval, budgeting, and forecasting. Build and maintain comprehensive financial models for new IRP projects including integrated financial statements, standardized evaluation metrics and appropriate tax, financing, accounting, and regulatory considerations. Prepare evidence and interrogatory responses for submission to the Ontario Energy Board OEB for IRP and Rate and Facilities Applications/Hearings. Support Enbridge Gas project approval process through the preparation of standardized materials, detailed review of financial models and response to inquiries by stakeholders. Prepare reports and documentation to satisfy all regulatory reporting requirements and internal decision records. Support the implementation of two IRP alternative pilot projects and future non-pilot IRP Plans.
Director	0.5	IRP	This role is responsible for the integration strategy and implementation of IRP

[5] Ibid.

2. East Kingston Creekford Rd Project

10. Enbridge Gas is proposing to recover $0.080 million in the IRP Operating Costs Deferral Account related to two IRP alternatives that were implemented to defer a pipeline reinforcement project in the Kingston, Ontario area. The evidence below describes the pipeline project, the IRP alternatives (IRPAs) and Enbridge Gas's proposal to recover the costs associated with the IRP alternatives.

3. Cost Recovery

11. The costs required to implement an IRP Plan for Kingston are below the financial threshold of $2 million for a Leave to Construct facilities project. Enbridge Gas did not file an IRP Plan to the OEB for approval as the OEB's IRP Decision found that "An IRP Plan approval will be mandatory if the forecast costs of the IRP Plan exceed the minimum project cost (currently $2 million, proposed to increase to $10 million) that would necessitate a Leave to Construct approval for a pipeline project."[6] In the case of the East Kingston Creekford Rd facilities project Enbridge Gas determined that this project could be deferred by implementing a supply side IRP alternative in the form of CNG, and a demand side IRP alternative, in the form of a Contract turnback, at a cost substantially less than the $2 million threshold. Enbridge Gas is requesting recovery of the costs incurred to implement CNG and the lost revenue associated with the contract demand reduction.

4. Project Description

12. The East Kingston Creekford Rd Reinforcement project was a planned $24.3 million capital reinforcement for 2024. Enbridge Gas's Asset Management Plan (AMP) included this investment in the 2024 – 2028 Rebasing application[7].The proposed facility project submitted in the AMP was a replacement of the entire existing NPS 6 pipeline from Westbrook check measurement station (CMS) to the Woodbine town boarder station (TBS) to account for forecasted growth, and to address class location and depth of cover issues which exist on the current Kingston Lateral.

[6] EB-2020-0091, OEB Decision and Order, p. 80.
[7] EB-2022-0200, Exhibit 2.6.2 Appendix A, p. 25 of 59.

13. The growth in the Kingston area is driven by general service growth. This growth is expected to occur downstream of the Woodbine TBS which regulates pressure from 6895 kPa MOP to 1210 kPa MOP throughout the Kingston system. The 1210 kPa MOP feeds 420 kPa MOP distribution systems downstream and also two large volume contract customers on the system. The system constraint for the Kingston Lateral NPS 6 pipeline is meeting the minimum inlet pressure to Woodbine TBS in order to maintain required pressures downstream on the 1210 kPa MOP system. As described below, Enbridge Gas has implemented two IRPAs to defer this project. Deferring this project provides additional time to assess and determine if a pipeline replacement project is needed, or if Ontario's energy transition will impact growth in a way, and in time, to avoid additional infrastructure.

14. As mentioned above, in addition to addressing the increased forecasted demands, the proposed facility project would also address depth of cover and class location issues on the current Kingston lateral. The depth of cover has been identified as a "medium risk" and has since been deemed acceptable for continued monitoring and assessment of the exposed location. Changes in depth of cover are event-based. As such, any timelines for remediation will be based on findings from monitoring programs. The class location compliance can also be monitored, but not indefinitely, however a delay to 2027 appears to be reasonable and the monitoring during this period will identify if action is required sooner.

15. The proposed IRPAs are not able to address the class location and depth of cover concerns; therefore, Enbridge Gas will continue to monitor these assets to ensure the risk remains tolerable. As the project is reassessed to identify if and when future system reinforcement may be required, remedies to the class location and depth of cover concerns will be considered.

5. IRP Alternative Assessment

16. Enbridge Gas reviewed the Kingston project for IRP alternatives including:

- Supply-side alternatives: Incremental pressure from TC Energy and Compressed Natural Gas (CNG)
- Demand-side alternatives: Contract Customer review and Enhanced Targeted Energy Efficiency (ETEE)

i. TC Energy Pressure:

Enbridge Gas engaged in discussions with TC Energy to determine if increased pressures could be provided to meet the project need. TC Energy was unable to provide higher pressures as it is also a low point on the TC Energy system. Therefore, the TCE supply side alternative could not be utilized for the project.

ii. CNG:

Enbridge Gas assessed a CNG IRP alternative (IRPA). The CNG IRPA assessed involved injecting CNG at the low point on the Kingston system to address the forecasted system constraint. Injecting CNG from a trailer into the Kingston natural gas pipeline ensures that the pressures do not drop below the system's minimum requirements. Without the CNG injection, the Kingston system was anticipated to fall below its minimum pressure requirements as early as the Winter of 2022/2023. Leveraging CNG in 2022 ensured Enbridge Gas maintained a safe and reliable system for customers in the Kingston project service area. As CNG can be quickly injected into the natural gas system, once the proper modifications have been made and a CNG trailer is secured, it can be used to meet near-term system constraints while demand side IRP alternatives, such as an ETEE program, if required, are implemented and the benefits begin to be realized. Enbridge GAs did explore ETEE and contract customer reductions for the Kingston project, as described below; however, because of the urgency of the near-term constraint and need, Enbridge Gas did not wait to implement the CNG alternative to ensure a safe and reliable system was maintained.

To leverage CNG for this project Enbridge Gas engaged CNG vendors to ensure this IRPA could address the deferral of the facility alternative in the required timeframe. Quotes were received from two vendors, the preferred CNG vendor required a two-year contract to be executed by July 1, 2022, to ensure an in-service date of December 1, 2022. The contracted CNG service is an enabling payment to a competitive service provider, where Enbridge does not own the asset, per the IRP Decision EB-2019-0091. As a result, $0.077 million has been included in the IRP Operating Costs Deferral Account, for which Enbridge Gas is seeking approval of through this application. The costs for the Kingston CNG IRP alternative were unplanned and unbudgeted for 2022 and 2023, and were needed in combination with the below noted contract customer reduction, to ensure reliability of the system, therefore, the costs have been included in the 2022 IRP Operating Costs Deferral Account for recovery.

iii. <u>Contract Customer Review:</u>

A Contract Customer review was completed to determine the possibility that contract customers in the project area may be able to turn back capacity or change all or part of their firm contract to interruptible rates to defer and/or reduce the size of the project. To understand this potential, Enbridge Gas contacted the two contract customers in the project area in November 2021 to determine if capacity could be turned back. At that time, both customers declined to turn back any portion of the firm demand contract. Enbridge Gas launched a formal In-Franchise Reverse Open Season in August 2022 to formally document the process and results. One turnback bid was received from a customer who had been contacted in November of 2021 in addition to the August Reverse Open Season. The turnback provided, 2,200 m3/hour and was confirmed by the Contract Customer on November

11, 2022. This capacity was sufficient to defer the reinforcement, however, it was not received in time to avoid a CNG contract and back-up solution. The contracted demand reduction results in a revenue loss of $2,860 in 2022, $35,322 in 2023 and $54,238 in 2024. Enbridge Gas proposes to recover the total lost revenue of $94,420, which does not go beyond 2024 as the customer's contract expires in November 2024.

iv. <u>ETEE:</u>

Enbridge Gas engaged Posterity to assess the ETEE potential for the Kingston project service area to understand if conservation could reduce demands and reduce, defer or eliminate the facility infrastructure needed. The analysis from Posterity concluded:

a. The total gross cost of the approximately 4,600 m3/hr of potential reduction that could be obtained by winter 2027/2028 would be approximately $28 million; or an average gross cost of approximately $6,100 per m3/hr reduction. By the winter of 2042/2043, the total gross cost of the approximate 6,950 m3/hr of potential reduction would be approximately $53 million; or an average gross cost of approximately $7,650 per m3/hr reduction.
b. The ETEE is not cost competitive in comparison to the IRPAs that have been implemented; however, ETEE will be revisited when Enbridge reassesses a longer-term solution for the project area.

17. Enbridge Gas was able defer the East Kingston Creekford Rd Reinforcement project from the original in-service date of 2024 to at least 2027 based on current demand forecasts. Enbridge Gas will monitor the demands in this area to ensure the CNG solution and contract reduction realized continue to meet the needs. CNG has been procured for the winters of 2022/2023 and 2023/2024 as noted above. In 2024, Enbridge Gas will need to revisit the demands in the area to determine if the CNG IRPA will be required in the winter of 2024/2025. The project will continue to be re-evaluated from a facility and IRP perspective to understand projected demands and

to reassess the depth of cover and class location issues to determine if a future facility or IRP alternative will be required in this area.

6. Posterity – General Model Enhancements

18. Enbridge Gas is proposing to recover $0.169 million in the IRP Operating Costs Deferral Account related to enhancements made to Posterity's proprietary model.

19. Enbridge Gas engaged Posterity in 2019 to develop an IRPA Model to support estimation of peak demand reduction potential from enhanced targeted energy efficiency (ETEE) and demand response (DR) measures. The IRPA Model uses the DSM "mirror model" of the 2019 Achievable Potential Study (APS)[8] as a basis; where additional calibration and development of load shapes were layered onto the "mirror model" to create the IRPA Model.

20. Enbridge Gas engaged Posterity in 2022 to further update the IRPA Model and refine aspects of the modelling approach to improve the accuracy of future IRPA analysis.

21. The key activities involved in this model enhancement include:
    a. Completing a data refresh: This included updating and recalibrating the base year data and reference case growth forecast to the most recent available data.
    b. Recalibrating end use load shapes at a sector or rate zone level to align with modelled design temperatures and exploring how different measures impact base loads versus heating loads and the impact on annual versus peak hour savings.
    c. Refinement of the selection of ETEE measures and program costs to better reflect differences in objectives between DSM and IRP.

[8] EB-2021-0002, Exhibit E, Tab 4, Schedule 7, Attachment 1.

d. Review of different scenarios (i.e., reference case, DSM business-as-usual, technical potential, etc.) and the methodology and assumptions behind each, such as net-to-gross (NTG), optimizing costs based on annual versus peak.

7. IRP Pilots

22. Enbridge Gas is proposing to recover $0.028 million in the IRP Operating Costs Deferral Account related to two ETEE assessments completed by Posterity for the two IRP Pilot Projects. In its IRP Decision, the OEB agreed with Enbridge's proposal to implement two IRP pilot projects as the pilot projects would be an "effective approach to understand and evaluate how IRP can be implemented to avoid, delay or reduce facility projects."[9]

23. Enbridge engaged Posterity to assess the potential ETEE and DR peak hour demand reduction for the two selected pilot service areas of Parry Sound and Southern Lake Huron which provided a reference point when designing the detailed ETEE and DR program. The cost for each ETEE potential assessment as $0.014 million for a total of $0.028 million.

8. Guidehouse Consulting

24. Enbridge Gas is proposing to recover $0.015 million in the IRP Operating Costs Deferral Account related to a jurisdictional scan of ETEE/DR pilots focused specifically on natural gas IRP implementation. The Guidehouse Jurisdictional report was provided to the IRP TWG in September 2022[10] The costs in 2022 are the final costs as the majority of the work was completed in 2021 and those costs were recovered in the 2021 deferral disposition.

25. Further, the OEB found in the IRP Decision that Enbridge Gas should study improvements to the DCF+ test for IRP[11]. Enbridge Gas is proposing to recover an

[9] EB-2020-0091, OEB IRP Decision, p.90
[10] https://engagewithus.oeb.ca/28744/widgets/145694/documents/98425.
[11] EB-2020-0091, Decision and Order, p. 57

additional $0.094 million in the IRP Operating Costs Deferral Account related to the consulting work completed by Guidehouse which developed recommendations on how the currently approved Discounted Cash Flow (DCF+) test could be improved to better identify and define the costs and benefits of Facility Alternatives and Integrated Resource Planning Alternatives (IRPAs), including infrastructure, supply-side and demand-side IRPAs. The Guidehouse Report was supplied to the IRP Technical Working group (TWG) in July 2022.[12] The TWG continues to work on revisions to the DCF+ test and will make available a DCF+ report when complete.

[12] https://www.oeb.ca/sites/default/files/IRPWG-Meeting7-Guidehouse-Report-20220705.pdf

ENBRIDGE GAS
DEFERRAL & VARIANCE ACCOUNT
ACTUAL & FORECAST BALANCES

Line No.	Account Description	Account Acronym		Col. 1 Forecast for clearance at January 1, 2024 Principal ($000's)	Col. 2 Interest ($000's)	Col. 3 Total ($000's)	Col.4 Reference to Evidence
	EGD Rate Zone Commodity Related Accounts						
1.	Storage and Transportation D/A	2022 S&TDA		8,074.4	493.3	8,567.7	D-1, Page 2
2.	Transactional Services D/A	2022 TSDA		(31,234.7)	(1,536.0)	(32,770.7)	D-1, Page 4
3.	Unaccounted for Gas V/A	2022 UAFVA		41,400.4	2,179.6	43,580.0	D-1, Page 6
4.	Total Commodity Related Accounts			18,240.1	1,136.9	19,377.0	
	EGD Rate Zone Non Commodity Related Accounts						
5.	Average Use True-Up V/A	2022 AUTUVA		6,904.5	339.5	7,244.0	D-1, Page 10
6.	Gas Distribution Access Rule Impact D/A	2022 GDARIDA		-	-	-	D-1, Page 23
7.	Deferred Rebate Account	2022 DRA		(72.7)	(8.9)	(81.6)	D-1, Page 12
8.	Transition Impact of Accounting Changes D/A	2022 TIACDA		4,435.8	-	4,435.8	D-1, Page 1
9.	Electric Program Earnings Sharing D/A	2022 EPESDA		-	-	-	D-1, Page 23
10.	Open Bill Revenue V/A	2022 OBRVA		-	-	-	D-1, Page 23
11.	Ex-Franchise Third Party Billing Services V/A	2022 EXFTPBSVA		-	-	-	D-1, Page 23
12.	OEB Cost Assessment V/A	2022 OEBCAVA		3,104.8	193.3	3,298.1	D-1, Page 13
13.	Dawn Access Costs D/A	2022 DACDA		1,184.8	58.3	1,243.1	D-1, Page 16
14.	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Dif	2022 P&OPEBFAVACPDVA		-	-	-	D-1, Page 23
15.	Total EGD Rate Zone (for clearance)			33,797.3	1,718.9	35,516.2	
	Union Rate Zones Gas Supply Accounts	OEB Account Number					
16.	Upstream Transportation Optimization	179-131	2022	8,899.7	437.6	9,337.3	E-1, Page 6
17.	Spot Gas Variance Account	179-107	2022	-	-	-	E-1, Page 58
18.	Unabsorbed Demand Costs Variance Account	179-108	2022	(5,623.7)	(345.5)	(5,969.2)	E-1, Page 1
19.	Base Service North T-Service TransCanada Capacity	179-153	2022	83.3	5.1	88.4	E-1, Page 52
20.	Total Gas Supply Accounts			3,359.3	97.2	3,456.5	
	Union Rate Zones Storage Accounts						
21.	Short-Term Storage and Other Balancing Services	179-70	2022	4,446.1	215.9	4,662.0	E-1, Page 8
	Union Rate Zones Other Accounts						
22.	Normalized Average Consumption	179-133	2022	8,769.8	564.7	9,334.5	E-1, Page 13
23.	Deferral Clearing Variance Account	179-132	2022	1,978.0	135.1	2,113.1	E-1, Page 21
24.	OEB Cost Assessment Variance Account	179-151	2022	1,254.2	77.8	1,332.0	E-1, Page 49
25.	Unbundled Services Unauthorized Storage Overrun	179-103	2022	-	-	-	E-1, Page 58
26.	Gas Distribution Access Rule Costs	179-112	2022	-	-	-	E-1, Page 58
27.	Conservation Demand Management	179-123	2022	-	-	-	E-1, Page 58
28.	Parkway West Project Costs	179-136	2022	(603.7)	(36.5)	(640.2)	E-1, Page 25
29.	Brantford-Kirkwall/Parkway D Project Costs	179-137	2022	(35.0)	(2.0)	(37.0)	E-1, Page 29
30.	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	179-142	2022	240.0	11.4	251.4	E-1, Page 41
31.	Lobo D/Bright C/Dawn H Compressor Project Costs	179-144	2022	1,315.6	53.8	1,369.4	E-1, Page 44
32.	Burlington-Oakville Project Costs	179-149	2022	(48.0)	(2.9)	(50.9)	E-1, Page 47
33.	Panhandle Reinforcement Project Costs	179-156	2022	(3,149.1)	(188.4)	(3,337.5)	E-1, Page 53
34.	Sudbury Replacement Project	179-162	2022	-	-	-	E-1, Page 58
35.	Parkway Obligation Rate Variance	179-138	2022	(81.0)	(4.0)	(85.0)	E-1, Page 58
36.	Unauthorized Overrun Non-Compliance Account	179-143	2022	(144.9)	(9.8)	(154.7)	E-1, Page 58
37.	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Dif	179-157	2022	-	(3,443.7)	(3,443.7)	E-1, Page 56
38.	Unaccounted for Gas Volume Variance Account	179-135	2022	40,046.6	1,969.3	42,015.9	E-1, Page 31
39.	Unaccounted for Gas Price Variance Account	179-141	2022	9,785.0	508.9	10,293.9	E-1, Page 38
40.	Total Other Accounts			59,327.5	(366.4)	58,961.1	
41.	Total Union Rate Zones (for clearance)			67,132.9	(53.4)	67,079.5	
	EGI Accounts						
42.	Earnings Sharing D/A	179-382	2022	-	-	-	C-1, Page 1
43.	Tax Variance - Accelerated CCA - EGI	179-383	2022	(29,236.7)	(1,723.9)	(30,960.6)	C-1, Page 12
44.	IRP Operating Costs Deferral Account	179-385	2022	2,159.4	126.1	2,285.5	C-1, Page 15
45.	IRP Capital Costs Deferral Account	179-386	2022	-	-	-	C-1, Page 1
46.	Green Button Initiative Deferral Account	179-387	2022	-	-	-	
47.	Expansion of Natural Gas Distribution Systems V/A	179-380	2022	-	-	-	C-1, Page 1
48.	Total EGI Accounts (for clearance)			(27,077.3)	(1,597.8)	(28,675.1)	
49.	Total Deferral and Variance Accounts (for clearance)			73,852.9	67.8	73,920.7	
	Not Being Requested for Clearance						
50.	Accounting Policy Changes D/A - Pension - EGI	179-120	2022	160,288.8	-	160,288.8	C-1, Page 2
51.	Accounting Policy Changes D/A - Other - EGI	179-120	2019	(1,749.5)	(156.4)	(1,905.9)	C-1, Page 2
52.	Accounting Policy Changes D/A - Other - EGI	179-120	2020	(14,789.5)	(1,125.8)	(15,915.3)	C-1, Page 2
53.	Accounting Policy Changes D/A - Other - EGI	179-120	2021	(13,864.6)	(990.2)	(14,854.8)	C-1, Page 2
54.	Accounting Policy Changes D/A - Other - EGI	179-120	2022	62,752.5	2,872.2	65,624.7	C-1, Page 2
55.	Tax Variance - Integration Capital Additions - EGI	179-383	2020	(3,736.3)	(249.9)	(3,986.2)	C-1, Page 12
56.	Tax Variance - Integration Capital Additions - EGI	179-383	2021	(10,178.9)	(689.4)	(10,868.2)	C-1, Page 12
57.	Tax Variance - Integration Capital Additions - EGI	179-383	2022	6,882.8	390.5	7,273.3	C-1, Page 12
58.	Incremental Capital Module Deferral Account - EGD	2020 ICMDA	2020	(254.0)	(18.3)	(272.3)	C-1, Page 1
59.	Incremental Capital Module Deferral Account - EGD	2021 ICMDA	2021	175.5	12.5	188.0	C-1, Page 1
60.	Incremental Capital Module Deferral Account - EGD	2022 ICMDA	2022	(6,873.6)	(343.4)	(7,217.0)	C-1, Page 1
61.	Incremental Capital Module Deferral Account - UGL	179-159	2019	(6,869.6)	(603.1)	(7,472.7)	C-1, Page 1
62.	Incremental Capital Module Deferral Account - UGL	179-159	2020	(5,615.4)	(424.6)	(6,040.0)	C-1, Page 1
63.	Incremental Capital Module Deferral Account - UGL	179-159	2021	(14,353.4)	(997.6)	(15,351.0)	C-1, Page 1
64.	Incremental Capital Module Deferral Account - UGL	179-159	2022	(1,719.3)	(102.4)	(1,821.7)	C-1, Page 1
65.	RNG Injection Service V/A	2022 RNGISVA	2022	(159.2)	(7.8)	(167.0)	D-1, Page 23
66.	Impacts Arising from the COVID-19 Emergency D/A - EGI	2020 IACEDA	2020	1,377.5	101.9	1,479.4	C-1, Page 1
67.	Impacts Arising from the COVID-19 Emergency D/A - EGI	2021 IACEDA	2021	34.3	2.4	36.7	C-1, Page 1
68.	Total of Accounts not being requested for clearance			151,348.2	(2,329.6)	149,018.6	

ENBRIDGE GAS
SUMMARY OF ACCOUNTING POLICY CHANGES DEFERRAL ACCOUNT (NO. 179-381)
UTILITY REVENUE REQUIREMENT

Line No.	($000's)	Col. 1 EGD - Change from Capital to O&M	Col. 2 UGL - Change from O&M to Capital	Col. 3 Capitalization Policy Alignment - Subtotal	Col. 4 EGD - Change from IDC rate at WACD to Board Prescribed	Col. 5 UGL - Elimination of IDC Threshold	Col. 6 IDC Policy Alignment - Subtotal	Col. 7 Depreciation Expense Policy Alignment	Col. 8 EGD - Change in Overhead Capitalization	Col. 9 UGL - Change in Overhead Capitalization	Col. 10 Overhead Capitalization Alignment - Subtotal	Col. 11 Amortized Gas Supply Storage and Transportation Costs	Col. 12 **APCDA Total**	Col. 13 Actuarial Gains/Losses on UGL Pension
	Cost of capital													
1.	Rate base	(7,435.0)	11,977.6	4,542.6	(3,023.2)	2,664.6	(358.6)	15,752.4	(5,419.5)	15,570.6	10,151.1	-	**30,087.5**	0.0
2.	Required rate of return*	6.20%	7.30%		6.20%	7.30%		7.30%	6.20%	7.30%		7.30%		7.30%
3.	Cost of capital*	(461.0)	874.4	413.4	(187.4)	194.5	7.1	1,149.9	(336.0)	1,136.7	800.7	-	**2,371.1**	-
	Cost of service													
4.	Gas costs	-	-	-	-	-	-	-	-	-	-	62,155.0	**62,155.0**	-
5.	Operation and Maintenance	1,512.2	(10,414.5)	(8,902.2)	-	-	-	-	(5,622.6)	14,985.1	9,362.5	-	**460.3**	(9,143.0)
6.	Depreciation and amortization	(180.0)	229.2	49.2	(73.4)	165.9	92.5	(2,749.4)	156.5	648.9	805.4	-	**(1,802.3)**	-
7.	Municipal and other taxes	-	-	-	-	-	-	-	-	-	-	-	**-**	-
8.	Cost of service	1,332.2	(10,185.3)	(8,853.0)	(73.4)	165.9	92.5	(2,749.4)	(5,466.1)	15,634.0	10,167.9	62,155.0	**60,813.0**	(9,143.0)
	Income taxes on earnings													
9.	Excluding tax shield	(275.6)	2,427.2	2,151.6	(47.1)	(598.0)	(645.1)	-	1,263.1	(2,482.9)	(1,219.8)	(16,471.1)	**(16,184.4)**	2,422.9
10.	Tax shield provided by interest expense	57.5	(127.0)	(69.5)	23.4	(28.2)	(4.8)	(167.0)	41.9	(165.0)	(123.1)	-	**(364.4)**	-
11.	Income taxes on earnings	(218.1)	2,300.2	2,082.1	(23.7)	(626.2)	(649.9)	(167.0)	1,305.0	(2,647.9)	(1,342.9)	(16,471.1)	**(16,548.8)**	2,422.9
	Taxes on (def) / suff.													
12.	Gross (def.) / suff.	(889.1)	9,538.1	8,649.0	387.1	361.5	748.6	2,402.4	6,118.5	(19,214.3)	(13,095.8)	(62,155.0)	**(63,450.8)**	9,143.0
13.	Net (def.) / suff.	(653.5)	7,010.5	6,357.0	284.5	265.7	550.2	1,765.8	4,497.1	(14,122.5)	(9,625.4)	(45,683.9)	**(46,636.3)**	6,720.1
14.	Taxes on (def.) / suff.	235.6	(2,527.6)	(2,292.0)	(102.6)	(95.8)	(198.4)	(636.6)	(1,621.4)	5,091.8	3,470.4	16,471.1	**16,814.5**	(2,422.9)
15.	Revenue requirement	888.7	(9,538.3)	(8,649.5)	(387.1)	(361.6)	(748.7)	(2,403.1)	(6,118.5)	19,214.6	13,096.1	62,155.0	**63,449.8**	(9,143.0)
16.	Gross revenue (def.) / suff.	(888.7)	9,538.3	8,649.5	387.1	361.6	748.7	2,403.1	6,118.5	(19,214.6)	(13,096.1)	(62,155.0)	**(63,449.8)**	9,143.0
												2021 True-Up for Overhead Capitalization	**697.3**	
												Total Booked to 2022 APCDA	**(62,752.5)**	

*Union rate zones 2013 Board-approved rate of return is 7.3% and EGD rate zone 2018 Board-approved rate of return is 6.2%.

ENBRIDGE GAS
CALCULATION OF THE BILL C-97 ACCELERATED CCA IMPACT TO BE RECORDED IN THE TAX VARIANCE DEFERRAL ACCOUNT

Line No.	2021 Year-End Particulars ($000s)		Opening UCC Accel. CCA	Opening UCC Regular CCA	Total Additions Qualifying for Accel. CCA	ICM & CPT Additions	CTA Additions	Additions Net of ICM CPT & CTA	Accel. CCA Depreciable UCC Balance	Regular CCA Depreciable UCC Balance	Rate (%)	Accelerated CCA	Regular CCA	Closing UCC Accel. CCA	Closing UCC Regular CCA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Class														
1.	1	Buildings, structures and improvements, services, meters, mains	-	-	-	-	-	-	-	-	4%	-	-	-	-
2.	1	Non-residential building acquired after March 19, 2007	12,300.6	13,111.6	31,455.0	-	1,745.2	29,709.8	56,865.3	27,966.5	6%	3,411.9	1,678.0	38,598.5	41,143.4
3.	2	Mains acquired before 1988	-	-	-	-	-	-	-	-	6%	-	-	-	-
4.	3	Buildings acquired before 1988	-	-	-	-	-	-	-	-	5%	-	-	-	-
5.	6	Other buildings	-	-	-	-	-	-	-	-	10%	-	-	-	-
6.	7	Compression equipment acquired after February 22, 2005	5,512.8	6,579.8	5,851.4	-	-	5,851.4	14,289.9	9,505.5	15%	2,143.5	1,425.8	9,220.7	11,005.4
7.	8	Compression assets, office furniture, equipment	40,764.0	52,410.9	27,950.8	7,820.2	54.0	20,076.6	70,878.9	62,449.2	20%	14,175.8	12,489.8	46,664.8	59,997.6
8.	10	Transportation, computer equipment	9,814.1	15,167.2	13,440.2	-	-	13,440.2	29,974.3	21,887.3	30%	8,992.3	6,566.2	14,261.9	22,041.2
9.	12	Computer software, small tools	-	5,293.9	75,425.7	-	67,370.4	8,055.4	8,055.4	9,321.6	100%	8,055.4	9,321.6	-	4,027.7
10.	13	Leasehold improvements	-	-	-	-	-	-	-	-	N/A	-	-	-	-
11.	14.1	Intangibles	3,478.5	3,666.5	2,802.8	18.8	-	2,784.0	7,654.5	5,058.5	5%	382.7	252.9	5,879.8	6,197.6
12.	14.1	Intangibles (pre 2017)	-	-	-	-	-	-	-	-	7%	-	-	-	-
13.	17	Roads, sidewalk, parking lot or storage areas	-	-	-	-	-	-	-	-	8%	-	-	-	-
14.	38	Heavy work equipment	8,376.4	12,945.4	5,402.9	-	-	5,402.9	16,480.9	15,646.9	30%	4,944.3	4,694.1	8,835.1	13,654.3
15.	41	Storage assets	19,190.4	26,866.6	54,897.2	-	-	54,897.2	101,536.3	54,315.2	25%	25,384.1	13,578.8	48,703.6	68,185.0
16.	45	Computers - Hardware acquired after March 22, 2004	-	-	-	-	-	-	-	-	45%	-	-	-	-
17.	49	Transmission pipeline additions acquired after February 23, 2005	92,947.8	101,397.7	75,856.8	-	-	75,856.8	206,733.0	139,326.0	8%	16,538.6	11,146.1	152,266.0	166,108.3
18.	50	Computers hardware acquired after March 18, 2007	6,241.1	25,856.2	9,034.9	-	555.8	8,479.1	18,959.8	30,095.7	55%	10,427.9	16,552.7	4,292.4	17,782.6
19.	51	Distribution pipelines acquired after March 18, 2007	1,012,108.0	1,078,840.4	810,728.0	103,778.6	-	706,949.4	2,072,532.1	1,432,315.1	6%	124,351.9	85,938.9	1,594,705.5	1,699,850.9
20.	Total		$ 1,210,733.8	1,342,136.2	1,112,845.7	111,617.6	69,725.3	931,502.8	2,603,960.4	1,807,887.6		$ 218,808.4	$ 163,644.9	1,923,428.3	2,109,994.1

Line No.	Class	2022 Year-End Particulars ($000s)	Opening UCC Accel. CCA	Opening UCC Regular CCA	Total Additions Qualifying for Accel. CCA	ICM & CPT Additions	CTA Additions	Additions Net of ICM CPT & CTA	Accel. CCA Depreciable UCC Balance	Regular CCA Depreciable UCC Balance	Rate (%)	Accelerated CCA	Regular CCA	Closing UCC Accel. CCA	Closing UCC Regular CCA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Class														
1.	1	Buildings, structures and improvements, services, meters, mains	-	-	-	-	-	-	-	-	4%	-	-	-	-
2.	1	Non-residential building acquired after March 19, 2007	38,598.5	41,143.4	24,119.1	-	(0.9)	24,120.0	74,778.5	53,203.4	6%	4,469.4	3,186.4	58,249.1	62,077.0
3.	2	Mains acquired before 1988	-	-	-	-	-	-	-	-	6%	-	-	-	-
4.	3	Buildings acquired before 1988	-	-	-	-	-	-	-	-	5%	-	-	-	-
5.	6	Other buildings	-	-	-	-	-	-	-	-	10%	-	-	-	-
6.	7	Compression equipment acquired after February 22, 2005	9,220.7	11,005.4	18,981.3	-	-	18,981.3	37,692.7	20,496.0	15%	5,653.9	3,074.4	22,548.1	26,912.3
7.	8	Compression assets, office furniture, equipment	46,664.8	59,997.6	90,158.5	-	-	90,158.5	181,902.6	105,076.9	20%	36,367.8	21,011.1	100,455.6	129,145.1
8.	10	Transportation, computer equipment	14,261.9	22,041.2	21,228.8	-	-	21,228.8	46,105.1	32,655.6	30%	13,800.1	9,786.2	21,690.6	33,483.7
9.	12	Computer software, small tools	-	4,027.7	43,553.6	-	32,350.8	11,202.7	11,202.7	9,629.0	100%	10,644.4	9,349.9	558.4	5,880.5
10.	13	Leasehold improvements	-	-	-	-	-	-	-	-	N/A	-	-	-	-
11.	14.1	Intangibles	5,879.8	6,197.6	891.2	6.6	-	884.6	7,206.7	6,639.9	5%	360.3	332.0	6,404.0	6,750.2
12.	14.1	Intangibles (pre 2017)	-	-	-	-	-	-	-	-	7%	-	-	-	-
13.	17	Roads, sidewalk, parking lot or storage areas	-	-	-	-	-	-	-	-	8%	-	-	-	-
14.	38	Heavy work equipment	8,835.1	13,654.3	6,785.9	-	-	6,785.9	19,013.9	17,047.2	30%	5,692.9	5,110.4	9,928.1	15,329.7
15.	41	Storage assets	48,703.6	68,185.0	39,628.5	-	-	39,628.5	108,146.3	87,999.3	25%	27,036.6	21,999.8	61,295.5	85,813.7
16.	45	Computers - Hardware acquired after March 22, 2004	-	-	-	-	-	-	-	-	45%	-	-	-	-
17.	49	Transmission pipeline additions acquired after February 23, 2005	152,266.0	166,108.3	65,474.3	-	-	65,474.3	250,477.5	198,845.5	8%	20,038.2	15,907.6	197,702.1	215,675.0
18.	50	Computers hardware acquired after March 18, 2007	4,292.4	17,782.6	15,698.0	-	1,936.4	13,761.6	24,934.7	24,663.4	55%	13,660.2	13,546.9	4,393.8	17,997.3
19.	51	Distribution pipelines acquired after March 18, 2007	1,594,705.5	1,699,850.9	923,232.9	95,445.4	-	827,787.5	2,836,386.8	2,113,744.7	6%	170,183.2	126,824.7	2,252,309.8	2,400,813.7
20.	Total		$ 1,923,428.3	2,109,994.1	1,249,752.1	95,452.0	34,286.3	1,120,013.7	3,597,847.5	2,670,001.0		$ 307,907.0	$ 230,129.5	2,735,535.0	2,999,878.3

	2018	2019	2020	2021	2022
CCA Variance (i) - (j)	13,580.7	70,503.0	47,308.8	55,163.5	77,777.5
Tax Rate	26.5%	26.5%	26.5%	26.5%	26.5%
Earnings Impact of Accelerated CCA	3,598.9	18,683.3	12,536.8	14,618.3	20,611.0
Earnings Impact Grossed-up for Taxes Recorded in the TVDA	4,896.4	25,419.4	17,056.9	19,888.9	28,042.2
Balances as filed in EB-2022-0110	4,896.4	25,133.9	16,588.8	18,694.4	N/A
variance	-	285.5	468.2	1,194.5	-
Include adjustment to 2019 balance in 2020 TVDA	-	(285.5)	285.5	-	-
Include adjustment to 2020 balance in 2021 TVDA	-	-	(468.2)	468.2	-
Include adjustment to 2021 balance in 2022 TVDA	-	-	-	(1,194.5)	1,194.5
Revised Balances	4,896.4	25,133.9	16,874.2	19,162.6	29,236.7

1 - Balance for 2019 was updated based on the change from EB-2020-0134 and Tax Filing on June 30, 2020.

Line No.		Particulars ($000s) 2021 Year-End - Integration Capital Additions	Opening UCC Accel. CCA	Opening UCC Regular CCA	CTA Additions	Accel. CCA Depreciable UCC Balance	Regular CCA Depreciable UCC Balance	Rate (%)	Accelerated CCA	Regular CCA	Closing UCC Accel. CCA	Closing UCC Regular CCA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Class											
1.	1	Buildings, structures and improvements, services, meters, mains	-	-	-	-	-	4%	-	-	-	-
2.	1	Non-residential building acquired after March 19, 2007	-	-	1,745.2	2,617.8	872.6	6%	157.1	52.4	1,588.1	1,692.8
3.	2	Mains acquired before 1988	-	-	-	-	-	6%	-	-	-	-
4.	3	Buildings acquired before 1988	-	-	-	-	-	5%	-	-	-	-
5.	6	Other buildings	-	-	-	-	-	10%	-	-	-	-
6.	7	Compression equipment acquired after February 22, 2005	-	-	-	-	-	15%	-	-	-	-
7.	8	Compression assets, office furniture, equipment	-	-	54.0	81.0	27.0	20%	16.2	5.4	37.8	48.6
8.	10	Transportation, computer equipment	-	-	-	-	-	30%	-	-	-	-
9.	12	Computer software, small tools	-	388.6	67,370.4	67,370.4	34,073.8	100%	67,370.4	34,073.8	-	33,685.2
10.	13	Leasehold improvements	-	-	-	-	-	N/A	-	-	-	-
11.	14.1	Intangibles	-	-	-	-	-	5%	-	-	-	-
12.	14.1	Intangibles (pre 2017)	-	-	-	-	-	7%	-	-	-	-
13.	17	Roads, sidewalk, parking lot or storage areas	-	-	-	-	-	8%	-	-	-	-
14.	38	Heavy work equipment	-	-	-	-	-	30%	-	-	-	-
15.	41	Storage assets	-	-	-	-	-	25%	-	-	-	-
16.	45	Computers - Hardware acquired after March 22, 2004	-	-	-	-	-	45%	-	-	-	-
17.	49	Transmission pipeline additions acquired after February 23, 2005	-	-	-	-	-	8%	-	-	-	-
18.	50	Computers hardware acquired after March 18, 2007	3,173.6	13,147.9	555.8	4,007.3	13,425.8	55%	2,204.0	7,384.2	1,525.4	6,319.5
19.	51	Distribution pipelines acquired after March 18, 2007	-	-	-	-	-	6%	-	-	-	-
20.		Total	$ 3,173.6	13,536.5	69,725.3	74,076.4	48,399.1		$ 69,747.6	$ 41,515.7	3,151.3	41,746.1

2022 Year-End - Integration Capital Additions

Line No.	Class	Particulars ($000s)	Opening UCC Accel. CCA (a)	Opening UCC Regular CCA (b)	CTA Additions (c)	Accel. CCA Depreciable UCC Balance (d)	Regular CCA Depreciable UCC Balance (e)	Rate (%) (f)	Accelerated CCA (g)	Regular CCA (h)	Closing UCC Accel. CCA (i)	Closing UCC Regular CCA (j)
1.	1	Buildings, structures and improvements, services, meters, mains	-	-	-	-	-	4%	-	-	-	-
2.	1	Non-residential building acquired after March 19, 2007	1,588.1	1,692.8	(0.9)	1,586.7	1,692.3	6%	95.2	101.5	1,492.0	1,590.3
3.	2	Mains acquired before 1988	-	-	-	-	-	6%	-	-	-	-
4.	3	Buildings acquired before 1988	-	-	-	-	-	5%	-	-	-	-
5.	6	Other buildings	-	-	-	-	-	10%	-	-	-	-
6.	7	Compression equipment acquired after February 22, 2005	-	-	-	-	-	15%	-	-	-	-
7.	8	Compression assets, office furniture, equipment	37.8	48.6	-	37.8	48.6	20%	7.6	9.7	30.2	38.9
8.	10	Transportation, computer equipment	-	-	-	-	-	30%	-	-	-	-
9.	12	Computer software, small tools	-	33,685.2	32,350.8	32,350.8	49,860.6	100%	32,350.8	49,860.6	-	16,175.4
10.	13	Leasehold improvements	-	-	-	-	-	N/A	-	-	-	-
11.	14.1	Intangibles	-	-	-	-	-	5%	-	-	-	-
12.	14.1	Intangibles (pre 2017)	-	-	-	-	-	7%	-	-	-	-
13.	17	Roads, sidewalk, parking lot or storage areas	-	-	-	-	-	8%	-	-	-	-
14.	38	Heavy work equipment	-	-	-	-	-	30%	-	-	-	-
15.	41	Storage assets	-	-	-	-	-	25%	-	-	-	-
16.	45	Computers - Hardware acquired after March 22, 2004	-	-	-	-	-	45%	-	-	-	-
17.	49	Transmission pipeline additions acquired after February 23, 2005	-	-	-	-	-	8%	-	-	-	-
18.	50	Computers hardware acquired after March 18, 2007	1,525.4	6,319.5	1,936.4	4,430.1	7,287.7	55%	2,436.5	4,008.2	1,025.3	4,247.7
19.	51	Distribution pipelines acquired after March 18, 2007	-	-	-	-	-	6%	-	-	-	-
20.		Total	$ 3,151.3	41,746.1	34,286.3	38,405.4	58,889.2		$ 34,890.1	$ 53,980.1	2,547.5	22,052.3

	2020	2021	2022
CCA Variance (i) - (j)	10,362.8	28,231.9	(19,090.0)
Tax Rate	26.5%	26.5%	26.5%
Earnings Impact of Accelerated CCA	2,746.1	7,481.5	(5,058.8)
Earnings Impact Grossed-up for Taxes Related to Integrated Capital Additions	3,736.3	10,178.9	(6,882.8)
Balances as filed in EB-2022-0110	3,736.3	10,462.6	N/A
variance	-	(283.7)	-
Include adjustment to 2021 balance in 2022 TVDA	-	283.7	(283.7)
Revised Balances	3,736.3	10,462.6	(7,166.5)

1 - Balance for 2021 was updated based on the change from EB-2022-0110 and Tax Filing on June 30, 2022.

2023 TRANSITION IMPACT OF ACCOUNTING CHANGES DEFERRAL ACCOUNT – EGD RATE ZONE

1. The purpose of the Transition Impact of Accounting Changes Deferral Account (TIACDA) is to track the un-cleared Other Post Employment Benefit (OPEB) costs which the OEB has approved for recovery. Within EB-2011-0354, the OEB approved the recovery of OPEB costs, which were forecast to be $90 million at the end of 2012, evenly over a 20-year period, commencing in 2013. The OPEB costs needed to be recognized as a result of EGD having to account for post-employment expenses on an accrual basis, upon transition to USGAAP for corporate reporting purposes in 2012. The use of USGAAP for regulatory purposes was approved within the 2013 rate proceeding, EB-2011-0354.

2. The final amount recorded in the TIACDA as of the end of 2012 was $88.716 million. The first ten installments (for each of 2013 through 2022) of $4.436 million each (1/20 of $88.716 million), were approved for recovery within the EB-2013-0046, EB-2014-0195, EB-2015-0122, EB-2016-0142, EB-2017-0102, EB-2018-0131, EB-2019-0105, EB-2020-0134, EB-2021-0149, and EB-2022-0110 proceedings.

3. Enbridge Gas is now requesting recovery of the eleventh, or 2023 installment of the OEB-Approved TIACDA amount, in the amount of $4.436 million (1/20 of $88.716 million). As per the approved description and scope of the account, interest is not applicable to the balances to be cleared from the TIACDA.

4. Enbridge Gas has requested disposition of the forecast residual TIACDA balance ($39.92 million), net of this eleventh installment, as part of the 2024 Rebasing Application (EB-2022-0200).

2022 STORAGE & TRANSPORTATION DEFERRAL ACCOUNT
EGD RATE ZONES

1. The purpose of the 2022 Storage & Transportation Deferral Account (S&TDA) is to record the difference between the forecast cost of Storage and Transportation included in the Company's approved rates and the actual cost of Storage and Transportation incurred by the Company. Storage and Transportation cost includes cost of service and market-based pricing.

2. The S&TDA also records the variance between the forecast Storage and Transportation demand levels and the actual Storage and Transportation demand levels. In addition, the S&TDA is used to record amounts received by the Company related to deferral account dispositions of other utilities deferral accounts.

3. The balance in the 2022 S&TDA that the Company is proposing to collect from customers is $8.1 million plus interest. A detailed breakdown of the S&TDA is provided in Exhibit D, Tab 1, Schedule 1.

4. The primary driver for the balance in the 2022 S&TDA is higher than forecasted transportation prices and higher than forecasted market-based storage costs in 2022, partially offset by a $1.5 million refund from the Union rate zone as part of Union's 2020 deferral disposition. Transportation prices are determined by the OEB-approved M12 Rate Schedule.

5. As outlined in the 2022 Annual Update to the 5 Year Gas Supply Plan, Enbridge Gas purchases market-based storage services on behalf of customers in the EGD rate zone through a competitive blind storage RFP process. On November 10, 2021, Enbridge Gas initiated an RFP for market-based storage capacity with deliveries to Dawn. The RFP was conducted by Ernst & Young LLP. The RFP requested offers of

storage services with terms of up to 3 years commencing April 1, 2022 with firm injections from May to September and firm withdrawals from December to March. The RFP letter is provided as Exhibit D, Tab 1, Schedule 5.

6. Enbridge Gas required this annual replacement of third-party storage in order to reliably and cost effectively meet demand on peak winter days as well as retain late season deliverability. The RFP responses were received by Enbridge Gas on December 2, 2021. The RFP manager made the recommendation and Enbridge Gas transacted based on the recommendation. Bids received and those that were selected are outlined in Confidential Exhibit D, Tab 1, Schedule 6.

2022 TRANSACTIONAL SERVICES DEFERRAL ACCOUNT
EGD RATE ZONE

1. The concept of Transactional Services operates under the premise that if circumstances arise where the assets acquired by Enbridge Gas to meet customer demand are not fully required then those assets can be made available to generate third party revenue. Transactional Services are the optimization of these assets.

2. Transactional Services optimization can be grouped into two different categories – storage optimization and transportation optimization. Storage optimization transactions typically rely on the storage of or the loan of gas between two points in time at the same location (i.e. Dawn). Transportation optimization transactions typically rely on the exchange of gas on the day between two locations.

3. Any revenues received from Transactional Services are to be shared 90:10 between the ratepayer and the Company. The EGD rate zone rates include an upfront benefit of $12.0 million in Transactional Services revenue that has been applied to reduce the overall costs to be collected from EGD rate zone ratepayers. The purpose of the TSDA is to capture the difference between the total ratepayer share of transactional services revenue and the amount already included in rates.

4. During 2022 the Company generated a total of $47.9 million in net Transactional Services revenue, of which the ratepayer portion represents $43.1 million, through a combination of Storage and Transportation Optimization. Exhibit D, Tab 1, Schedule 2 provides a breakdown of Transactional Services revenue by type of transaction, and sets out the details of the amount, $31.1 million, proposed to be credited to-customers through the disposition of the 2022 TSDA. For comparison purposes the schedule also includes amounts recorded in the applicable TSDA accounts for years 2021, 2020, 2019, and 2018

5. The transactions that Enbridge Gas entered into in 2022 contained the three elements of Transactional Services as were described in the Company’s evidence in EB-2013-0046 in that they were unplanned, the result of a Third-Party service request and were available because of temporary surplus capacity. Transactional services optimization in the Enbridge Gas rate zones is higher than what has been included in rates due to changing market dynamics. The majority of this increase results from the increase in the Dawn-Waddington spread. This spread is impacted by the lack of pipeline infrastructure serving US Northeast markets.

2022 UNACCOUNTED FOR GAS VARIANCE ACCOUNT
EGD RATE ZONE

1. The purpose of the Unaccounted for Gas Variance Account (UAFVA) is to capture the cost associated with the volumetric variances between the actual volume of unaccounted for gas (UAF)[1] and the OEB approved UAF volumetric forecast. This evidence provides details regarding the balance recorded in the 2022 UAFVA.

2. In the EGD Rate Zone, actual UAF was determined to be 256,332 10^3m^3. The forecast UAF volume of UAF was 106,677 10^3m^3. The variance between actual and forecasted UAF volumes of 149,656 10^3m^3, resulted in a debit balance of $41.4 million in the UAFVA, plus interest. Exhibit D, Tab 1, Schedule 3 provides the detailed calculations of the UAFVA balance.

3. To support the relief sought by Enbridge Gas, this exhibit contains additional evidence organized as follows:
   - Section 1: Historical UFG Volumes and UAFVA Balances
   - Section 2: Benchmarking
   - Section 3: Impacts of Pricing
   - Section 4: Commitments from 2021
   - Section 5: Actions Taken to Address UFG

Section 1: Historical UFG Volumes and UAFVA Balances

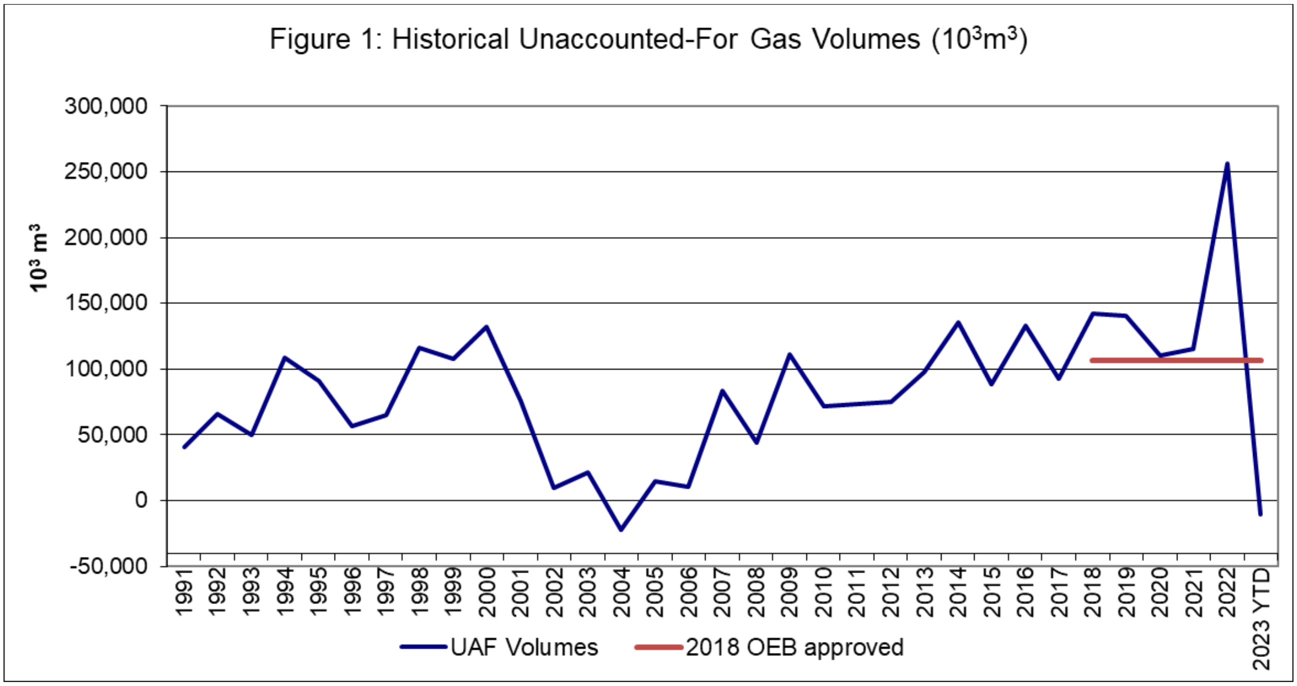
4. Table 1 provides historical UAF volumes for the EGD Rate Zone from 1991 to 2023 YTD.

[1] "UAF" is the term historically used in reference to distribution related gas losses in the EGD rate zone. All references to unaccounted for gas will be harmonized to be "UFG" in 2024, as described in the 2024 Rebasing Application, Exhibit 4, Tab 3, Schedule 1.

Table 1: Historical UAF Volumes for EGD Rate Zone

Calendar Year	UAF Volumes (10^3 m^3)
1991	40,662
1992	66,028
1993	49,782
1994	108,765
1995	90,655
1996	56,739
1997	65,228
1998	116,376
1999	108,201
2000	132,021
2001	75,606
2002	9,284
2003	21,412
2004	-22,406
2005	14,815
2006	10,274
2007	83,823
2008	44,424
2009	110,917
2010	72,104
2011	73,355
2012	74,762
2013	97,361
2014	135,380
2015	88,438
2016	133,112
2017	93,077
2018	142,086
2019	140,594
2020	110,234
2021	115,553
2022	256,333
2023 YTD	-10,273

5. Figure 1 compares historical UAF volumes for the EGD Rate Zone from 1991 to 2023 YTD to the 2018 OEB-approved UAF volume forecast.



6. The UAF volumes used in OEB-approved rates was determined as part of the Company's 2018 Rates proceeding (EB-2017-0086) using a regression model designed to estimate the relationship between historical UAF and total historical unlocked customers, assuming that the amount of UAF is directly correlated to the size of the distribution system. Since 2018, the annual UAF forecast has been fixed at 106,677 10^3m^3, profiled monthly in proportion to annual forecasted throughput volumes (see section 4.1 for additional detail). The UAFVA was established in 2002 as part of the Company's 2002 Rates proceeding (RP-2001-0032), in recognition of the need to record gas costs associated with variances between forecast and actual unaccounted for gas volumes.

7. Since the current UAF volume forecast was fixed in 2018, actual UAF volumes for the EGD Rate Zone has averaged 152,960 10^3m^3 (2018 – 2022). As a result, the Company has consistently recorded balances in the UAFVA for the EGD Rate Zone. Table 2 shows the historical UAFVA balances.

Table 2
EGD Rate Zone UAFVA Historical Balances

Line No.	Year	Actual UAF (10^3m^3) (a)	OEB Approved UAF (10^3m^3) (b)	UAF Variance (10^3m^3) (c)	UAFVA Balance ($ millions) (d)
1	2013	97,361	73,092	24,269	2.21
2	2014	135,380	77,660	57,720	11.92
3	2015	88,438	81,519	6,919	1.30
4	2016	133,112	84,766	48,346	7.92
5	2017	93,077	98,279	-5,202	(1.13)
6	2018	142,086	106,677	35,409	5.62
7	2019	140,594	106,677	33,917	4.88
8	2020	110,234	106,677	3,557	0.22
9	2021	115,553	106,677	8,876	0.75
10	2022	256,333	106,677	149,656	41.40

Note:
(1) UAF Variance (c) = Actual UAF (a) - OEB Approved UAF (b)

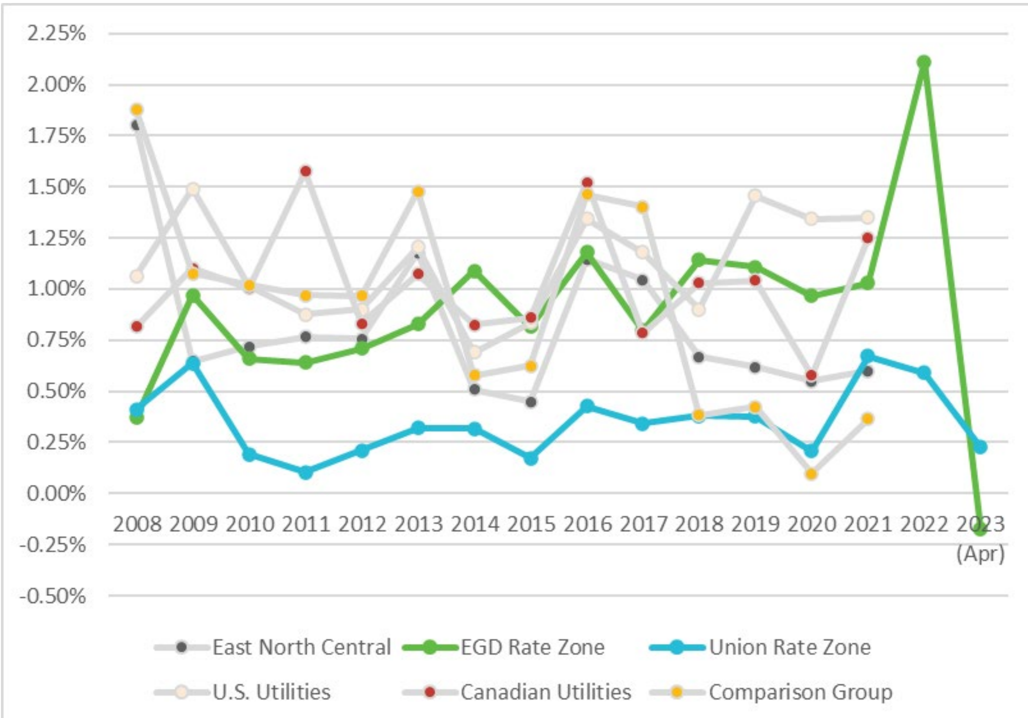
Section 2: Benchmarking

8. The 2019 Report on Unaccounted for Gas prepared by ScottMadden Management Consultants filed in the Company's 2020 Rates Application (EB-2019-0194) (the "2019 UFG Report") included a UFG Benchmark Analysis for the period of 2008 to 2017. Based on the results of the analysis completed, ScottMadden noted that Enbridge Gas had demonstrated lower UFG levels than comparative gas utilities (across all legacy EGD and Union Rate Zones).[2] For the purposes of the current Application, Enbridge Gas gathered the most current publicly available data for the same comparative gas utilities (up to and including 2021 for comparative utilities and 2023 YTD[3] for the Company) and updated the benchmark analysis set out in Figure 1 of the 2019 UFG Report[4]. Figure 2 reflects the best available data

[2] EB 2019-0194, Report on Unaccounted for Gas, pp. 3-4, December 19, 2019.
[3] April 30, 2023.
[4] Refer to EB 2019-0194, Report on Unaccounted for Gas, page 15 for details regarding comparative utilities included in Benchmark Analysis.

regarding UFG levels for each of the comparative utilities.

Figure 2: UFG Benchmark Analysis



9. Figure 2 demonstrates that all utilities included in the benchmark analysis experienced similar volatility in UFG, with material increases recorded in one year generally reversing in subsequent years. As noted in the 2019 UFG Report, the Alberta Utilities Commission stated in its decision on a UFG rider:

> The Commission recognizes that all gas distribution pipeline systems have UFG as an element of operating a natural gas distribution system and that because of the numerous factors that impact UFG, the UFG percentage will fluctuate over time.[5]

10. Figure 2 also reflects certain industry-wide trends across comparative utilities, such as a general decline in UFG levels recorded in each of 2014, 2015 and 2020

[5] Alberta Utilities Commission, Decision 22889-D01-2017, 2017-2018 Unaccounted-For Gas Rider D. (ATCO Gas and Pipelines Ltd.)

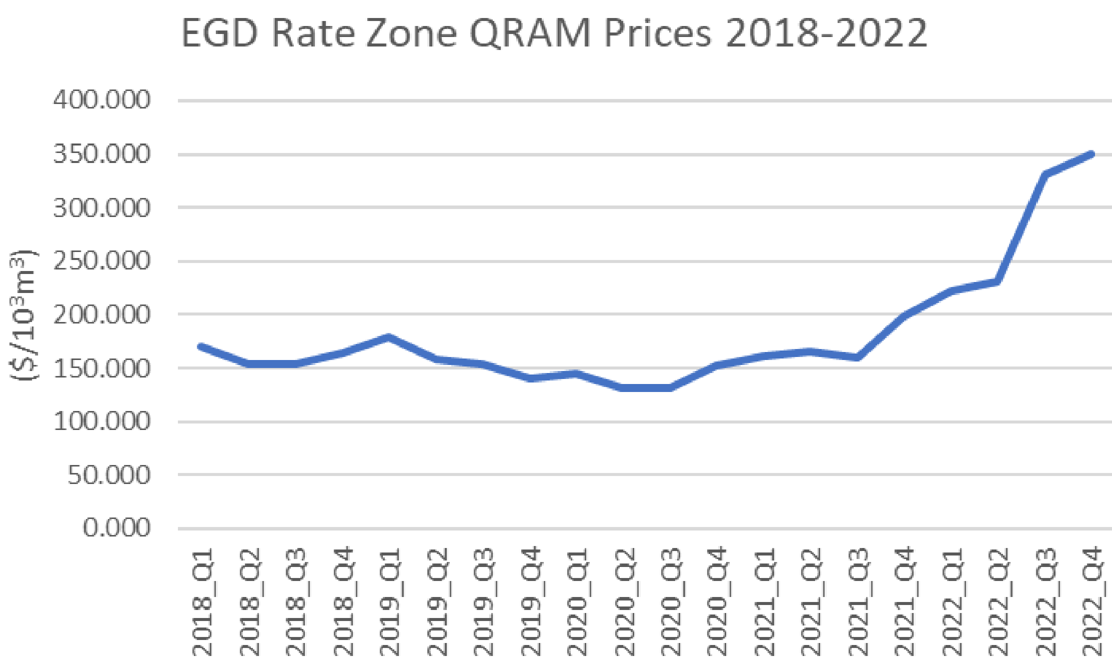
followed by increases in UFG levels recorded in subsequent years. It is reasonable to assume that such trends may be reflective of common macro-economic and/or national/continental weather trends, both of which have the potential to impact utility throughput and UFG broadly across the industry. Such trends highlight the value of comparing UFG levels experienced by a single utility to relevant peer groups before concluding whether any significant or material variation in year-over-year UFG levels is reasonable.

11. Figure 2 shows that the EGD and Union Rate Zones' UFG levels and annual fluctuations are generally consistent with other gas utilities. It also demonstrates that while Enbridge Gas has experienced recent increases in UFG levels in the EGD Rate Zone in 2022 and in the Union Rate Zones in 2021/2022, UFG levels are now trending lower for 2023 YTD. In response to the elevated levels of UFG recently experienced, Enbridge Gas has taken the initial steps to establish a discrete team with the express mandate to investigate root causes, make recommendations to reduce and monitor, and to implement a sustainment and governance model for UFG for the utility.

Section 3: Impact of Pricing

12. Actual UAF volumes recorded in the UAFVA in any given year are multiplied by the OEB-approved reference price to calculate the UAFVA balance. Accordingly, drastic increases in the reference price of natural gas realized throughout 2022 have contributed to the 2022 UAFVA balance. The magnitude of reference price increases is demonstrated within Figure 3, which shows the historical annual average OEB-approved reference price for 2018 to 2022 for the EGD Rate Zone.

Figure 3



13. While UAF volumes increased on a year-over-year basis as shown in Table 1, the elevated QRAM prices in 2022 are a significant contributor to the 2022 UAFVA balance. Most notably, in the last quarter of 2022, where approximately 30%[6] of the UAF Volume Variance is recorded, the QRAM price was 77% higher on a year over year basis[7].

Section 4: Commitments from 2021

14. In the Settlement Proposal in the 2021 Deferral and Variance Account and Earnings Sharing proceeding (EB-2022-0110)[8], Enbridge Gas committed to include the following items in its filing in this proceeding:

> Detailed evidence on the derivation of UFG balances, including evidence on items such as:
> (a) the process used to determine forecast and actual UFG at the end of each year and the beginning of the following year,

[6] Exhibit D, Tab 1, Schedule 3, Note (3).
[7] October 2022 $351/10^3m^3$ vs October 2021 $199/10^3m^3$
[8] EB-2022-0110, Decision on Settlement Proposal and Rate Order, November 8, 2022, p.4.

(b) the way that UFG is determined on an ongoing basis as forecast (unbilled) volumes are billed, and
(c) the impact of billing adjustments on UFG
(d) continuity schedule showing forecast and actual UFG on a monthly basis for 2020, 2021 and 2022.

15. Accordingly, this section of evidence is organized to respond directly to each of the commitments previously made by the Company, as follows:
    - Section 4.1: Determination of UFG Forecast
    - Section 4.2: Determination of Actual UFG – Monthly Processes
    - Section 4.3: Determination of Actual UFG – Annual Processes
    - Section 4.4: Forecast and Actual UFG on a Monthly Basis

Section 4.1:Determination of UFG Forecast

16. As explained in section 1, the current method to forecast UAF volumes in the EGD Rate Zone is based on a single equation regression model that estimates the relationship between historical UFG and the total historical unlocked/active customers. The number of unlocked/active customers is used as an independent variable based on the presumption that UAF volume is directly correlated to the size of the distribution system. Historically, the UAF volume forecast was updated annually and approved by the OEB as part of the Company's annual rate setting proceedings. Since the amalgamation of Enbridge Gas Distribution Inc. and Union Gas Limited, the UAF volume forecast for the EGD Rate Zone has been fixed at the level approved by the OEB as part of the Company's 2018 Rates proceeding (EB-2017-0086) of 106,677 10^3m^3. The OEB-approved UAF volume forecast is an annual amount, which is profiled monthly in proportion to annual forecasted total throughput volumes for the EGD Rate Zone.

Section 4.2: Determination of Actual UFG – Monthly Processes

17. At a high level, UFG is the difference between two primary components: net gas sendout (Sendout) and consumption.

    UFG loss/(gain) = Sendout – Consumption

18. Sendout is the net amount of natural gas delivered into the distribution system. At all custody transfer points, there is both custody transfer measurement (third-party) and check measurement (Enbridge Gas), both of which utilize Measurement Canada certified equipment that is required to comply with a +/- 3% measurement error tolerance. Internally, Enbridge Gas operates within a more stringent +/- 2% measurement error tolerance and investigates any measurement variance that exceeds those bounds. Enbridge Gas has established manual and automated means by which to validate measurement accuracy and takes volumetric, energy content, temperature, and pressure factors/variables into consideration when investigating measurement variances compared to prescribed reasonability tolerances, in addition to validating measurement completeness.

19. Consumption includes both billed consumption and unbilled consumption.

20. Billed consumption is calculated within the billing system based on a combination of actual and estimated meter reads. Certain customers, generally contract rate customers, have daily actual measurement recorded which is used to calculate their billed consumption. The remaining customers have periodic meter reads completed and so rely on a combination of actual and estimated meter reads to calculate their billed consumption. Estimated meter reads are calculated at the individual customer level based on consumption history for their respective premise(s). When insufficient usage history exists to derive an accurate estimated meter read, the billing system uses a combination of degree day data and standard factors for the customer's property type to derive an estimate.

21. In instances where a bill is based on an estimated meter read, a subsequent true-up will occur once an actual meter read is next recorded. In other words, Enbridge Gas reviews such accounts after obtaining an actual meter read and performs a volumetric adjustment (spread out over the estimated period since the last actual reading and taking into account weather[9], the number of days in each billing period, and the customer's actual consumption for the prior year). In situations where the customer's consumption pattern varies by season Enbridge Gas works with the customer to understand the nature of their consumption between actual meter reads and tailors the volumetric adjustment accordingly[10].

22. While the billing system ensures that the consumption is billed to the customer at the appropriate rate for the period in which the consumption occurred, to the extent volumetric adjustments are recorded, they are reflected in the accounting period in which billing occurred.

23. To demonstrate the impacts of the various true-ups described in this section, a number of illustrative examples are provided below:

    a) Scenario 1: Base Case
    b) Scenario 2: Estimated Meter Read
    c) Scenario 3: No Bill

    Note: Illustrative examples assume no UFG due to physical losses

    a) Scenario 1: Base Case
       Sendout = 100 units (actual)
       Consumption = 100 units (actual meter read)
       Billed Consumption = 100 units

[9] Heating degree days.
[10] When a volumetric adjustment spans more than a single fiscal quarter, the Company also ensures that the appropriate quarterly QRAM rate for that time period is applied.

UFG Recorded in Utility Month End Financial Results:

UFG = 100 – 100 = 0

Cumulative UFG = 0

b) Scenario 2: Estimated Meter Read

Month 1 (estimated read):

Sendout = 100 units (actual)

Consumption = 95 units (based on estimated meter read)

Billed Consumption = 95 units

UFG Recorded In Utility Month End Financial Results:

UFG = 100 – 95 = 5

Cumulative UFG = 5

Month 2 (actual meter read):

Sendout = 100 units (actual)

Consumption = 200 units (difference between last actual meter read and current actual meter read)

Billed Consumption = 200 - 95 units (billed in month 1) = 105 units

UFG Recorded in In Utility Month End Financial Results:

UFG = 100 – 105 = (5)

Cumulative UFG = 5 + (5) = 0

c) Scenario 3: “No Bill” Example

Month 1 (no bill issued to customer):

Sendout = 100 units (actual)

Consumption = 80 units (estimated for month-end accounting purpose)

Billed Consumption = 0 units (no bill issued to customer)

UFG In Utility Month End Financials:
UFG = 100 – 80 = 20
Cumulative UFG = 20

Month 2 (bill issued to customer for two months of consumption)
Sendout = 100 units (actual)
Consumption = 200 units (difference between last actual meter read and current actual meter read)
Billed Consumption = 200 units

UFG Recorded In Utility Month End Financial Results:
UFG = 100 – (200-80) = (20)
Cumulative UFG = 20 + (20) = 0

24. Consumption also includes an estimation of gas consumed but not yet billed. Enbridge Gas utilizes cycle billing, which means that customers are billed in cycles staggered throughout the month. As a result of cycle billing, there is a portion of consumption at any point in time that has not been billed. At the end of every monthly reporting period, Enbridge Gas records an estimate of gas delivered but not yet billed. This estimate is calculated at the rate class level and considers factors such as number of customers, average use, actual weather and demand coefficients. The unbilled estimate that is recorded in a given reporting period is reversed in the following reporting period and replaced by actual billed consumption. To the extent that the estimate of the unbilled consumption differs from the actual billed consumption, a true-up is recorded to reflect the difference.

25. If the estimation of unbilled consumption was determined to be understated upon the analysis of billed data, it has the impact of temporarily creating a UFG loss in the period that the unbilled estimation was recorded and creating a UFG gain in the

subsequent period when the estimate is reversed and replaced with actual billed consumption. The inverse is also true. True-ups associated with the unbilled estimate function similar to the no bill scenario described previously.

26. One additional adjustment that may occur on a monthly basis relates to measurement errors. The 2019 Report on UFG notes that measurement errors can be attributable to causes such as meter failure, meters that do not accurately correct for temperature of pressure variations or meters that are not sized properly.[11] Measurement errors result in a difference between actual and metered volumes. While the cause of the adjustment differs from true-ups/adjustments associated with estimated reads and unbilled estimates, the impact is the same. In the period when measurement error occurrs, it will result in a UAF loss/(gain). In the period when measurement error is corrected/adjusted, there will be an equal and offsetting impact.

27. On a monthly basis, the calculation of UAF is adjusted to exclude Company use volumes which are recorded as a gas cost and not recovered through the UAFVA.

28. On a monthly basis, the calculation of UAF volumes is recorded based on an annual heat value for natural gas delivered to customers. In the following month, when the actual heat values are available, the difference between the actual and annual heat value is recorded in the UAFVA.

Section 4.3: Determination of Actual UFG – Annual Processes

29. The processes described in section 4.2 are normal course of business (i.e, for each monthly accounting reporting period, including the end of the calendar fiscal year). In the EGD rate zone, there is one additional step that is completed after the end of the calendar fiscal year. The current accounting order for the UAFVA states: “An adjustment will be made to the UAFVA in the subsequent year to record any

[11] EB-2019-0194, Report on Unaccounted for Gas, p. 28.

differences between the estimated UAF and actual UAF."

30. In the EGD rate zone, the variance between the unbilled estimated recorded in December and the associated billed consumption recorded in January is included in the calculation of UAFVA in the fiscal year when the unbilled estimate was recorded. This ensures that the true-up is recorded in the reporting period that the consumption pertains to, and eliminates a timing variance that crosses fiscal years.

31. The UFG Volume Deferral Account in the Union Rate Zone does not include a similar provision to record an adjustment relating to estimation true-ups that cross fiscal years. As such, to the extent that there is a difference between estimated consumption and actual consumption, the true-up will be recorded in the subsequent fiscal year.

32. In the 2024 Rebasing Application[12], Enbridge Gas has proposed to harmonize the UFG Variance and Deferral accounts, including the provision in the proposed Accounting Order for the UFG Variance Account to adjust for differences in estimated UFG and actual UFG, similar to the current EGD Rate Zone treatment.

Section 4.4: Forecast and Actual UFG on a Monthly Basis for 2020-2022

33. As noted in Section 4: Commitments from 2021, Enbridge Gas committed to provide continuity schedule showing forecast and actual UFG on a monthly basis for 2020, 2021, and 2022. Table 3 includes forecast/budget and actual UAF volumes for 2017-2023 YTD.

[12] EB-2022-0200, Exhibit 9, Tab 1, Schedule 1, Attachment 3.

Table 3: Monthly Continuity of Actual and Forecast UFG Volumes for 2017-2023 for the EGD Rate Zone

Line No.	Particulars	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	Budget UFG Volume (10^3m^3)	2017	16,645	16,942	14,277	10,578	6,247	3,120	2,284	2,456	2,558	3,717	7,486	11,970	98,279
2	Actual UFG Volumes (10^3m^3)	2017	96,780	(26,650)	15,294	(21,864)	(33,637)	(15,132)	(14,975)	18,630	(41,200)	47,894	85,818	(17,881)	93,077
3	Budget UFG Volume (10^3m^3)	2018	17,033	18,952	16,299	11,723	6,620	3,360	2,496	2,412	2,463	3,884	8,289	13,146	106,677
4	Actual UFG Volumes (10^3m^3)	2018	158,791	(28,707)	(62,377)	51,446	(66,011)	(19,965)	36,506	(6,654)	14,940	(45,702)	43,543	66,279	142,086
5	Budget UFG Volume (10^3m^3)	2019	17,033	18,952	16,299	11,723	6,620	3,360	2,496	2,412	2,463	3,884	8,289	13,146	106,677
6	Actual UFG Volumes (10^3m^3)	2019	43,151	15,003	46,325	(1,406)	(18,597)	13,723	(43,504)	(5,651)	(2,567)	(41,912)	49,833	86,196	140,594
7	Budget UFG Volume (10^3m^3)	2020	17,033	18,952	16,299	11,723	6,620	3,360	2,496	2,412	2,463	3,884	8,289	13,146	106,677
8	Actual UFG Volumes (10^3m^3)	2020	101,494	25,721	(76,167)	(29,974)	38,767	(29,450)	(20,108)	38,740	(30,631)	11,147	42,691	38,004	110,234
9	Budget UFG Volume (10^3m^3)	2021	17,033	18,952	16,299	11,723	6,620	3,360	2,496	2,412	2,463	3,884	8,289	13,146	106,677
10	Actual UFG Volumes (10^3m^3)	2021	(7,547)	76,849	52,037	(103,603)	7,820	25,313	(22,799)	(21,997)	8,378	23,040	25,779	52,282	115,553
11	Budget UFG Volume (10^3m^3)	2022	17,033	18,952	16,299	11,723	6,620	3,360	2,496	2,412	2,463	3,884	8,289	13,146	106,677
12	Actual UFG Volumes (10^3m^3)	2022	76,061	(61,350)	139,110	(69,010)	(10,953)	2,531	25,502	11,401	(43,101)	55,190	(1,164)	132,116	256,333
13	Budget UFG Volume (10^3m^3)	2023	17,033	18,952	16,299	11,723									64,006
14	Actual UFG Volumes (10^3m^3)	2023	(3,024)	45,455	16,725	(69,430)									(10,273)

34. Enbridge Gas has provided additional data beyond what has been requested to illustrate several key points. First, the historical actual monthly UAF volumes exhibit fluctuations from month to month across all the years provided in Table 3. These fluctuations are due in part to the factors discussed in Section 2, 4.2 and 4.3. While Enbridge Gas has experienced recent increases in the annual UAF levels in the EGD rate zone in 2022 and in the Union Rate Zones in 2021/2022, the fluctuations in actual monthly UAF volumes existed prior to those time periods as well. Furthermore, Table 3 shows that UAF levels are now trending lower for 2023 YTD.

Section 5: Actions Taken to Address UFG

35. In accordance with commitments made by the Company in its 2020 Rates application (EB 2019-0194), Enbridge Gas included an update in its 2024 Rate Rebasing Application and pre-filed evidence regarding progress made in implementing recommendations set out within the 2019 UFG Report and other such UFG management/mitigation-related activities. More specifically, a UFG Progress Report initially filed in the 2022 Annual Rate Application[13] was also filed in the 2024

[13] EB-2021-0148.

Rebasing Application.[14] A Supplemental UFG Progress Report was also filed in the 2024 Rebasing Application.[15] Both reports have been included in Attachments 1 and 2 to this exhibit. Additional updates on the status of implementing items noted in the UFG Progress Report and the Supplemental UFG Progress Report provided in response to interrogatories in the 2024 Rate Rebasing proceeding[16] are provided in Attachment 3 to this exhibit.

36. Enbridge Gas is continuing to monitor and address potential contributors to UFG. In response to the elevated level of UFG recently experienced in both the EGD and Union Rate Zones, Enbridge Gas took the initial steps to establish a discrete team with the express mandate to investigate root causes, make recommendations to reduce and monitor, and to implement a sustainment and governance model for UFG for the utility.

[14] EB-2022-0200 Exhibit 4, Tab 3, Schedule 1, Attachment 3.
[15] EB-2022-0200 Exhibit 4, Tab 3, Schedule 1, Attachment 4.
[16] EB-2022-0200 Exhibit I.4.2-STAFF-108.

2022 ACTUAL AVERAGE USE TRUE-UP VARIANCE ACCOUNT EGD RATE ZONE

1. The purpose of this evidence is to provide information in support of the 2022 Average Use True-up Variance Account (AUTUVA) balance.

2. Table 1 of Exhibit D, Tab 1, Schedule 4 details the calculations that result in a debit from ratepayers of $6.904 million, plus interest of $0.340 million for a total debit from ratepayers of $7.244 million. The collection is attributable to actual Rate 1 (residential) and Rate 6 (apartment, small commercial and industrial) average uses being lower than 2022 forecast levels.

3. Lower weather-normalized actual average use for Rate 1 is primarily attributable to higher actual natural gas prices in 2022 than were forecast. For Rate 6, lower GDP growth and high commercial vacancy rates than were expected have been offset by higher employment growth than was forecast. Therefore, the actual Rate 6 average use was slightly lower than the forecast Rate 6 average use in 2022.

4. The purpose of the AUTUVA is to record (true-up) the revenue impact (exclusive of gas costs) of the normalized volumetric difference between the forecast of average use per customers in Rate 1 and Rate 6 and the actual weather-normalized average use experienced during the year. The revenue impact is calculated using a unit rate determined in the same manner as the impact used in the derivation of the Lost Revenue Adjustment Mechanism (LRAM).

5. As detailed in Table 1 of Exhibit D, Tab 1, Schedule 4, the calculation of the volumetric variance between forecast average use and actual normalized average use subtracts the volumetric impact of Demand Side Management (DSM) programs

in the year. As has been the case in previous applications, since the audited actual volume savings of 2022 DSM activities will not be available until a later date, the 2022 OEB-Approved Budget DSM volumes are used as an estimate of 2022 actuals. Without the exclusion of a DSM volumetric variance in the AUTUVA calculation, the impacts of DSM are inherently included. As a result, 2022 LRAM amounts which will be filed at a later date, will exclude the impact of Rate 1 and Rate 6 customers.

2022 DEFERRED REBATE ACCOUNT
EGD RATE ZONE

1. The purpose of the 2022 Deferred Rebate Account (DRA), consistent with prior fiscal years, was to record any amounts payable to, or receivable from, EGD rate zone customers as a result of clearing Deferral and Variance Accounts, which remain outstanding due to the inability to locate such customers.

2. During 2022, the Company cleared the EGD Rate Zone 2020 Federal Carbon deferral and variance accounts (EB-2021-0209) and 2020 deferral and variance accounts (EB-2021-0149) in April. In July, the Company also cleared the 2020 DSM related deferral and variance accounts (EB-2022-0007).

3. The ($72.7) thousand recorded in the 2022 DRA and requested for clearance (and corresponding interest of ($8.9) thousand), reflects the outstanding amount resulting from the clearance of deferral and variance accounts in the EGD rate zone which occurred during 2022 and the inability to locate and dispose of the approved amounts to all of the intended customers.

2022 ONTARIO ENERGY BOARD COST ASSESSMENT VARIANCE ACCOUNT EGD RATE ZONE

1. The purpose of the 2022 Ontario Energy Board Cost Assessment Variance Account (OEBCAVA) was to record any material variances between the OEB costs assessed to Enbridge Gas (relevant to the EGD rate zone) through application of the revised Cost Assessment Model (CAM), which became effective April 1, 2016, and the OEB costs which were included in EGD rate zone rates, which were determined through application of the prior Cost Assessment Model. The scope of the account is consistent with prior OEBCAVAs. However, in accordance with the EB-2020-0134 OEB-approved Settlement Proposal[1], in EGI's 2019 Earnings Sharing and Deferral Disposition proceeding, the base OEB costs assumed to be included in rates have been escalated to the reflect the growth in the amount recovered through rates, which results from annual price cap adjustments and customer growth. The OEBCAVA was originally approved for establishment by an OEB letter dated February 9, 2016, entitled: *Revisions to the Ontario Energy Board Cost Assessment Model.*

2. The amount recorded within the 2022 OEBCAVA is $3.105 million, plus interest of $0.193 million for a total debit balance of $3.298 million. This amount reflects the variance between OEB costs assessed to Enbridge Gas (relevant to EGD rate zone) in each quarter of fiscal 2022, utilizing the revised CAM, and EGD's average quarterly OEB cost assessment under the prior CAM, escalated in accordance with the EB-2020-0134 OEB-approved Settlement Proposal.

3. In order to calculate the amount to be recovered through the 2022 EGD rate zone OEBCAVA, the Company first needed to apportion the actual 2022 OEB assessed costs between the legacy rate zones. Commencing with the OEB's 2019 / 2020 fiscal first quarter assessment (for the period April 1, 2019 through June 30, 2019),

[1] EB-2020-0134, Decision on Settlement Proposal, January 25, 2021, pp. 5-6.

and continuing since, EGI has been receiving one consolidated quarterly bill for the amalgamated utility. To apportion the quarterly assessments received in 2022 between rate zones, the assessments were prorated based on the total invoices received by each legacy utility for the OEB's 2018 / 2019 fiscal year (for the period April 1, 2018 through March 31, 2019), the final year for which the OEB issued invoices to each legacy utility. Table 1 below shows the proration of the OEB's 2018 / 2019 fiscal year assessments between each legacy utility / rate zone (59.76% EGD rate zone, 40.24% Union rate zones). Table 2 shows the apportionment of EGI's 2022 assessed costs to the EGD rate zone, and the calculation of the amount recorded in the 2022 EGD rate zone OEBCAVA.

4. To calculate the amount for recovery through the 2022 EGD rate zone OEBCAVA, the Company also needed to establish the base comparator, reflecting the OEB costs included in EGD rate zone rates, determined through application of the prior Cost Assessment Model. In accordance with the EB-2020-0134 OEB-approved Settlement Proposal, the amount reflected in rates is to be increased, or escalated, to reflect the growth in the amount recovered as a result of annual price cap adjustments and customer growth. To establish the 2022 base comparator, the Company escalated the 2021 quarterly comparator of $0.799 million by the sum of the 2022 Price Cap Index (PCI) of 1.40%, and the EGD rate zone ICM threshold calculation Growth Factor (g) of 1.32%, which were approved as part of EGI's 2022 Rate Application (EB-2021-0147/0148). The escalation resulted in a 2022 quarterly comparator of $0.821 million ($0.779 million * (1 + (1.40% + 1.32%))). As noted above, Table 2 below shows the apportionment of EGI's actual 2022 assessed costs to the EGD rate zone, and the calculation of the amount recorded in the 2022 EGD rate zone OEBCAVA utilizing a base comparator of $0.821 million.

5. Within this proceeding, the Company is requesting clearance of the principal and interest balances recorded in the 2022 OEBCAVA, in the amount of $3.105 million and $0.193 million respectively, as shown in Exhibit C, Tab 1, Schedule 1.

Table 1

OEB 2018/2019 Cost Assessments

	EGD	UGL	Total
Apr. 1 to Jun. 30, 2018	1,467,963	988,479	2,456,442
Jul. 1 to Sep. 30, 2018	1,356,860	913,873	2,270,733
Oct. 1 to Dec. 31, 2018	1,356,860	913,873	2,270,733
Jan. 1 to Mar. 31, 2019	1,356,860	913,873	2,270,733
	5,538,543	3,730,098	9,268,641
Percentage of Total	59.76%	40.24%	100.00%

Table 2

Calculation of 2022 EGD RZ OEBCAVA

		EGD Rate Zone	Average Cost	Variance to EGD
Period	EGI Assessment	Share (59.76%)	Assessment Comparator	Rate Zone OEBCAVA
Jan. 1 to Mar. 31, 2022	2,379,075.00	1,421,735.22	821,240.30	600,494.92
Apr. 1 to Jun. 30, 2022	2,834,829.00	1,693,972.43	821,240.30	872,732.13
Jul. 1 to Sep. 30, 2022	2,740,205.00	1,637,429.18	821,240.30	816,188.88
Oct. 1 to Dec. 31, 2022	2,738,848.00	1,636,618.29	821,240.30	815,377.99
				3,104,793.92

2022 DAWN ACCESS COSTS DEFERRAL ACCOUNT
EGD RATE ZONE

1. The purpose of the Dawn Access Costs Deferral Account (DACDA), as established in the EB-2014-0323 Settlement Agreement, was to record for recovery the revenue requirement impact of the incremental costs incurred to implement the Dawn Transportation Service (DTS), including the costs for required system changes. In addition, in accordance with Legacy EGD's 2017 Rate Application Settlement Proposal (EB-2016-0215) the revenue requirement related to additional costs incurred to accommodate the heat value conversion modification, implemented in conjunction with the Dawn Transportation Service system development process, were also to be recorded within this account. Under the terms of the EB-2014-0323 Settlement Agreement, recovery of amounts recorded in the DACDA will be from all bundled customers, regardless of whether they are system or direct purchase and regardless of the service to which they currently subscribe, because all have the option of taking DTS if they so choose. Further details explaining the DACDA, including the recovery method, are included within Section 2.7 of the Settlement Agreement filed at Exhibit B, Tab 2, Schedule 1 of the EB-2014-0323 proceeding.

2. As was indicated in the EB-2018-0131, EB-2019-0105, EB-2020-0134, EB-2021-0149, and EB-2022-0110 proceedings (in support of the clearance of the 2017 through 2021 revenue requirement amounts recorded in the 2017 through 2021 DACDAs), all incremental costs incurred by the Company to implement the DTS (and functionality for 2 additional receipt points) and heat value conversion modification were capital in nature. Capital costs of $6.5 million were incurred to develop, test, and integrate enhancements to the functionality of Enbridge's EnTRAC and connected systems. The systems modifications were placed into service effective November 1, 2017, in conjunction with the implementation of Phase 2 of the Dawn Access Settlement. The annual revenue requirement amounts

sought for refund/recovery in association with those capital costs, includes the typical items in a cost of service revenue requirement, such as total return on rate base, including interest and return on equity, depreciation, and income taxes.

3. Within this proceeding, the Company is requesting clearance of the 2022 revenue requirement, or principal balance, of $1.185 million (and corresponding interest of $0.0583 million) for a total debit from ratepayers of $1.243 million. As indicated above, this amount represents the 2022 revenue requirement associated with the capital spending incurred to accommodate the DTS and heat value changes, which were placed into service in 2017. The Company has used the 2022 actual required capital structure within the 2022 revenue requirement calculation (consistent with the use of the actual capital structures which were utilized in determining previous revenue requirements which were approved for clearance). As of December 31, 2022, the costs are fully depreciated and no further revenue requirement impacts beyond 2022. The 2022 amount was slightly lower than 2021, due to a declining rate base value and lower required rate of return resulting in a lower cost of capital, but was higher than 2017 and 2018 as both years' revenue requirements benefited from a significant Capital Cost Allowance (CCA) tax deduction that does not repeat in subsequent years beyond 2018.

4. The revenue requirement sought for recovery will be allocated to the various rate classes based on the bundled annual deliveries of each rate class.

5. The determination of the 2022 DACDA revenue requirement deferral account amount and related costs are shown below. The approved 2017, 2018, 2019, 2020, & 2021 revenue requirement amounts are also shown for continuity

UTILITY CAPITAL STRUCTURE
2022 DACDA Impacts

		Col. 1	Col. 2	Col. 3	Col. 1	Col. 2	Col. 3	Col. 1	Col. 2	Col. 3	Col. 1	Col. 2	Col. 3	Col. 1	Col. 2	Col. 3	Col. 1	Col. 2	Col. 3
		2017 Actual Capital Structure			2018 Actual Capital Structure			2019 Actual Capital Structure			2020 Actual Capital Structure			2021 Actual Capital Structure			2022 Actual Capital Structure		
Line No.		Component	Indicated Cost Rate	Return Component	Component	Indicated Cost Rate	Return Component	Component	Indicated Cost Rate	Return Component	Component	Indicated Cost Rate	Return Component	Component	Indicated Cost Rate	Return Component	Component	Indicated Cost Rate	Return Component
		%	%	%	%	%	%	%	%	%	%	%	%	%	%	%	%	%	%
1.	Long-term debt	56.88	4.86	2.76	57.05	4.72	2.69	61.13	4.44	2.71	63.07	4.38	2.76	60.03	4.35	2.61	58.85	4.25	2.50
2.	Short-term debt	5.57	1.05	0.06	5.65	1.81	0.10	2.87	2.04	0.06	0.93	0.60	0.01	3.97	0.31	0.01	5.15	2.31	0.12
3.		62.45		2.82	62.70		2.80	64.00		2.77	64.00		2.77	64.00		2.62	64.00		2.62
4.	Preference shares	1.55	2.32	0.04	1.30	2.98	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.	Common equity	36.00	8.78	3.16	36.00	9.00	3.24	36.00	8.98	3.23	36.00	8.52	3.07	36.00	8.34	3.00	36.00	8.66	3.12
6.		100.00		6.02	100.00		6.07	100.00		6.01	100.00		5.84	100.00		5.63	100.00		5.74

	($ 000's)	2017	2018	2019	2020	2021	2022
7.	Ontario Utility Income	685.0	(521.2)	(1,324.9)	(1,349.0)	(1,359.7)	(855.3)
8.	Rate base	259.7	5,623.8	4,283.2	2,912.8	1,542.4	269.3
9.	Indicated rate of return	263.77 %	(9.27)%	(30.93)%	(46.31)%	(88.15)%	(317.60)%
10.	(Def.) / suff. in rate of return	257.75 %	(15.34)%	(36.94)%	(52.15)%	(93.78)%	(323.34)%
11.	Net (def.) / suff.	669.4	(862.7)	(1,582.2)	(1,519.0)	(1,446.5)	(870.8)
12.	Gross (def.) / suff.	910.7	(1,173.7)	(2,152.7)	(2,066.7)	(1,968.0)	(1,184.8)

UTILITY RATE BASE
2022 DACDA Impacts

($ 000's)

Line No.		2017	2018	2019	2020	2021	2022
	Property, plant, and equipment						
1.	Cost or redetermined value	264.4	6,421.6	6,453.2	6,453.2	6,453.2	6,453.2
2.	Accumulated depreciation	(4.7)	(797.8)	(2,170.0)	(3,540.4)	(4,910.8)	(6,183.9)
3.		259.7	5,623.8	4,283.2	2,912.8	1,542.4	269.3
	Allowance for working capital						
4.	Accounts receivable merchandise finance plan	-	-	-	-	-	-
5.	Accounts receivable rebillable projects	-	-	-	-	-	-
6.	Materials and supplies	-	-	-	-	-	-
7.	Mortgages receivable	-	-	-	-	-	-
8.	Customer security deposits	-	-	-	-	-	-
9.	Prepaid expenses	-	-	-	-	-	-
10.	Gas in storage	-	-	-	-	-	-
11.	Working cash allowance	-	-	-	-	-	-
12.		-	-	-	-	-	-
13.	Ontario utility rate base	259.7	5,623.8	4,283.2	2,912.8	1,542.4	269.3

UTILITY INCOME
2022 DACDA Impacts

($ 000's)

Line No.		2017	2018	2019	2020	2021	2022
	Revenue						
1.	Gas sales	-	-	-	-	-	-
2.	Transportation of gas	-	-	-	-	-	-
3.	Transmission and compression	-	-	-	-	-	-
4.	Other operating revenue	-	-	-	-	-	-
5.	Other income	-	-	-	-	-	-
6.	Total revenue	-	-	-	-	-	-
	Costs and expenses						
7.	Gas costs	-	-	-	-	-	-
8.	Operation and Maintenance	-	-	-	-	-	-
9.	Depreciation and amortization	112.3	1,372.4	1,370.4	1,370.4	1,370.4	857.2
10.	Municipal and other taxes	-	-	-	-	-	-
11.	Total costs and expenses	112.3	1,372.4	1,370.4	1,370.4	1,370.4	857.2
12.	**Utility income before inc. taxes**	(112.3)	(1,372.4)	(1,370.4)	(1,370.4)	(1,370.4)	(857.2)
	Income taxes						
13.	Excluding interest shield	(795.4)	(809.5)	(14.1)	-	-	-
14.	Tax shield on interest expense	(1.9)	(41.7)	(31.4)	(21.4)	(10.7)	(1.9)
15.	Total income taxes	(797.3)	(851.2)	(45.5)	(21.4)	(10.7)	(1.9)
16.	**Ontario utility net income**	685.0	(521.2)	(1,324.9)	(1,349.0)	(1,359.7)	(855.3)

UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2022 DACDA Impacts

($ 000's)

Line No.		2017	2018	2019	2020	2021	2022
1.	Utility income before income taxes	(112.3)	(1,372.4)	(1,370.4)	(1,370.4)	(1,370.4)	(857.2)
	Add Backs						
2.	Depreciation and amortization	112.3	1,372.4	1,370.4	1,370.4	1,370.4	857.2
3.	Large corporation tax	-	-	-	-	-	-
4.	Other non-deductible items	-	-	-	-	-	-
5.	Any other add back(s)	-	-	-	-	-	-
6.	Total added back	112.3	1,372.4	1,370.4	1,370.4	1,370.4	857.2
7.	Sub total - pre-tax income plus add backs	-	-	-	-	-	-
	Deductions						
8.	Capital cost allowance - Federal	3,001.6	3,054.9	53.2	-	-	-
9.	Capital cost allowance - Provincial	3,001.6	3,054.9	53.2	-	-	-
10.	Items capitalized for regulatory purposes	-	-	-	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-	-	-	-
12.	Amortization of share and debt issue expense	-	-	-	-	-	-
13.	Amortization of cumulative eligible capital	-	-	-	-	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-	-	-	-
15.	Any other deduction(s)	-	-	-	-	-	-
16.	Total Deductions - Federal	3,001.6	3,054.9	53.2	-	-	-
17.	Total Deductions - Provincial	3,001.6	3,054.9	53.2	-	-	-
18.	Taxable income - Federal	(3,001.6)	(3,054.9)	(53.2)	-	-	-
19.	Taxable income - Provincial	(3,001.6)	(3,054.9)	(53.2)	-	-	-
20.	Income tax provision - Federal	(450.2)	(458.2)	(8.0)	-	-	-
21.	Income tax provision - Provincial	(345.2)	(351.3)	(6.1)	-	-	-
22.	Income tax provision - combined	(795.4)	(809.5)	(14.1)	-	-	-
23.	Part V1.1 tax	-	-	-	-	-	-
24.	Investment tax credit	-	-	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(795.4)	(809.5)	(14.1)	-	-	-
	Tax shield on interest expense						
26.	Rate base as adjusted	259.7	5,623.8	4,283.2	2,912.8	1,542.4	269.3
27.	Return component of debt	2.82%	2.80%	2.77%	2.77%	2.62%	2.62%
28.	Interest expense	7.3	157.5	118.6	80.7	40.4	7.1
29.	Combined tax rate	26.500%	26.500%	26.500%	26.500%	26.500%	26.500%
30.	Income tax credit	(1.9)	(41.7)	(31.4)	(21.4)	(10.7)	(1.9)
31.	**Total income taxes**	(797.3)	(851.2)	(45.5)	(21.4)	(10.7)	(1.9)

UTILITY REVENUE REQUIREMENT
2022 DACDA Impacts

($ 000's)

Line No.		2017	2018	2019	2020	2021	2022
	Cost of capital						
1.	Rate base	259.7	5,623.8	4,283.2	2,912.8	1,542.4	269.3
2.	Required rate of return	6.02%	6.07%	6.01%	5.84%	5.63%	5.74%
3.	Cost of capital	15.6	341.4	257.4	170.1	86.8	15.5
	Cost of service						
4.	Gas costs	-	-	-	-	-	-
5.	Operation and Maintenance	-	-	-	-	-	-
6.	Depreciation and amortization	112.3	1,372.4	1,370.4	1,370.4	1,370.4	857.2
7.	Municipal and other taxes	-	-	-	-	-	-
8.	Cost of service	112.3	1,372.4	1,370.4	1,370.4	1,370.4	857.2
	Misc. & Non-Op. Rev						
9.	Other operating revenue	-	-	-	-	-	-
10.	Other income	-	-	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-	-	-
	Income taxes on earnings						
12.	Excluding tax shield	(795.4)	(809.5)	(14.1)	-	-	-
13.	Tax shield provided by interest expense	(1.9)	(41.7)	(31.4)	(21.4)	(10.7)	(1.9)
14.	Income taxes on earnings	(797.3)	(851.2)	(45.5)	(21.4)	(10.7)	(1.9)
	Taxes on (def) / suff.						
15.	Gross (def.) / suff.	910.7	(1,173.7)	(2,152.7)	(2,066.7)	(1,968.0)	(1,184.8)
16.	Net (def.) / suff.	669.4	(862.7)	(1,582.2)	(1,519.0)	(1,446.5)	(870.8)
17.	Taxes on (def.) / suff.	(241.3)	311.0	570.5	547.7	521.5	314.0
18.	**Revenue requirement**	(910.7)	1,173.6	2,152.8	2,066.8	1,968.0	1,184.8
	Revenue at existing Rates						
19.	Gas sales	0.0	0.0	0.0	0.0	0.0	0.0
20.	Transportation service	0.0	0.0	0.0	0.0	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0	0.0	0.0	0.0	0.0
22.	Rounding adjustment	0.0	(0.1)	0.1	0.0	0.0	0.0
23.	Revenue at existing rates	0.0	(0.1)	0.1	0.0	0.0	0.0
24.	**Gross revenue (def.) / suff.**	910.7	(1,173.7)	(2,152.7)	(2,066.8)	(1,968.0)	(1,184.8)

ACCOUNTS WITH A ZERO BALANCE
EGD RATE ZONE

1. The following 2022 accounts for the EGD Rate Zone have no balance, and are therefore not requested for clearance to customers:
   - Gas Distribution Access Rule Impact (GDARIDA) Deferral Account
   - Electric Program Earnings Sharing (EPESDA) Deferral Account
   - Pension and OPEB Forecast Accrual vs. Actual Cash Payment Differential Variance Account
   - Open Bill Revenue (OBRVA) Variance Account
   - Ex-Franchise Third Party Billing Services (EXTPBSDA) Deferral Account

2. Consistent with past annual deferral and variance account clearance proceedings, Enbridge Gas has not listed accounts that will be reviewed through other processes in Exhibit C, Tab 1, Schedule 1, and these accounts are not addressed in this proceeding. Examples include the PGVA, DSM related accounts and Federal Carbon Charge accounts.

ENBRIDGE GAS INC.

PROGRESS REPORT ON IMPLEMENTATION OF SCOTTMADDEN RECOMMENDATIONS ON UNACCOUNTED FOR GAS (UFG)

CONTENTS

1.0 INTRODUCTION

1.1 PURPOSE

In its 2016 Earnings Sharing and Deferral Account Disposition proceeding (EB 2017-0102), legacy Enbridge Gas Distribution agreed to review potential metering issues that might be contributing to Unaccounted for Gas (UFG) and to report on that review as part of the 2018 Rate Adjustment Application[1]. In the 2018 Rate Application, Legacy Enbridge Gas Distribution agreed to continue this review and report on it as part of the 2019 Rate Adjustment Application.[2] In the MAADs decision EB-2017-0306/EB-2017-0307, the Ontario Energy Board (OEB) directed Enbridge Gas Inc (Enbridge Gas or EGI) to file a report on UFG for both legacy Union Gas (LUG) and legacy Enbridge Gas Distribution (LEGD) service areas by December 31, 2019. Accordingly, Enbridge Gas filed a UFG report (the UFG Report) prepared by ScottMadden Management Consultants in December 2019. The UFG Report reviewed and evaluated factors contributing to UFG for the legacy Companies. The Report indicated that the main sources of UFG included retail meter variations, gate station meter variations, leaks, fugitive emissions, third-party theft, company use and accounting adjustments.

The UFG Report was considered as part of the 2020 Rate Application Phase 2 (EB-2019-0194). In that proceeding, Enbridge Gas committed to "….report upon its progress in implementing the recommendations set out in the UFG Report in its 2022 rates filing."[3] Enbridge Gas has also committed in the same application[4] to assess its UFG forecasting methodology in the 2024 rebasing proceeding and to include information about the implementation of the UFG Report recommendations and other activities to address UFG, and the impacts of such activities. Furthermore, Enbridge Gas committed[5] to provide reporting of UFG results, segregated by rate zone and activity (distribution, transmission, storage), with the most recent historical information as part of the rebasing filing.

Enbridge Gas has always monitored and actively managed UFG. The UFG Report provided numerous recommendations to enhance the ongoing efforts already in place. This update provides details of Enbridge Gas' progress in implementing the recommendations set out in the UFG Report. The recommendations from the UFG Report were to "identify and standardize "best practices" across the legacy

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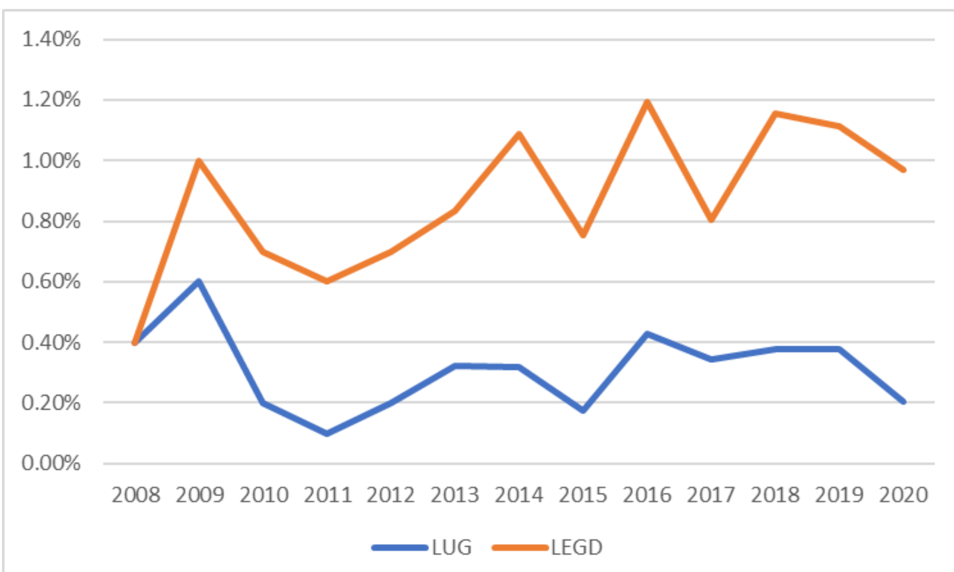
[1] EB-2017-0102, Settlement Proposal, page 14.
[2] EB-2017-0086, Settlement Proposal, Exhibit N2, Tab 1, Schedule 1, page 12.
[3] EB-2019-0194, Reply Argument of Enbridge Gas dated May 1, 2020, page 33; EB-2019-0194, Decision and Order dated May 14, 2020, page 20.
[4] EB-2019-0194, Reply Arguement, page 34.
[5] EB-2019-0194, Reply Arguement, page 34

Companies…..document data, processes and studies related to monitoring and managing UFG……[and] investigate the sources of UFG, research industry practices and initiatives for monitoring and managing sources of UFG, and implement, as appropriate, new practices and initiatives to better monitor and manage sources of UFG"[6]. This update outlines how Enbridge Gas is actively taking steps to implement the recommendations from the UFG Report, while continuing to prudently monitor and manage UFG.

1.2 UNACCOUNTED FOR GAS (UFG) OVERVIEW

UFG is broadly defined as the difference between gas receipts and gas deliveries, where gas receipts are volumes that enter the distribution system and gas deliveries are volumes that exit the distribution system. Gas receipts generally include gas supplies from pipeline and withdrawals from on-system storage facilities, while gas deliveries generally include sales to retail customers and injections into on-system storage facilities. The UFG Report included benchmarking analysis that demonstrated that UFG as a percentage of throughput for both legacy Companies was lower than its peers. Figure 1 shows UFG as a percentage of throughput for both legacy Companies. UFG as a percentage of throughput for both legacy Companies has remained flat or decreased for the last five years.

Figure 1: UFG as a % of Throughput for LUG and LEGD



[6] EB 2019-0194, ScottMadden Report, December 2019, page 47.

Figure 2: Historical UFG Volumes and % of Throughput

Year	LEGD UFG Volume (103m3)	LUG UFG Volume (103m3)	LEGD UFG as a % of Throughput	LUG UFG as a % of Throughput
2008	44,424	143,880	0.373%	0.411%
2009	110,917	201,845	0.981%	0.637%
2010	72,104	67,283	0.662%	0.192%
2011	73,355	35,668	0.647%	0.105%
2012	74,762	68,690	0.711%	0.210%
2013	97,361	113,997	0.834%	0.320%
2014	135,380	97,109	1.089%	0.318%
2015	88,438	54,408	0.752%	0.174%
2016	133,112	131,588	1.194%	0.427%
2017	93,077	108,901	0.804%	0.342%
2018	142,086	136,447	1.157%	0.379%
2019	140,594	137,652	1.114%	0.376%
2020	110,234	74,120	0.968%	0.208%

2.0 Main Sources of UFG

Overview

As part of its research and analysis for the UFG Report, ScottMadden identified certain common sources of UFG across the industry, including physical losses (eg.leaks, third-party damage and venting during construction and maintenance activities), metering variations, non-registering meters, theft, line pack and billing and accounting adjustments. ScottMadden also determined that the sources of UFG for the legacy Companies were generally consistent with those at other gas utilities. The following sections provide additional detail regarding the sources of UFG at Enbridge Gas.

2.1 Physical Losses

Physical losses are a source of UFG at Enbridge Gas. Contributors to physical losses include: leaks and emissions from natural gas facilities, releases of natural gas during maintenance, construction and emergency situations, and line hits due to third-party construction or excavation activities.

Enbridge Gas reports fugitive, vented and flared emissions annually to Environment and Climate Change Canada and the Ontario Ministry of Environment, Conservation and Parks. Figure 3 shows a 15% decline in emissions and leaks within the consolidated Enbridge Gas operations from 2015 to 2020. The slight increase in leaks and fugitive emissions reported in 2019 and 2020 is a result of the use of improved emissions factors. Since 2018, Enbridge Gas continues to refine the emissions and activity factors used to quantify and estimate leaks and fugitive emissions. Changes to these factors are described in EGI Interrogatory Response (EB-2019-0194, Exhibit I.STAFF.30), as well as in section 3.1 (iii) of this report. Figure 3 shows lost gas from leaks and emissions on a combined basis for Enbridge Gas, while Figure 4 provides a breakdown of the total leaks and emissions for Enbridge Gas by type.

Figure 3: Lost Gas from Leaks and Emissions (10^6m^3)

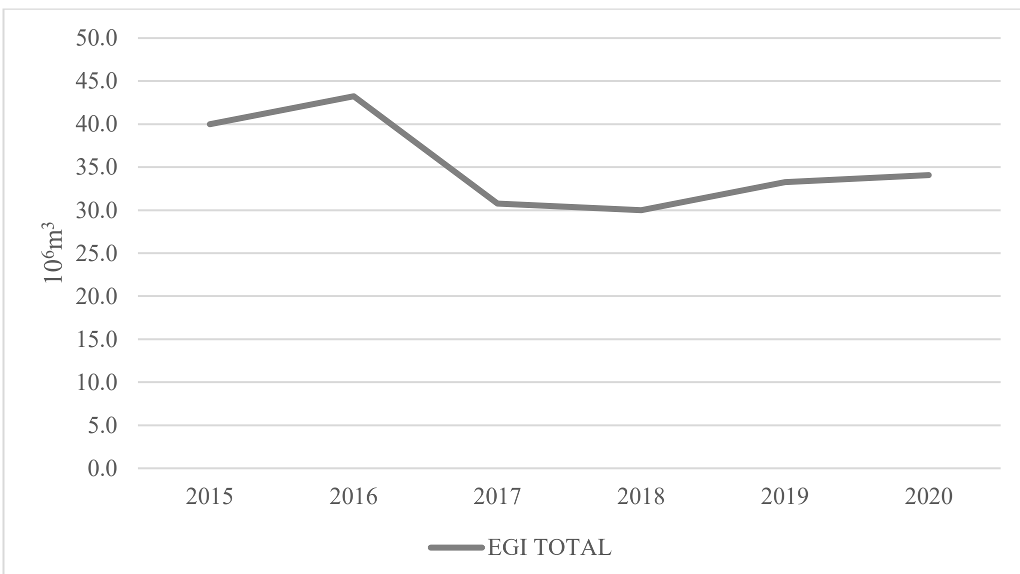
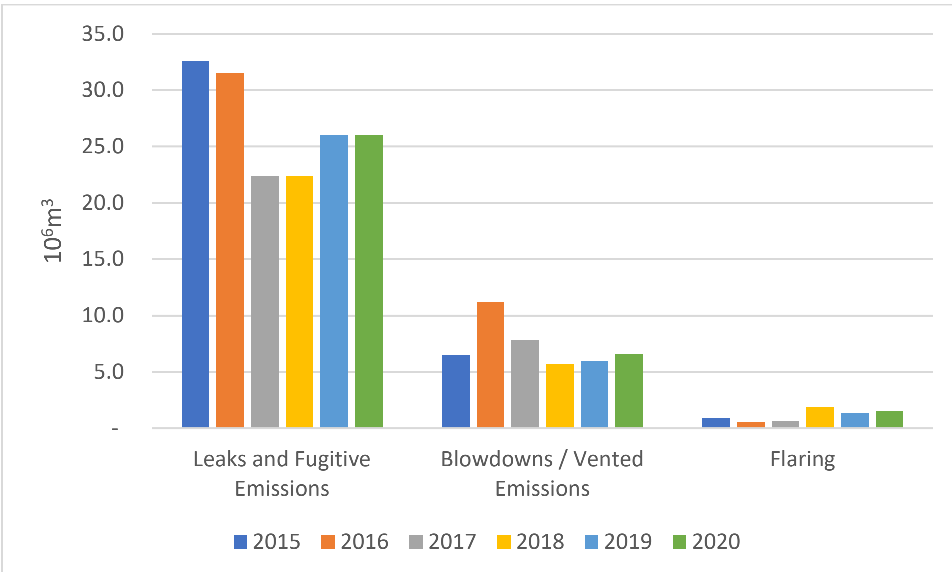


Figure 4: Lost Gas from Leaks and Emissions (10^6m^3) by Type



2.2 Retail Meter Variations

Retail meter variations represent variations between actual and metered volumes at customer locations. These variations can be attributed to factors including: inherent measurement uncertainties of meters, meter failure, inaccurate corrections for temperature and pressure variations or improperly sized meters. Enbridge Gas conducts meter testing on a sample of diaphragm meters annually. These tests are conducted under low-flow and high-flow conditions. Historical test results going back to 2014 are shown in Figure 5 and 6 below.

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Figure 5: LEGD Meter Test Results vs Measurement Canada (MC) Standard

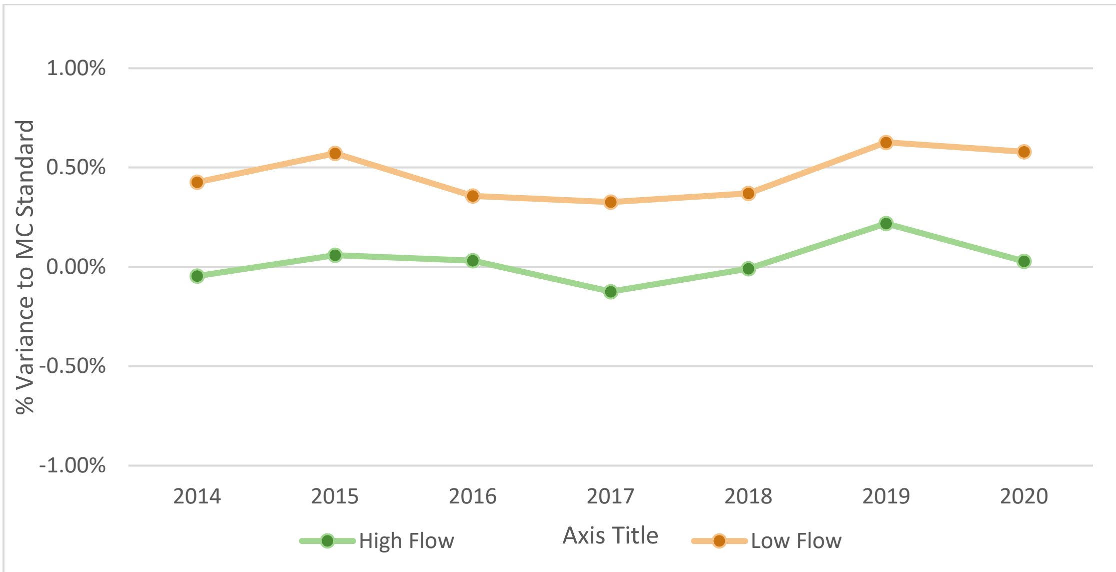

Figure 6: LUG Meter Test Results vs Measurement Canada (MC) Standard

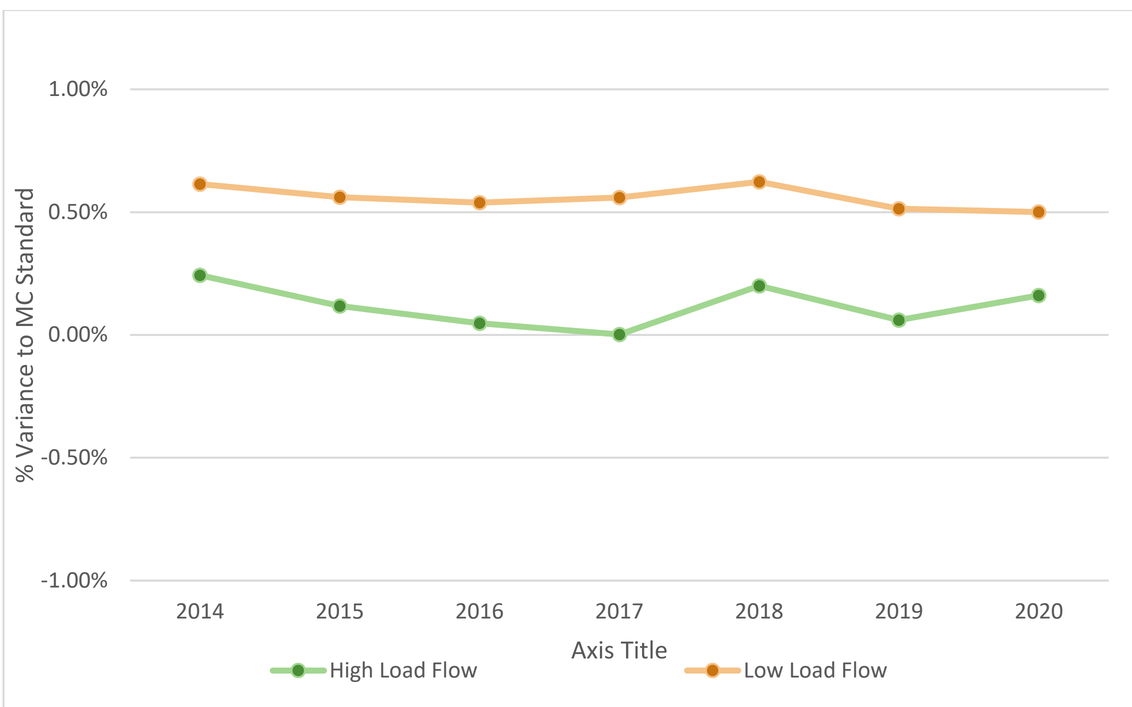

Figure 5 and 6 show that tests under high-flow and low-flow conditions result in the following variances since 2014:

	High-Flow Conditions % Variance to Measurement Canada Standard	Low-Flow Conditions % Variance to Measurement Canada Standard
LEGD	0.02%	0.47%
LUG	0.12%	0.56%

The variances to the Measurement Canada standard are within the Measurement Canada tolerance of +/- 3.0 percent. Meters whose test results that fall outside of the +/- 3.0 percent tolerance are taken out of service. All rotary turbine, and ultrasonic meters are tested on a frequency which is prescribed by Measurement Canada[7].

2.3 Gate Station Meter Variations

Gate station meter variations represent a potential source of UFG if there are differences at receipt points between actual and metered volumes. However, not all gate station meter variations can be wholly attributable to UFG, as the variations may only represent differences in meters, and may not represent actual lost gas.

Enbridge Gas utilizes check meters to validate the accuracy of the custody or supplier meters. A comparison between Enbridge Gas' check meters and third-party custody transfer meters is depicted in Figure 7 below. This figure demonstrates that Enbridge Gas' check measurement falls within the Measurement Canada prescribed range of +/- 3% and with the +/- 2% tolerance of the Enbridge Gas internal benchmark.

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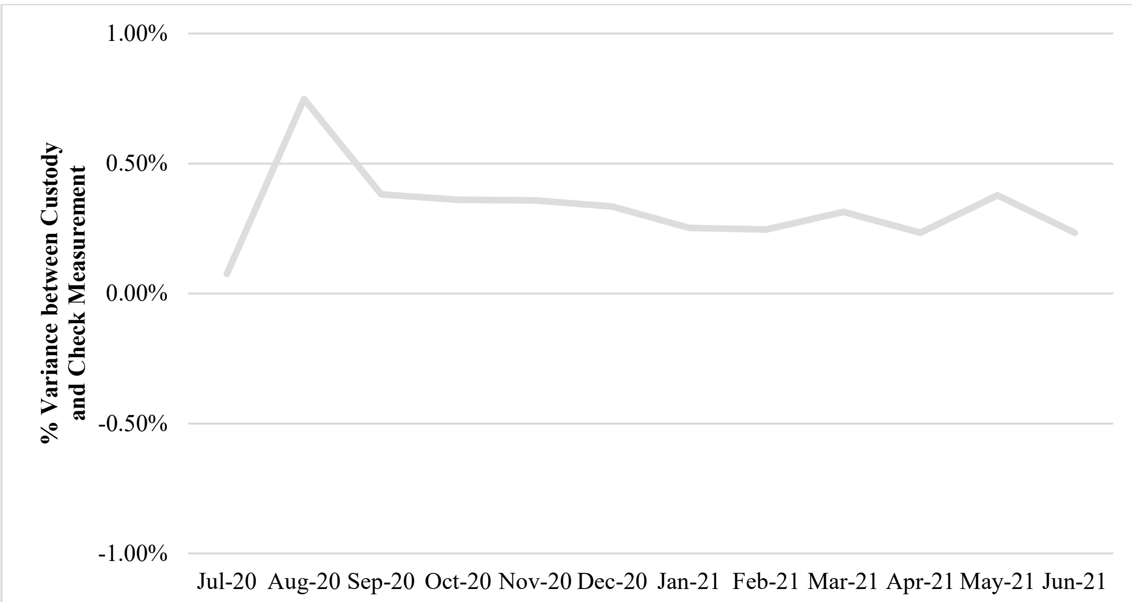
[7] Gas Bulletin G-18: Reverification periods for gas meters, ancillary devices and metering installations (http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm00607.html) and
Gas Bulletin G-03: Natural gas meters and ancillary devices qualified for a lengthened initial reverification period, identifies meter manufacturers and models (http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm00576.html)

Figure 7: Third Party Custody Transfer vs Enbridge Gas Check Meters Differences



2.4 OTHERS (INCL. ACCOUNTING ADJUSTMENTS, COMPANY USE, THEFT AND NON-REGISTERING METERS)

The remaining primary contributors of UFG at Enbridge Gas include theft and non-registering meters, company use, and accounting adjustments. Theft and non-registering meters account for volumes that are not metered or recorded due to unauthorized use or faulty equipment. Company use contributor represents the portion of company use volumes used by Enbridge Gas that are not metered and/or recorded. Accounting adjustments represent variations between actual and reported volumes due to various accounting adjustments, including unbilled sales adjustments, billing adjustments, line pack and other accounting related adjustments.

3.0 UPDATE ON RECOMMENDATIONS BY SOURCE

SUMMARY OF SCOTTMADDEN RECOMMENDATIONS

In the UFG Report, ScottMadden recommended that Enbridge Gas identify and standardize “best practices” across the legacy Companies. ScottMadden also recommended that Enbridge Gas document data, process and studies related to monitoring and managing UFG. Finally, ScottMadden recommended that, on a periodic basis, Enbridge Gas investigate the sources of UFG, research industry practices and initiatives for monitoring and managing sources of UFG, and implement, as appropriate, new practices and initiatives to better monitor and manage sources of UFG. In addition to these general recommendations, ScottMadden also provided recommendations specific to each of the main sources of UFG. The following sections highlight the work that has been done for each of these recommendations in relation to each main source of UFG.

3.1 Physical Losses

i. Identify and Standardize Best Practices at EGI

Enbridge Gas implemented a harmonized leak operating standard across the legacy Companies in July 2020. This new standard includes: harmonized internal compliance requirements for leak monitoring and repair timelines, increased traceability and tracking of leak repairs (including the addition of new work order types corresponding to type and severity of leaks, an enhancement for both legacy Companies), increased monitoring frequencies and harmonized repair timelines for above ground leaks (which increased the frequency of monitoring for LEGD assets to align with the LUG standard), harmonization of survey cycles based on asset age and pressure (designed to survey assets with higher probability of failure on a more frequent cycle), and initiation of the station leak survey program.

In conjunction with the new leak operating standard, Enbridge Gas has developed a three-year program to eliminate a backlog of leaks identified prior to the roll out of the new standard.

In the area of controlled releases of gas during maintenance and construction activities, Enbridge Gas has been able to leverage best practices across the legacy Companies. LUG historically relied on lower pressure markets, where available, to draw down sections of pipeline for construction and maintenance, with the remaining gas vented to atmosphere. Since the integration of the two legacy Companies, Enbridge Gas has been able to leverage a portable drawdown compressor previously utilized by LEGD for construction related maintenance activities across the legacy Companies service areas.
g

ii. Document Data/Processes/Studies related to monitoring and managing UFG

As noted in the UFG Report, Enbridge Gas has a program to review and evaluate replacement of bare-steel mains. This is an existing program that was in place prior to the amalgamation of the two Legacy Companies, originating from the LUG Pipeline Integrity Management Program, and more recently, has been included in Enbridge Gas' Asset Management Plan. Since 2019, approximately 9,800 kms of bare-steel mains have been replaced across the Enbridge Gas service area, with a target of replacing all remaining bare-steel mains by the end of 2024.

Enbridge Gas also has a program in place to replace vintage steel and plastic mains. This program leverages the Asset Health Review (AHR) process to forecast when corrosion and crack leaks might occur. The AHR process involves an evaluation of Enbridge Gas' gas carrying assets and their characteristics. The AHR utilizes reliability and risk models, both of which were updated in 2021 with additional historical data, and in some case, updates to the methodologies used in the models. A risk assessment is developed using the results of the reliability and risk models and an evaluation of the consequences of failure. This assessment is used to proactively select main replacements.

iii. Research Industry Practices and Initiatives for Monitoring and Managing Sources of UFG

Enbridge Gas continues to sponsor emissions studies, in partnership with the Canadian Energy Partnership for Environmental Innovation (CEPEI) and its member natural gas companies across Canada. The goal of these studies is to improve emission and activity factors and emission estimation methodologies in the natural gas storage, transmission and distribution industry. Recent studies have been completed to better quantify emissions related to residential, commercial and industrial meter sets, with the updated emission and activity factors results being incorporated into the Enbridge Gas emissions inventory starting with the 2019 emissions inventory. Additionally, Enbridge Gas is part of a study that is currently underway to update emission and activity factors related to valve sites. The survey work for the study was completed in 2020, and the results of the study are pending.

iv. Implement New Practices and Initiatives

Enbridge Gas has implemented new practices and initiatives relating to damage reduction and reduction of methane emissions from venting and fugitive leaks.

In 2020, the federal Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (Methane Regulation) came into effect, to help reduce methane emissions from Canada's oil and gas sector. In response to the Methane Regulation, Enbridge Gas has introduced programs and initiatives targeted at reducing fugitive and vented gas.

Enbridge Gas implemented a more robust leak detection and repair (LDAR) program within its Storage and Transmission operations in 2020. The LDAR program details the frequency of completion of leak surveys at compressor, storage and metering stations within Enbridge Gas' storage and transmission system, as well as specifying the timelines for completing leak repairs. The frequency of leak surveys increased from annually to three times per year. The goal of the LDAR program is to improve the detection and repair of leaks, resulting in a reduction in leaks and fugitive emissions, as well as reducing UFG. Additionally, results from these surveys have been incorporated into the Enbridge Gas GHG inventory, starting with the 2019 inventory.

Furthermore, starting in 2020, compressor unit rod packing and seal venting emissions are measured in order to meet regulatory emissions targets. In response to this regulatory requirement, Enbridge Gas implemented a measurement and compliance program in 2020 with respect to compressor venting, which includes measurement timelines, emission limits and repair deadlines for units that are over the limit. As such, vented emissions from this emissions source are expected to be reduced as compared to historical emissions.

Enbridge Gas has also implemented a program to replace continuous high-bleed pneumatic devices with low-bleed or no-bleed alternatives during the 2021-2022 calendar years. This will result in a reduction of vented emissions from pneumatic devices within storage and transmission operations.

Pipeline maintenance activities have begun to utilize an incinerator, which combusts the gas entering the atmosphere rather than venting methane. This practice began in 2021. The primary use has been to create the proper flow conditions on a pipeline to facilitate in-line inspections or to condition new pipelines during initial odourization, however it has the secondary benefit of reducing GHG emissions in lieu of venting.

Enbridge Gas has also developed a Damage Reduction Strategy, which commenced in 2021. This strategy includes a specific focus on reinforcement of safe excavation practices with contractors working in the vicinity of Enbridge Gas assets, increasing homeowner awareness and education on locate requirements and excavation guidelines (including the promotion of the "Call Before You Dig" program), improving in-field engagement with third party excavators, and increasing proactive efforts with respect to high risk excavators and high risk locate tickets.

The Damage Reduction Strategy supplements on-going damage prevention activities. This includes identification of high risk assets during the locate process which allows Enbridge Gas to deploy personnel to monitor and communicate safe excavation practices, deploying aircraft and field personnel to patrol high risk pipelines to ensure no unauthorized excavations are occurring, and maintaining repeat offenders list provided to the Technical Standards and Safety Authority (TSSA). This addresses the recommendation in the 2019 ScottMadden report, which recommended that Enbridge Gas "….monitor and identify disturbances around high risk assets, including aerial patrol and vital main locate identification. Communicate with third party contractors prior to excavation"[8].

3.2 Retail Meter Variations

i. Identify and Standardize Best Practices at EGI

Beginning in 2021, Enbridge Gas standardized meter shop processes by adopting LUG' accredited processes. All meters are now tested under one common process. Diaphragm meter testing continues to be conducted annually under the integrated process. The results from tests conducted under low-flow and high-flow conditions continue to be well within Measurement Canada's regulations which prescribe maximum in-service limits of error of +/- 3.0%.

As noted in the UFG Report, there has been an ongoing effort to standardize the supercompressibility factors across the legacy Companies. Gas composition parameters and supercompressibility factors are used in Electronic Volume Integrators (EVI) and Remote Terminal Units (RTUs) to calculate the conversion of gas volumes from line conditions to standard conditions. There are various methods that can be used to do the calculation and each method requires gas quality parameters in order to calculate the supercompressibility factor. Gas quality parameters are updated periodically to ensure that the parameters match the quality of measured gas.

In the absence of specific regulatory or industry requirements relating to the updating of gas quality parameters, the approach for making updates differed amounst the two legacy Companies. LUG had been routinely updating gas quality parameters since 2002, while LEGD had not. Due to outdated fixed gas quality parameters, LEGD was under-calculating supercompressibility and under-measuring volumes, resulting in an increase in UFG volumes. In 2019, LEGD aligned with LUG and adopted the practice of updating gas quality parameters and supercompressibility factors, on a specified frequency, depending on the type of equipment, as described below.

In early 2020, Enbridge Gas began to implement the update of gas quality parameters and supercompressibility factors. This initiative was referenced in the 2019 ScottMadden report where it was recommended to "review and update supercompressibility parameters to more accurately measure and record volumes at elevated pressures"[9]. Enbridge Gas has aligned practices across both legacy Companies to regularly update gas quality parameters during routine pressure regulation and measurement inspections. These inspections vary from once every 6

[8] ScottMadden Report, December 2019, page 27
[9] ScottMadden Report, December 2019, page 31

months up to once every 5 years, depending on the station type and equipment within the station. These inspections fall under the Enbridge Gas Pressure Regulator Station Inspection Standard, which has also been updated and aligned across the two legacy Companies. The Pressure Regulator standard ensures that all stations are inspected and will have the gas quality parameters updated by 2025.

ii. Document Data/Processes/Studies related to monitoring and managing UFG

N/A

iii. Research Industry Practices and Initiatives for Monitoring and Managing Sources of UFG

Enbridge Gas stays abreast of industry practices and initiatives relating to retail measurement through its active participation in the Canadian Gas Association (CGA) Measurement and Regulation Steering Group. In addition to sharing best practices within the industry, the Steering Group also works closely with Measurement Canada, bringing forward recommendations relating to policies and regulations that impact the industry.

A focus of this working group recently has been the management of COVID-19 pandemic impacts as it relates to electricity and gas meter compliance and reverification requirements. The CGA has also recently proposed to form two working groups to address the finalization of specifications for Pressure Factor Metering and Ultrasonic Meter Specifications. The active participation with the CGA and Measurement Canada demonstrates Enbridge Gas's intent to stay abreast of and influence industry practices and initiatives.

iv. Implement New Practices and initiatives

A number of specific recommendations regarding the implementation of new practices and initiatives were noted in the UFG Report. First, it was recommended to:

> "Evaluate standardizing supercompressibility standards between interconnects and industrial customer sites to more accurately measure and record volumes. At interconnects, AGA-8 Supercompressibility standard is applied, while at industrial sites, the NX-19 standard is applied. The variation in standards can result in meters registering less than actual gas usage"[10]

[10] ScottMadden Report, December 2019, page 31

Enbridge Gas is in the midst of standardizing supercompressibility standards between interconnects and industrial customer sites. Enbridge Gas has developed a New Product Introduction process that provides direction regarding the approval of new measurement instruments, including Electronic Volume Integrators (EVIs) for use. Completion of this internal process is expected by Q1 2022. Upon completion of the process, EGI will start installing the AGA-8 Supercompressibility standard at industrial customer sites.

The 2019 UFG report also recommended to “Review Automated Meter Reading (“AMR”) and Advanced Metering Infrastructure (“AMI”) for improved accuracy of measured and recorded volumes”. While this was called out as a new practice by ScottMadden, both legacy Companies have previously completed AMR pilot projects to explore these technologies. LEGD initiated a pilot project in 2006 and LUG initiated a pilot project in 1999. In 2021, Enbridge Gas has engaged a cross functional team to complete an updated assessment of both AMR and AMI technologies. The team is currently evaluating the costs and benefits of AMR and AMI solutions. Efforts are underway to identify Enbridge Gas’ current risk profile and opportunities to reduce risk with an AMR or AMI solution. The team is also pursuing the execution of an AMI pilot program. The outcome of these evaluations will be incorporated into a proposal that will be filed with the OEB as part of the 2024 rebasing application.

3.3 Gate Station Meter variations

i. Identify and Standardize Best Practices at EGI

As noted in the UFG report, gate station monitoring responsibilities were transferred to a specialized measurement group. Since that transition, there has been alignment and standardization of best practices for this function at Enbridge Gas, including increased monitoring of measurement data. Furthermore, the LEGD measurement data has been added to the LUG Gas Measurement Accounting System and is subject to additional automated validation checks, already utilized for LUG measurement data, including tolerances for volumes, temperature, pressure and data completeness. The measurement data for both legacy entities continues to be subject to the Sarbanes-Oxley (SOX) reporting requirement and is now consolidated within one reporting system and under the accountability of one group within Enbridge Gas.

In addition, a cross-functional measurement working group, focused on dealing with measurement issues and sharing of best practices, has been expanded to include representatives from across Enbridge Gas.

ii. Document Data/Processes/Studies related to monitoring and managing UFG

In its 2016 Earnings Sharing and Deferral Account Disposition proceeding, LEGD agreed to review potential metering issues that might be contributing to UFG and to report on that review. LEGD also agreed to look specifically at the metering design at Victoria Square Gate Station.[11] In the LEGD amended settlement proposal in 2018 Rate Application[12], LEGD agreed to continue this review and report on its progress in the 2019 rate application. Further update was provided through the 2019 UFG Report completed by ScottMadden which was filed as part of the 2020 Rates Application Phase 2 (EB 2019-0194), noting that the project was scheduled to commence in 2020[13].

The redesign of the Victoria Square Gate Station was completed in 2020. Prior to the redesign, Victoria Square had one 30" ultrasonic meter run. The uncertainty of measurement of gas volumes with a single large meter is high, especially at low flow rates and this uncertainty of measurement can be a contributorto UFG variations. To reduce the measurement uncertainty, the Victoria Square Gate Station was upgraded to replace a single 30" meter run with 3 parallel ultrasonic meter runs: two 16" meters and a 4" meter.

The design also included staging so that the runs to each meter open or close depending on flow conditions, which provides a more accurate measurement over a greater range. This upgrade reduced the uncertainty of measurement by a factor of 1.4 (square root of the number of 16" meter runs) for normal flow rates and up to a factor of 5 for low flow rates.

The impact of the redesign of Victoria Sqare Gate Station was quantified in EGI Interrogatory Response (EB 2021-0149, Exhibit I.STAFF.10), where EGI noted that "A comparison of the measurement differences prior to the rebuild versus after the rebuild shows a reduction in volume difference from 12.4 10^6m^3 to 2.65 10^6m^3. While the UAF benefits can not be directly measured, as noted in the 2019 UAF study completed by ScottMadden, a primary source of UAF is gate station meter variations which improved significantly at Victoria Square Gate Station".

iii. Research Industry Practices and Initiatives for Monitoring and Managing Sources of UFG

Enbridge Gas is a member of a number of international industry research organizations, such as the Pipeline Research Council International (PRCI), NYSEARCH (part of the

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[11] EB-2017-0102, Exhibit I.B.EGDI.BOMA.21, filed: 2017-07-14
[12] EB-2017-0086, Exhibit N2, Tab 1, Schedule 1, page 12, filed: December 6, 2017
[13] ScottMadden Report, December 2019, page 39

Northeast Gas Association), and HYREADY (an international consortium of companies creating guidelines for preparing natural gas networks for hydrogen injection). This participation allows Enbridge Gas to keep abreast of the latest research in the area of measurement for the gas industry and apply research results to Enbridge Gas's processes and procedures in the area of measurement.

Based on the research led by PRCI relating to diagnostics and reverification intervals for ultrasonic meters, Enbridge Gas was able to optimize reverification intervals of ultrasonic meters. This included setting a 6-year reverification interval for renewed ultrasonic meters and an 8-year reverification interval for ultrasonic meters under Low Intervention Level agreement with TransCanada Energy (TCE). In addition, Enbridge Gas replaced single rotor meters with dual rotor meters, based on PRCI projects on turbine metering, which evaluated auto-adjust and self-checking capabilities of dual rotor turbine meters.

iv. <u>Implement New Practices and initiatives</u>

Enbridge Gas has addressed the recommendations from the UFG Report relating to gate station measurement. The report recommended reviewing meter point changes and exchanging/swapping check meters to evaluate meter bias. Enbridge Gas' Gas Measurement Integrity Team completes extensive data validation, review for completeness and monitoring, as described previously. These activities ensure alignment of check measurement with receipt point metering and trigger required action required if results are outside of acceptable tolerances.

The UFG Report also contained a recommendation to review requests for meter audits. It is routine practice for Enbridge Gas to notify and engage interconnecting parties for measurement maintenance activities, as well as witnessing measurement maintenance activities of interconnecting party's facilities. Furthermore, Enbridge Gas also facilitates requests for audits of interconnecting stations, such as the 2014 audit of Enbridge Gas' Kirkwall station by TCE. Enbridge Gas and TCE also have a Low Intervention Level (G-14) Agreement in place which specifies the frequency of measurement maintenance at Enbridge Gas' interconnections with TCE, in compliance with Measurement Canada requirements.

3.4 OTHERS *(INCL. ACCOUNTING ADJUSTMENTS, COMPANY USE, THEFT, NON-REGISTERING METERS)*

i. Identify and Standardize Best Practices at EGI

Upon amalgamation in 2019, Enbridge Gas continued to maintain separate customer billing systems within the legacy Companies until the recent transition in July 2021 to one consolidated billing system. During the period of time that the legacy Companies retained separate billing systems, there were process and policy alignment initiatives completed that were not constrained by the broader system integration effort. As it relates specifically to UFG, the customer billing teams aligned the processes relating to theft of gas, with nominal changes to process and forms.

A notable change that occurred in December 2019 was that the LUG delivery areas moved from monthly meter reading to bi-monthly meter reading, to align with the LEGD practice. This change did not impact the methodology for estimating un-billed consumption but rather only increased the amount of billed volumes that were based on estimated consumption. It should be noted that the change from monthly to bi-monthly meter reading does not contribute to incremental UFG; however, it could contribute to increased volatility in the short-term. As noted in the UFG Report "Usage estimation variances may be large enough to create an apparent negative UFG volume in a given month or, more rarely, two or three consecutive months. Negative UFG volumes on a monthly basis occur almost exclusively in the shoulder and summer months, are low in relation to total UFG volumes, and generally reverse or correct themselves within a one-year period".[14]

There have also been alignment efforts relating to the accounting for UFG. The UFG Report notes that "Presently, LUG adjusts for line pack in its calculations of UFG. In December 2019, Enbridge plans to adjust for line pack in its calculation of UFG."[15] Since the filing of the UFG Report, line pack is now included in the LEGD Unaccounted for Gas Variance Account (UAFVA) calculation, which is filed annually as part of the annual earning sharing proceeding.

ii. Document Data/Processes/Studies related to monitoring and managing UFG

N/A

[14] ScottMadden Report, December 2019, page 44
[15] ScottMadden Report, December 2019, page 46

iii. Research Industry Practices and Initiatives for Monitoring and Managing Sources of UFG

N/A

iv. Implement New Practices and initiatives

The UFG Report noted that the Legacy Companies measure, record and account for Company use on a monthly basis[16]. Enbridge Gas has continued to refine the tracking and recording of company use. Since 2019, gas used in company-owned vehicles is also included in the calculation of company use, which has reduced the amount of UFG recorded associated with that gas use.

4.0 Summary

Since 2019, Enbridge Gas has actively addressed the recommendations outlined in the UFG Report. In addition to a number of specific recommendations, ScottMadden also recommended to identify and standardize “best practices” across the legacy Companies, document data, processes and studies related to monitoring and managing UFG, and investigate the sources of UFG, research industry practices and initiatives for monitoring and managing sources of UFG, and implement, as appropriate, new practices and initiatives to better monitor and manage sources of UFG”. This progress report demonstrates the actions taken for each source of UFG to address the recommendations laid out by ScottMadden.

As noted in EB 2019-0194, Enbridge Gas will provide further information in the upcoming rebasing proceeding regarding subsequent efforts to address the UFG Report’s recommendations and other activities to address UFG and how these measures have impacted Enbridge Gas’s UFG. Enbridge Gas will also present a proposal for consistent forecasting of UFG across its full service area and will report actual UFG results, segregated by rate zone and activity (distribution, transmission, storage) using the most recent historical information available.

[16] ScottMadden Report, December 2019, page 42

UNACCOUNTED FOR GAS
SUPPLEMENTAL PROGRESS REPORT

1. The purpose of this evidence is to report on progress in implementing the recommendations set out in the Report on Unaccounted for Gas (UFG) considered as part of the 2020 Rate Application[1]. This report is a supplement to the UFG Progress Report, as originally filed in the 2022 Rate Application,[2] provided at Exhibit 4, Tab 3, Schedule 1, Attachment 3.

2. This evidence is organized as follows:
    1. Background
    2. Benchmarking Analysis
    3. Updates on UFG by Source

1. Background

3. In its 2016 Earnings Sharing and Deferral Account Disposition proceeding[3], EGD agreed to review potential metering issues that might contribute to UFG and to report on that review as part of the 2018 Rate Adjustment Application. In the 2018 Rates proceeding[4], EGD agreed to continue the review and report on it as part of the 2019 Rate Adjustment Application.

4. In the MAADs Decision[5], the OEB directed Enbridge Gas to file a report on UFG for both the EGD and Union rate zones by December 31, 2019. Enbridge Gas filed a

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[1] EB-2019-0194.
[2] EB-2021-0148.
[3] EB-2017-0102.
[4] EB-2017-0086, Settlement Proposal, Exhibit N2, Tab 1, Schedule 1, December 6, 2017, p.12.
[5] EB-2017-0306/EB-2017-0307, OEB Decision and Order, August 30, 2018.

Report on Unaccounted for Gas (Report on UFG) prepared by ScottMadden Management Consultants in December 2019.

5. The Report on UFG was considered as part of the 2020 Rate Application Phase 2[6]. In that proceeding, Enbridge Gas committed to report upon its progress in implementing the recommendations set out in the Report on UFG in its 2022 Rates filing. In response to that commitment, Enbridge Gas filed a UFG Progress Report in its 2022 Rate Application. However, the OEB determined that the issues relating to UFG were out of scope for that proceeding and that the UFG Progress Report and other updates as it relates to the implementation of recommendations from the 2019 Report on UFG would be considered as part of the 2024 Rebasing proceeding.

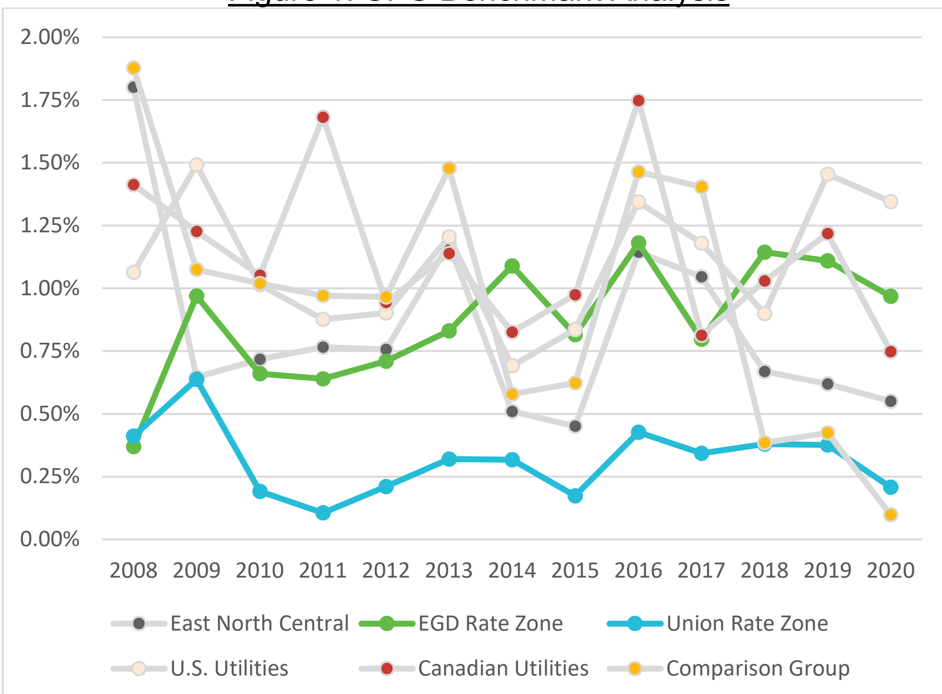
6. In accordance with the OEB direction, the UFG Progress Report, as originally filed in the 2022 Rates Application, has been provided at Exhibit 4, Tab 3, Schedule 1, Attachment 3. This supplemental progress report is intended to provide updates that have occurred since the filing of the initial UFG Progress Report.

2. Benchmarking Analysis

7. The 2019 Report on UFG included benchmarking analysis that demonstrated that UFG, as a percentage of throughput for Enbridge Gas in both the EGD and Union rate zones, was lower than its peers. Enbridge Gas has collected the most current publicly available data for the same peer group included in the benchmarking analysis from the 2019 Report on UFG. The benchmarking analysis from the Report on UFG has been updated with data up to and including 2020 and is provided in Figure 1.

[6] EB-2019-0194.

Figure 1: UFG Benchmark Analysis



8. Based on the data in Figure 1, Enbridge Gas, in both the EGD and Union rate zones, continues to demonstrate lower UFG levels than comparative gas utilities. Figure 1 shows that the EGD and Union rate zones have an average UFG level of 0.87% and 0.32% of throughput, respectively, from 2008 to 2020. During the same period, U.S. gas utilities have an average UFG level of 1.10%, select Canadian gas utilities have an average UFG level of 1.10%, regional U.S. gas utilities have an average UFG level of 0.83%, and a “Comparison” group of gas utilities have an average UFG level of 0.95% of gas receipts.

3. Updates on UFG by Source

9. As part of its research and analysis for the Report on UFG, ScottMadden identified certain common sources of UFG across the industry, including physical losses (e.g.

leaks, third-party damage and venting during construction and maintenance activities), metering variations, non-registering meters, theft, linepack and billing and accounting adjustments.

10. In the Report on UFG, ScottMadden also provided a number of recommendations as follows:
    a) Identify and standardize “best practices” across the legacy Companies;
    b) Document data, process and studies related to monitoring and managing UFG; and
    c) Investigate the sources of UFG, research industry practices and initiatives for monitoring and managing sources of UFG, and implement, as appropriate, new practices and initiatives to better monitor and manage sources of UFG.

11. The following sections provide updated data relating to the individual sources of UFG, as well as updates on the implementation of the recommendations noted above that are incremental to those in the UFG Progress Report provided at Exhibit 4, Tab 3, Schedule 1, Attachment 3.

3.1. Physical Losses

12. Physical losses are a source of UFG at Enbridge Gas. Contributors to physical losses include leaks and emissions from natural gas facilities, releases of natural gas during maintenance, construction and emergency situations, and line hits due to third-party construction or excavation activities.

13. Enbridge Gas reports fugitive, vented and flared emissions annually to Environment and Climate Change Canada and the Ontario Ministry of Environment, Conservation and Parks. Figure 2 shows a 13% decline in emissions and leaks

within the consolidated Enbridge Gas operations from 2015 to 2021. Figure 2 shows lost gas from leaks and emissions on a combined basis for Enbridge Gas, while Figure 3 provides a breakdown of the total leaks and emissions for Enbridge Gas by type.

Figure 2: Lost Gas from Leaks and Emissions (10^6m^3)

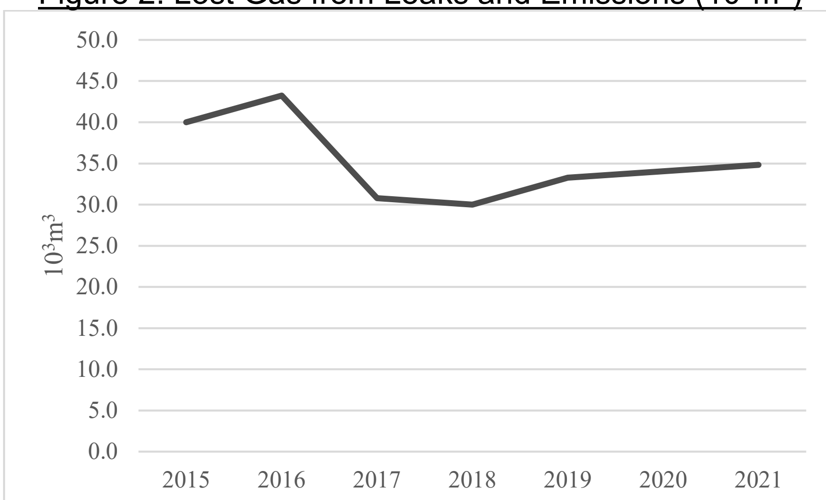
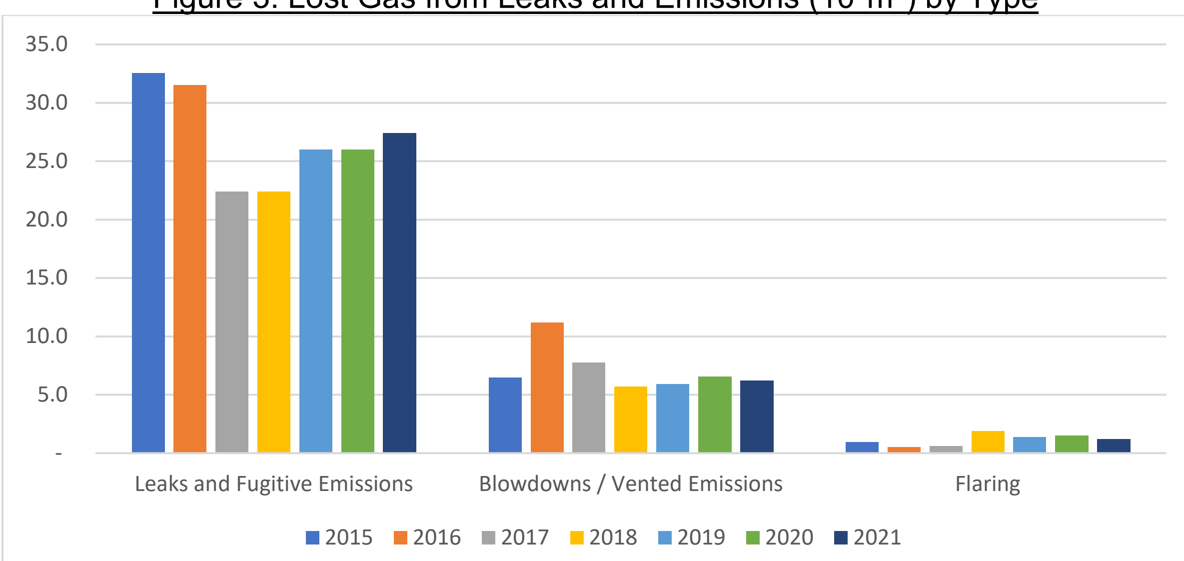


Figure 3: Lost Gas from Leaks and Emissions (10^6m^3) by Type



14. Enbridge Gas has undertaken efforts to reduce physical losses and emissions from its operations. Scope 1 GHG emissions result from Enbridge Gas's operations, and scope 2 emissions result from off-site generation of electricity, which Enbridge Gas buys and consumes. A reduction of scope 1 GHG emissions would indirectly impact the level of UFG experienced within Enbridge Gas's operations.

15. Enbridge Gas has committed to reducing GHGs from Company facilities. To support achievement of the federal and provincial GHG emission targets, as well as the Enbridge GHG reduction targets provided at Exhibit 1, Tab 10, Schedule 3, Enbridge Gas is developing and implementing a scope 1 and 2 GHG emission reduction strategy. Details are provided at Exhibit 1, Tab 10, Schedule 8.

3.2. Retail Meter Variations

16. Retail meter variations represent variations between actual and metered volumes at customer locations. These variations can be attributed to factors including inherent measurement uncertainties of meters, meter failure, inaccurate corrections for temperature and pressure variations or improperly sized meters. Enbridge Gas conducts meter testing on a sample of diaphragm meters annually. These tests are conducted under low-flow and high-flow conditions. Historical test results from 2014 to 2021 are shown in Figure 4 and 5.

Figure 4: EGD Rate Zone Meter Test Results vs Measurement Canada (MC) hStandard

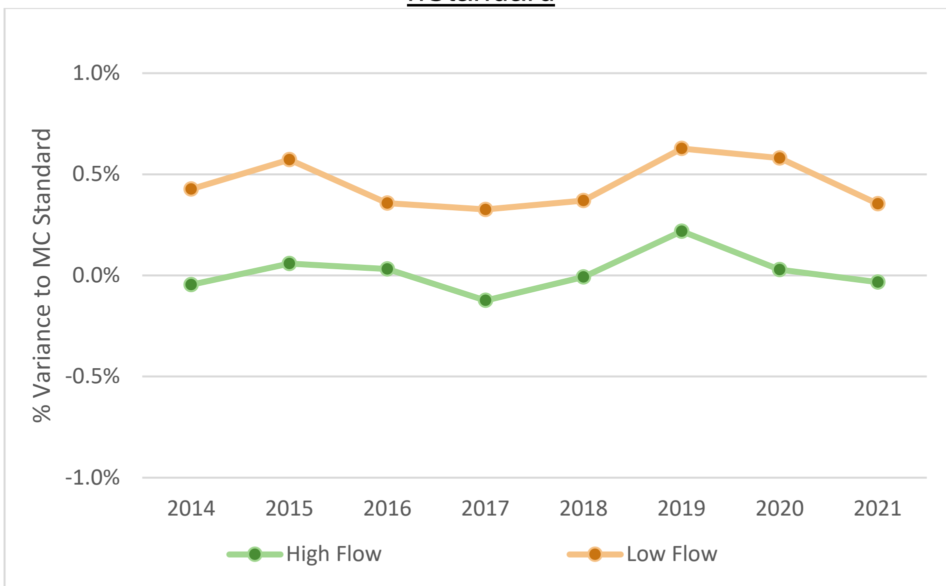
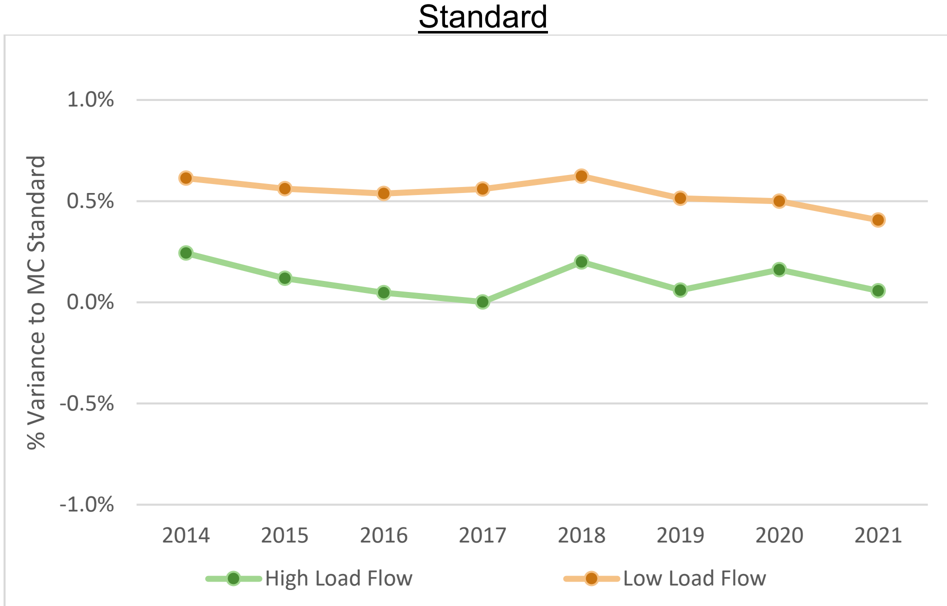


Figure 5: Union Rate Zone Meter Test Results vs Measurement Canada (MC) Standard



17. The variances to the Measurement Canada standard are within the Measurement Canada tolerance of +/- 3.0%. Meters whose test results that fall outside of the +/- 3.0% tolerance are taken out of service. All rotary turbine, and ultrasonic meters are tested on a frequency which is prescribed by Measurement Canada.

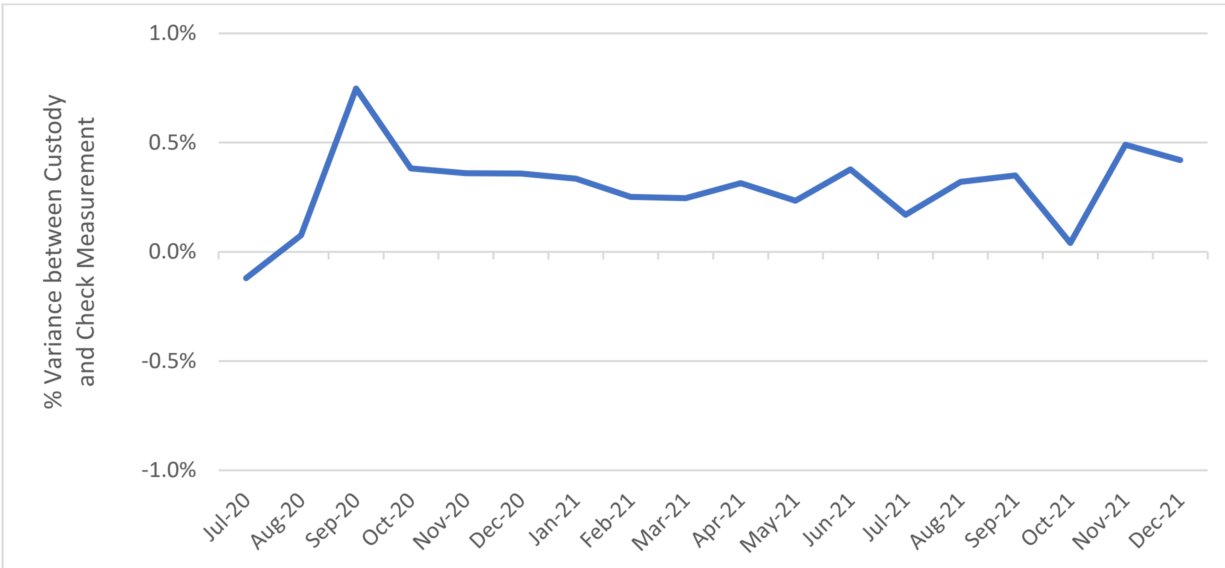
18. In 2022, Enbridge Gas has undertaken an initiative to align the applications utilized for large volume customer meter measurement and ensure consistent volume measurement data validation for large volume customer meter measurement.

3.3. Gate Station Meter Variations

19. Gate station meter variations represent a potential source of UFG if there are differences at receipt points between actual and metered volumes. However, not all gate station meter variations can be wholly attributable to UFG, as the variations may only represent differences in meters, and may not represent actual lost gas.

20. Enbridge Gas utilizes check meters to validate the accuracy of the custody or supplier meters. A comparison between Enbridge Gas's check meters and third-party custody transfer meters is depicted in Figure 6. This figure demonstrates that Enbridge Gas's check measurement falls within the Measurement Canada prescribed range of +/- 3% and with the +/- 2% tolerance of the Enbridge Gas internal benchmark.

Figure 6: Third-Party Custody Transfer vs. Enbridge Gas Check Meters Differences



21. In 2022, Enbridge Gas installed a new Measurement Canada certified remote terminal unit (RTU) at the Gatineau interconnect, which ensured that both custody and check measurement is in place, whereas only one source of measurement was previously available. This also enabled an increased level of data validation by the team accountable for gate station measurement.

3.4. Other Sources of UFG

22. The remaining primary contributors of UFG at Enbridge Gas include theft and non-registering meters, company use, and accounting adjustments. Theft and non-registering meters account for volumes that are not metered or recorded due to unauthorized use or faulty equipment. Company use contributor represents the portion of company use volumes used by Enbridge Gas that are not metered and/or recorded. Accounting adjustments represent variations between actual and reported volumes due to various accounting adjustments, including unbilled sales estimates, billing adjustments, linepack and other accounting related adjustments.

23. In 2022, Enbridge Gas initiated a system application change to refine the reporting underpinning a portion of the unbilled sales estimates recorded at the end of every reporting period for financial accounting purposes. The intended outcome of the change is to improve the accuracy of the estimate, which would help to minimize variances that are temporary in nature associated with the estimate of unbilled volumes.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

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

Question(s):

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

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

Response:

Many of the specific measures noted in the UFG Progress Report and Supplemental UFG Progress Report have been implemented and are part of ongoing operations, standard practices, policies, and procedures. Others are ongoing in nature, such as meter audits between interconnecting parties, participation in industry groups and associations and regular meetings of cross functional measurement groups.

There are specific measures that were identified in the UFG Progress Report and Supplemental UFG Progress Report that have not yet been implemented. A status update on those items have been provided below.

Updates relating to Exhibit 4, Tab 3, Schedule 1, Attachment 3:

The 2019 UFG Report included a recommendation to review automated meter reading (AMR) and advanced metering infrastructure (AMI) technology. Enbridge Gas has brought forward a proposal in the 2024 Rebasing Application regarding AMI. Please see Exhibit 2, Tab 7, Schedule 2 for an overview of how AMI is being considered for use within Enbridge Gas and a summary of Enbridge Gas's progress and activities related to developing an AMI proposal.

Enbridge Gas continues to update gas quality parameters during routine pressure regulation and measurement inspections, and progress remains on track to complete the update of gas quality parameters by 2025 as previously noted.

Enbridge Gas developed a three-year program to eliminate a backlog of leaks identified prior to the roll out of a new leak operating standard. The program will be completed by the end of 2023.

Updates relating to Exhibit 4, Tab 3, Schedule 1, Attachment 4:

In 2022, Enbridge Gas undertook an initiative to align the applications used for large volume customer meter measurement to ensure consistent volume measurement data validation for large volume customer meter measurement. Enbridge Gas continues to explore and test potential alternatives.

In 2022, Enbridge Gas initiated a system application change request to refine the reporting underpinning a portion of the unbilled sales estimates recorded at the end of every reporting period for financial accounting purposes. This system application change is under development.

Enbridge Gas is developing and implementing a Scope 1 and 2 GHG emission reduction strategy. The details of this work are provided at Exhibit 1, Tab 10, Schedule 8.

In addition to the actions outlined above, Enbridge Gas is establishing a team that will conduct an end-to-end process review of UFG and make changes to ongoing sustainment processes.

BREAKDOWN OF THE 2022 STORAGE AND TRANSPORTATION DEFERRAL ACCOUNT (2022 S&TDA) - EGD RATE ZONE

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
Line No.	Contracted Union Capacity	Budgeted Daily Contract Demand Volume	Monthly Demand Toll Assumed in 2018 Budget	Forecasted Annual Cost (2)	Actual Daily Contract Demand Volume	Monthly Demand Toll Effective January 1, 2022 to December 31, 2022	Annual Cost (3)	Balance in the 2022 S&TDA (4)
		(GJ)	($/GJ)	($Millions)	(GJ)	($/GJ)	($Millions)	($Millions)
1	Union Gas Dawn to Lisgar	67,929	2.865	2.3	67,929	3.130	2.6	
2	Union Gas Dawn to Parkway	2,792,173	3.402	114.0	2,792,173	3.689	123.6	
3	Union Gas Dawn to Parkway - M12X	200,000	4.239	10.2	200,000	4.560	10.9	
4	Union Gas F24 T	85,000	0.069	0.1	85,000	0.074	0.1	
5	Union Transmission Costs			126.6			137.2	(10.6)
6	Dawn T Service Costs			(11.2)			(15.0)	3.8
7	Federal Carbon Costs			-			1.5	(1.5)
8	Union & Third Party Market Based Storage			20.1			21.4	(1.3)
9	2020 Deferral Disposition - UG (1)			-			(1.5)	1.5
10	Total			135.5			143.6	(8.1)

Notes
(1) Transporation deferral adjustments related to 2020 S&TDA reduced actual costs by $1.5M
M12 Transport ($1.4M), M16 Transport ($0.03M), Federal Carbon ($0.1M)
(2) Col. 1 * Col. 2 * 12
(3) Col. 4 * Col. 5 * 12
(4) Col. 3 - Col. 6

TRANSACTIONAL SERVICES REVENUE BY TYPE OF TRANSACTION ("TSDA") - EGD RATE ZONE

Line No.	Particulars	Col. 1 2018 ($000's)	Col. 2 2019 ($000's)	Col. 3 2020 ($000's)	Col. 4 2021 ($000's)	Col. 5 2022 ($000's)
1.	Storage Optimization	423.9	60.7	0.0	0.0	0.0
2.	Transportation Optimization	14,292.4	13,084.5	17,643.4	17,509.0	47,904.8
3.	Transactional Services Revenue	14,716.2	13,145.2	17,643.4	17,509.0	47,904.8
4.	Amount Included in Rates	12,000.0	12,000.0	12,000.0	12,000.0	12,000.0
5.	Less Ratepayer Portion of TS	13,244.6	11,830.7	15,879.1	15,758.1	43,114.3
6.	TSDA sub-total	(1,244.6)	169.3	(3,879.1)	(3,758.1)	(31,114.3)
7.	ETT Revenue - Rider H	60.1	35.1	5.8	146.1	120.3
8.	TSDA Total	(1,304.7)	134.3	(3,884.9)	(3,904.1)	(31,234.7)

BREAKDOWN OF THE 2022 UNACCOUNTED-FOR GAS VARIANCE ACCOUNT ("2022 UAFVA") - EGD RATE ZONE

		Col . 1	Col . 2	Col . 3	Col . 4	Col . 5	Col . 6	Col . 7	Col . 8	Col . 9	Col . 10	Col . 11	Col . 12	Col . 13
Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	Budget UAF (10^3m^3)	17,033	18,952	16,299	11,723	6,620	3,360	2,496	2,412	2,463	3,884	8,289	13,146	106,677
2	PGVA Reference Price	223	223	223	231	231	231	330	330	330	351	351	351	
3	Budget UAF Cost ($)	3,794,017	4,221,373	3,630,569	2,708,462	1,529,401	776,223	825,060	797,122	814,080	1,361,605	2,905,763	4,608,543	27,972,218
4	Budget UAF based on actual throughput (10^3m^3) (1)	17,110	17,650	13,543	10,567	5,182	3,762	3,348	3,331	3,989	6,854	11,071	14,579	110,989
5	UAF Annual Variance (10^3m^3) (2)(3)	22,406	23,114	17,735	13,838	6,786	4,926	4,385	4,363	5,224	8,975	14,498	19,092	145,343
6	Total Actual UAF (10^3m^3) (4)	39,517	40,764	31,278	24,405	11,969	8,688	7,733	7,694	9,214	15,829	25,570	33,671	256,333
7	PGVA Rate	223	223	223	231	231	231	330	330	330	351	351	351	
8	Actual UAF Cost ($) (5)	8,802,165	9,080,037	6,967,057	5,638,616	2,765,218	2,007,381	2,555,840	2,542,864	3,045,081	5,549,006	8,963,563	11,803,627	69,720,454
9	UAFVA Volume Variance (6)	22,484	21,813	14,979	12,682	5,349	5,329	5,237	5,282	6,751	11,945	17,281	20,525	149,656
10	UAFVA Cost Variance ($) (7)	5,008,147	4,858,664	3,336,488	2,930,154	1,235,817	1,231,158	1,730,780	1,745,742	2,231,001	4,187,401	6,057,800	7,195,084	41,748,236
11	Line Pack Gas (LPG) Allocation													(70,667)
12	2022 Damage Adjustment													(114,103)
13	2021 Company Use True up													(163,051)
14	Total 2022 UAFVA (8)													41,400,414

Notes
(1) UAF volumes based on budget throughput percentage multiplied by actual throughput volumes
(2) Line 5 = Line 6 - Line 4
(3) UAF annual variance allocation Based on actual throughput profile

15%	16%	12%	10%	5%	3%	3%	3%	4%	6%	10%	13%	
22,406	23,114	17,735	13,838	6,786	4,926	4,385	4,363	5,224	8,975	14,498	19,092	145,343

(4) Line 4 + Line 5

(5) Line 6 * Line 7	0.15	0.16	0.12	0.10	0.05	0.03	0.03	0.03	0.04	0.06	0.10	0.13

(6) Line 6 - Line 1
(7) Line 8 - Line 3
(8) Line 10 + Line 11 + Line 12 + Line 13

2022 AVERAGE USE TRUE UP VARIANCE ACCOUNT - EGD RATE ZONE

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
Rate Class	Budget Annual Use	Normalized Actual Annual Use	Normalized Usage Variance (1)	Budget Customer Meters	Normalized Volumetric Variance (2)	DSM Budget	DSM Actual	DSM Volumetric Variance (3)	Normalized Volumetric Variance Excluding DSM (4)	Unit Rate	AUTUVA: Revenue Impact, Exclusive of Gas Costs (5)
	(m^3)	(m^3)	(m^3)		(10^6m^3)	(10^6m^3)	(10^6m^3)	(10^6m^3)	(10^6m^3)	($/$m^3$)	($Millions)
1	2,417	2,374	(43)	2,112,540	(91.3)	(4.8)	(4.8)	0.0	(91.3)	0.0734	(6.70)
6	27,669	27,643	(26)	170,526	(4.5)	(10.8)	(10.8)	0.0	(4.5)	0.0447	(0.20)
Total											(6.90)

Notes
(1) Col. 2 - Col. 1
(2) Col. 3 * Col. 4
(3) Col. 7 - Col. 6
(4) Col. 5 - Col. 8
(5) Col. 9 * Col. 10

ENBRIDGE

Enbridge Gas Inc.
50 Keil Drive N
Chatham, Ontario N7M 5M1
Canada

November 10, 2021

Dear Recipient,

Subject: Storage at Dawn, injections commencing April 1, 2022

Enbridge Gas Inc. operating as Enbridge Gas Distribution (Enbridge Gas) requires firm natural gas storage services with injections commencing April 1, 2022.

This storage service request is being administered by Ernst & Young LLP on behalf of Enbridge Gas Inc.

Enbridge Gas is seeking a diverse portfolio of storage services that both meet and exceed the minimum requirements below. This includes those that allow higher deliverability and access to multiple nomination windows for each gas day.

Enbridge Gas requires that these storage services meet the following specifications:

Term: Up to three (3) years commencing April 1, 2022. To encourage storage contracts term diversity, Enbridge Gas is seeking service offerings of various term lengths. The amount placed will be at Enbridge Gas' discretion.

Term	Potential to be contracted
1 - year	2 PJ's
2 - year	2 PJ's
3 - year	3 PJ's

Location: Enbridge Gas will deliver gas to Storage Provider at Union Dawn for injection, and Storage Provider will re-deliver gas to Enbridge Gas at Union Dawn for withdrawal. If any transportation capacity is included as part of the storage offering to facilitate Dawn injections and withdrawals, please provide details.

Firm Injection Requirements: Must include the months from May 1 through Sept. 30

Firm Withdrawal Schedule: Must include the months from Dec. 1 through March 31

Responses: Should you be interested in supplying this storage service to Enbridge Gas, please complete the attached Excel form, stating the delivery points, term, MSB and service attributes with the relevant pricing, including demand, commodity charges and other items indicated.[1] Enbridge Gas also requires sample invoices

The deadline to submit your proposal(s) is **11 a.m. Mountain Standard Time (MST) on Dec. 1, 2021,** after which time Enbridge Gas will contact the parties which submitted proposals that have been selected[2]. Please submit your proposal(s) to the attention of Chester Mercier at the e-mail address provided below:

Chester.Mercier@EY.com

All questions and responses are to be directed to Chester.Mercier@EY.com. Do not contact Enbridge Gas directly regarding this process.

*The deadline for any **queries** is 12 p.m.(noon) Mountain Standard Time (MST) on Nov.17, 2021. All queries and responses will be provided to all parties on Nov. 22, 2021.*

Additional Information: Enbridge Gas invites all potential participants to review a presentation that has been posted to its website, in the Storage and Transportation section of its website, within News and Presentations.

Enbridge Gas will contact successful bidders following the close of the RFP process.

Sincerely,

Chester Mercier

Ernst & Young LLP

[1] This storage service request may have Dodd Frank Act implications and may require specific clauses to be included in any storage agreement between the parties. Any such storage agreement will not be binding until a definitive agreement is executed by the parties.

[2] Please note that successful suppliers must meet all of Enbridge's credit criteria. Enbridge, in its sole discretion and for whatever reason, may accept or reject any and all proposals. Enbridge reserves the right at any time after the deadline to conduct negotiations with one or more of the bidders to the exclusion of others, and such negotiations may include changes to the storage service described in this letter.

Response	Total cost (CAD/GJ)	Total Annual cost - 1 turn - CAD	Total Annual cost - 1PJ - CAD	Term (years)	Volume (GJ)	High/Low flexibility	Max Withdrawal rights - %	Ratchet score / # of days to w/d	max Injection rate (GJ/day)	max Withdrawal rate (GJ/day)	Days to Inject	Notes
[redacted]												

UNABSORBED DEMAND COSTS (UDC) VARIANCE ACCOUNT
UNION RATE ZONES

1. The balance in the UDC Variance Account is a credit to ratepayers of $5.624 million plus interest as of December 31, 2022, of $0.346 million, for a total of $5.969 million. The $5.624 million balance is the difference between the actual UDC incurred by the Union Rate Zones and the amount of UDC collected in rates.

1. UDC Recovery in Rates

2. To meet customer demands across the Union rate zones and to meet the planned storage inventory levels at October 31, approved rates for the Union rate zones in 2022 included planned unutilized pipeline capacity of 11.3 PJ in Union North West, 3.1 PJ in Union North East and 0 PJ in Union South. The UDC volumes included in 2022 rates are based on the Gas Supply Plan filed in Union's Dawn Reference Price proceeding[1].

3. As discussed in the Enbridge Gas 5 Year Gas Supply Plan[2], in Union North, the upstream transportation capacity (long-haul, short-haul and STS) is first sized to meet the design day requirements. The amount of transportation capacity needed to meet average annual demand requirements is less than the capacity required to meet design day requirements. Therefore, a portion of contracted capacity for the Union rate zones is planned to be unutilized. In a warmer than normal year, UDC may be incurred in Union South, and additional UDC in Union North, to balance supply with lower demands. The Union North and Union South transportation portfolios are managed on an integrated basis and the pipeline to leave unutilized, if necessary, is determined based on the least cost option. In the EB-2021-0149

[1] EB-2015-0181, Exhibit A, Tab 2, Appendix A, Schedule 1.
[2] EB-2019-0137, p. 82.

Decision for the disposition of the 2020 UDC Variance account, Enbridge Gas agreed:

> In future deferral and variance account clearance applications related to the deferred rebasing term, Enbridge Gas agrees that it will include evidence reporting on: UDC and transportation capacity released by rate zone, and the costs and revenues transferred between rate zones.[3]"

4. Table 1 provides the capacity released by rate zone and the associated UDC costs and/or revenue. The path released does not determine where the UDC costs or associated revenue for the releases will be allocated. Instead, the costs and revenue are allocated based on the portion of the UDC variance driven by each respective rate zone, as can be seen in Table 2.

Table 1

Capacity Released & Related Costs Incurred

Line No.	Particulars	Union North East	Union North West	Union South	Total Franchise Area
1	Capacity Released (TJ)	8,813	5,972	1,931	16,716
2	UDC Costs Incurred ($000's)	715	3,853	2,569	7,136
3	Released UDC Capacity ($000's)	0	(3,628)	(44)	(3,672)

5. Enbridge Gas collected $9.088 million in rates for UDC for the Union rate zones during 2022 and recorded an associated interest credit of $0.346 million (see Table 2). Actual UDC costs in 2022 were $7.136 million offset by $3.672 million in released capacity value, resulting in a net cost of $3.465 million (see Table 3). Actual UDC costs are allocated to Union North West, Union North East and Union South in proportion to the actual supply and demand variances which occurred in each respective area.

[3] EB-2021-0149, Exhibit N1, Tab 1, Schedule 1, p. 15.

6. The variance between the amounts collected in rates and the actual UDC costs, including the interest credit of $0.346 million, results in a net credit to ratepayers in the UDC Variance Account of $5.969 million.

7. The balance applicable to sales service and bundled DP customers in Union North West is a credit of $5.143 million and in Union North East, a credit of $1.636 million. There is a debit of $0.810 million applicable to sales service customers in Union South.

8. Table 2 provides the derivation of the UDC variance account balances by operational area.

Table 2

UDC Variance Account by Operational Area

Line No.	Particulars ($000's)	Union North East	Union North West	Union South	Total Franchise Area
1	UDC Collected in Rates	(1,567)	(7,521)	-	(9,088)
2	UDC Costs Incurred (Table 3)	26	2,675	763	3,465
3	Variance (line 1 + line 2)	(1,541)	(4,845)	763	(5,624)
4	Interest	(95)	(298)	47	(346)
5	(Credit)/Debit to Operations Area	(1,636)	(5,143)	810	(5,969)

A description of each item in Table 2 is set out below:

1.1 UDC Collected in Rates

9. The 2022 OEB-approved rates include $8.661 million of UDC associated with 14.4 PJ of planned unutilized pipeline capacity in Union North West and Union North East and no planned unutilized pipeline capacity in Union South. The total cost of UDC in rates assumes TC Energy final tolls effective January 1, 2022. On an actual

basis in 2022, Enbridge Gas recovered $9.088 million in Union North West and Union North East and $0.0 million in Union South.

1.2 UDC Costs Incurred

10. The actual unutilized capacity in 2022 was 16.7 PJ. The level of unutilized capacity experienced in 2022 was largely due to planned unutilized capacity (and resulting UDC) and lower customer use.

11. The costs reflected in the UDC Variance Account are the total demand charges for unutilized pipeline capacity totaling $7.136 million, partially offset by $3.672 million generated from releasing the pipeline transportation capacity to the market. Unutilized upstream transportation capacity is released and sold on the secondary market to minimize UDC. The value generated from the transportation releases is credited to the UDC Variance Account mitigating the overall UDC impact as shown in Table 3.

Table 3
UDC Costs Incurred

Line No.	Particulars ($000's)	Union North East	Union North West	Union South	Total Franchise Area
1	UDC Costs Incurred	54	5,511	1,572	7,136
2	Released Capacity Revenue	(28)	(2,835)	(809)	(3,672)
3	Net UDC Costs (Credit)/Debit	26	2,675	763	3,465

ACCOUNT NO. 179-131 UPSTREAM TRANSPORTATION OPTIMIZATION UNION RATE ZONES

1. The Upstream Transportation Optimization Deferral Account was approved by the OEB in its EB-2011-0210 Decision to capture the variance between the ratepayers' 90% share of actual net revenues from optimization activities, and the amount refunded to ratepayers in rates. The 2022 balance in this deferral account is a debit from ratepayers of $8.900 million plus interest of $0.438 million for a total debit from ratepayers of $9.337 million.

2. In setting rates for 2022, the OEB approved a forecast of optimization revenue of $14.918 million. Of that amount, 90% or $13.426 million, was credited to ratepayers in the OEB-approved 2022 rates.[1] On an actual basis, consistent with the method approved in its EB-2011-0210 Decision and Rate Order, Union credited $16.649 million in rates to ratepayers during 2022, $3.223 million greater than the OEB-approved amount of $13.426 million. The credit is due to actual sales service volumes exceeding the forecast sales service volumes in rates. The main driver of actual sales service volumes exceeding the forecasted amount is customer growth since 2013.

3. The Company earned $8.610 million in net revenues from upstream transportation optimization during 2022 in the Union Rate Zones. In accordance with the OEB-approved sharing methodology, 90% of this net revenue, or $7.749 million, is to be credited to customers. As stated above, $16.649 million has already been credited through rates; therefore, the deferral balance is a debit from ratepayers of $8.900 million ($16.649 million less $7.749 million).

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[1] Detailed schedule last filed at EB-2017-0087 (2018 Rates), Draft Rate Order, Working Papers, Schedule 14, p. 1. The credit of $13.426 million to Union rate zone in-franchise customers is maintained in the setting of rates for the 2019-2023 deferred rebasing period in accordance with the approved rate-setting mechanism.

4. The net revenue associated with upstream transportation optimization in the Union Rate Zones is lower as compared to the net revenue associated with the Enbridge Gas Distribution (EGD) Rate Zone primarily because of the portfolio of contracts held by each rate zone. The EGD rate zone contracts used to transact exchanges are more likely to be scheduled and provide greater revenue.

5. Exhibit E, Tab 1, Schedule 1, provides a summary of the calculation of the balance in this deferral account. 2022 actual Upstream Transportation Optimization revenue in the Union rate zones is lower than 2013 OEB-approved revenue primarily due to the elimination of the TransCanada FT-RAM program ($5.800 million).

ACCOUNT NO. 179-70 SHORT-TERM STORAGE AND OTHER BALANCING SERVICES – UNION RATE ZONES

1. The Short-Term Storage and Other Balancing Services Deferral Account includes revenues from C1 Off-Peak Storage, Gas Loans, Supplemental Balancing Services and C1 Short-Term Firm Peak Storage. The deferral account compares the ratepayer share (90%) of net revenue for Short-Term Storage and Other Balancing Services with the amount credited to ratepayers in rates for Short-Term Storage and Other Balancing Services. The net revenue for Short-Term Storage and Other Balancing Services is determined by deducting the costs incurred to provide service from the gross revenue. The balance in this deferral account is a debit from ratepayers of $4.446 million, plus interest of $0.216 million for a total debit from ratepayers of $4.662 million.

2. As shown in Table 3, the balance is calculated by comparing $0.105 million (ratepayer 90% share of the actual 2022 Short-Term Storage and Other Balancing Services net revenue of $0.117 million) to the net revenue included in Union rate zone rates of $4.551 million.[1] The details of the balance are found at Exhibit E, Tab 1, Schedule 2.

[1] EB-2011-0210, Decision and Rate Order, January 17, 2013, p. 16.

Table 3

Deferral Summary: Short-term Storage and Other Storage Services

Line No.	Particulars ($000's)	Actual 2022
1	Net Revenue	117
2	Ratepayer Portion (90%)	12
3	Approved in Rates	4,551
4	Deferral Balance Payable to/(Collectable from) Ratepayers	(4,446)

3. Actual 2022 revenues from C1 Off-Peak Storage, Gas Loans and all other Balancing services of $1.189 million were $1.311 million lower than the 2013 OEB-approved forecast of $2.500 million.

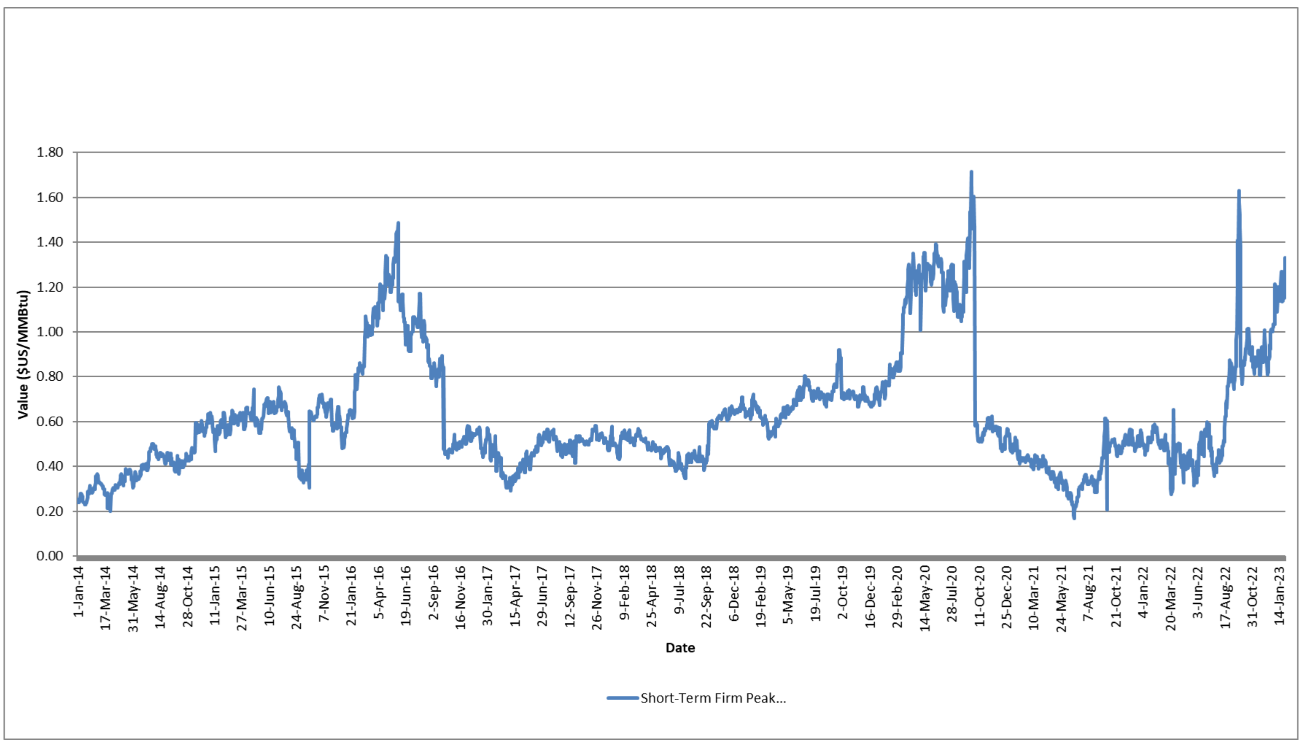
4. The C1 Short-Term Firm Peak Storage revenues of $2.108 million were $5.775 million lower than the 2013 Board-approved forecast of $7.883 million. Actual Union rate zone utility storage requirements for 2022 were 7.8 PJ higher than the 2013 OEB-approved forecast, resulting in a decrease in the C1 Short-Term Firm Peak Storage available for sale (from 11.3 PJ in 2013 OEB-approved to 3.5 PJ in 2022). Union rate zone customers received the value of storage directly through the use of the storage space, rather than through the sale of short-term storage.

5. Year-over-year, actual utility storage requirements for 2022 were 0.5 PJ lower than the requirement in 2021, resulting in an increase in the C1 Short-Term Peak Storage available for sale (from 3.0 PJ in 2021 to 3.5 PJ in 2022). This is a result of a decrease in the storage requirement for utility customers. The storage requirement for the general service market was calculated using the OEB-approved aggregate excess methodology. The storage requirement for the contract market was calculated specifically for each customer using either the OEB-approved aggregate excess methodology, the 15 times obligated Daily Contracted Quantity (DCQ) storage methodology, or the 10 times Firm Contract Demand (CD) storage methodology (for

those customers who have elected the Customer Managed Service).[2] Enbridge Gas has included the calculation for utility storage space requirements and the deliverability by rate class at Exhibit E, Tab 1, Schedule 2, Appendix A.[3]

6. The 2013 OEB-approved forecast implied an annual average value for C1 Short-Term Firm Peak Storage of $0.70/GJ ($7.883 million/11.3 PJ), and the actual average annual C1 Short-Term Firm Peak Storage value in 2022 was $0.61/GJ ($2.1 million/3.5 PJ). Please see Figure 1 for Short-Term Peak Storage values in US dollars.

Figure 1 - Historical Short-Term Firm Peak Storage Values at Dawn 2014-2022



[2] EB-2016-0245, Decision and Rate Order, Schedule 1, Settlement Proposal, p. 7.
[3] EB-2021-0149, Decision on Settlement Proposal, Schedule 1, Settlement Proposal, p.16.

1. Non-Utility Storage Balances for 2022

7. In its EB-2011-0210 Decision, the OEB directed Union to file a report similar to that ordered in EB-2011-0038 to monitor the inventory related to non-utility storage operations. Exhibit E, Tab 1, Schedule 3 shows the non-utility inventory balances for October and November of 2022 (for l Union storage).

8. During the 2022 injection season, the non-utility storage balance peaked on November 6, 2022 at 96.26% full with a balance of 124.5 PJ compared to available space of 129.3 PJ. At October 31, 2022, the date to which the Company manages its storage balance, the non-utility balance was 94.82% of available space. The balance stayed below the total non-utility available space of 100% for the rest of 2022.

9. In EB-2011-0210, the OEB further ordered Union to file a calculation for a storage encroachment payment from Union's non-utility business to Union's utility business, if Union's non-utility business encroached on Union's utility space. There was no encroachment of utility space in 2022 and therefore no calculation applies.

2. Sale of Non-Utility Storage Space

10. Enbridge Gas prioritizes the sale of Union utility storage ahead of the sale of its short-term non-utility storage and allocates short-term peak storage margins between utility and non-utility as directed by the OEB in EB-2011-0210.[4] Margins from short-term peak storage services are proportionately split between the utility and non-utility customers based on the utility and non-utility share of the total quantity of short-term peak storage sold each calendar year. Short-term peak sales include any sale of storage space for a term of less than two storage years.

11. In 2022, Enbridge Gas sold a total of 3.5 PJ of short-term peak storage (Union). The total 3.5 PJ was excess utility space, calculated by deducting 96.5 PJ of in-franchise utility requirement (as per the Gas Supply Plan) from the total 100 PJ of in-franchise

[4] EB-2011-0210, Decision and Order, pp. 116-117.

utility storage. There was no sale of short-term peak storage from non-utility space. Total revenue from the sale of C1 Short-Term Peak Storage (Utility) in 2022 was $2.108 million. Details of the above sales are reflected in Exhibit E, Tab 1, Schedule 4.

ACCOUNT NO. 179-133 NORMALIZED AVERAGE CONSUMPTION (NAC) UNION RATE ZONES

1. The purpose of the NAC deferral account is to record the variance in delivery revenue and storage revenue and costs resulting from the difference between the target NAC included in OEB-approved rates and the actual NAC for general service rate classes Rate M1, Rate M2, Rate 01 and Rate 10. As described in Union's 2014 Deferral Account Disposition[1] proceeding, including the revenue from storage rates in the NAC deferral account requires storage-related costs associated with the difference in target and actual NAC to also be included in the deferral account balance.

2. For 2022, the balance in the NAC deferral account is a debit to ratepayers of $8.770 million plus interest of $0.565 million for a total debit to ratepayers of $9.334 million.

3. The NAC Deferral Account follows the same methodology agreed to by parties in Union's 2014-2018 Incentive Regulation (IR) Settlement Agreement[2] and as subsequently modified in Union's 2015 Rates[3] proceeding.

1. Target and Actual NAC

4. The 2022 target NAC used to calculate base rates for each rate class was approved by the OEB in Enbridge Gas's 2022 Rates[4] proceeding. The 2020 actual NAC, weather normalized using the 2022 weather normal, was used to determine the 2022 target NAC for each rate class to calculate base rates. Setting the 2022 target NAC based on the 2020 actual NAC recognizes that over the two-year span to the current year, any volumes saved and lost revenues due to DSM activities will be captured by the variance between the target NAC and actual NAC. This is due to the

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[1] EB-2015-0010.
[2] EB-2013-0202.
[3] EB-2014-0271.
[4] EB-2021-0147.

inclusion of the DSM saved volumes within the actual reported consumption.

5. The 2022 forecast usage used to calculate Y factor unit rates for each rate class was approved by the OEB in Enbridge Gas's 2022 Rates[5] proceeding. The unit rates for pass-through (Y factor) costs are derived based on OEB-approved cost allocation and rate design methodologies and are passed through to customers at cost.

6. The 2022 actual NAC for each rate class is weather normalized using the 2022 weather normal, which is produced using the OEB-approved weather methodology consisting of a 50:50 average of the 30-year average and the 20-year trend estimates of annual heating degree-days.

7. Table 1 provides the 2022 target NAC and 2022 actual NAC by rate class for base rates.

Table 1
2022 Target and Actual NAC - Base Rates

Line No.	Particulars (m^3/customer)	Rate 01	Rate 10	Rate M1	Rate M2
		(a)	(b)	(c)	(d)
1	2022 Target NAC	2,866	160,773	2,729	159,225
2	2022 Actual NAC	2,765	141,564	2,694	153,228
3	Variance (Target - Actual NAC)	101	19,208	36	5,997

8. Table 2 provides the 2022 target NAC and 2022 actual NAC by rate class for Y factor rates.

[5] EB-2021-0147.

Table 2
2022 Target and Actual NAC - Y Factor Rates

Line No.	Particulars (m^3/customer)	Rate 01	Rate 10	Rate M1	Rate M2
		(a)	(b)	(c)	(d)
1	2022 Target NAC	2,809	166,354	2,658	162,473
2	2022 Actual NAC	2,765	141,564	2,694	153,228
3	Variance (Target - Actual NAC)	44	24,790	(36)	9,245

2. Delivery and Storage Revenues

9. The deferral account balance is calculated by multiplying the variance between the weather normalized target NAC and the weather normalized actual NAC by the 2013 OEB-approved number of customers and the 2022 OEB-approved delivery and storage rates for each general service rate class. A credit balance in the NAC Deferral Account reflects that the actual NAC is greater than the target NAC, while a debit balance in the NAC Deferral Account reflects that the actual NAC is less than the target NAC.

10. Table 3 provides the NAC Deferral Account balances by rate class. The detailed calculation of the NAC Deferral Account balance can be found at Exhibit E, Tab 1, Schedule 5.

Table 3
2022 NAC Deferral Account

Line No.	Particulars ($000s)	Rate 01 (a)	Rate 10 (b)	Rate M1 (c)	Rate M2 (d)	Total (e)
1	Delivery Revenue Balances	3,068	2,729	1,046	2,267	9,110
2	Storage Revenue Balances	1,550	1,442	314	308	3,613
3	Storage Cost Balances	(697)	70	(1,957)	(1,370)	(3,954)
4	Interest	289	90	218	(33)	565
5	Total NAC Deferral Balance	4,210	4,331	(378)	1,172	9,334

3. Deferral Account Impacts

11. For Rate M1, the 2022 actual NAC is lower than the target NAC used to derive base rates by 36 m^3/customer (Table 1, line 3, column (c)) and higher than the target NAC used to derive Y factor rates by 36 m^3/customer (Table 2, line 3, column (c)). As shown in Table 3, this results in a delivery and storage revenue debit to ratepayers of $1.360 million ($1.046 million and $0.314 million respectively). In addition, the NAC volume variance decreases the Rate M1 storage requirement by 2.150 PJ. Accordingly, Enbridge Gas must refund an amount of $1.957 million (Table 3,line 3, column (c)) to Rate M1 customers to recognize the decreased Rate M1 storage requirements.

12. For Rate M2, the 2022 actual NAC is lower than the target NAC used to derive base rates by 5,997 m^3/customer (Table 1, line 3, column (d)) and lower than the target NAC used to derive Y factor rates by 9,245 m^3/customer (Table 2, line 3, column (d)). As shown in Table 3, this results in a delivery and storage revenue debit to ratepayers of $2.575 million ($2.267 million and $0.308 million respectively). In addition, the NAC volume variance decreases the Rate M2 storage requirement by 1.510 PJ. Accordingly, Enbridge Gas must refund $1.370 million (Table 3, line 3, column (d)) to Rate M2 customers to recognize the decreased Rate M2 storage requirements.

13. For Rate 01, the 2022 actual NAC is lower than the target NAC used to derive base rates by 101 m^3/customer (Table 1, line 3, column (a)) and lower than the target NAC used to derive Y factor rates by 44 m^3/customer (Table 2, line 3, column (a)). As shown in Table 3, this results in a delivery and storage revenue debit to ratepayers of $4.618 million ($3.068 million and $1.550 million respectively). In addition, the NAC volume variance decreases the Rate 01 storage requirement by 0.630 PJ. Accordingly, Enbridge Gas must refund an amount of $0.697 million (Table 3, line 3, column (a)) to Rate 01 customers to recognize the decreased Rate 01 storage requirements.

14. For Rate 10, the 2022 actual NAC is lower than the target used to derive base rates NAC by 19,208 m^3/customer (Table 1, line 3, column (b)) and lower than the target NAC used to derive Y factor rates by 24,790 m^3/customer (Table 2, line 3, column (b)). As shown in Table 3, this results in a delivery and storage revenue debit to ratepayers of $4.171 million ($2.729 million and $1.442 million respectively). In addition, the NAC volume variance increases the Rate 10 storage requirement by 0.060 PJ. Accordingly, Enbridge Gas must collect $0.070 million (Table 3, line 3, column (b)) from Rate 10 customers to recognize the increased Rate 10 storage requirements.

<u>4. Storage Costs</u>

15. The storage costs recognize that variances between the 2022 target NAC and the 2013 OEB-approved NAC change the storage requirements for each general service rate class. As OEB-approved storage rates are not updated during the IR term to reflect changes in storage requirements due to NAC variances, Enbridge Gas must capture the NAC-related change in storage costs in the NAC Deferral Account for the Union rate zones as per the OEB's Decision in Union's 2013 Deferrals Disposition proceeding (EB-2014-0145), page. 9, "starting in 2014, the NAC Deferral Account, which replaces the Average Use Per Customer Deferral Account, will include storage related revenues and costs for general service rate classes."

16. To determine the change in storage requirements for each general service rate class due to NAC variances, the Company calculated the NAC volume variance per customer between its 2022/2023 Gas Supply Plan and the 2013 OEB-approved volumes multiplied by the 2013 OEB-approved number of customers.

17. Using the OEB-approved aggregate excess methodology, Enbridge Gas calculated the change in storage requirements for each of the general service rate classes due to variances in NAC. The 2022/2023 Gas Supply Plan volumes represent the April 1, 2022 to March 31, 2023 period, which are used to determine the storage requirements for general service rate classes effective November 1, 2022. These general service rate class storage requirements are then used in the calculation of the total in-franchise utility storage space requirement at November 1, 2022. The difference between the total in-franchise utility storage requirement and the total 100 PJ of utility storage represents the excess utility storage capacity available for sale (excess utility space) at November 1, 2022.

18. For Rate M1, the NAC volume variance between the 2022/2023 Gas Supply Plan and the 2013 OEB-approved volumes was a decrease of 10.125 PJ. The majority of the NAC volume variance decrease occurred in the winter months, which decreased the Rate M1 storage requirement by 2.150 PJ. This resulted in decreased storage costs of $1.957 million (Table 3, line 3, column (c)).

19. For Rate M2, the NAC volume variance between the 2022/2023 Gas Supply Plan and the 2013 OEB-approved volumes was an increase of 2.490 PJ. The majority of the NAC volume variance increase occurred in the summer months, which decreased the Rate M2 storage requirement by 1.510 PJ and resulted in decreased storage costs of $1.370 million (Table 3, line 3, column (d)).

20. For Rate 01, the NAC volume variance between the 2022/2023 Gas Supply Plan and the 2013 OEB-approved volumes was a decrease of 0.401 PJ. The majority of the NAC volume variance decrease occurred in the winter months, which decreased the Rate 01 storage requirement by 0.630 PJ and decreased storage costs by $0.697 million (Table 3, line 3, column (a)).

21. For Rate 10, the NAC volume variance between the 2022/2023 Gas Supply Plan and the 2013 OEB-approved volumes was an increase of 0.500 PJ. The NAC volume variance increase occurred similarly in the summer and in the winter months, which increased the Rate 10 storage requirement by 0.060 PJ and resulted in increased storage costs of $0.070 million (Table 3, line 3, column (b)).

22. Overall, the NAC volume variance between the 2022/2023 Gas Supply Plan and the 2013 OEB-approved volumes resulted in a decrease in general service storage requirements of 4.230 PJ. Accordingly, Enbridge Gas has included a storage cost credit of $3.954 million in the NAC Deferral Account. Please see Table 4 for a summary of the change in general service storage requirements due to NAC volume variances by rate class.

Table 4
Change in General Service Storage Requirements from 2013 OEB-approved
(based on weather normalized NAC)

Line No.		PJ		PJ
1	Rate M1	(2.150)	Rate 01	(0.630)
2	Rate M2	(1.510)	Rate 10	0.060
3	Total South	(3.660)	Total North	(0.570)

23. The reduction in storage activity has decreased storage deliverability costs, the commodity-related costs at Dawn and storage inventory carrying costs.

24. The 4.230 PJ reduction in general service storage requirements due to NAC volume variances forms part of the 3.483 PJ of excess utility space available for sale for winter 2022/2023. The revenue from the sale of the 3.483 PJ of excess utility space is recorded in the Short-Term Storage and Other Balancing Deferral Account (Account No. 179-70).

DEFERRAL CLEARING VARIANCE ACCOUNT– UNION RATE ZONES

1. The purpose of the Deferral Clearing Variance Account (DCVA) is to capture the differences between the forecast and actual volumes associated with the disposition of deferral account balances to the Union rate zones. The intent of the variance account is to minimize or eliminate the gains or losses to ratepayers and the Company as a result of volume variances associated with the disposition of deferral account balances.

2. The balance in this variance account is a debit from Union rate zones ratepayers of $1.978 million, plus interest to December 31, 2022 of a $0.135 million, for a total debit of $2.113 million. The balance includes the residual amounts not disposed of from the following deferral dispositions: 2020 Earnings Sharing and Deferrals (EB-2021-0149) cleared effective April 2022, 2020 Demand Side Management (EB-2022-0007) cleared effective July 2022, and 2020 Federal Carbon Pricing Program (EB-2021-0209) cleared effective April 2022. The total forecast disposition balance of these combined was a debit of $5.812 million, total recoveries were a credit of $3.834 million, resulting in a net residual debit balance of $1.978 million. A summary is provided below:

Proceeding	Amount ($ millions)
2020 Earnings Sharing and Deferrals (EB-2021-0149)	11.784
2020 Demand Side Management (EB-2022-0007)	(6.061)
2020 Federal Carbon Pricing Program (EB-2021-0209)	0.089
Subtotal – Approved for Disposition in 2022	5.812
Amounts disposed of in 2022 through one-time billing adjustments	(3.834)
Residual balance to Deferral Clearing Variance Account	1.978

3. The residual balance reflects the outstanding amount resulting from the clearance of deferral and variance accounts in the Union rate zone which occurred during 2022 and the inability to locate and dispose of the approved amounts to all intended customers.

PARKWAY WEST PROJECT COSTS DEFERRAL ACCOUNT – UNION RATE ZONES

1. In its Parkway West Project (EB-2012-0433) Decision, the OEB approved the establishment of the Parkway West Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Parkway West Project and the revenue requirement included in rates.

2. Enbridge Gas is seeking interim disposition of the 2022 balance in the Parkway West Project Costs Deferral Account, consistent with the 2016 to 2021 deferral and variance account disposition proceedings. The final costs and/or 2024 rate base value for all projects completed since the last rebasing cases for EGD and Union (including the Parkway West project) are being considered and determined in the current EB-2022-0200 rebasing case. Once that determination is made, Enbridge Gas will seek approval of the final disposition of this account as part of a subsequent proceeding (or within this proceeding if timing permits).

3. The balance in this deferral account is a credit to Union rate zones ratepayers of \$0.604 million plus interest of \$0.037 million for a total credit balance of \$0.640 million. The balance of \$0.604 million represents the difference between the revenue requirement of \$20.178 million included in 2022 rates (EB-2021-0147) and the calculation of the actual revenue requirement for 2022 of \$19.574 million as shown in Table 1.

TABLE 1
2022 PARKWAY WEST PROJECT RATE BASE AND REVENUE REQUIREMENT

Line No.	Particulars ($000's)	Col. 1 2022 Board-approved (a)	Col. 2 2022 Actuals (b)	Col. 3 Difference (c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	-	729	729
2.	Cumulative Capital Expenditures	233,147	232,432	(715)
3.	Average Investment	194,208	192,919	(1,289)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	2,250	1,947	(303)
5.	Depreciation Expense (1)	5,532	5,497	(35)
6.	Property Taxes	591	395	(196)
7.	Total Operating Expenses	8,373	7,839	(534)
8.	Required Return (2)	10,991	10,918	(73)
9.	Total Operating Expense and Return	19,364	18,757	(607)
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	2,251	2,236	(15)
11.	Income Taxes - Utility Timing Differences (4)	(1,438)	(1,419)	19
12.	Total Income Taxes	814	817	3
13.	Total Revenue Requirement	20,178	19,574	(604)

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The required return assumes a capital structure of 64% long-term debt at 3.82% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2022 required return calculation is as follows:
$192.919 million * 64% * 3.82% = $4.716 million plus
$192.919 million * 36% * 8.93% = $6.202 million for a total of $10.918 million.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

1. Capital Expenditures

4. The actual 2022 capital expenditures on in-service assets are $0.729 million higher than 2022 OEB-approved as shown in Table 2.

TABLE 2
PARKWAY WEST CAPITAL EXPENDITURES

Line No.	Particulars ($000's)	2022 Board-approved	2022 Actuals	Difference
		(a)	(b)	(c) = (b - a)
1.	Plant Infrastructure	-	729	729
2.	Compressor Equipment	-	-	-
3.	Total Capital Expenditures	-	729	729

5. Plant infrastructure costs were $0.729 million higher than costs included in 2022 OEB-approved rates due to the work completed and costs incurred to implement the mothball plan and stabilize the heritage homes located on the Parkway West property. A long term maintenance and monitoring plan has been put in place until such time as either the homes are sold or demolished. The heritage homes were initially discussed in the Company's 2019 Earnings Sharing and Deferrals Disposition interrogatory response to OEB staff[1].

2. Average Investment

6. The average investment difference of $1.289 million from OEB-approved is due to the cumulative capital expenditures being $0.715 million lower than OEB-approved.

3. Operating Expenses

7. Operating and maintenance expenses were $0.303 million below the costs included in the 2022 OEB-approved rates. The decrease is a result of the continued absence of a Long-term Service Agreement (LTSA) that was forecasted and included in 2022 OEB-approved rates but not incurred in actual O&M expense. The Company elected

[1] EB-2020-0134, EGI 2019 Earnings Sharing and Deferrals Disposition, Exhibit I.STAFF.25, a).

not to enter an LTSA, that would have provided loss of critical unit coverage should the Company experience operational issues with Parkway B, as with the commissioning of Parkway D it was determined that it provided the required backup.

8. Property taxes were $0.196 million lower than costs included in 2022 OEB-approved rates. The decrease is a result of the Municipal Property Assessment Corporation (MPAC) deciding not to apply a Land Classification tax charge that was expected for 2019 and onwards.

BRANTFORD KIRKWALL/PARKWAY D PROJECT COSTS
UNION RATE ZONES

1. In its Brantford-Kirkwall/Parkway D (EB-2013-0074) Decision, the OEB approved the establishment of the Brantford-Kirkwall/Parkway D Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Brantford-Kirkwall/Parkway D Project and the revenue requirement included in rates.

2. The balance in this deferral account is a credit to Union rate zone ratepayers of $0.035 million plus interest of $0.002 million for a total credit balance of $0.037 million. The balance of $0.035 million represents the difference between the revenue requirement of $15.447 million included in 2022 rates (EB-2021-0147) and the calculation of the actual revenue requirement for 2022 of $15.412 million as shown in Table 1. The minor variance in the actual revenue requirement results from lower average investment in the capital cost of the project and lower than forecast municipal taxes related to the property.

TABLE 1
2022 BRANTFORD-KIRKWALL PIPELINE/PARKWAY D PROJECT RATE BASE AND REVENUE REQUIREMENT

		Col. 1	Col. 2	Col. 3
Line No.	Particulars ($000's)	2022 Board-approved	2022 Actuals	Difference
		(a)	(b)	(c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	-	-	-
2.	Cumulative Capital Expenditures	197,404	197,378	(26)
3.	Average Investment	162,713	162,689	(24)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	-	-	-
5.	Depreciation Expense (1)	4,995	4,995	-
6.	Property Taxes	995	962	(33)
7.	Total Operating Expenses	5,990	5,957	(33)
8.	Required Return (2)	9,209	9,207	(2)
9.	Total Operating Expense and Return	15,199	15,164	(35)
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	1,886	1,886	-
11.	Income Taxes - Utility Timing Differences (4)	(1,638)	(1,638)	-
12.	Total Income Taxes	248	248	-
13.	Total Revenue Requirement	15,447	15,412	(35)

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The required return assumes a capital structure of 64% long-term debt at 3.82% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2022 required return calculation is as
$162.689 million * 64% * 3.82% = $3.977 million plus
$162.689 million * 36% * 8.93% = $5.23 million for a total of $9.207 million.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

UNACCOUNTED FOR GAS VOLUME DEFERRAL ACCOUNT
UNION RATE ZONES

1. The purpose of the Unaccounted for Gas Volume Deferral Account (UFGVDA) is to capture the difference between the cost of Unaccounted for Gas (UFG) recovered in rates, as previously approved by the OEB, and actual UFG costs incurred annually.[1] The balance recorded within the UFGVDA to be cleared to customers is subject to a symmetrical dead-band of $5.0 million, with amounts within such dead-band being recorded to Enbridge Gas's account. This evidence provides details regarding the balance recorded in the 2022 UFGVDA.

2. In the Union Rate Zones, 2022 OEB-approved rates included $15.7 million in UFG costs (based on forecasted throughput volumes). Based on 2022 actual throughput volumes, Enbridge Gas recovered $20.7 million in UFG costs through rates. In comparison, Enbridge Gas's actual 2022 UFG costs were $65.8 million. The variance between 2022 UFG costs recovered through rates and actual 2022 UFG costs of $45 million exceeds the $5.0 million dead band established by the OEB for the UFGVDA. As a result, there is a debit balance of $40 million in the UFGVDA, plus interest of $2.0 million for a total 2022 debit balance of $42.0 million. See Table 1.

[1] Deferral Account No. 179-135.

Table 1
2022 UTILITY UFG VARIANCES FROM OEB-APPROVED

Line No.	Particulars	Variance ($Millions)
1	UFG Cost Included in Rates	$ 15.7
2	Net Recovery Variance	$ 5.1
3	Total UFG Collected in 2022 Rates (line 1 + line 2)	$ 20.7
4	Total Utility UFG Actual Cost	$ 65.8
5	Total Utility UFG Variance (line 3 - line 4)	-$ 45.0
6	$5M UFG Symmetrical Dead-band	$ 5.0
7	UFG Volume Deferral (receivable)	-$ 40.0

(1) OEB Approved throughput was 32,010 10^6m^3 versus actual throughput of 42,378 10^6m^3

(2) OEB Approved UFG % is 0.219% versus actual UFG % of 0.592% for 2022.

3. To support the relief sought by Enbridge Gas, this exhibit contains additional evidence organized as follows:
    Section 1: Historical UFG Volumes, % of Throughput and UFGVDA Balances
    Section 2: Benchmarking
    Section 3: Impact of Pricing
    Section 4: Commitments from 2021
    Section 5: Actions Taken to Address UFG

Section 1: Historical UFG Volumes, % of Throughput and UFGVDA Balances

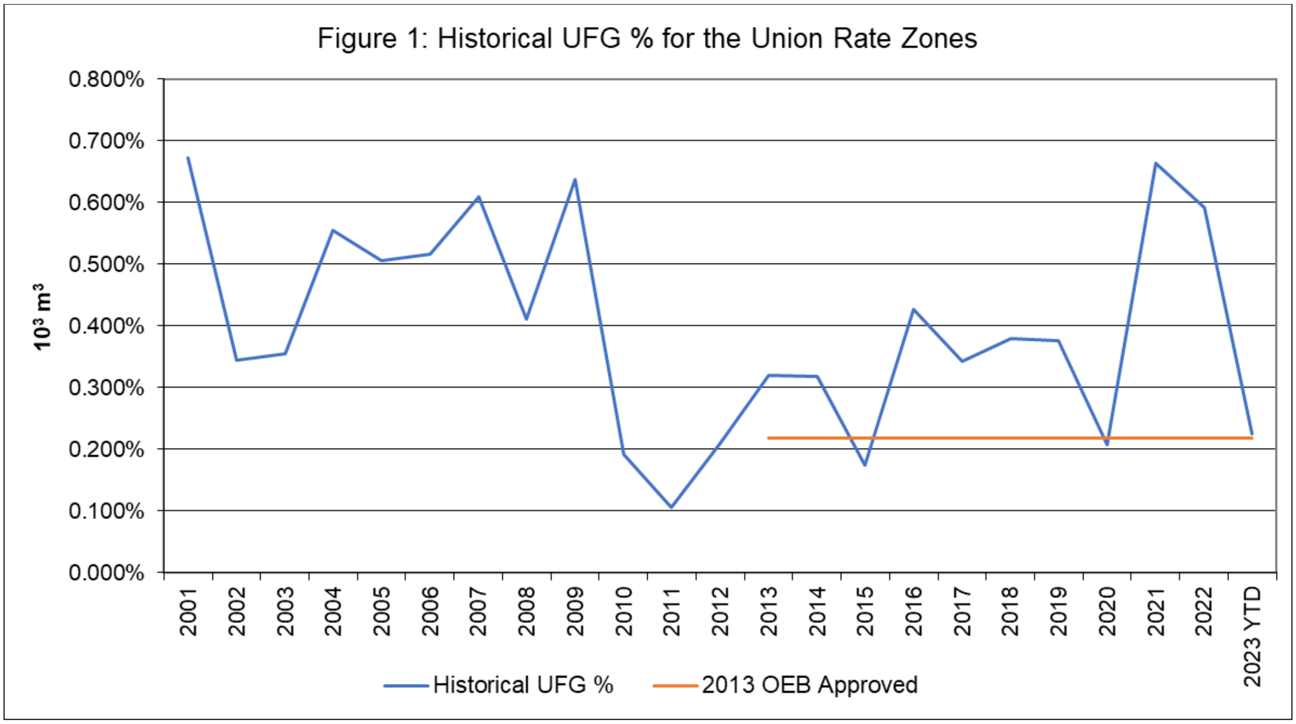
4. Table 2 provides historical total UFG volumes (utility and non-utility) and UFG volumes as a percentage of total throughput (UFG%) for the Union Rate Zones from 2001 to 2023.

Table 2
Historical UFG Volumes and Percentage of Throughput for the Union Rate Zones (1)

Calendar Year	UFG Volumes (10^3 m^3)	UFG %
2001	184,102	0.673%
2002	109,542	0.344%
2003	108,819	0.356%
2004	176,650	0.554%
2005	169,540	0.507%
2006	154,015	0.516%
2007	203,713	0.609%
2008	143,880	0.411%
2009	201,845	0.637%
2010	67,283	0.192%
2011	35,668	0.105%
2012	68,690	0.210%
2013	113,997	0.320%
2014	97,109	0.318%
2015	54,408	0.174%
2016	131,588	0.427%
2017	108,901	0.342%
2018	136,447	0.379%
2019	137,652	0.376%
2020	74,120	0.208%
2021	252,582	0.663%
2022	250,692	0.592%
2023 YTD	40,164	0.225%

Note:
(1) Includes utility and non-utility volumes

5. Figure 1 compares historical UFG% for the Union Rate Zones from 2001 to 2023 YTD to the 2013 OEB-approved UFG%.



6. The UFG% used in OEB-approved rates was determined as part of the Company's 2013 Rate Rebasing proceeding (EB-2011-0210) using a weighted average of the previous three years' actual UFG%. At the time that 2013 rates were set, the most recent three years of actual UFG% available was for 2009 to 2011. The OEB-approved methodology used a 3:2:1 weighting with the most recent year weighted most heavily, resulting in a UFG% of 0.219% (see section 4.1, for additional detail). As a result of this methodology, the UFG% included in rates was disproportionally influenced by the UFG% realized in each of 2010 and 2011. This is problematic since, as demonstrated by the data set out in Table 2, the UFG levels for 2010 and 2011 are among two of the three lowest recorded from 2001 to 2023 YTD. The Company's expressed concerns regarding the ability to manage UFG relative to the historically low ratio established via the 2013 Rate Rebasing proceeding contributing to the establishment of a new deferral account to capture variances (the UFGVDA).[2]

[2] Approved as part of the Company's 2014-2018 IRM proceeding (EB-2013-0202).

7. Since the 2013 OEB-approved UFG% of 0.219% was established, actual UFG% for the Union Rate Zones has averaged 0.38% (2013 – 2022). As a result, the Company has consistently recorded balances in the UFGVDA for the Union Rate Zones. Table 3 shows the historical UFGVDA balance with and without the impact of the $5 million dead band. As a result of the established dead band, since 2014 Enbridge Gas has been prevented from recovering a total of $27.8 million of UFG-related costs.

Table 3 - Union UFG Volume Deferral Account Deadband Impact

Line No.	Year	Actual UFG %	OEB Approved UFG %	UFG Volume Deferral Account Balance With Deadband ($ millions)	UFG Volume Deferral Account Balance Without Deadband ($ millions)	Deadband Impact ($ millions)
		(a)	(b)	(c)	(d)	(e) = (c) - (d)
1	2014	0.318%	0.219%	0.00	4.12	(4.12)
2	2015	0.174%	0.219%	0.00	(3.61)	3.61
3	2016	0.427%	0.219%	5.18	10.18	(5.00)
4	2017	0.342%	0.219%	0.00	2.71	(2.71)
5	2018	0.379%	0.219%	1.73	6.73	(5.00)
6	2019	0.376%	0.219%	1.56	6.56	(5.00)
7	2020	0.208%	0.219%	0.00	(0.41)	0.41
8	2021	0.672%	0.219%	20.48	25.48	(5.00)
9	2022	0.592%	0.219%	40.05	45.05	(5.00)
					Total Cumulative Impact	(27.80)

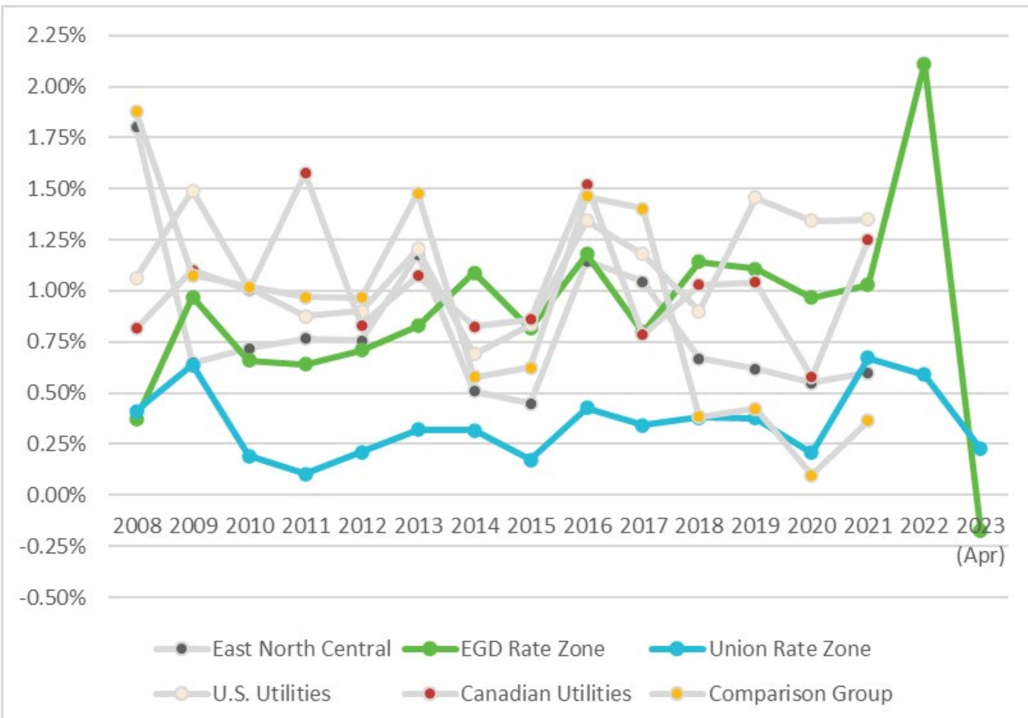
Section 2: Benchmarking

8. The 2019 Report on Unaccounted for Gas prepared by ScottMadden Management Consultants filed in the Company's 2020 Rates Application (EB-2019-0194) (the 2019 UFG Report) included a UFG Benchmark Analysis for the period of 2008 to 2017. Based on the results of the analysis completed, ScottMadden noted that Enbridge Gas had demonstrated lower UFG levels than comparative natural gas utilities (across all legacy EGD and Union Rate Zones).[3] For the purposes of the

[3] EB 2019-0194, Report on Unaccounted for Gas, pp.3-4, December 2019.

current Application, Enbridge Gas gathered the most current publicly available data for the same comparative gas utilities (up to and including 2021 for comparative utilities and 2023 YTD[4] for the Company) and updated the benchmark analysis set out in Figure 1 of the 2019 UFG Report[5]. Figure 2 reflects the best available data regarding UFG levels for each of the comparative utilities.

Figure 2: UFG Benchmark Analysis



9. Figure 2 demonstrates that all utilities included in the benchmark analysis experienced similar volatility in UFG, with material increases recorded in one year generally reversing in subsequent years. As noted in the 2019 UFG Report, the Alberta Utilities Commission stated in its decision on a UFG rider:

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4 April 30, 2023.
5 Refer to EB 2019-0194, Report on Unaccounted for Gas, p.15 for details regarding comparative utilities included in Benchmark Analysis.

> The Commission recognizes that all gas distribution pipeline systems have UFG as an element of operating a natural gas distribution system and that because of the numerous factors that impact UFG, the UFG percentage will fluctuate over time.[6]

10. Figure 2 also reflects certain industry-wide trends across comparative utilities, such as a general decline in UFG levels recorded in each of 2014, 2015 and 2020 followed by increases in UFG levels recorded in subsequent years. It is reasonable to assume that such trends may be reflective of common macro-economic and/or national/continental weather trends, both of which have the potential to impact utility throughput and UFG broadly across the industry. Such trends highlight the value of comparing UFG levels experienced by a single utility to relevant peer groups before concluding whether any significant or material variation in year-over-year UFG levels is reasonable.

11. Figure 2 shows that the EGD and Union Rate Zones' UFG levels and annual fluctuations are generally consistent with other gas utilities. It also demonstrates that the while Enbridge Gas has experienced recent increases in UFG levels in the EGD Rate Zone in 2022 and in the Union Rate Zones in 2021/2022, UFG levels are now trending lower for 2023 YTD. In response to the elevated levels of UFG recently experienced, Enbridge Gas has taken the initial steps to establish a discrete team with the express mandate to investigate root causes, make recommendations to reduce and monitor, and to implement a sustainment and governance model for UFG for the utility.

<u>Section 3: Impacts of Pricing</u>

12. Actual UFG volumes recorded in any given year are multiplied by the OEB-approved reference price to calculate the UFGVDA balance. Accordingly, drastic increases in the reference price of natural gas realized throughout 2022 have

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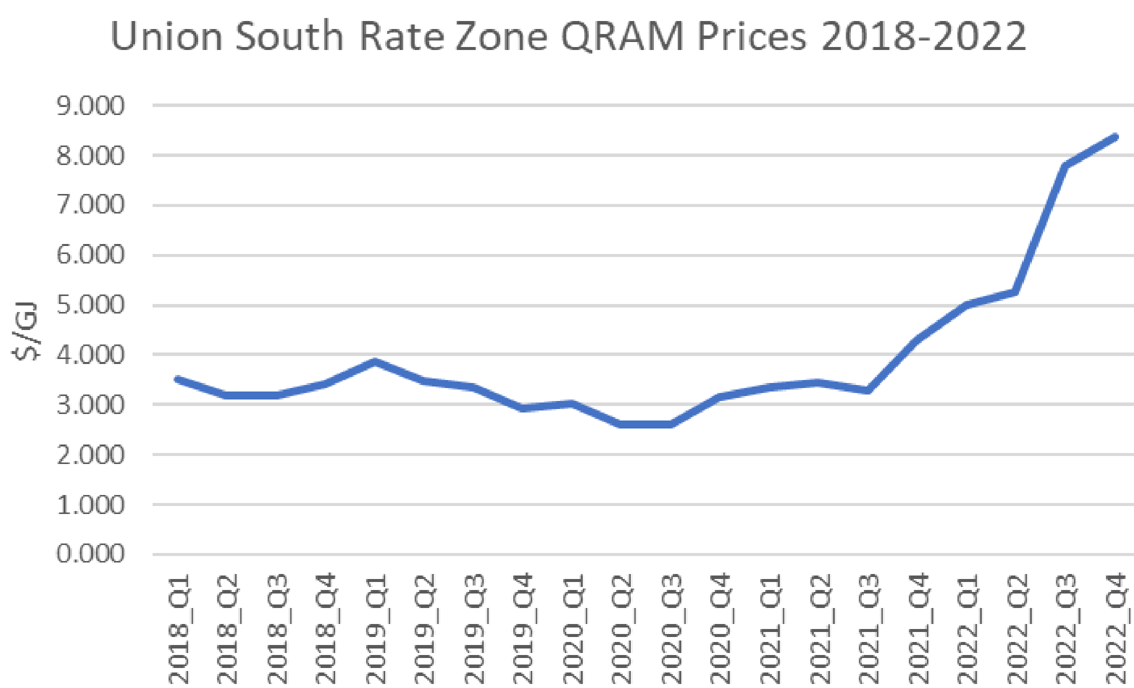
[6] Alberta Utilities Commission, Decision 22889-D01-2017, 2017-2018 Unaccounted-For Gas Rider D. (ATCO Gas and Pipelines Ltd.)

contributed to the 2022 UFGVDA balance. The magnitude of reference price increases is demonstrated within Figure 3, which shows the historical annual average OEB-approved reference price for 2018 to 2022 for the Union South Rate Zone.[7]

Figure 3



13. Table 2 shows that Total UFG volumes decreased slightly from 2021 to 2022 (252,582 10^3m^3 vs 250,692 10^3m^3). However, Table 3 shows that the UFGVDA balance increased by approximately $20 million from 2021 to 2022. This increase on a year over year basis is attributable to the reference price increases depicted in Figure 3.

[7] Union North East and Union North West QRAM price trends are consistent with the Union South Rate Zone.

Section 4: Commitments from 2021

14. In the Settlement Proposal in the 2021 Deferral and Variance Account and Earnings Sharing proceeding (EB-2022-0110), Enbridge Gas committed to include the following items in its filing in this proceeding:[8]

> Detailed evidence on the derivation of UFG balances, including evidence on items such as:
> (a) the process used to determine forecast and actual UFG at the end of each year and the beginning of the following year,
> (b) the way that UFG is determined on an ongoing basis as forecast (unbilled) volumes are billed, and
> (c) the impact of billing adjustments on UFG
> (d) continuity schedule showing forecast and actual UFG on a monthly basis for 2020, 2021 and 2022.

15. Accordingly, this section of evidence is organized to respond directly to each of the commitments previously made by the Company, as follows:
    - Section 4.1: Determination of UFG Forecast
    - Section 4.2: Determination of Actual UFG – Monthly Processes
    - Section 4.3: Determination of Actual UFG – Annual Processes
    - Section 4.4: Historical Forecast and Actual UFG on a Monthly Basis

Section 4.1: Determination of UFG Forecast

16. As explained in section 1, the current methodology to forecast UFG volumes in the Union Rate Zones is based on calculating a 3-year weighted average of the ratio of UFG volumes to total system throughput. The ratio of UFG volumes to total system throughput is weighted, where the most recent year has a weighting of 3:6 (50%), the second most recent year has a weighting of 1:3 (33%), and the third most recent year has a weighting of 1:6 (17%). Based on the OEB-approved forecasting methodology, the ratio of UFG volumes to total system throughput used to forecast UFG volumes for the period of 2013 to 2023 is 0.219%, as approved in Union's

[8] EB-2022-0110, Decision on Settlement Proposal and Rate Order, November 8, 2022, p. 4

2013 Cost of Service Application.[9] The OEB-approved 0.219% ratio is then multiplied by the annual throughput forecast to derive an annual forecast of UFG volumes. The UFG volume included in rates is calculated by applying the 0.219% ratio to the 2013 OEB approved forecast throughput volumes.

Section 4.2: Determination of Actual UFG – Monthly Processes

17. At a high level, UFG is the difference between two primary components: net gas sendout (Sendout) and consumption.

UFG loss/(gain) = Sendout – Consumption

18. Sendout is the net amount of natural gas delivered into the distribution system. At all custody transfer points, there is both custody transfer measurement (third-party) and check measurement (Enbridge Gas), both of which utilize Measurement Canada certified equipment that is required to comply with a +/- 3% measurement error tolerance. Internally, Enbridge Gas operates within a more stringent +/- 2% measurement error tolerance and investigates any measurement variance that exceeds those bounds. Enbridge Gas has established manual and automated means by which to validate measurement accuracy and takes volumetric, energy content, temperature, and pressure factors/variables into consideration when investigating measurement variances compared to prescribed reasonability tolerances, in addition to validating measurement completeness.

19. Consumption includes both billed consumption and unbilled consumption.

20. Billed consumption is calculated within the billing system based on a combination of actual and estimated meter reads. Certain customers, generally contract rate customers, have daily actual measurement recorded which is used to calculate their

[9] EB-2011-0210, Exhibit D3, Tab 2, Schedule 2, Updated; EB-2011-0210, OEB Decision and Order, October 24, 2012.

billed consumption. The remaining customers have periodic meter reads completed and so rely on a combination of actual and estimated meter reads to calculate their billed consumption. Estimated meter reads are calculated at the individual customer level based on consumption history for their respective premise(s). When insufficient usage history exists to derive an accurate estimated meter read, the billing system uses a combination of degree day data and standard baseload factors for the customer's property type to derive an estimate.

21. In instances where a bill is based on an estimated meter read, a subsequent true-up will occur once an actual meter read is next recorded. In other words, Enbridge Gas reviews such accounts after obtaining an actual meter read and performs a volumetric adjustment (spread out over the estimated period since the last actual reading and taking into account weather[10], the number of days in each billing period, and the customer's actual consumption for the prior year). In situations where a customer's consumption pattern varies by season Enbridge Gas works with the customer to understand the nature of their consumption between actual meter reads and tailors the volumetric adjustment accordingly.[11]

22. While the billing system ensures that the consumption is billed to the customers at the appropriate rate for the period in which the consumption occurred, to the extent volumetric adjustments are recorded, they are reflected in the accounting period in which billing occurred.

23. To demonstrate the impacts of the various true-ups described in this section, a number of illustrative examples are provided below:

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[10] Heating degree days.
[11] When a volumetric adjustment spans more than a single fiscal quarter, the Company also ensures that the appropriate quarterly QRAM rate for that time period is applied.

a) Scenario 1: Base Case
b) Scenario 2: Estimated Meter Read
c) Scenario 3: No Bill

Note: Illustrative examples assume no UFG due to physical losses

a) <u>Scenario 1: Base Case</u>

Sendout = 100 units (actual)

Consumption = 100 units (actual meter read)

Billed Consumption = 100 units

UFG Recorded in Utility Month End Financial Results:

UFG = 100 – 100 = 0

Cumulative UFG = 0

b) <u>Scenario 2: Estimated Meter Read</u>

Month 1 (estimated read):

Sendout = 100 units (actual)

Consumption = 95 units (based on estimated meter read)

Billed Consumption = 95 units

UFG Recorded In Utility Month End Financial Results:

UFG = 100 – 95 = 5

Cumulative UFG = 5

Month 2 (actual meter read):

Sendout = 100 units (actual)

Consumption = 200 units (difference between last actual meter read and current actual meter read)

Billed Consumption = 200 - 95 units (billed in month 1) = 105 units

UFG Recorded in In Utility Month End Financial Results:

UFG = 100 – 105 = (5)

Cumulative UFG = 5 + (5) = 0

c) <u>Scenario 3: “No Bill” Example</u>

Month 1 (no bill issued to customer):

Sendout = 100 units (actual)

Consumption = 80 units (estimated for month-end accounting purpose)

Billed Consumption = 0 units (no bill issued to customer)

UFG In Utility Month End Financials:

UFG = 100 – 80 = 20

Cumulative UFG = 20

Month 2 (bill issued to customer for two months of consumption)

Sendout = 100 units (actual)

Consumption = 200 units (difference between last actual meter read and current actual meter read)

Billed Consumption = 200 units

UFG Recorded In Utility Month End Financial Results:

UFG = 100 – (200-80) = (20)

Cumulative UFG = 20 + (20) = 0

24. Consumption also includes an estimation of gas consumed but not yet billed. Enbridge Gas utilizes cycle billing, which means that customers are billed in cycles staggered throughout the month. As a result of cycle billing, there is a portion of consumption at any point in time that has not been billed. At the end of every monthly reporting period, Enbridge Gas records an estimate of gas delivered but not yet billed. This estimate is calculated at the rate class level and considers factors such as number of customers, average use, actual weather, and demand

coefficients. The unbilled estimate that is recorded in a given reporting period is reversed in the following reporting period and replaced by billed consumption. To the extent that the estimate of the unbilled consumption differs from the billed consumption, a true-up is recorded to reflect the difference.

25. If the estimation of unbilled consumption was determined to be understated upon the analysis of billed data, it has the impact of temporarily creating a UFG loss in the period that the unbilled estimation was recorded and creating a UFG gain in the subsequent period when the estimate is reversed and replaced with actual billed consumption. The inverse is also true. True-ups associated with the unbilled estimate function similar to the no bill scenario described previously.

26. The impact of the true-up of unbilled consumption for the Union Rate Zones has been quantified for 2020 to 2022 in Table 5:

Table 5: UFG Volumes for Union Rate Zone Adjusted for Estimation Variances

Line No.	Particulars (10^3m^3)	2020	2021	2022
1	Estimated Unbilled Volumes (Dec 15-31)	531,070	441,068	467,655
2	Actual Billed Volumes (Dec 15-31)	484,587	437,434	423,240
3	Estimation Variance	(46,483)	(3,634)	(44,415)
4	UFG Volumes	66,056	223,637	218,904
5	Estimation Variance for Prior Year (1)	(48,699)	(46,483)	(3,634)
6	Estimation Variance for Current Year	46,483	3,634	44,415
7	UFG Volumes Adjusted for Estimation Variances	63,839	180,788	259,685

Notes:
(1) Impact of estimation variances have not been adjusted for unregulated allocation

27. One additional adjustment that may occur monthly relates to measurement errors. The 2019 Report on UFG notes that measurement errors can be attributable to causes such as meter failure, meters that do not accurately correct for temperature

of pressure variations or meters that are not sized properly[12]. Measurement errors result in a difference between actual and metered volumes. While the cause of adjustments relating to measurement errors differs from adjustments associated with estimated reads and unbilled estimates, the impact is the same. In the period when measurement error occurs, it will result in a UFG loss/(gain). In the period when the measurement error is corrected, there will be an equal and offsetting impact.

28. On a monthly basis, the calculation of UFG is adjusted to exclude Company use volumes which are recorded as a gas cost and not recovered through the UFGVDA.

29. On a monthly basis, the calculation of UFG volumes is recorded based on an annual heat value for natural gas delivered to customers. In the following month, when the actual heat values become available, the difference between the actual and annual heat value is recorded in the UFGVDA.

<u>Section 4.3: Determination of Actual UFG – Annual Processes</u>

30. The processes described in section 4.2 occur monthly in the normal course of business (i.e., for each monthly accounting reporting period, including the end of the calendar fiscal year). In the EGD rate zone, there is one additional step that is completed after the end of the calendar fiscal year. The current accounting order for the UAFVA states: “An adjustment will be made to the UAFVA in the subsequent year to record any differences between the estimated UAF and actual UAF.”

31. In the EGD rate zone, the variance between the unbilled estimate recorded in December and the associated billed consumption recorded in January is included in the calculation of UAFVA in the fiscal year when the unbilled estimate was

[12] EB-2019-0194, Report on Unaccounted for Gas, p. 28.

recorded. This ensures that the true-up is recorded in the reporting period that the consumption pertains to, and eliminates a timing variance that crosses fiscal years.

32. The UFG Volume Deferral Account in the Union Rate Zones does not include a similar provision to record an adjustment relating to unbilled estimation true-ups that cross fiscal years. As such, to the extent that there is a difference between estimated consumption and actual consumption, the true-up will be recorded in the subsequent fiscal year. The estimation variance relating to the unbilled estimate is quantified for the Union Rate Zones for 2020-2022 in Table 5.

33. In the 2024 Rebasing Application[13], Enbridge Gas has proposed to harmonize the UFG Variance and Deferral accounts, including the provision in the proposed Accounting Order for the UFG Variance Account to adjust for differences in estimated UFG and actual UFG, similar to the current EGD Rate Zone treatment.

34. For the Union Rate Zones, there is an annual allocation of UFG to the unregulated business. A fulsome description of the current and proposed methodology to determine this allocation was filed in the 2024 Rebasing Application[14] and is included as Attachment 1 to this evidence.

Section 4.4: Historical Forecast and Actual UFG on a Monthly Basis

35. As noted in Section 4: Commitments from 2021, Enbridge Gas committed to provide a continuity schedule showing forecast and actual UFG on a monthly basis for 2020, 2021 and 2022. Table 6 includes forecast/budget and actual UFG volumes for 2017-2023 YTD.

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[13] EB-2022-0200, Exhibit 9, Tab 1, Schedule 1, Attachment 3.
[14] EB-2022-0200, Exhibit 1, Tab 13, Schedule 2, Attachment 1.

Table 6: Monthly Continuity of Actual and Forecast UFG Volumes for 2017-2023 for the Union Rate Zone

Line No.	Particulars	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	Budget UFG Volume (10^3m^3) (1)	2017	8,742	7,288	8,473	5,044	4,059	3,383	3,806	3,987	3,813	4,399	7,072	9,578	69,643
2	Actual UFG Volumes (10^3m^3) (1)	2017	(4,051)	3,177	13,380	(12,703)	(1,891)	11,299	(1,693)	11,379	7,403	26,740	66,270	(10,411)	108,901
3	Budget UFG Volume (10^3m^3) (2)	2018	10,419	8,080	8,966	7,007	4,783	4,034	4,357	4,589	4,271	5,338	8,085	8,863	78,793
4	Actual UFG Volumes (10^3m^3) (2)	2018	30,975	9,068	(18,974)	25,445	(28,363)	5,163	(433)	16,123	20,592	76,817	12,899	(12,864)	136,447
5	Budget UFG Volume (10^3m^3) (3)	2019	10,910	9,103	9,608	5,932	4,786	3,981	4,693	4,369	3,998	4,990	8,153	9,608	80,130
6	Actual UFG Volumes (10^3m^3) (3)	2019	9,421	22,195	(24,579)	17,357	14,003	6,255	(5,271)	24,436	52,175	(8,436)	34,556	(4,460)	137,652
7	Budget UFG Volume (10^3m^3) (4)	2020	9,460	9,399	7,517	5,443	5,462	4,724	4,761	5,196	4,352	5,605	6,721	9,539	78,177
8	Actual UFG Volumes (10^3m^3) (4)	2020	24,482	(12,580)	(9,710)	(7,682)	(5,555)	7,179	14,927	15,762	3,505	40,881	(35,002)	37,913	74,120
9	Budget UFG Volume (10^3m^3) (5)	2021	10,350	7,210	10,856	5,929	5,005	4,987	4,876	5,865	4,793	5,561	7,723	9,216	82,371
10	Actual UFG Volumes (10^3m^3) (5)	2021	42,009	859	22,489	26,673	6,386	(12,950)	28,375	(1,146)	23,599	21,456	80,357	14,477	252,582
11	Budget UFG Volume (10^3m^3) (6)	2022	12,091	10,070	9,463	7,006	5,856	5,230	5,897	5,746	5,519	6,614	7,861	11,655	93,008
12	Actual UFG Volumes (10^3m^3) (6)	2022	84,114	130,012	35,638	53,403	(66,878)	(2,111)	2,982	(48,950)	25,784	8,438	44,414	(16,153)	250,692
13	Budget UFG Volume (10^3m^3) (7)	2023	10,946	10,656	10,280	7,225									39,107
14	Actual UFG Volumes (10^3m^3) (7)	2023	150,077	(132,603)	13,147	9,543									40,164

Note:
(1) Includes utility and non-utility UFG volumes prior to allocation to regulated Short Term Storage of 1.76% and Unregulated Storage Allocation of 10.19%
(2) Includes utility and non-utility UFG volumes prior to allocation to regulated Short Term Storage of 1.68% and Unregulated Storage Allocation of 8.92%
(3) Includes utility and non-utility UFG volumes prior to allocation to regulated Short Term Storage of 1.26% and Unregulated Storage Allocation of 10.78%
(4) Includes utility and non-utility UFG volumes prior to allocation to regulated Short Term Storage of 1.35% and Unregulated Storage Allocation of 9.53%
(5) Includes utility and non-utility UFG volumes prior to allocation to regulated Short Term Storage of 1.33% and Unregulated Storage Allocation of 10.13%
(6) Includes utility and non-utility UFG volumes prior to allocation to regulated Short Term Storage of 2.02% and Unregulated Storage Allocation of 10.66%
(7) Includes utility and non-utility UFG volumes prior to allocation to regulated Short Term Storage and Unregulated Storage Allocation; final allocation will be determined based on 2023 actuals

36. Enbridge Gas has provided additional data beyond what has been requested to illustrate several key points. First, the historical actual monthly UFG volumes exhibit fluctuations from month to month across all the years provided in Table 6. These fluctuations are due in part to the factors discussed in Section 2, 4.2 and 4.3. While Enbridge Gas has experienced recent increases in the annual UFG levels in the EGD rate zone in 2022 and in the Union Rate Zones in 2021/2022, the fluctuations in actual monthly UFG volumes existed prior to those time periods as well. Furthermore, Table 6 shows that UFG levels are now trending lower for 2023 YTD.

Section 5: Actions Taken to Address UFG

37. In accordance with commitments made by the Company in its 2020 Rates application (EB 2019-0194), Enbridge Gas included an update in its 2024 Rate Rebasing Application and pre-filed evidence regarding progress made in implementing recommendations set out within the 2019 UFG Report and other such UFG management/mitigation-related activities. More specifically, a UFG Progress

Report initially filed in the 2022 Annual Rate Application[15] was also filed in the 2024 Rebasing Application.[16] A Supplemental UFG Progress Report was also filed in the 2024 Rebasing Application.[17] Both reports have been filed at Exhibit D-1 Attachments 1 and 2. Additional updates on the status of implementing items noted in the UFG Progress Report and the Supplemental UFG Progress Report provided in response to interrogatories in the 2024 Rate Rebasing proceeding[18] at Exhibit D-1, Attachment 3.

38. Enbridge Gas is continuing to monitor and address potential contributors to UFG. To date in 2023, in response to the elevated level of UFG recently experienced in both the EGD and Union Rate Zones, Enbridge Gas took the initial steps to establish a discrete team with the express mandate to investigate root causes, make recommendations to reduce and monitor, and to implement a sustainment and governance model for UFG for the utility.

15 EB-2021-0148.
16 EB-2022-0200 Exhibit 4, Tab 3, Schedule 1, Attachment 3.
17 EB-2022-0200 Exhibit 4, Tab 3, Schedule 1, Attachment 4.
18 EB-2022-0200 Exhibit I.4.2-STAFF-108.

UNACCOUNTED FOR GAS (UFG) PRICE VARIANCE ACCOUNT
UNION RATE ZONES

1. The UFG Price Variance Account captures the variance between the average monthly price of the Company's purchases for the Union rate zones and the applicable OEB-approved reference price, applied to the Company's actual UFG volumes for the Union rate zones. Price variances are initially recorded in the PGVA deferral accounts and the portion of the price variances associated with UFG volumes is transferred from the PGVA to the UFG Price Variance Account. This transfer ensures that costs are borne by the appropriate group of ratepayers, consistent with the UFG cost allocation.

2. During 2022, the Company purchased 142,204 10^3m^3 of gas supply in Union rate zones related to actual UFG volumes on behalf of ratepayers. The actual UFG purchases exclude the actual UFG collected from ratepayers who provide UFG in kind as part of customer supplied fuel (CSF).

3. The average actual cost of the UFG purchases in 2022 is $68.80/$10^3m^3$ higher than the OEB-approved reference prices included in rates based on the Union South rate zone gas portfolio cost of $258.69/$10^3m^3$. The result is a $9.78 million balance to be collected from ratepayers, as shown in Table 1. Table 2 provides the detailed calculation supporting the price variance of $68.80/$10^3m^3$.

Table 1
Calculation of 2022 UFG Price Variance

Line No.	Particulars	UFG Volumes (10^3m^3)
1	Experienced Regulated UFG (1)	218,904
2	UFG Collected through CSF	76,700
3	UFG Volumes – Company Supplied (2)	142,204
		Deferral Calculation
4	UFG Volumes (10^3m^3) – Company Supplied (2)	142,204
5	Price Variance ($/$10^3m^3$) (3)	$68.80
6	Variance Account Balance ($ millions)	$9.78

Notes
(1) Converted using the following heat values (39.32 Jan-Mar) (39.12 April-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) See Table 2 for the price variance calculation.

Table 2
Calculation of 2022 Union South Price Varaince

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average Price
1.0	Board Approved Reference Price ($ / 10^3m^3)	$ 196.76	$ 196.76	$ 196.76	$ 206.12	$ 206.12	$ 206.12	$ 304.71	$ 304.71	$ 304.71	$ 327.16	$ 327.16	$ 327.16	$ 258.69
2.0	Actual Purchase ($)	$ 67,738,854	$ 99,712,180	$ 73,951,792	$ 81,977,914	$ 115,029,585	$ 125,299,168	$ 85,128,871	$ 108,547,700	$ 116,288,095	$ 110,842,126	$ 91,298,394	$ 101,168,060	
3.0	Purchase Volumes (10^3m^3)	317,957	328,014	317,873	317,725	328,785	289,685	262,685	274,139	255,022	332,622	300,440	309,719	
4.0	Average Purchase Cost (Union South) ($ / 10^3m^3) (1)	$ 213.04	$ 303.99	$ 232.65	$ 258.02	$ 349.86	$ 432.54	$ 324.07	$ 395.96	$ 455.99	$ 333.24	$ 303.88	$ 326.64	$ 327.49
5.0	Union South Price Variance ($ / 10^3m^3) (2)	$ (16.29)	$ (107.23)	$ (35.89)	$ (51.89)	$ (143.74)	$ (226.41)	$ (19.37)	$ (91.25)	$ (151.29)	$ (6.08)	$ 23.28	$ 0.52	$ (68.80)

Notes
(1) Line 2 / Line 3
(2) Line 1 - Line 4

LOBO C COMPRESSOR/HAMILTON MILTON PIPELINE PROJECT COSTS DEFERRAL ACCOUNT – UNION RATE ZONES

1. In its Dawn Parkway 2016 Expansion (EB-2014-0261) Decision, the OEB approved the establishment of the Lobo C Compressor/Hamilton-Milton Pipeline Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Project and the revenue requirement included in rates.

2. The balance in this deferral account is a debit from Union Rate Zone ratepayers of \$0.240 million plus interest of \$0.011 million for a total debit balance of \$0.251 million. The balance of \$0.240 million represents the difference between the revenue requirement of \$26.328 million included in 2022 rates (EB-2021-0147) and the calculation of the actual revenue requirement for 2022 of \$26.568 million as shown in Table 1.

TABLE 1
2022 LOBO C COMPRESSOR/HAMILTON-MILTON PIPELINE PROJECT RATE BASE AND REVENUE REQUIREMENT

Line No.	Particulars ($000's)	Col. 1 2022 Board-approved (a)	Col. 2 2022 Actuals (b)	Col. 3 Difference (c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	-	-	-
2.	Cumulative Capital Expenditures	347,980	347,062	(918)
3.	Average Investment	298,609	297,803	(806)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	879	1,364	485
5.	Depreciation Expense (1)	8,261	8,214	(47)
6.	Property Taxes	1,234	1,058	(176)
7.	Total Operating Expenses	10,374	10,636	262
8.	Required Return (2)	16,021	15,978	(43)
9.	Total Operating Expense and Return	26,395	26,614	219
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	3,466	3,451	(15)
11.	Income Taxes - Utility Timing Differences (4)	(3,533)	(3,497)	36
12.	Total Income Taxes	(67)	(46)	21
13.	Total Revenue Requirement	26,328	26,568	240

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The required return assumes a capital structure of 64% long-term debt at 3.36% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2022 required return calculation is as follows:
$297.803 million * 64% * 3.36% = $6.404 million plus
$297.803 million * 36% * 8.93% = $9.574 million for a total of $15,978 million.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

1. Average Investment

3. The average investment decrease of $0.806 million from OEB-approved is due to the cumulative capital expenditures being $0.918 million lower than OEB-approved capital expenditures.

2. Operating Expenses

4. Operating and maintenance expenses were $0.485 million higher than the costs included in 2022 OEB-approved rates. The increase is a result of higher general maintenance and repairs to equipment and assets incurred in 2022, not in the original forecast.

3. Property Tax

5. Property taxes were $0.176 million lower than costs included in 2022 OEB-approved rates. The decrease is a result of continued Provincial tax reductions for business education tax rates on commercial, industrial, and pipeline tax in 2022.

LOBO D/BRIGHT C/DAWN H COMPRESSOR PROJECT COSTS
UNION RATE ZONES

1. In its EB-2015-0116 Decision, the OEB approved the establishment of the Lobo D/Bright C/Dawn H Compressor Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Lobo D/Bright C/Dawn H Compressor Project and the revenue requirement included in rates.

2. The balance in this deferral account is a debit to Union Rate Zone ratepayers of $1.315 million plus interest of $0.054 million, for a total debit balance of $1.369 million. The balance of $1.369 million includes a debit of $2.661 million which represents the difference between the revenue requirement of $46.496 million included in 2022 rates (EB-2021-0147) and the calculation of the actual revenue requirement for 2022 of $49.157 million as shown in Table 1.

3. A $1.345 million credit relates to the 2022 revenue generated from the sale of surplus Dawn Parkway system capacity of 30,393 GJ/day associated with the Lobo D/Bright C/Dawn H Compressor Project. In accordance with the 2018 Disposition of Deferral and Variance Account Balances and Utility Earnings proceeding (EB-2019-0105) approved Settlement Proposal, the surplus capacity is deemed to be sold long-term and the revenue credit for the 2022 year is calculated based on the M12 Dawn-Parkway rate of $3.689/GJ approved in the EB-2021-0147 Rate Order, dated September 29, 2021. A schedule supporting the 2022 revenue calculation is provided at Exhibit E, Tab 1, Schedule 6.

TABLE 1

2022 DAWN H/LOBO D/BRIGHT C COMPRESSOR PROJECT RATE BASE AND REVENUE REQUIREMENT

Line No.	Particulars ($000's)	Col. 1 2022 Board-approved (a)	Col. 2 2022 Actuals (b)	Col. 3 Difference (c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	-	-	-
2.	Cumulative Capital Expenditures	622,500	620,050	(2,450)
3.	Average Investment	534,951	534,722	(229)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	1,796	4,165	2,369
5.	Depreciation Expense (1)	17,418	17,437	19
6.	Property Taxes	1,089	1,062	(27)
7.	Total Operating Expenses	20,304	22,664	2,360
8.	Required Return (2)	28,462	28,449	(13)
9.	Total Operating Expense and Return	48,766	51,113	2,347
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	6,200	6,196	(4)
11.	Income Taxes - Utility Timing Differences (4)	(8,470)	(8,153)	317
12.	Total Income Taxes	(2,270)	(1,957)	313
13.	Total Revenue Requirement	46,496	49,157	2,661

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The required return assumes a capital structure of 64% long-term debt at 3.29% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2022 required return calculation is as
$534.722 million * 64% * 3.29% = $11.259 million plus
$534.722 million * 36% * 8.93% = $17.190 million for a total of $28.449 million.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

1. Average Investment

4. The average investment decrease of $0.229 million from OEB-approved is due to the cumulative capital expenditures being $2.450 million lower than OEB-approved.

2. Operating Expenses

5. Operating and maintenance expenses were $2.369 million higher than the costs included in 2022 OEB-approved rates. The increase is a result of higher salaries/wages, higher general maintenance costs than budgeted due to a major Power Turbine repair at Dawn H, and higher utility costs at Lobo D. Table 2 shows the breakdown and comparison of actual 2022 operating and maintenance costs versus OEB-approved.

TABLE 2
2022 DAWN H/LOBO D/BRIGHT C COMPRESSOR OPERATING AND MAINTENANCE EXPENSES

		Col. 1	Col. 2	Col. 3
Line No.	Particulars ($Millions)	2022 Board-approved	2022 Actuals	Difference
		(a)	(b)	(c) = (b - a)
1.	Salaries & Wages	888	1,521	633
2.	HR Costs	400	681	282
3.	Fleet Costs	133	228	95
4.	Training, Travel and PE	68	9	(59)
5.	Other O&M (Contract Services)	168	1,407	1,239
6.	Company Used Fuel	74	1	(73)
7.	Utility Costs	65	318	253
8.	Total Capital Expenditures	1,796	4,165	2,369

3. Income Taxes

6. The $0.313 million decrease in “Income Taxes – Utility Timing Difference” credit relates to a lower Capital Cost Allowance (CCA) deduction due to the lower average investment in 2022, versus OEB-approved, as well as lower CCA available on additions that were previously qualified for Bill C-97 accelerated CCA.

BURLINGTON OAKVILLE PROJECT COSTS DEFERRAL ACCOUNT
UNION RATE ZONES

1. In its EB-2015-0116 Decision, the OEB approved the establishment of the Burlington Oakville Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Project and the revenue requirement included in rates.

2. The balance in this deferral account is a credit to Union rate zone ratepayers of $0.048 million plus interest of $0.003 million for a total credit balance of $0.051 million. The balance of $0.051 million represents the difference between the revenue requirement of $5.787 million included in 2022 rates (EB-2021-0147) and the calculation of the actual revenue requirement for 2022 of $5.739 million as shown in Table 1. The small decline in the actual revenue requirement results from minor underages in the capital cost and operating costs of the project.

TABLE 1
2022 BURLINGTON OAKVILLE PIPELINE PROJECT RATE BASE AND REVENUE REQUIREMENT

Line No.	Particulars ($000's)	Col. 1 2022 Board-approved (a)	Col. 2 2022 Actuals (b)	Col. 3 Difference (c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	-	-	-
2.	Cumulative Capital Expenditures	83,349	83,262	(87)
3.	Average Investment	73,082	72,972	(110)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	17	-	(17)
5.	Depreciation Expense (1)	1,732	1,737	5
6.	Property Taxes	137	118	(19)
7.	Total Operating Expenses	1,886	1,855	(31)
8.	Required Return (2)	3,921	3,915	(6)
9.	Total Operating Expense and Return	5,807	5,770	(37)
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	848	846	(2)
11.	Income Taxes - Utility Timing Differences (4)	(869)	(877)	(8)
12.	Total Income Taxes	(20)	(31)	(11)
13.	Total Revenue Requirement	5,787	5,739	(48)

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The required return assumes a capital structure of 64% long-term debt at 3.36% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2022 required return calculation is as follows:
$72.972 million * 64% * 3.36% = $1.569 million plus
$72.972 million * 36% * 8.93% = $2.345 million for a total of $3.915 million.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

2022 ONTARIO ENERGY BOARD COST ASSESSMENT VARIANCE ACCOUNT UNION RATE ZONES

1. The purpose of the 2022 Ontario Energy Board Cost Assessment Variance Account (OEBCAVA) was to record any variances between the OEB costs assessed to Enbridge Gas (relevant to the Union rate zones) through application of the revised Cost Assessment Model (CAM), which became effective April 1, 2016, and the OEB costs which were included in Union rate zones rates, which were determined through application of the prior CAM. The scope of the account is consistent with prior OEBCAVAs. However, in accordance with the EB-2021-0149 OEB-approved Settlement Proposal, in Enbridge Gas's 2020 Earnings Sharing and Deferral Disposition proceeding, the base OEB costs assumed to be included in rates have been escalated to the reflect the growth in the amount recovered through rates, which results from annual price cap adjustments and customer growth. The OEBCAVA was originally approved for establishment by OEB letter dated February 9, 2016, entitled: *Revisions to the Ontario Energy Board Cost Assessment Model.*

2. The amount recorded within the 2022 OEBCAVA is a $1.254 million debit plus interest of $0.078 million for a total debit balance of $1.332 million. This amount reflects the variance between OEB costs assessed to Enbridge Gas (relevant to Union rate zones) in each quarter of fiscal 2022, utilizing the revised CAM, and Union's average quarterly OEB cost assessment under the prior CAM, escalated in accordance with the EB-2021-0149 OEB-approved Settlement Proposal.

3. In order to calculate the amount to be recovered through the 2022 Union rate zones OEBCAVA, the Company first needed to apportion the actual 2022 OEB assessed costs between the legacy rate zones. Commencing with the OEB's 2019/2020 fiscal

first quarter assessment (for the period April 1, 2019 through June 30, 2019), and continuing since, EGI has been receiving one consolidated quarterly bill for the amalgamated utility. To apportion the quarterly assessments received in 2022 between rate zones, the assessments were prorated based on the total invoices received by each legacy utility for the OEB's 2018/2019 fiscal year (for the period April 1, 2018 through March 31, 2019), the final year for which the OEB issued invoices to each legacy utility. Table 1 below shows the proration of the OEB's 2018/2019 fiscal year assessments between each legacy utility/rate zone (59.76% EGD rate zone, 40.24% Union rate zones). Table 2 shows the apportionment of EGI's 2022 assessed costs to the Union rate zones, and the calculation of the amount recorded in the 2022 Union rate zones OEBCAVA.

4. To calculate the amount for recovery through the 2022 Union rate zones OEBCAVA, the Company also needed to establish the base comparator, reflecting the OEB costs included in Union rate zones rates, determined through application of the prior Cost Assessment Model. In accordance with the EB-2021-0149 OEB approved Settlement Proposal, the amount reflected in rates is also to be increased, or escalated, to reflect the growth in the amount recovered as a result of annual price cap adjustments and customer growth. To establish the 2022 base comparator, the Company escalated the 2021 quarterly comparator of $0.741 million by the sum of the 2022 Price Cap Index (PCI) of 1.40% and the Union rate zones ICM threshold calculation Growth Factor (g) of 1.46%, which were approved as part of Enbridge Gas's 2022 Rate Application, EB-2021-0147/0148. The escalation resulted in a 2022 quarterly comparator of $0.762 million ($0.741 million * (1 + (1.40% + 1.46%))). As noted above, Table 2 below shows the apportionment of EGI's actual 2022 assessed costs to the Union rate zones, and the calculation of the amount recorded in the 2022 Union rate zones OEBCAVA utilizing a base comparator of $0.762 million.

5. Within this proceeding, the Company is requesting clearance of the principal and interest balances recorded in the 2022 OEBCAVA, in the amount of $1.254 million and $0.078 million respectively, as shown in Exhibit C, Tab 1, Schedule 1.

Table 1

OEB 2018/2019 Cost Assessments

	EGD	UGL	Total
Apr. 1 to Jun 30, 2018	1,467,963.00	988,479.00	2,456,442.00
Jul. 1 to Sept. 30, 2018	1,356,860,.00	913,873.00	2,270,733.00
Oct. 1 to Dec. 31, 2018	1,356,860,.00	913,873.00	2,270,733.00
Jan. 1 to Mar. 31, 2019	1,356,860,.00	913,873.00	2,270,733.00
	5,538,543.00	3,730,098.00	9,268,641.00
Percentage of Total	59.76%	40.24%	100.00%

Table 2

Calculation of 2022 UGL RZ OEBCAVA

Period	EGI Assessment	UGL Rate Zone Share (40.24%)	Average cost assessment Comparator	Variance to UGL Rate Zone OEBCAVA
Jan. 1 to Mar. 31, 2022	2,379,075.00	957,339.78	762,247.05	195,092.73
Apr. 1, to Jun. 30, 2022	2,834,829.00	1,140,856.57	762,247.05	378,609.52
Jul. 1 to Sep. 30, 2022	2,740,205.00	1,102,775.82	762,247.05	340,528.77
Oct. 1 to Dec. 31, 2022	2,738,848.00	1,102,229.71	762,247.05	339,982.66
Cumulative	10,692,957.00	4,303,201.88	3,048,988.20	1,254,213.68

2022 BASE SERVICE NORTH T-SERVICE TRANSCANADA CAPACITY DEFERRAL ACCOUNT – UNION RATE ZONE

1. In the EB-2015-0181 decision, the OEB approved a new optional Union North T-service Transportation from Dawn to allow T-service customers in the Union North East Zone with access to Dawn-based supply. To facilitate this service, Enbridge Gas was required to contract for 15-year transportation capacity with TransCanada from Parkway to the Union CDA, Union NCDA and Union EDA. The approved rates for the service are equal to the EGI C1 rate from Dawn to Parkway and the TransCanada Firm Transportation (FT) toll to Delivery Area.

2. The purpose of the North T-service TransCanada Capacity Deferral Account is to record the difference between the costs for the capacity from Parkway to the northern Delivery Area as part of the Base Service offering of the North T-Service Transportation from Dawn and the demand revenues collected from the North T-Service customers.

3. The total cost Enbridge Gas paid for the contracted TransCanada capacity in 2022 was $2.168 million or $180,671.58 per month. On an actual basis, the Company collected $2.084 million demand revenues from the North T-service customers. As a result, the balance of the 2022 North T-service TransCanada Capacity Deferral Account is a collection from ratepayers of $0.083 million plus interest of $0.005 million and the balance will be cleared amongst all North T-service from Dawn customers. The variance is driven by a net reduction of 480 GJ per day of contracted capacity by North T-service customers.

PANHANDLE REINFORCEMENT PROJECT COSTS DEFERRAL ACCOUNT UNION RATE ZONES

1. In its Panhandle Reinforcement Project (EB-2016-0186) Decision, the OEB approved the establishment of the Panhandle Reinforcement Project Costs Deferral Account to track the differences between the actual net revenue requirement related to costs for the Project and the net revenue requirement included in rates.

2. The balance in this deferral account is a credit to Union rate zone ratepayers of \$3.149 million plus interest of \$0.188 million for a total credit balance of \$3.337 million. The balance of \$3.149 million represents the difference between the net revenue requirement of \$10.177 million included in 2022 rates (EB-2021-0147) and the calculation of the actual net revenue requirement for 2022 of \$7.028 million as shown in Table 1.

TABLE 1
2022 PANHANDLE REINFORCEMENT PROJECT RATE BASE AND REVENUE REQUIREMENT

Line No.	Particulars ($000's)	Col. 1 2022 Board-approved (a)	Col. 2 2022 Actuals (b)	Col. 3 Difference (c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	-	-	-
2.	Cumulative Capital Expenditures	232,844	228,574	(4,270)
3.	Average Investment	209,013	204,940	(4,073)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	17	-	(17)
5.	Depreciation Expense (1)	4,944	4,788	(156)
6.	Property Taxes	1,848	1,620	(228)
7.	Total Operating Expenses	6,809	6,408	(401)
8.	Required Return (2)	11,120	10,903	(217)
9.	Total Operating Expense and Return	17,929	17,311	(618)
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	2,422	2,375	(47)
11.	Income Taxes - Utility Timing Differences (4)	(3,106)	(3,123)	(17)
12.	Total Income Taxes	(684)	(748)	(64)
13.	Total Revenue Requirement	17,245	16,563	(682)
14.	Incremental Project Revenue	7,069	9,535	2,466
15.	Net Revenue Requirement	10,177	7,028	(3,149)

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The required return assumes a capital structure of 64% long-term debt at 3.29% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2022 required return calculation is as
$204.940 million * 64% * 3.29% = $4.315 million plus
$204.940 million * 36% * 8.93% = $6.588 million for a total of $10.903 million.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

1. Average Investment

3. The average investment decrease of $4.073 million from OEB-approved is due to the cumulative capital expenditures being $4.270 million lower than OEB-approved.

2. Property Tax

4. Property taxes were $0.228 million lower than costs included in 2022 OEB-approved rates. The decrease is a result of Provincial tax reductions for business education tax rates on commercial, industrial, and pipeline tax in 2022.

3. Required Return

5. The decrease in the required return of $0.217 million is the result of a lower average rate base.

4. Incremental Project Revenue

6. The actual incremental revenue of $9.535 million reflects the continued impacts of customer growth and expansion by existing customers in the Panhandle market, and is $2.466 million higher than the forecast incremental revenue included in 2022 Rates.

UNAUTHORIZED OVERRUN NON-COMPLIANCE DEFERRAL ACCOUNT UNION RATE ZONES

1. In Union's 2016 Rates Decision and Order (EB-2015-0116), the OEB ordered the Company to establish the Unauthorized Overrun Non-Compliance Deferral Account to record any unauthorized overrun non-compliance charges incurred by interruptible distribution customers for not complying with a distribution interruption.

2. In 2022, there were 13 interruption events called in the Union North rate zone for a total of 27 days and 13 interruption events called in the Union South rate zone for a total of 30 days. Five (5) customers were not compliant with interruptions in 2022, resulting in unauthorized overrun non-compliance charges and a credit to ratepayers of $0.145 million, plus interest of $0.010 million for a total credit to ratepayers of $0.155 million.

PARKWAY OBLIGATION RATE VARIANCE DEFERRAL ACCOUNT
UNION RATE ZONES

1. In Union's 2014 Rates Settlement Agreement (EB-2013-0365), parties agreed to permanently shift the Union South direct purchase (DP) Parkway Delivery Obligation (PDO) to Dawn over time. The parties also agreed to the payment of a Parkway Delivery Commitment Incentive (PDCI) for any continuing obligated Daily Contract Quantity (DCQ) deliveries at Parkway beginning November 1, 2016. As part of the PDO Settlement Framework, parties agreed to record rate variances associated with the timing differences between the effective date of the PDO and PDCI changes and the inclusion of the cost impacts in approved rates in the Parkway Obligation Rate Variance Deferral Account.

2. Effective November 1, 2022, Enbridge Gas reduced the PDO of DP customers by shifting 26,573 GJ of PDO to Dawn and contracting for a market-based exchange service for five years of an equivalent quantity for delivery at Parkway. Enbridge Gas has reflected the impacts of the 26,573 GJ of PDO shift and cost of the market-based exchange service in approved rates effective January 1, 2023[1].

3. The balance in this deferral account is a credit to Union South rate zone ratepayers of ($0.081) million plus interest of ($0.004) million for a total credit balance of ($0.085) million. The balance of ($0.081) million represents the cost difference between the reduction in PDCI payment costs and the cost of the market-based exchange service for November and December 2022. Table 1 provides the detailed calculation of the account balance.

[1] EB-2022-0133.

Table 1
Derivation of 2022 Parkway Obligation Rate Variance Account Balance

Line No.	Particulars	2022
		(a)
1	Market Based Alternative Contracted Rate ($/GJ/d) (1)	0.110
2	2022 PDCI Unit Rate ($/GJ/d) (2)	0.160
3	Difference ($/GJ/d) (Line 1 - Line 2)	(0.050)
4	PDO Shift/Market Based Alternative Contracted Capacity (GJ) (1)	26,573
5	Days in November, December 2022	61
6	Parkway Obligation Rate Variance Account Balance (3) ($000s)	(81.0)

Notes:
(1) Per EB-2022-0133, Exhibit D, Tab 2, Rate Order, Working Papers, Schedule 11, page 2, note (3).
(2) 2022 PDCI unit rate of $0.159/GJ per Enbridge Gas's 2022 Rates proceeding (EB-2021-0147) updated to reflect a $0.001/GJ increase per Enbridge Gas's 2022 Federal Carbon Pricing Program Application EB-2021-0209, effective April 1, 2022.
(3) Line 3 * Line 4 * Line 5 / 1000.

2022 PENSION AND OPEB FORECAST ACCRUAL VS ACTUAL CASH PAYMENT DIFFERENTIAL VARIANCE ACCOUNT – UNION RATE ZONES

1. In its EB-2015-0040 report to all regulated entities, dated September 14, 2017, titled *"Regulatory Treatment of Pension and Other Post-employment Benefits (OPEB) Costs",* the OEB ordered the establishment of the deferral account, effective January 1, 2018, to be used by utilities that are approved to recover their pension and OPEB costs on an accrual basis[1]. The Company recovers its pension and OPEB costs on an accrual basis.

2. The purpose of the Pension and OPEB Forecast Accrual vs Actual Cash Payment Differential Variance Account is to track the differences between forecast accrual pension and OPEB amounts recovered in rates, and the actual cash payments made for both pension and OPEB, on a go-forward basis from the date the account was established.

3. In 2022, the accrual pension and OPEB amount recovered in rates for the Union rate zones was $47.4 million and the actual cash payments made for both pension and OPEB were $21.0 million, resulting in an annual $26.5 million credit variance. The variance carried forward from 2021 is a $75.5 million credit variance, resulting in a cumulative $102.0 million credit variance through 2022.

4. In accordance with the OEB's Report (EB-2015-0040), when the cumulative forecasted accrual amount recovered in rates exceeds the cumulative actual cash payments, an asymmetrical carrying charge, to be returned to ratepayers, should be accrued based on the opening monthly difference between amount recovered in rates and actual cash payments. The balance in the account for 2022 is an interest

[1] EB-2015-0040, *Regulatory Treatment of Pension and Other Post-employment Benefits (OPEB) Costs*, September 14, 2017, p.2.

credit to ratepayers of $3.44 million to December 31, 2022[2]. Table 1 sets out the detailed calculation of the forecast accrual versus actual cash payments, and associated interest.

TABLE 1

DETAILS OF 2022 INTEREST CALCULATED ON FORECAST ACCRUALS VS ACTUAL CASH PAYMENTS
IN PENSION AND OPEB VARIANCE ACCOUNT (NO. 179-157)

Particulars ($000's)	21-Dec	22-Jan	22-Feb	22-Mar	22-Apr	22-May	22-Jun	22-Jul	22-Aug	22-Sep	22-Oct	22-Nov	22-Dec	Total
Forecast accrual amounts		3,951	3,951	3,951	3,951	3,951	3,951	3,951	3,951	3,951	3,951	3,951	3,951	47,416
Actual cash payments		4,264	456	971	3,957	214	952	3,881	196	4,567	316	215	962	20,951
Monthly variance		312	-3,495	-2,980	6	-3,738	-2,999	-70	-3,755	616	-3,636	-3,736	-2,989	-26,465
Cumulative variance	-75,488	-75,175	-78,671	-81,651	-81,645	-85,383	-88,382	-88,452	-92,208	-91,592	-95,228	-98,964	-101,953	
OEB prescribed CWIP rate		2.72%	2.72%	2.72%	3.31%	3.31%	3.31%	4.66%	4.66%	4.66%	5.01%	5.01%	5.01%	
Asymmetrical interest		-0.171	-0.170	-0.178	-0.225	-0.225	-0.236	-0.343	-0.343	-0.358	-0.382	-0.398	-0.413	-3.444

[2] Interest is as of December 31, 2022, as interest on this account is calculated on a cumulative account balance basis.

ACCOUNTS WITH A ZERO BALANCE
UNION RATE ZONES

1. The following 2022 accounts for the Union rate zones have no balance, and are therefore not requested for clearance to customers:
   - Spot Gas Variance Account
   - Unbundled Services Unauthorized Storage Overrun Deferral Account
   - Gas Distribution Access Rule (GDAR) Costs Deferral Account
   - Conservation Demand Management Deferral Account
   - Sudbury Replacement Project Costs Deferral Account

UNREGULATED STORAGE COST ALLOCATIONS AND ELIMINATIONS

COLIN HEALEY, DIRECTOR FINANCIAL PLANNING & ANALYSIS
RACHEL GOODREAU, MANAGER REVENUE AND COST OF GAS
DANIELLE DREVENY, MANAGER CAPITAL FINANCIAL PLANNING & ANALYSIS

1. This section of evidence presents the proposed harmonized unregulated storage allocation methodology for Enbridge Gas as directed by the OEB[1]. The purpose of this evidence is to summarize the storage allocation methodologies previously in place at EGD and Union and to describe and request approval for the proposed harmonized methodology. Ernst & Young LLP (EY) was retained by Enbridge Gas to assist management in its determination of the Company's harmonized unregulated storage allocation methodology.

2. This evidence is organized as follows:
    1. Background and History
    2. Proposed Harmonized Methodology
    3. Impact of the Proposed Harmonized Methodology

1. Background and History

3. Prior to amalgamation, EGD and Union both sold storage services to in-franchise and ex-franchise customers. In-franchise customers could purchase cost-based storage and all customers could purchase market-based storage services. Since the amalgamation, the combined storage facility continues to offer the same suite of storage services to meet customers' storage demands. Enbridge Gas's underground storage assets are one of the largest facilities in North America with

[1] EB-2020-0256 Decision and Order, April 22, 2021, p.4.

approximately 280 billion cubic feet (Bcf) of net working storage capacity at the Dawn Hub.

4. In 2006, as part of its Natural Gas Electricity Interface Review (NGEIR)[2] the OEB determined that EGD and Union operated in competitive storage markets. Consequently, the OEB determined it would no longer regulate prices for either Utility's storage services offered to ex-franchise customers, for new storage services offered to in-franchise customers, and for all storage services offered by other storage operators.

5. As a result of the OEB's NGEIR decision[3], storage services at EGD and Union were separated into regulated and unregulated storage operations. Separate and independent reviews were carried out by each company to determine the appropriate cost allocation process for its regulated and unregulated storage operations. Union's methodology, which assigned storage-related expenses on an asset basis, was approved in 2011[4]. EGD's methodology, which relied on storage activity, was approved in 2012[5]. The methodologies continue to be in place until the end of 2023.

6. Following amalgamation, EY was commissioned to undertake an unregulated storage cost allocation study that would facilitate management's selection of an integrated cost allocation methodology that best represented the separation of activity and costs between regulated and unregulated storage operations. Enbridge Gas is proposing to implement the changes set out in the study and harmonize the

[2] EB-2005-0551.
[3] EB-2005-0551, OEB Decision with Reasons, November 7, 2006.
[4] EB-2011-0038, OEB Decision and Order, January 20, 2012.
[5] EB-2011-0354, Decision on Revised Settlement Agreement, November 2, 2012.

unregulated storage allocation methodology effective January 1, 2024. The Unregulated Storage Cost Allocation Study is provided at Attachment 1.

2. Proposed Harmonized Methodology

7. The harmonized methodology was guided by the NGEIR Decision[6], and subsequent OEB decisions on EGD's and Union's unregulated storage allocation methodologies referenced in paragraph 5. The following guiding principles were applied to ensure the methodology selected was appropriate and adhered to established regulatory principles. These are:
   a) Fair allocation of costs based on the underlying activities;
   b) Consistency of assumptions, decisions, and approach;
   c) Transparency and traceability throughout the allocation process;
   d) Consistency with prior OEB findings and decisions;
   e) Conformity with operational or organizational changes due to amalgamation;
   f) Ease of implementation to support regular updates; and
   g) Adaptability to current or future IT systems.

8. The harmonized methodology is largely consistent with the previously approved Union storage allocation methodology which is appropriate and expected considering the relative size and scope of Union's storage operations compared to EGD's. Modifications to the methodology are in line with the guiding principles Enbridge Gas seeks to achieve. Allocated costs are based on the underlying amalgamated unregulated storage operations. A consistent set of assumptions and approach will be applied to harmonized cost groupings within the amalgamated storage operations structure. Calculations are transparent and traceable and support regular updates as part of the annual budget process.

[6] EB-2005-0551, OEB Decision with Reasons, November 7, 2006.

9. The following section provides an overview of the proposed harmonized approach. Supporting rationale is detailed in the Unregulated Storage Cost Allocation Study provided at Attachment 1. Table 1 summarizes asset and expense cost elements in scope along with the harmonized allocation approach including page references to the Unregulated Storage Cost Allocation Study. For each element, the harmonized methodology is either 1) consistent with the Union approach, or 2) a modification of the Union approach. Where no change is indicated, the EGD and Union OEB-approved methodologies align and no further alignment is required. In addition to meeting guiding principles, Enbridge Gas believes that the proposed changes are appropriate as they best represent the costs incurred by the unregulated storage business and remain consistent with historical OEB decisions.

Table 1

Summary of Methodology Changes

Allocation Area	EGI Harmonized Allocation Methodology	Unregulated Storage Allocation Study
Assets		Page References
2.1 Materials and Supplies	Modified Union methodology	Not included in study
2.2 New Storage assets (net)	No change – EGD and Union methodologies aligned	9-11
2.3 General plant assets (net)	Modified Union methodology	11-14
Expenses		
2.4 Cost of gas: Unaccounted for gas	Modified Union methodology	14-17
2.5 Cost of gas: Fuel used to move gas	Union methodology	16-17
2.6 Operating & Maintenance: Storage operations	Modified Union methodology	17-20
2.7 Operating & Maintenance: Storage support – administrative and general	Modified Union methodology	20-21
2.8 Operating & Maintenance: Storage support – variable	Union methodology	21-22
2.9 Depreciation expense: Storage Assets	No change – EGD and Union methodologies aligned	22-24

Allocation Area	EGI Harmonized Allocation Methodology	Unregulated Storage Allocation Study
2.10 Depreciation expense: General Plant Assets	Union methodology	22-24
2.11 Property tax expense: Storage Assets	Union methodology	24-25
2.12 Property tax expenses: General Plant Assets	Union methodology	24-25
2.13 Unutilized in-franchise capacity	No change – allocation area only applicable to Union	25-27
2.14 Interest expense on long-term debt	Union methodology	26-27

2.1 Materials and Supplies

10. Prior to 2019, Union allocated materials and supplies inventory to unregulated storage in proportion to unregulated storage plant as a percentage of total plant. Throughout the 2019 to 2023 deferred rebasing term, Enbridge Gas continues to apply a portion of materials and supplies inventory to its unregulated business leaving only the utility portion in its working capital component for the Union rate zones. Prior to 2019, EGD did not allocate any of its materials and supplies inventory to unregulated storage operations, which continued through the deferred rebasing term for the EGD rate zone.

11. To harmonize, Enbridge Gas will allocate a portion of materials and supplies inventory to the unregulated storage using a composite rate, based on the proportion of the Company's unregulated Operating & Maintenance (O&M) expenses relative to total O&M expenses. The portion allocated to unregulated storage operations will be excluded from Enbridge Gas's utility working capital.

12. This is a modification of the Union methodology which serves to enhance the accuracy of the allocations.

2.2 New Storage Assets

13. Storage assets are directly attributable to either the regulated or unregulated storage operations. At the time of the NGEIR decision[7], EGD's storage assets were allocated 100% to the regulated business as the existing assets were required to serve in-franchise customers. Union's assets were split between the regulated and unregulated business based on a one-time allocation. Allocations of new storage assets to the unregulated storage business are made on a one-time basis for each new storage asset placed in-service. This enables maintenance of plant accounting records at the individual asset level for unregulated storage operations. In addition, the split between unregulated storage assets and regulated utility assets at each individual storage pool is updated annually to reflect additions and retirements that occurred throughout the prior year, for the purposes of allocating costs associated with capital maintenance of the assets.

14. No change is required for harmonization as the EGD and Union OEB-approved methodologies align and are consistent with unregulated storage cost allocation studies approved by the OEB.

2.3 General Plant Assets

15. The harmonized allocation of general plant assets first requires an aligned definition of general plant assets to include certain EGD buildings and land assets. These assets were historically classified as distribution plant assets and were not allocated to EGD's unregulated storage operations. Union historically allocated all general

[7] EB-2005-0551, OEB Decision with Reasons, November 7, 2006.

plant assets by applying different allocators for vehicles and heavy work equipment, and all other general plant assets. Under the harmonized methodology, new Enbridge Gas general plant assets are allocated monthly to the unregulated storage operations using a composite allocation rate based on the proportion of the Company's unregulated assets and O&M expenses relative to total assets and O&M expenses. To implement the harmonized methodology, a one-time allocation of EGD general plant assets will use this approach using EGD input values.

16. The modification of the Union methodology will be implemented to simplify and improve the traceability of the allocator.

2.4 Cost of Gas: Unaccounted for Gas

17. Enbridge Gas will allocate unaccounted for gas, which includes all components of gas loss, such as leakages, venting, meter errors and other similar considerations to unregulated storage monthly using actual gross unregulated storage activity as a percentage of total actual gross storage and transportation activity. Gross activity is the sum of the absolute volumes as it relates to both injections and withdrawals.

18. The change to allocating based on monthly volumetric activity is a modification of Union's annual allocation of unaccounted for gas to capture activity fluctuations as well as gas reference price fluctuations throughout the year.

2.5 Cost of Gas: Fuel Used to Move Gas

19. Enbridge Gas will allocate compressor fuel to the unregulated storage business using actual net daily unregulated storage activity as a percentage of total actual net daily storage and transportation activity. Net activity is composed of injections less withdrawals.

20. The Enbridge Gas harmonized methodology is consistent with Union's OEB-approved methodology for this allocation area.

2.6 O&M: Storage Operations

21. Enbridge Gas will allocate O&M costs directly related to storage operations based on the proportion of underlying storage assets assigned to the unregulated storage operations. This proportion will be updated annually and will be used to derive a single allocator per storage asset category that aggregates all storage asset locations. The harmonized approach is simplified in comparison to the more complex, multi-factor (i.e. asset category and asset location) approach previously used by Union.

22. This is a modification of the Union methodology so that an average storage asset allocator will be used to simplify and increase the transparency of the calculation while maintaining a causal linkage that results in a fair allocation.

2.7 O&M: Storage Support - Administrative and General

23. Enbridge Gas will allocate actual administrative and general O&M support costs (excluding the variable O&M support costs provided in Section 2.8) in proportion with O&M expenses incurred by the unregulated storage operations.

24. This is a modification of the Union methodology which serves to enhance the accuracy of the allocations by removing the influence of storage support costs in the allocator.

2.8 O&M: Storage Support – Variable

25. Enbridge Gas will allocate, by department, variable storage support O&M costs based on time spent on unregulated storage support activities carried out by these

departments. Support costs vary from year to year depending on the nature and level of unregulated storage activity being carried out by departments or functions such as Business Development, Asset Management, Lands and Permitting, Engineering and Regulatory Affairs.

26. The Enbridge Gas harmonized methodology is consistent with Union's OEB-approved methodology.

2.9 Depreciation Expense: Storage Assets

27. The depreciation rates for underground storage assets were approved by the OEB in 2013 and 2014 for Union[8] and EGD[9], respectively. Depreciation expense is calculated at the individual asset account level using the applicable rates for the storage class.

28. No change is required for harmonization as the Union and EGD OEB-approved methodologies are aligned.

2.10 Depreciation Expense: General Plant Assets

29. The depreciation expense related to the general plant assets is allocated to unregulated storage according to the proportion of unregulated general plant assets to total general plant assets.

30. The Enbridge Gas harmonized methodology is consistent with Union's OEB-approved methodology.

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[8] EB-2011-0210, Decision and Order, October 24, 2012.
[9] EB-2012-0459, Decision and Order, August 22, 2014.

2.11 Property Tax expense: Storage Assets

31. Actual property taxes related to storage assets will be allocated to unregulated storage operations based on the proportion of unregulated storage assets (excluding general plant assets) to total storage assets.

32. The Enbridge Gas harmonized methodology is consistent with Union's OEB-approved methodology.

2.12 Property Tax expense: General Plant Assets

33. Property tax related to general plant assets will be allocated to the unregulated storage operations using the same allocator used to allocate new general plant assets provided in Section 2.3.

34. The Enbridge Gas harmonized methodology is consistent with Union's OEB-approved methodology

2.13 Cost of Unutilized In-franchise Storage Capacity

35. Unutilized in-franchise (regulated) storage capacity is the difference between the amount of storage reserved for in-franchise customers and the amount required by in-franchise customers. The portion of storage capacity that is not being used by in-franchise customers is made available to ex-franchise customers for short-term storage. As such, the costs associated with the unutilized capacity are assigned to unregulated storage operations through the excess utility storage space non-utility cross charge. The OEB deemed 11.3 PJ of space to be unutilized in-franchise storage capacity in the Union rate zone.[10] The OEB also approved $3.81 million of O&M costs to be allocated to the revenue associated with the unutilized in-franchise

[10] EB-2011-0210, Decision and Order, October 24, 2012.

storage capacity, in the determination of the balance in the Short-term Storage Deferral account for Union.[11] The allocation of O&M costs associated with the unutilized capacity is adjusted annually in proportion to the actual amount of unutilized in-franchise storage capacity relative to the 11.3 PJ OEB-approved amount.

36. The Enbridge Gas harmonized methodology is consistent with Union's OEB-approved methodology. There is no equivalent methodology for the EGD rate zone to consider, as there is no unutilized in-franchise storage capacity in the EGD rate zone

37. In 2024, there is no longer a requirement for an excess utility storage space non-utility cross charge as there is no unutilized in-franchise storage capacity available. Please see Exhibit 4, Tab 2, Schedule 1, Section 1.4, page 16 for further detail.

2.14 Interest Expense on Long-term Debt

38. The cost of long-term debt is allocated between regulated and unregulated operations based on regulated and unregulated rate base as a percentage of total rate base.

39. This approach is consistent with Union's OEB-approved methodology and was adopted for the EGD rate zone in 2019.

3. Impact of the Proposed Harmonized Methodology

40. Table 2 summarizes the forecasted impact of implementing the harmonized unregulated storage allocation methodologies relative to the previously approved methodologies for the 2024 Test Year.

[11] EB-2011-0210, Decision and Order, October 24, 2012.

Table 2
Increase/(Decrease) in Unregulated Storage Cost Allocations Resulting from Harmonized Methodology

Line No.	Particulars ($ millions)	2024 Test Year (a)	
	Unregulated Storage Asset Balances		
1	Materials and Supplies Inventory	(0.7)	
2	Net Underground Storage Plant	-	
3	Net General Plant	8.7	
4	Total Increase to Net Unregulated Storage Assets	8.0	
	Unregulated Storage Operating Expenses		
5	Cost of Gas: Unaccounted For Gas	0.6	
6	Cost of Gas: Fuel Used to Move Gas	0.2	
7	O&M: Storage Operations	4.1	
8	O&M: Storage Support – Administrative and General	2.0	/u
9	O&M: Storage Support – Variable	0.6	
10	Depreciation Expense: Storage Assets	-	
11	Depreciation Expense: General Plant Assets	1.4	
12	Property Tax Expense: Storage Assets	0.0	
13	Property Tax Expense: General Plant Assets	0.1	
14	Unutilized In-franchise Capacity	-	
15	Interest Expense on Long Term Debt	-	
16	Total Increase to Unregulated Storage Operating Expenses	9.0	/u

41. The overall annual impact is a net increase to unregulated storage assets and expenses, and therefore, a net decrease to regulated storage assets and costs. The net decrease to regulated storage costs is primarily driven by a higher allocation of O&M and depreciation expense to unregulated storage operations.

42. The increase in O&M costs allocated to unregulated storage is attributable to the impact of adopting Union’s methodology, or a modified version of it, on EGD rate

zone costs. Storage operations O&M will be allocated to unregulated storage using an asset-based allocation. This approach reflects the larger unregulated storage operation of Enbridge Gas as compared to the capacity or commodity-based allocations previously applied at EGD. Additionally, support costs were previously based on a markup of direct labour for storage. Instead, the harmonized methodology applies an allocation for unregulated storage based on a more comprehensive pool of administrative and general costs that is based on the proportion of unregulated storage O&M to total O&M, as well as activity-based allocations for variable support costs.

43. The increase in net general plant assets and depreciation expense to unregulated storage is attributable to adopting Union's methodology, or a modified version of it, on EGD rate zone assets. General plant assets will now be allocated to unregulated storage using an allocator derived from asset information and O&M expenses. The approach supports the nature of general plant assets as their function is to support the day-to-day operations of Enbridge Gas, which includes storage operations.

TRANSPORTATION OPTIMIZATION DEFERRAL ACCOUNT - UNION RATE ZONES

Line No.	Particulars	Col. 1 2013 Board Approved ($000's)	Col. 3 2021 Actual Total ($000's)	Col. 3 2022 Actual Total ($000's)
1.	Base Exchange Revenue	(9,118.00)	(7,528.52)	(8,609.89)
2.	FT RAM Exchange Revenue	(5,800.00)		
3.	Total Exchange Revenue	(14,918.00)	(7,528.52)	(8,609.89)
4.	Exchange Revenue Subject to Deferral		(7,528.52)	(8,609.89)
5.	Ratepayer portion - 90%	(13,426.20)	(6,775.67)	(7,748.91)
6.	10% Union Incentive Payment		(752.85)	(860.99)
7.	Less: Gas Supply Optimization Margin in Rates	13,426.00	15,391.98	16,648.65
8.	2022 Deferral Account Balance receivable from Ratepayers		8,616.31	8,899.74

BREAKDOWN OF SHORT TERM STORAGE DEFERRAL ACCOUNT ("STSDA") - UNION RATE ZONES

Line No.	Particulars ($000's)	Col .1 Board-Approved 2013	Col. 2 Actual 2021	Col. 3 Actual 2022
	Revenue			
1.	C1 Off-Peak Storage	500	433	138
2.	Supplemental Balancing Services	2,000	640	1,053
3.	Gas Loans		1	(1)
4.	LBA		0	0
5.		2,500	1,075	1,189
6.	C1 ST Firm Peak Storage	7,883	1,536	2,108
7.	Total Revenue (1)	10,383	2,610	3,297
	Costs			
8.	O&M (2)	3,810	1,004	1,172
9.	UFG (3)	316	266	1,521
10.	Compressor Fuel (4)	1,201	257	487
11.	Total Costs	5,327	1,528	3,180
12.	Net Revenue (line 7 - 11)	5,056	1,082	117
13.	Less Shareholder Portion (10%)	505	108	12
14.	Ratepayer Portion	4,551	974	105
15.	Approved in Rates	4,551	4,551	4,551
16.	Deferral balance payable to / (collectable from) ratepayers	(0)	(3,577)	(4,446)

Notes:
(1) Based on short-term storage services provided
(2) Revenue Requirement on 11.3 PJ's of board approved excess in-franchise storage capacity
(3) Based on short-term storage volumes in proportion to total volumes
(4) Based on short-term storage activity in proportion to total actual storage activity

ENBRIDGE GAS INC.
2022 Storage Space & Deliverability

Line No.	Particulars	2022 (1) Storage Space (2) (PJ)	Storage Deliverability (2) (GJ/d)
		(a)	(b)
	Union North Rate Zone		
1	Rate 01	11.8	212,164
2	Rate 10	2.8	60,995
3	Rate 20	2.3	35,295
4	Rate 25	-	-
5	Rate 100	0.1	1,140
6	Total Union North Rate Zone	17.0	309,594
	Union South Rate Zone		
7	Rate M1	40.0	929,251
8	Rate M2	10.6	298,210
9	Rate M4	2.9	163,356
10	Rate M5	0.0	273
11	Rate M7	2.1	63,022
12	Rate M9	0.3	8,860
13	Rate M10	0.0	136
14	Rate T1	1.5	38,399
15	Rate T2	9.3	188,438
16	Rate T3	3.2	66,517
17	Total Union South Rate Zone	70.0	1,756,462
	Ex-Franchise		
18	Excess Utility Storage	3.5 (3)	41,795
19	Rate C1	-	-
20	Rate M12	-	-
21	Rate M13	-	-
22	Rate M16	-	-
23	Total Ex-Franchise	3.5	41,795
24	System Integrity Space	9.5	-
25	Total Union Rate Zone	100.0	2,107,851
	EGD Rate Zone		
26	Rate 1	61.1	1,205,299
27	Rate 6	58.6	960,446
28	Rate 9	-	-
29	Rate 100	-	-
30	Rate 110	2.2	5,064
31	Rate 115	0.5	2,008
32	Rate 125	-	-
33	Rate 135	-	-
34	Rate 145	0.3	-
35	Rate 170	0.8	-
36	Rate 200	2.0	20,307
37	Total EGD Rate Zone	125.6	2,193,125
38	Total Enbridge Gas (line 25 + line 37)	225.6	4,300,976

Notes:
(1) Allocation to rate classes using Board-approved cost allocation methodologies.
(2) Union Rate Zone storage space based on actual W22/23 usage and storage deliverability based on forecast W22/23 requirements. EGD Rate Zone storage space and deliverability based on 2022 Gas Supply plan.
(3) EB-2023-0092, Exhibit E, Tab 1, Page 4.

Table 1
SUMMARY OF NON-UTILITY STORAGE BALANCES - UNION RATE ZONES

Date	Entitlement (PJ)	Balance (PJ)	% Full (%)	Date	Entitlement (PJ)	Balance (PJ)	% Full (%)
1-Oct-22	129.3	114.8	88.7%	1-Nov-22	129.3	123.3	95.4%
2-Oct-22	129.3	114.8	88.8%	2-Nov-22	129.3	123.5	95.5%
3-Oct-22	129.3	114.7	88.7%	3-Nov-22	129.3	123.9	95.8%
4-Oct-22	129.3	114.8	88.8%	4-Nov-22	129.3	124.1	96.0%
5-Oct-22	129.3	115.1	89.0%	5-Nov-22	129.3	124.3	96.1%
6-Oct-22	129.3	115.9	89.7%	6-Nov-22	129.3	124.5	96.3%
7-Oct-22	129.3	116.8	90.3%	7-Nov-22	129.3	124.4	96.2%
8-Oct-22	129.3	117.4	90.8%	8-Nov-22	129.3	124.2	96.1%
9-Oct-22	129.3	118.0	91.3%	9-Nov-22	129.3	124.1	96.0%
10-Oct-22	129.3	118.6	91.7%	10-Nov-22	129.3	124.1	96.0%
11-Oct-22	129.3	119.4	92.4%	11-Nov-22	129.3	124.0	95.9%
12-Oct-22	129.3	120.4	93.1%	12-Nov-22	129.3	123.9	95.8%
13-Oct-22	129.3	120.7	93.4%	13-Nov-22	129.3	123.7	95.6%
14-Oct-22	129.3	121.2	93.7%	14-Nov-22	129.3	122.9	95.0%
15-Oct-22	129.3	121.5	93.9%	15-Nov-22	129.3	122.5	94.7%
16-Oct-22	129.3	121.5	94.0%	16-Nov-22	129.3	121.9	94.3%
17-Oct-22	129.3	121.3	93.8%	17-Nov-22	129.3	121.4	93.8%
18-Oct-22	129.3	121.1	93.6%	18-Nov-22	129.3	121.0	93.6%
19-Oct-22	129.3	120.8	93.4%	19-Nov-22	129.3	120.8	93.4%
20-Oct-22	129.3	120.6	93.3%	20-Nov-22	129.3	120.4	93.1%
21-Oct-22	129.3	120.8	93.4%	21-Nov-22	129.3	120.1	92.9%
22-Oct-22	129.3	121.5	94.0%	22-Nov-22	129.3	120.0	92.8%
23-Oct-22	129.3	122.0	94.4%	23-Nov-22	129.3	120.4	93.1%
24-Oct-22	129.3	122.3	94.6%	24-Nov-22	129.3	121.1	93.7%
25-Oct-22	129.3	122.4	94.6%	25-Nov-22	129.3	122.0	94.3%
26-Oct-22	129.3	122.6	94.8%	26-Nov-22	129.3	122.8	95.0%
27-Oct-22	129.3	122.5	94.8%	27-Nov-22	129.3	123.5	95.5%
28-Oct-22	129.3	122.6	94.8%	28-Nov-22	129.3	123.6	95.6%
29-Oct-22	129.3	123.0	95.1%	29-Nov-22	129.3	123.8	95.7%
30-Oct-22	129.3	123.2	95.2%	30-Nov-22	129.3	124.0	95.9%
31-Oct-22	129.3	122.6	94.8%				

UNION RATE ZONE
Southern Operations Area
Allocation of Short Term Peak Storage Revenues Between Utility and Non Utility

Line No.	Particulars	Utility Storage Space (PJ)	Short Term Peak Storage Sold (PJ)	Revenue from Short Term Peak Storage ($ millions)
1	Net Revenues from Short Term Peak Storage			2.1
2	Total Short Term Peak Storage Sales		3.5	
3	Storage Space reserved for Utility	100.0		
4	Utility Space Requirement	96.5		
5	Excess Utility Storage Space (line 3 - line 4)	3.5		
6	Total Utility Short Term Peak Storage Sales (line 2)		3.5	
7	Total Non Utility Short Term Peak Storage Sales		0.0	
8	Short Term Peak Storage Net Revenues - Utility (line 6 / line 2 * line 1)			2.1
9	Short Term Peak Storage Net Revenues - Non Utility (line 7 / line 2 * line 1)			-

UNION RATE ZONES
Calculation of Balances by Rate Class in the NAC Deferral Account (No. 179-133) - Base Rates and Y-Factor

Line No.	Particulars		Rate 01 (a)	Rate 10 (b)	Rate M1 (c)	Rate M2 (d)	Net Account Balance (e)
	Base Rates						
1	2022 Target NAC: m³		2,866.0	160,772.7	2,729.2	159,224.5	
2	2022 Actual NAC: m³		2,765.3	141,564.4	2,693.7	153,227.6	
3	Actual change in NAC: m³ (line 1 - 2)		100.7	19,208.3	35.5	5,996.9	
	Y Factor Rates						
4	2022 Target NAC: m³		2,808.8	166,354.1	2,657.9	162,472.5	
5	2022 Actual NAC: m³		2,765.3	141,564.4	2,693.7	153,227.6	
6	Actual change in NAC: m³ (line 4 - 5)		43.5	24,789.6	(35.8)	9,244.9	
7	2013 Board-approved number of Customers at December		323,287.0	2,064.0	1,067,757.0	6,778.0	1,399,886.0
	Base Rates						
8	Annual Volume Impact (10^3m^3)	(1)	32,198	39,308	37,640	40,548	149,693
9	2022 Net Annual Average Delivery Rate ($/m3)	(2)	$0.093	$0.058	$0.041	$0.037	
10	2022 Net Annual Average Storage Rate ($/m3)	(3)	$0.048	$0.037	$0.008	$0.008	
11	Delivery Rate Annual Balance Amount ($000)	(4)	$2,978	$2,297	$1,543	$1,506	$8,325
12	Storage Rate Annual Balance Amount ($000)	(4)	$1,550	$1,441	$314	$308	$3,613
	Y Factor Rates						
13	Annual Volume Impact (10^3m^3)	(1)	13,820	50,783	(38,116)	62,660	89,147
14	2022 Net Annual Average Delivery Rate ($/m3)	(2)	$0.006	$0.008	$0.013	$0.012	
15	2022 Net Annual Average Storage Rate ($/m3)	(3)	$0.000	$0.000	$0.000	$0.000	
16	Delivery Rate Annual Balance Amount ($000)	(4)	$89	$432	($497)	$761	$785
17	Storage Rate Annual Balance Amount ($000)	(4)	$0	$0	$0	$0	$1
	Total Annual Balance Amounts ($000)						
18	Total Delivery Rate Annual Balance Amount (line 11+16)		$3,068	$2,729	$1,046	$2,267	$9,110
19	Total Storage Rate Annual Balance Amount (line 12+17)		$1,550	$1,442	$314	$308	$3,613
20	Storage Cost Annual Balance Amount ($000)		($697)	$70	($1,957)	($1,370)	($3,954)
21	Interest ($000)	(5)	$289	$90	$218	($33)	$565
22	Total Deferral Account Amounts ($000) (line 18+19+20+21)		$4,210	$4,331	($378)	$1,172	$9,334

Notes:
(1) The annual volume is obtained from a monthly calculation of approved customers and the monthly usage variance.
(2) The Net Annual Average Delivery Rate is the volume-weighted average of Board-approved monthly unit rates in effect
(3) The Net Annual Average Storage Rate is the volume-weighted average of Board-approved monthly unit rates in effect
(4) The annual revenue is obtained from a monthly calculation of volumes (lines 8 and 13) and the monthly unit delivery and storage rates (lines 9, 10, 14 and 15).
(5) Interest is calculated on the monthly opening balance in the deferral account in accordance with the methodology approved by the Board in EB-2006-0117. Interest is calculated to Dec 31, 2023.

CALCULATION OF 2022 TRANSPORTATION REVENUES ON THE LOBO D/BRIGHT C/DAWN H COMPRESSOR PROJECT COST DEFERRAL ACCOUNT
UNION RATE ZONES

Particulars	Volume (TJ/d) [1]	Revenue ($000's) [2]	Project Surplus Allocation (%)	Allocation ($000's)
	(a)	(b)	(a)	(d) = (b) x (c)
2022				
January	30	112	100%	112
February	30	112	100%	112
March	30	112	100%	112
April	30	112	100%	112
May	30	112	100%	112
June	30	112	100%	112
July	30	112	100%	112
August	30	112	100%	112
September	30	112	100%	112
October	30	112	100%	112
November	30	112	100%	112
December	30	112	100%	112
Total		1,345		1,345

Notes
(1) Capacity of 30,393 GJ/d assumed to be sold long term.
(2) Sold at the Dawn to Parkway M12 Rate of $3.689 $/GJ

ALLOCATION AND DISPOSITION OF 2022 DEFERRAL AND VARIANCE ACCOUNT BALANCES

1. The purpose of this evidence is to address the allocation and disposition of 2022 deferral and variance account balances identified at Exhibit C, Tab 1, Schedule 1.

2. Enbridge Gas proposes to dispose of the approved 2022 deferral and variance account balances with the first QRAM application following the OEB's approval, as early as January 1, 2024.

3. This exhibit of evidence is organized as follows:
   1. Allocation of Deferral and Variance Accounts
      - 1.1 EGI Accounts
      - 1.2 EGD Rate Zone Accounts
      - 1.3 Union Rate Zones' Accounts
   2. Disposition of Deferral and Variance Accounts
   3. General Service Bill Impacts

1. Allocation of Deferral and Variance Accounts

4. In accordance with the OEB's EB-2017-0306/EB-2017-0307 Decision and Order (MAADs Decision), the OEB approved new Enrbidge Gas deferral and variance accounts that apply to both the EGD rate zone and Union rate zones effective January 1, 2019. The applicability of other deferral and variance accounts that were approved to continue during the deferred rebasing period is for either the EGD rate zone or the Union rate zones.

1.1. EGI Accounts

5. The OEB previously approved[1] the following deferral and variance accounts for Enbridge Gas that are applicable to both the EGD and Union rate zones:
    - Accounting Policy Changes Deferral Account (APCDA),
    - Earnings Sharing Mechanism Deferral Account (ESMDA),
    - Tax Variance Deferral Account (TVDA),
    - Expansion of Natural Gas Distribution System Variance Account (ENGDSVA),
    - IRP Operating Costs Deferral Account,
    - IRP Capital Costs Deferral Account, and
    - Impacts Arising from the COVID-19 Emergency Deferral Account (IACEDA).

6. Enbridge Gas is proposing to dispose of the 2022 balance in the TVDA and the IRP Operating Costs Deferral Account as part of this application. The balance in the APCDA and IACEDA are not proposed for disposition as part of this application, as described at Exhibit C, Tab 1. There is no balance for the ESMDA, ENGDSVA and IRP Capital Costs Deferral Account, as shown at Exhibit C, Tab 1, Schedule 1.

7. The 2022 TVDA balance, including interest, is a credit of $30.961 million as shown at Exhibit C, Tab 1, Schedule 1. Consistent with the methodology approved by the OEB in previous years, Enbridge Gas has split the credit balance of $30.961 million between the EGD and Union rate zones in proportion to the 2018 actual rate base for each rate zone.[2] Splitting the $30.961 million TVDA credit balance in proportion to 2018 actual rate base results in a credit of $16.344 million being cleared to the

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[1] EB-2017-0306/EB-2017-0307 Decision and Order established the APCDA, ESMDA and TVDA. The ENGDSVA was established in accordance with Section 4 of Ontario Regulation 24/19. The IRP Operating Costs Deferral Account and the IRP Capital Costs Deferral Account were established in accordance with the EB-2020-0091 Decision and Order.
[2] EB-2020-0134 Decision and Order, May 6, 2021, page 16.

EGD rate zone and a credit of $14.617 million being cleared to the Union rate zones. The details of the split to rate zones is provided at Exhibit F, Tab 1, Schedule 1.

8. The 2022 IRP Operating Cost Deferral Account balance, including interest, is a debit of $2.286 million as shown at Exhibit C, Tab 1, Schedule 1. Included in the balance is a $0.085 million[3] debit, including interest, for IRP project costs related to an IRP Plan to defer a pipeline reinforcement project in the Kingston, Ontario area.[4] Enbridge Gas has directly assigned $0.085 million to the Union rate zones. Consistent with the methodology approved in previous years, Enbridge Gas has split the remaining debit balance of $2.201 million, which excludes IRP project costs, between the EGD and Union rate zones in proportion to the 2018 actual rate base for each rate zone.[5] Splitting the $2.201 million debit balance in proportion to 2018 actual rate base results in a debit of $1.162 million being cleared to the EGD rate zone and a debit of $1.039 million being allocated to the Union rate zones. The total debit balance to be cleared to the Union rate zones is $1.124 million[6]. The details of the split to rate zones is provided at Exhibit F, Tab 1, Schedule 1.

9. Enbridge Gas proposes to allocate the $0.085 million balance related to Kingston IRP project costs to Union North rate classes in proportion to the system peak and average day demands, excluding the demands of customers who are served by sole use mains. The proposed allocation methodology is consistent with the allocation of joint use mains in the Union North rate zone in Union's 2013 OEB-approved Cost Allocation Study.[7] The proposed allocation methodology is the same as the

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[3] $0.080 million of IRP project costs plus $0.005 million of interest.
[4] The balance of the IRP Operating Costs Deferral Account, including a description of the IRP project costs is described at Exhibit C, Tab 1.
[5] In the EB-2022-0110 Decision and Order, November 8, 2022, the OEB accepted the settlement proposal where parties agreed to the allocation of the IRP Operating Costs Deferral Account balance where there are no associated IRP project costs.
[6] $0.085 million direct assignment for IRP project costs plus $1.039 allocation of remaining balance.
[7] EB-2010-0210.

methodology that would be used for the assets that would be installed under the pipeline reinforcement project that was deferred as a result of the Kingston IRP project.

10. Enbridge Gas has allocated the split balance of the TVDA and the remaining split balance of the IRP Operating Cost Deferral Account to rate classes in each rate zone in proportion to 2018 rate base for the EGD rate zone and 2013 rate base for the Union rate zones, consistent with the methodology approved in previous years. The rate base allocation for each rate zone is taken from the last fully allocated cost study prepared for each rate zone. The allocation to EGD rate classes is provided at Exhibit F, Tab 2, Schedule 3. The allocation to Union rate classes is provided at Exhibit F, Tab 3, Schedule 2.

1.2 EGD Rate Zone Accounts

11. The 2022 deferral and variance account balances to be cleared to the EGD rate zone are provided at Exhibit F, Tab 2, Schedule 2, including the EGD rate zone allocation of the EGI accounts.

12. The 2022 EGD rate zone deferral and variance account balances are allocated to the customer classes using the same methodologies that the OEB approved in previous years.

13. The allocation of account balances to EGD rate classes based on cost drivers for each type of account is provided at Exhibit F, Tab 2, Schedule 3. A summary of the allocation of account balances by rate class and type of service is provided at Exhibit F, Tab 2, Schedule 4.

1.3 Union Rate Zones' Accounts

14. The 2022 deferral and variance account balances to be cleared to the Union rate zones are provided at Exhibit F, Tab 3, Schedule 2, including the Union rate zones allocation of the EGI accounts.

15. The 2022 Union rate zones' deferral and variance account balances are allocated to the customer classes using the same methodologies that the OEB approved in previous years.

16. The allocation of account balances to Union South and Union North rate classes is provided at Exhibit F, Tab 3, Schedule 3.

2. Disposition of Deferral and Variance Accounts

17. Enbridge Gas proposes to dispose of the approved 2022 deferral and variance account balances with the first QRAM application following the OEB's approval, as early as January 1, 2024.

18. Enbridge Gas proposes to dispose of the 2022 deferral and variance account balances as a one-time billing adjustment. The billing adjustment will appear as a separate line item on customers' bills, the earliest being January 2024. The one-time billing adjustment will be derived for each customer by applying the disposition unit rates to each customer's actual consumption volume or contract demand, as applicable, for the period January 1, 2022 to December 31, 2022.

19. The unit rates for disposition by rate class and service type are provided at Exhibit F, Tab 2, Schedule 1 and Schedule 5 for the EGD rate zone. The unit rates for disposition for the Union rate zones, including a summary of the balances to be

disposed of to ex-franchise rate classes are provided at Exhibit F, Tab 3, Schedule 4.

3. General Service Bill Impacts

20. For a Rate 1 sales service and western t-service customer in the EGD rate zone with annual consumption of 2,400 m^3, the one-time billing adjustment charge is $2.74.[8]

21. For a Rate M1 sales service residential customer in Union South with annual consumption of 2,200 m^3, the one-time billing adjustment charge is $7.54. For a Rate M1 bundled direct purchase (DP) residential customer, the one-time billing adjustment charge is $0.39.

22. For a Rate 01 sales service and bundled DP residential customer in Union North West with annual consumption of 2,200 m^3, the one-time billing adjustment credit is $33.46.

23. For a Rate 01 sales service and bundled DP residential customer in Union North East with annual consumption of 2,200 m^3, the one-time billing adjustment charge is $2.37.

24. Bill impacts of the proposed disposition are provided at Exhibit F, Tab 2, Schedule 6 for the EGD rate zone and Exhibit F, Tab 3, Schedule 5 for the Union rate zones.

[8] In addition to the EGD rate zone 2022 Deferral bill impacts, the allocation of Union rate zone deferrals to Rate M12 results in a bill impact of approximately $2.70 to a typical Rate 1 residential customer in the EGD rate zone.

ENBRIDGE GAS INC.
Split of EGI Account Balances to Rate Zones

Line No.	Particulars ($ millions)	Allocator: 2018 Actual Rate Base (1)	Account Balance: Principal	Interest	Total
		(a)	(b)	(c)	(d) = (b+c)
	2022 Tax Variance Deferral Account				
	Allocation (2)				
1	EGD rate zone	6,729	(15.433)	(0.910)	(16.344)
2	Union rate zones	6,018	(13.803)	(0.814)	(14.617)
3	Total Balance (lines 1 + 2) (3)	12,748	(29.237)	(1.724)	(30.961)
	2022 IRP Operating Costs Deferral Account				
4	Total Deferral Account (3)		2.159	0.126	2.286
5	Direct Assignment to Union rate zones (4)		0.080	0.005	0.085
6	Remaining Balance to Be Allocated		2.080	0.121	2.201
	Remaining Balance Allocation (2)				
7	EGD rate zone	6,729	1.098	0.064	1.162
8	Union rate zones	6,018	0.982	0.057	1.039
9	Total Remaining Balance Allocation	12,748	2.080	0.121	2.201
	Total Balance Allocation				
10	EGD rate zone (line 7)		1.098	0.064	1.162
11	Union rate zones (line 5 + 8)		1.062	0.062	1.124
12	Total Balance (lines 10 + 11)		2.159	0.126	2.286

Notes:
(1) 2018 actual rate base per EB-2019-0105, Exhibit B, Tab 2, Appendix B, Schedule 1 for the EGD rate zone and EB-2019-0105, Exhibit C, Tab 2, Appendix A, Schedule 4 for the Union rate zones.
(2) Principal and interest allocated in proportion to column (a).
(3) Exhibit C, Tab 1, Schedule 1.
(4) Direct assignment to Union North rate zone consistent with evidence presented at Exhibit F, Tab 1, page 3.

ENBRIDGE GAS INC.
EGD RATE ZONE
UNIT RATE AND TYPE OF SERVICE: CLEARING IN JANUARY 2024

		COL.1
		UNIT RATE (¢/m³)
Bundled Services:		
RATE 1	- SYSTEM SALES	0.1140
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.4992
	- DAWN T-SERVICE	0.4992
	- WESTERN T-SERVICE	0.1140
RATE 6	- SYSTEM SALES	0.0237
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.4089
	- DAWN T-SERVICE	0.4089
	- WESTERN T-SERVICE	0.0237
RATE 9	- SYSTEM SALES	0.0000
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0000
	- DAWN T-SERVICE	0.0000
	- WESTERN T-SERVICE	0.0000
RATE 100	- SYSTEM SALES	0.0131
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.3983
	- DAWN T-SERVICE	0.3983
	- WESTERN T-SERVICE	0.0000
RATE 110	- SYSTEM SALES	(0.0127)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.3725
	- DAWN T-SERVICE	0.3725
	- WESTERN T-SERVICE	(0.0127)
RATE 115	- SYSTEM SALES	(0.0202)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.3650
	- DAWN T-SERVICE	0.3650
	- WESTERN T-SERVICE	0.0000
RATE 135	- SYSTEM SALES	(0.0220)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0000
	- DAWN T-SERVICE	0.3632
	- WESTERN T-SERVICE	0.0000
RATE 145	- SYSTEM SALES	(0.0300)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0000
	- DAWN T-SERVICE	0.3552
	- WESTERN T-SERVICE	0.0000
RATE 170	- SYSTEM SALES	(0.0075)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.3777
	- DAWN T-SERVICE	0.3777
	- WESTERN T-SERVICE	0.0000
RATE 200	- SYSTEM SALES	0.0237
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.4089
	- DAWN T-SERVICE	0.4089
	- WESTERN T-SERVICE	0.0000
Unbundled Services (Billing based on CD):		
RATE 125	- All	(0.7753)
RATE 300	- All	(3.6622)
RATE 332	- All	(0.7758)

ENBRIDGE GAS INC.

EGD RATE ZONE

DETERMINATION OF BALANCES TO BE CLEARED

FROM THE 2022 DEFERRAL AND VARIANCE ACCOUNTS

ITEM NO.		COL. 1 PRINCIPAL FOR CLEARING ($000)	COL. 2 INTEREST ($000)	COL. 3 TOTAL FOR CLEARING ($000)
EGD RATE ZONE				
1.	TRANSACTIONAL SERVICES D/A	(31,234.7)	(1,536.0)	(32,770.7)
2.	UNACCOUNTED FOR GAS V/A	41,400.4	2,179.6	43,580.0
3.	STORAGE AND TRANSPORTATION D/A	8,074.4	493.3	8,567.7
4.	DEFERRED REBATE ACCOUNT	(72.7)	(8.9)	(81.6)
5.	OEB COST ASSESSMENT VARIANCE ACCOUNT	3,104.8	193.3	3,298.1
6.	AVERAGE USE TRUE-UP V/A	6,904.5	339.5	7,244.0
7.	TRANSITION IMPACT OF ACCT CHANGE D/A	4,435.8	-	4,435.8
8.	DAWN ACCESS COSTS D/A	1,184.8	58.3	1,243.1
9.	EGD RATE ZONE SUB-TOTAL	33,797.3	1,718.9	35,516.2
EGI ACCOUNTS				
10.	TAX VARIANCE - ACCELERATED CCA - EGD RATE ZONE PORTION	(15,433.5)	(910.0)	(16,343.5)
11.	IRP OPERATING COST DEFERRAL ACCOUNT - EGD RATE ZONE PORTION	1,097.7	64.1	1,161.9
12.	EGI SUB-TOTAL	(14,335.7)	(845.9)	(15,181.6)
13.	TOTAL	19,461.6	873.1	20,334.6

ENBRIDGE GAS INC.
EGD RATE ZONE
CLASSIFICATION AND ALLOCATION OF DEFERRAL AND VARIANCE ACCOUNT BALANCES

ITEM NO.		COL.1 TOTAL ($000)	COL. 2 SALES AND WBT ($000)	COL. 3 TOTAL SALES ($000)	COL. 4 TOTAL DELIVERIES ($000)	COL. 5 SPACE ($000)	COL. 6 DELIVE-RABILITY ($000)	COL. 7 DIRECT ($000)	COL. 8 NUMBER OF CUSTOMERS ($000)	COL. 9 RATE BASE ($000)	COL. 10 BUNDLED ANNUAL DELIVERIES ($000)
	CLASSIFICATION										
1.	TRANSACTIONAL SERVICES D/A	(32,770.7)	(32,644.4)			(43.0)	(83.3)				
2.	UNACCOUNTED FOR GAS V/A	43,580.0			43,580.0						
3.	STORAGE AND TRANSPORTATION D/A	8,567.7				2,916.7	5,651.0				
4.	DEFERRED REBATE ACCOUNT	(81.6)			(81.6)						
5.	OEB COST ASSESSMENT VARIANCE ACCOUNT	3,298.1								3,298.1	
6.	TAX VARIANCE - ACCELERATED CCA - EGI	(16,343.5)								(16,343.5)	
7.	AVERAGE USE TRUE-UP V/A	7,244.0						7,244.0			
8.	IRP OPERATING COST DEFERRAL ACCOUNT - EGI	1,161.9								1,161.9	
9.	TRANSITION IMPACT OF ACCT CHANGE D/A	4,435.8								4,435.8	
10.	DAWN ACCESS COSTS D/A	1,243.1									1,243.1
	TOTAL	20,334.6	(32,644.4)	0.0	43,498.4	2,873.7	5,567.7	7,244.0	0.0	(7,447.8)	1,243.1
	ALLOCATION										
1.1	RATE 1	6,074.4	(19,417.2)	0.0	18,376.6	1,385.0	3,058.1	7,032.4	0.0	(4,885.6)	525.1
1.2	RATE 6	7,446.4	(12,131.9)	0.0	17,229.9	1,293.0	2,421.2	211.6	0.0	(2,069.6)	492.4
1.3	RATE 9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.4	RATE 100	96.8	(49.8)	0.0	132.5	7.7	18.6	0.0	0.0	(15.9)	3.8
1.5	RATE 110	3,992.0	(470.5)	0.0	4,310.9	104.8	13.0	0.0	0.0	(89.4)	123.2
1.6	RATE 115	1,459.5	(4.0)	0.0	1,443.1	6.7	5.2	0.0	0.0	(32.8)	41.2
1.7	RATE 125	(71.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(71.8)	0.0
1.8	RATE 135	204.4	(9.9)	0.0	212.4	0.0	0.0	0.0	0.0	(4.1)	6.1
1.9	RATE 145	62.2	(5.0)	0.0	68.0	4.5	0.0	0.0	0.0	(7.4)	1.9
1.10	RATE 170	1,073.2	(29.6)	0.0	1,050.7	32.4	0.0	0.0	0.0	(10.3)	30.0
1.11	RATE 200	239.7	(526.4)	0.0	674.3	39.6	51.6	0.0	0.0	(18.7)	19.3
1.12	RATE 300	(0.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.6)	0.0
1.13	RATE 332	(241.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(241.6)	0.0
		20,334.6	(32,644.4)	0.0	43,498.4	2,873.7	5,567.7	7,244.0	0.0	(7,447.8)	1,243.1

ENBRIDGE GAS INC.
EGD RATE ZONE
ALLOCATION BY TYPE OF SERVICE

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DIRECT	NUMBER OF CUSTOMERS	RATE BASE	BUNDLED ANNUAL DELIVERIES
		($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Bundled Services:											
RATE 1	- SYSTEM SALES	5,734.8	(19,372.9)	-	18,099.8	1,364.1	3,012.1	6,926.5	-	(4,812.1)	517.2
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	0.0	-	-	0.0	0.0	0.0	0.0	-	(0.0)	0.0
	- DAWN T-SERVICE	326.5	-	-	235.3	17.7	39.2	90.1	-	(62.6)	6.7
	- WBT	13.1	(44.3)	-	41.4	3.1	6.9	15.9	-	(11.0)	1.2
RATE 6	- SYSTEM SALES	719.7	(11,679.0)	-	10,911.4	818.8	1,533.3	134.0	-	(1,310.7)	311.8
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	206.4	-	-	181.6	13.6	25.5	2.2	-	(21.8)	5.2
	- DAWN T-SERVICE	6,492.4	-	-	5,713.6	428.8	802.9	70.2	-	(686.3)	163.3
	- WBT	27.9	(452.9)	-	423.2	31.8	59.5	5.2	-	(50.8)	12.1
RATE 9	- SYSTEM SALES	-	-	-	-	-	-	-	-	-	-
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	-	-	-	-	-	-	-	-	-	-
	- DAWN T-SERVICE	-	-	-	-	-	-	-	-	-	-
	- WBT	-	-	-	-	-	-	-	-	-	-
RATE 100	- SYSTEM SALES	1.7	(49.8)	-	46.5	2.7	6.5	-	-	(5.6)	1.3
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	7.8	-	-	7.1	0.4	1.0	-	-	(0.9)	0.2
	- DAWN T-SERVICE	87.3	-	-	78.9	4.6	11.1	-	-	(9.5)	2.3
	- WBT	-	-	-	-	-	-	-	-	-	-
RATE 110	- SYSTEM SALES	(14.4)	(439.3)	-	410.5	10.0	1.2	-	-	(8.5)	11.7
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	136.9	-	-	132.2	3.2	0.4	-	-	(2.7)	3.8
	- DAWN T-SERVICE	3,870.5	-	-	3,739.1	90.9	11.3	-	-	(77.5)	106.9
	- WBT	(1.0)	(31.2)	-	29.1	0.7	0.1	-	-	(0.6)	0.8
RATE 115	- SYSTEM SALES	(0.2)	(4.0)	-	3.7	0.0	0.0	-	-	(0.1)	0.1
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	542.4	-	-	534.8	2.5	1.9	-	-	(12.2)	15.3
	- DAWN T-SERVICE	917.3	-	-	904.6	4.2	3.2	-	-	(20.6)	25.8
	- WBT	-	-	-	-	-	-	-	-	-	-
RATE 135	- SYSTEM SALES	(0.6)	(9.9)	-	9.3	-	-	-	-	(0.2)	0.3
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	-	-	-	-	-	-	-	-	-	-
	- DAWN T-SERVICE	205.0	-	-	203.1	-	-	-	-	(3.9)	5.8
	- WBT	-	-	-	-	-	-	-	-	-	-
RATE 145	- SYSTEM SALES	(0.4)	(5.0)	-	4.7	0.3	-	-	-	(0.5)	0.1
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	-	-	-	-	-	-	-	-	-	-
	- DAWN T-SERVICE	62.5	-	-	63.4	4.2	-	-	-	(6.8)	1.8
	- WBT	-	-	-	-	-	-	-	-	-	-
RATE 170	- SYSTEM SALES	(0.6)	(29.6)	-	27.7	0.9	-	-	-	(0.3)	0.8
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	543.1	-	-	517.4	15.9	-	-	-	(5.1)	14.8
	- DAWN T-SERVICE	530.7	-	-	505.6	15.6	-	-	-	(5.0)	14.4
	- WBT	-	-	-	-	-	-	-	-	-	-
RATE 200	- SYSTEM SALES	32.4	(526.4)	-	491.8	28.9	37.6	-	-	(13.6)	14.1
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	5.0	-	-	4.4	0.3	0.3	-	-	(0.1)	0.1
	- DAWN T-SERVICE	202.3	-	-	178.0	10.5	13.6	-	-	(4.9)	5.1
	- WBT	-	-	-	-	-	-	-	-	-	-
Unbundled Services: (Billing based on CD)											
RATE 125		(71.8)	-	-	-	-	-	-	-	(71.8)	-
RATE 300		(0.6)	-	-	-	-	-	-	-	(0.6)	-
RATE 332		(241.6)	-	-	-	-	-	-	-	(241.6)	-
		20,334.6	(32,644.4)	0.0	43,498.4	2,873.7	5,567.7	7,244.0	0.0	(7,447.8)	1,243.1

ENBRIDGE GAS INC.
EGD RATE ZONE
UNIT RATE BY TYPE OF SERVICE*

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DIRECT	NUMBER OF CUSTOMERS	RATE BASE	BUNDLED ANNUAL DELIVERIES
		(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)
Bundled Services:											
RATE 1	- SYSTEM SALES	0.1140	(0.3852)	0.0000	0.3599	0.0271	0.0599	0.1377	0.0000	(0.0957)	0.0103
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.4992	0.0000	0.0000	0.3599	0.0271	0.0599	0.1377	0.0000	(0.0957)	0.0103
	- DAWN T-SERVICE	0.4992	0.0000	0.0000	0.3599	0.0271	0.0599	0.1377	0.0000	(0.0957)	0.0103
	- WESTERN T-SERVICE	0.1140	(0.3852)	0.0000	0.3599	0.0271	0.0599	0.1377	0.0000	(0.0957)	0.0103
RATE 6	- SYSTEM SALES	0.0237	(0.3852)	0.0000	0.3599	0.0270	0.0506	0.0044	0.0000	(0.0432)	0.0103
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.4089	0.0000	0.0000	0.3599	0.0270	0.0506	0.0044	0.0000	(0.0432)	0.0103
	- DAWN T-SERVICE	0.4089	0.0000	0.0000	0.3599	0.0270	0.0506	0.0044	0.0000	(0.0432)	0.0103
	- WESTERN T-SERVICE	0.0237	(0.3852)	0.0000	0.3599	0.0270	0.0506	0.0044	0.0000	(0.0432)	0.0103
RATE 9	- SYSTEM SALES	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- DAWN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 100	- SYSTEM SALES	0.0131	(0.3852)	0.0000	0.3599	0.0208	0.0506	0.0000	0.0000	(0.0432)	0.0103
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.3983	0.0000	0.0000	0.3599	0.0208	0.0506	0.0000	0.0000	(0.0432)	0.0103
	- DAWN T-SERVICE	0.3983	0.0000	0.0000	0.3599	0.0208	0.0506	0.0000	0.0000	(0.0432)	0.0103
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 110	- SYSTEM SALES	(0.0127)	(0.3852)	0.0000	0.3599	0.0088	0.0011	0.0000	0.0000	(0.0075)	0.0103
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.3725	0.0000	0.0000	0.3599	0.0088	0.0011	0.0000	0.0000	(0.0075)	0.0103
	- DAWN T-SERVICE	0.3725	0.0000	0.0000	0.3599	0.0088	0.0011	0.0000	0.0000	(0.0075)	0.0103
	- WESTERN T-SERVICE	(0.0127)	(0.3852)	0.0000	0.3599	0.0088	0.0011	0.0000	0.0000	(0.0075)	0.0103
RATE 115	- SYSTEM SALES	(0.0202)	(0.3852)	0.0000	0.3599	0.0017	0.0013	0.0000	0.0000	(0.0082)	0.0103
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.3650	0.0000	0.0000	0.3599	0.0017	0.0013	0.0000	0.0000	(0.0082)	0.0103
	- DAWN T-SERVICE	0.3650	0.0000	0.0000	0.3599	0.0017	0.0013	0.0000	0.0000	(0.0082)	0.0103
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 135	- SYSTEM SALES	(0.0220)	(0.3852)	0.0000	0.3599	0.0000	0.0000	0.0000	0.0000	(0.0070)	0.0103
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- DAWN T-SERVICE	0.3632	0.0000	0.0000	0.3599	0.0000	0.0000	0.0000	0.0000	(0.0070)	0.0103
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 145	- SYSTEM SALES	(0.0300)	(0.3852)	0.0000	0.3599	0.0239	0.0000	0.0000	0.0000	(0.0389)	0.0103
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- DAWN T-SERVICE	0.3552	0.0000	0.0000	0.3599	0.0239	0.0000	0.0000	0.0000	(0.0389)	0.0103
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 170	- SYSTEM SALES	(0.0075)	(0.3852)	0.0000	0.3599	0.0111	0.0000	0.0000	0.0000	(0.0035)	0.0103
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.3777	0.0000	0.0000	0.3599	0.0111	0.0000	0.0000	0.0000	(0.0035)	0.0103
	- DAWN T-SERVICE	0.3777	0.0000	0.0000	0.3599	0.0111	0.0000	0.0000	0.0000	(0.0035)	0.0103
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 200	- SYSTEM SALES	0.0237	(0.3852)	0.0000	0.3599	0.0211	0.0275	0.0000	0.0000	(0.0100)	0.0103
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.4089	0.0000	0.0000	0.3599	0.0211	0.0275	0.0000	0.0000	(0.0100)	0.0103
	- DAWN T-SERVICE	0.4089	0.0000	0.0000	0.3599	0.0211	0.0275	0.0000	0.0000	(0.0100)	0.0103
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unbundled Services (Billing based on CD, ¢/m3):											
RATE 125	- All	(0.7753)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(0.7753)	0.0000
	- Customer-specific **										
RATE 300	- All	(3.6622)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(3.6622)	0.0000
	- Customer-specific **										
RATE 332	- All	(0.7758)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(0.7758)	0.0000

Notes:

* Unit Rates derived based on 2022 actual volumes

ENBRIDGE GAS INC.
EGD RATE ZONE
2022 DEFERRAL AND VARIANCE ACCOUNT CLEARING
BILL ADJUSTMENT IN JANUARY 2024 FOR TYPICAL CUSTOMERS

ITEM NO.	COL. 1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10
			UNIT RATE				BILL ADJUSTMENT			
	GENERAL SERVICE	ANNUAL VOLUME	SALES	ONTARIO TS	DAWN TS	WESTERN TS	SALES CUSTOMERS	ONTARIO TS CUSTOMERS	DAWN TS CUSTOMERS	WESTERN TS CUSTOMERS
		m^3	(¢/m^3)	(¢/m^3)	(¢/m^3)	(¢/m^3)	($)	($)	($)	($)
1.1	RATE 1 RESIDENTIAL									
1.2	Heating & Water Heating	2,400	0.1140	0.4992	0.4992	0.1140	2.74	11.98	11.98	2.74
2.1	RATE 6 COMMERCIAL									
2.2	Heating & Other Uses	22,606	0.0237	0.4089	0.4089	0.0237	5.37	92.44	92.44	5.37
2.3	General Use	43,285	0.0237	0.4089	0.4089	0.0237	10.28	177.01	177.01	10.28
	CONTRACT SERVICE									
3.1	RATE 100									
3.2	Industrial - small size	339,188	0.0131	0.3983	0.3983	0.0000	44.46	1,350.99	1,350.99	-
4.1	RATE 110									
4.2	Industrial - small size, 50% LF	598,568	(0.0127)	0.3725	0.3725	(0.0127)	(75.76)	2,229.88	2,229.88	(75.76)
4.3	Industrial - avg. size, 75% LF	9,976,121	(0.0127)	0.3725	0.3725	(0.0127)	(1,262.72)	37,164.60	37,164.60	(1,262.72)
5.1	RATE 115									
5.2	Industrial - small size, 80% LF	4,471,609	(0.0202)	0.3650	0.3650	0.0000	(904.86)	16,319.47	16,319.47	-
6.1	RATE 135									
6.2	Industrial - Seasonal Firm	598,567	(0.0220)	0.0000	0.3632	0.0000	(131.60)	-	2,174.04	-
7.1	RATE 145									
7.2	Commercial - avg. size	598,568	(0.0300)	0.0000	0.3552	0.0000	(179.43)	-	2,126.21	-
8.1	RATE 170									
8.2	Industrial - avg. size, 75% LF	9,976,121	(0.0075)	0.3777	0.3777	0.0000	(745.40)	37,681.92	37,681.92	-

Notes:
Col. 7 = Col. 2 x Col. 3
Col. 8 = Col. 2 x Col. 4
Col. 9 = Col. 2 x Col. 5
Col. 10 = Col. 2 x Col. 6

ENBRIDGE GAS INC.
Union Rate Zones
Unit Rate and Type of Service
2022 Deferral Account Disposition

Line No.	Particulars	Sales/System Gas Unit Rate for Billing Unit Rate (cents/m³) (a)	Bundled T-Service Unit Rate for Billing Unit Rate (cents/m³) (b)	T-Service Unit Rate for Billing Unit Rate (cents/m³) (c)
	Union North West			
1	Rate 01	(1.5208)	(1.5208)	0.3202
2	Rate 10	0.0587	0.0587	1.3639
3	Rate 20	(8.8765)	(8.8765)	(0.0235)
4	Rate 25	0.1663	0.1663	(0.0211)
5	Rate 100	(0.0243)	(0.0243)	(0.0243)
6	Bundled-T Storage Service ($/GJ)	-	-	0.231
	Union North East			
7	Rate 01	0.1079	0.1079	0.3202
8	Rate 10	1.1907	1.1907	1.3639
9	Rate 20	(2.0627)	(2.0627)	(0.0235)
10	Rate 25	(0.0930)	(0.0930)	(0.0211)
11	Rate 100	(0.0243)	(0.0243)	(0.0243)
12	Bundled-T Storage Service ($/GJ)	-	-	0.231
13	North T-Service Transportation from Dawn Base Service ($/GJ)	-	-	0.372
	Union South			
14	Rate M1	0.3426	0.0177	-
15	Rate M2	0.5919	0.2670	-
16	Rate M4	0.4670	0.1421	-
17	Rate M5	0.1045	(0.2204)	-
18	Rate M7	0.5124	0.1875	-
19	Rate M9	0.5242	0.1993	-
20	Rate M10	0.2500	(0.0749)	-
21	Rate T1	-	-	0.0956
22	Rate T2	-	-	0.1174
23	Rate T3	-	-	0.2026

ENBRIDGE GAS INC.
Union Rate Zones
2022 Deferral Account Balances To Be Cleared
Year Ending December 31, 2022

Line No.	Account Number	Account Name ($000's)	Balance (a)	Interest (b)	Total (c)
1	179-131	Upstream Transportation Optimization	8,900	438	9,337
2	179-107	Spot Gas Variance Account	-	-	-
3	179-108	Unabsorbed Demand Costs Variance Account	(5,624)	(346)	(5,969)
4	179-153	Base Service North T-Service TransCanada Capacity	83	5	88
5	179-070	Short-Term Storage and Other Balancing Services	4,446	216	4,662
6	179-133	Normalized Average Consumption	8,770	565	9,334
7	179-132	Deferral Clearing Variance Account	1,978	135	2,113
8	179-151	OEB Cost Assessment Variance Account	1,254	78	1,332
9	179-103	Unbundled Services Unauthorized Storage Overrun	-	-	-
10	179-112	Gas Distribution Access Rule Costs	-	-	-
11	179-123	Conservation Demand Management	-	-	-
12	179-136	Parkway West Project Costs	(604)	(37)	(640)
13	179-137	Brantford-Kirkwall/Parkway D Project Costs	(35)	(2)	(37)
14	179-142	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	240	11	251
15	179-144	Lobo D/Bright C/Dawn H Compressor Project Costs	1,316	54	1,369
16	179-149	Burlington-Oakville Project Costs	(48)	(3)	(51)
17	179-156	Panhandle Reinforcement Project Costs	(3,149)	(188)	(3,338)
18	179-162	Sudbury Replacement Project	-	-	-
19	179-138	Parkway Obligation Rate Variance	(81)	(4)	(85)
20	179-143	Unauthorized Overrun Non-Compliance Account	(145)	(10)	(155)
21	179-157	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Differential V/A	-	(3,444)	(3,444)
22	179-135	Unaccounted for Gas Volume Variance Account	40,047	1,969	42,016
23	179-141	Unaccounted for Gas Price Variance Account	9,785	509	10,294
24	**Total for Union Rate Zone Specific Accounts (Lines 1 through 23)**		67,133	(53)	67,080
25	179-382	Earnings Sharing (Union Rate Zones Portion)	-	-	-
26	179-383	Tax Variance - Accelerated CCA (Union Rate Zones Portion)	(13,803)	(814)	(14,617)
27	179-385	IRP Operating Costs Deferral Account (Union Rate Zones Portion)	1,062	62	1,124
28	179-386	IRP Capital Costs Deferral Account	-	-	-
29	179-387	Green Button Initiative Deferral Account	-	-	-
30	179-380	Expansion of Natural Gas Distribution Systems V/A (Union Rate Zones Portion)	-	-	-
31	**Total for EGI Accounts allocated to Union Rate Zones (Lines 25 through 30)**		(12,742)	(752)	(13,493)
32	**Total Union Rate Zones Deferral Account Balances (Line 24 + Line 31)**		54,391	(805)	53,586

ENBRIDGE GAS INC.
Union Rate Zones
Classification and Allocation of Deferral and Variance Account Balances

Line No.	Particulars ($000's)	Acct No.	Union North: Rate 01	Rate 10	Rate 20	Rate 100	Rate 25	Union South: M1	M2	M4	M5A	M7	M9	M10	T1	T2	T3	M12	M13	Excess Utility	C1	M16	M17	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)
	Gas Supply Related Deferrals:																							
1	Upstream Transportation Optimization	179-131	56	(42)	(29)	-	69	7,544	1,420	163	5	104	48	1	-	-	-	-	-	-	-	-	-	9,337
2	Spot Gas Variance Account	179-107	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(7,012)	(1,371)	(267)	-	-	2,178	410	47	1	30	14	0	-	-	-	-	-	-	-	-	-	(5,969)
4	Base Service North T-Service TransCanada Capacity Account	179-153	-	-	65	23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	88
5	Total Gas Supply Related Deferrals		(6,955)	(1,413)	(230)	23	69	9,722	1,829	210	6	134	62	1	-	-	-	-	-	-	-	-	-	3,457
	Storage Related Deferrals:																							
6	Short-Term Storage and Other Balancing Services	179-70	637	180	98	3	-	1,452	548	246	3	137	25	0	105	1,110	118	-	-	-	-	-	-	4,662
	Delivery Related Deferrals:																							
7	Normalized Average Consumption (NAC)	179-133	4,210	4,331	-	-	-	(378)	1,172	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9,334
8	Deferral Clearing Variance Account	179-132	361	114	6	7	1	1,136	438	4	0	5	1	0	3	34	2	-	-	-	-	-	-	2,113
9	OEB Cost Assessment Variance Account	179-151	267	23	20	18	8	673	63	24	26	7	1	0	17	47	5	125	0	5	3	0	-	1,332
10	Unbundled Services Unauthorized Storage Overrun	179-103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Gas Distribution Access Rule Costs	179-112	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Conservation Demand Management	179-123	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Parkway West Project Costs	179-136	4	(8)	(1)	2	1	109	4	3	4	0	(0)	0	4	20	(1)	(785)	0	1	3	0	-	(640)
14	Brantford-Kirkwall/Parkway D Project Costs	179-137	(6)	(1)	(1)	(1)	(0)	(13)	(2)	(1)	(1)	(0)	(0)	(0)	(0)	(2)	(0)	(9)	(0)	(0)	(0)	(0)	-	(37)
15	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	179-142	(6)	4	0	(1)	(1)	(76)	(7)	(3)	(2)	(1)	(0)	(0)	(4)	(20)	(0)	369	(0)	(0)	(0)	(0)	-	251
16	Lobo D/Bright C/Dawn H Compressor Project Costs	179-144	(177)	2	(11)	(15)	(7)	(479)	7	(2)	(23)	3	3	(0)	(8)	10	18	2,062	0	(8)	(3)	(1)	-	1,369
17	Burlington-Oakville Project Costs	179-149	(3)	(1)	(0)	(0)	(0)	(25)	(8)	(2)	(0)	(1)	(0)	(0)	(2)	(13)	(2)	6	0	(0)	0	0	-	(51)
18	Panhandle Reinforcement Project Costs	179-156	(47)	(8)	(5)	(4)	(2)	(742)	(245)	(260)	(7)	(57)	(0)	(0)	(173)	(1,263)	(2)	(62)	(0)	(1)	(378)	(81)	-	(3,338)
19	Sudbury Replacement Project	179-162	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Parkway Obligation Rate Variance	179-138	-	-	-	-	-	(42)	(16)	(3)	(0)	(3)	(1)	(0)	(2)	(14)	(4)	-	-	-	-	-	-	(85)
21	Unauthorized Overrun Non-Compliance Account	179-143	-	-	-	-	-	(61)	(21)	(12)	(0)	(5)	(1)	(0)	(4)	(46)	(5)	-	-	-	-	-	-	(155)
22	Pension & OPEB Forecast Accrual vs Actual Cash Payment Differer	179-157	(692)	(63)	(62)	(52)	(25)	(1,694)	(163)	(69)	(79)	(17)	(3)	(1)	(47)	(119)	(13)	(326)	(0)	(11)	(7)	(0)	-	(3,444)
23	Unaccounted for Gas Volume Variance Account	179-135	778	116	18	-	44	4,338	1,671	820	83	1,022	132	0	560	5,486	442	18,542	40	-	7,839	63	22	42,016
24	Unaccounted for Gas Price Variance Account	179-141	293	44	7	-	16	1,636	630	309	31	385	50	0	110	1,073	86	3,628	15	-	1,951	24	4	10,294
25	Tax Variance - Accelerated CCA - EGI	179-383	(2,598)	(400)	(284)	(218)	(78)	(5,674)	(859)	(214)	(181)	(74)	(14)	(1)	(148)	(655)	(87)	(3,015)	(2)	(84)	(27)	(4)	-	(14,617)
26	IRP Operating Costs Deferral Account - EGI	179-385	216	39	38	37	10	403	61	15	13	5	1	0	11	47	6	214	0	6	2	0	-	1,124
27	IRP Capital Costs Deferral Account - EGI	179-386	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Green Button Initiative Deferral Account - EGI	179-387	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Total Delivery-Related Deferrals		2,600	4,191	(275)	(229)	(32)	(890)	2,726	610	(137)	1,269	168	(0)	316	4,585	445	20,750	53	(93)	9,384	2	26	45,468
30	Total 2022 Storage and Delivery Disposition (Line 6 + Line 29)		3,237	4,371	(177)	(226)	(32)	562	3,274	855	(134)	1,406	193	(0)	422	5,695	563	20,750	53	(93)	9,384	2	26	50,130
31	Total 2022 Deferral Account Disposition (Line 5 + Line 30)		(3,719)	2,958	(408)	(203)	37	10,284	5,103	1,065	(128)	1,540	255	1	422	5,695	563	20,750	53	(93)	9,384	2	26	53,586
32	Earnings Sharing Deferral Account - EGI	179-382	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	Grand Total (Line 31 + Line 32)		(3,719)	2,958	(408)	(203)	37	10,284	5,103	1,065	(128)	1,540	255	1	422	5,695	563	20,750	53	(93)	9,384	2	26	53,586

ENBRIDGE GAS INC.
Union Rate Zones
Allocation of 2022 Gas Supply Related Deferral Accounts by Union North East and Union North West

Line No.	Particulars ($000's)	Acct No.	Rate 01	Rate 10	Rate 20	Rate 100	Rate 25	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (sum b:f)
	Union North West							
	Gas Supply Related Deferrals:							
1	Spot Gas Variance Account	179-107	-	-	-	-	-	-
2	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(6,297)	(1,205)	(242)	-	-	(7,745)
3	Upstream Transportation Optimization	179-131	861	206	86	-	85	1,238
4	Total Gas Supply Related Deferrals		(5,436)	(999)	(156)	-	85	(6,506)
	Storage Related Deferrals:							
5	Short-Term Storage and Other Balancing Services (1)	179-70	182	45	9	-	-	236
6	Total North West Deferral Account Disposition (Line 4 + Line 5)		(5,254)	(954)	(147)	-	85	(6,270)
	Union North East							
	Gas Supply Related Deferrals:							
7	Spot Gas Variance Account	179-107	-	-	-	-	-	-
8	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(715)	(166)	(24)	-	-	(905)
9	Upstream Transportation Optimization	179-131	(804)	(248)	(115)	-	(17)	(1,184)
10	Total Gas Supply Related Deferrals		(1,519)	(414)	(139)	-	(17)	(2,089)
	Storage Related Deferrals:							
11	Short-Term Storage and Other Balancing Services (1)	179-70	455	135	59	-	-	649
12	Total North East Deferral Account Disposition (Line 10 + Line 11)		(1,065)	(279)	(80)	-	(17)	(1,440)
	Total North							
	Gas Supply Related Deferrals:							
13	Spot Gas Variance Account	179-107	-	-	-	-	-	-
14	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(7,012)	(1,371)	(267)	-	-	(8,649)
15	Upstream Transportation Optimization	179-131	56	(42)	(29)	-	69	54
16	Total North Gas Supply Related Deferrals		(6,955)	(1,413)	(295)	-	69	(8,595)
	Storage Related Deferrals:							
17	Short-Term Storage and Other Balancing Services (1)	179-70	637	180	68	-	-	885
18	Total North Deferral Account Disposition (Line 16 + Line 17)		(6,319)	(1,233)	(227)	-	69	(7,710)

Notes:
(1) Excludes allocation to Rate 20/100 bundled storage service.

ENBRIDGE GAS INC.
Union Rate Zones
Unit Rates for One-Time Adjustment - Delivery
2022 Deferral Account Disposition

Line No.	Particulars	Rate Class	2022 Deferral Balances ($000's)	2022 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2022 Actual Volume (10^3m^3)	Unit Rate (cents/m^3)
			(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
	Union North						
1	Small Volume General Service	01	3,237	-	3,237	1,010,936	0.3202
2	Large Volume General Service	10	4,371	-	4,371	320,456	1.3639
3	Medium Volume Firm Service	20	(207)	-	(207)	879,345	(0.0235)
4	Large Volume High Load Factor	100	(229)	-	(229)	943,946	(0.0243)
5	Large Volume Interruptible	25	(32)	-	(32)	151,281	(0.0211)
	Union South						
6	Small Volume General Service	M1	562	-	562	3,183,662	0.0177
7	Large Volume General Service	M2	3,274	-	3,274	1,226,228	0.2670
8	Firm Com/Ind Contract	M4	855	-	855	601,877	0.1421
9	Interruptible Com/Ind Contract	M5	(134)	-	(134)	60,809	(0.2204)
10	Special Large Volume Contract	M7	1,406	-	1,406	750,067	0.1875
11	Large Wholesale	M9	193	-	193	96,890	0.1993
12	Small Wholesale	M10	(0)	-	(0)	331	(0.0749)
13	Contract Carriage Service	T1	422	-	422	440,944	0.0956
14	Contract Carriage Service	T2	5,695	-	5,695	4,850,508	0.1174
15	Contract Carriage- Wholesale	T3	563	-	563	278,032	0.2026

ENBRIDGE GAS INC.
Union Rate Zones
Unit Rates for One-Time Adjustment - Gas Supply Commodity
2022 Deferral Account Disposition

Line No.	Particulars	Rate Class	2022 Deferral Balances ($000's)	2022 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2022 Actual Volume (10^3m^3)	Unit Rate (cents/m^3)
			(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
1	Small Volume General Service	M1	9,722	-	9,722	2,992,122	0.3249
2	Large Volume General Service	M2	1,829	-	1,829	563,032	0.3249
3	Firm Com/Ind Contract	M4	210	-	210	64,479	0.3249
4	Interruptible Com/Ind Contract	M5	6	-	6	1,835	0.3249
5	Special Large Volume Contract	M7	134	-	134	41,088	0.3249
6	Large Wholesale	M9	62	-	62	18,996	0.3249
7	Small Wholesale	M10	1	-	1	331	0.3249

ENBRIDGE GAS INC.
Union Rate Zones
Unit Rates for One-Time Adjustment - Gas Supply Transportation and Bundled Storage
2022 Deferral Account Disposition

Line No.	Particulars	Rate Class	2022 Deferral Balances ($000's)	2022 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2022 Actual Volume/ Demand	Billing Units	Unit Volumetric/ Demand Rate (cents/m^3)
			(a)	(b)	(c) = (a + b)	(d)		(e) = (c / d) * 100
	Gas Supply Transportation Charges							
	Union North West							
1	Small Volume General Service	01	(5,436)	-	(5,436)	295,290	10^3m^3	(1.8410)
2	Large Volume General Service	10	(999)	-	(999)	76,545	10^3m^3	(1.3053)
3	Medium Volume Firm Service	20	(156)	-	(156)	1,764	10^3m^3/d	(8.8529)
4	Large Volume Interruptible	25	85	-	85	45,547	10^3m^3	0.1875
	Union North East							
5	Small Volume General Service	01	(1,519)	-	(1,519)	715,646	10^3m^3	(0.2123)
6	Large Volume General Service	10	(414)	-	(414)	238,900	10^3m^3	(0.1733)
7	Medium Volume Firm Service	20	(139)	-	(139)	6,820	10^3m^3/d	(2.0392)
8	Large Volume Interruptible	25	(17)	-	(17)	23,122	10^3m^3	(0.0718)
9	North T-Service Transportation from Dawn Base Service ($/GJ)	20T/100T	88	-	88	237,864	GJ/d	0.372
	Storage ($/GJ)							
10	Bundled-T Storage Service	20T/100T	33	-	33	141,504	GJ/d	0.231

ENBRIDGE GAS INC.
Union Rate Zones
Storage and Transportation Service Amounts for Disposition
2022 Deferral Account Disposition

Line No.	Particulars ($000's) (1)	Rate Class	2022 Deferral Balances	2022 Earnings Sharing Mechanism	Deferral Balance for Disposition
			(a)	(b)	(c) = (a + b)
1	Transportation	M12	20,750	-	20,750
2	Transportation of Locally Produced Gas	M13	53	-	53
3	Cross Franchise Transportation	C1	9,384	-	9,384
4	Storage and Transportation Services	M16	2	-	2
5	Transporation Service	M17	26		26

Notes:
(1) Ex-franchise customer specific amounts determined using approved deferral account allocation methodologies.

ENBRIDGE GAS INC.
Union Rate Zones
Calculation of One-Time Adjustments for Typical General Service Customers

Line No.	Particulars	Deferral Unit Rate (cents/m^3)	Annual Volume (m^3) (1)	Bill Impact ($)
		(a)	(b)	(c) = (a x b) / 100
	Small Volume General Service			
	Rate M1 - Union South			
1	Delivery	0.0177	2,200	0.39
2	Commodity	0.3249	2,200	7.15
3	Sales Service Impact	0.3426		7.54
4	Direct Purchase Impact			0.39
	Rate 01 - Union North West			
5	Delivery	0.3202	2,200	7.04
6	Commodity	-	2,200	-
7	Transportation	(1.8410)	2,200	(40.50)
8	Sales Service Impact	(1.5208)		(33.46)
9	Bundled-T (Direct Purchase) Impact			(33.46)
	Rate 01 - Union North East			
10	Delivery	0.3202	2,200	7.04
11	Commodity	-	2,200	-
12	Transportation	(0.2123)	2,200	(4.67)
13	Sales Service Impact	0.1079		2.37
14	Bundled-T (Direct Purchase) Impact			2.37
	Large Volume General Service			
	Rate M2 - Union South			
15	Delivery	0.2670	73,000	194.89
16	Commodity	0.3249	73,000	237.19
17	Sales Service Impact	0.5919		432.08
18	Direct Purchase Impact			194.89
	Rate 10 - Union North West			
19	Delivery	1.3639	93,000	1,268.47
20	Commodity	-	93,000	-
21	Transportation	(1.3053)	93,000	(1,213.91)
22	Sales Service Impact	0.0587		54.56
23	Bundled-T (Direct Purchase) Impact			54.56
	Rate 10 - Union North East			
24	Delivery	1.3639	93,000	1,268.47
25	Commodity	-	93,000	-
26	Transportation	(0.1733)	93,000	(161.15)
27	Sales Service Impact	1.1907		1,107.32
28	Bundled-T (Direct Purchase) Impact			1,107.32

ENBRIDGE GAS INC.
Union Rate Zones
Calculation of One-Time Adjustments for Typical Small and Large Customers

Line No.	Particulars	Deferral Unit Rate (cents/m³)	Billing Units (m³)	Bill Impact ($) (1)
		(a)	(b)	(c)
	Union North			
	Small Rate 20 - Union North West			
1	Delivery	(0.0235)	3,000,000	(706)
2	Transportation	(8.8529)	14,000	(14,873)
3	Sales Service Impact	(8.8765)		(15,579)
4	Bundled-T (Direct Purchase) Impact			(15,579)
	Large Rate 20 - Union North West			
5	Delivery	(0.0235)	15,000,000	(3,531)
6	Transportation	(8.8529)	60,000	(63,741)
7	Sales Service Impact	(8.8765)		(67,272)
8	Bundled-T (Direct Purchase) Impact			(67,272)
	Small Rate 20 - Union North East			
9	Delivery	(0.0235)	3,000,000	(706)
10	Transportation	(2.0392)	14,000	(3,426)
11	Sales Service Impact	(2.0627)		(4,132)
12	Bundled-T (Direct Purchase) Impact			(4,132)
	Large Rate 20 - Union North East			
13	Delivery	(0.0235)	15,000,000	(3,531)
14	Transportation	(2.0392)	60,000	(14,682)
15	Sales Service Impact	(2.0627)		(18,213)
16	Bundled-T (Direct Purchase) Impact			(18,213)
	Average Rate 25 - Union North West			
17	Delivery	(0.0211)	2,275,000	(481)
18	Transportation	0.1875	2,275,000	4,265
19	Sales Service Impact	0.1663		3,784
20	Bundled-T (Direct Purchase) Impact			3,784
	Average Rate 25 - Union North East			
21	Delivery	(0.0211)	2,275,000	(481)
22	Transportation	(0.0718)	2,275,000	(1,634)
23	Sales Service Impact	(0.0930)		(2,115)
24	Bundled-T (Direct Purchase) Impact			(2,115)
	Small Rate 100			
25	T-Service (Direct Purchase) Impact	(0.0243)	27,000,000	(6,553)
	Large Rate 100			
26	T-Service (Direct Purchase) Impact	(0.0243)	240,000,000	(58,253)
	Union South			
	Small Rate M4			
27	Delivery	0.1421	875,000	1,243
28	Commodity	0.3249	875,000	2,843
29	Sales Service Impact	0.4670		4,086
30	Direct Purchase Impact			1,243
	Large Rate M4			
31	Delivery	0.1421	12,000,000	17,052
32	Commodity	0.3249	12,000,000	38,990
33	Sales Service Impact	0.4670		56,042
34	Direct Purchase Impact			17,052

Notes:
(1) Transportation bill impacts based on monthly demand (m³/d).

ENBRIDGE GAS INC.
Union Rate Zones
Calculation of One-Time Adjustments for Typical Small and Large Customers

Line No.	Particulars	Deferral Unit Rate (cents/m³)	Billing Units (m³)	Bill Impact ($) (1)
		(a)	(b)	(c)
	Union South (continued)			
	Small Rate M5 Interruptible			
1	Delivery	(0.2204)	825,000	(1,819)
2	Commodity	0.3249	825,000	2,681
3	Sales Service Impact	0.1045		862
4	Direct Purchase Impact			(1,819)
	Large Rate M5 Interruptible			
5	Delivery	(0.2204)	6,500,000	(14,329)
6	Commodity	0.3249	6,500,000	21,120
7	Sales Service Impact	0.1045		6,791
8	Direct Purchase Impact			(14,329)
	Small Rate M7			
9	Delivery	0.1875	36,000,000	67,495
10	Commodity	0.3249	36,000,000	116,970
11	Sales Service Impact	0.5124		184,465
12	Direct Purchase Impact			67,495
	Large Rate M7			
13	Delivery	0.1875	52,000,000	97,493
14	Commodity	0.3249	52,000,000	168,957
15	Sales Service Impact	0.5124		266,450
16	Direct Purchase Impact			97,493
	Small Rate M9			
17	Delivery	0.1993	6,950,000	13,850
18	Commodity	0.3249	6,950,000	22,582
19	Sales Service Impact	0.5242		36,432
20	Direct Purchase Impact			13,850
	Large Rate M9			
21	Delivery	0.1993	20,178,000	40,210
22	Commodity	0.3249	20,178,000	65,562
23	Sales Service Impact	0.5242		105,772
24	Direct Purchase Impact			40,210
	Rate M10			
25	Delivery	(0.0749)	94,500	(71)
26	Commodity	0.3249	94,500	307
27	Sales Service Impact	0.2500		236
28	Direct Purchase Impact			(71)
	Small Rate T1			
29	Direct Purchase Impact	0.0956	7,537,000	7,205
	Average Rate T1			
30	Direct Purchase Impact	0.0956	11,565,938	11,056
	Large Rate T1			
31	Direct Purchase Impact	0.0956	25,624,080	24,495
	Small Rate T2			
32	Direct Purchase Impact	0.1174	59,256,000	69,576
	Average Rate T2			
33	Direct Purchase Impact	0.1174	197,789,850	232,235
	Large Rate T2			
34	Direct Purchase Impact	0.1174	370,089,000	434,541
	Large Rate T3			
35	Direct Purchase Impact	0.2026	272,712,000	552,483

Notes:
(1) Transportation bill impacts based on monthly demand (m³/d).

2022 SCORECARD RESULTS – ENBRIDGE GAS

1. The purpose of the scorecard is to provide management a tool to measure and monitor performance. For 2022, Enbridge Gas has met or exceeded all elements of the scorecard results except for two measures: Time to Reschedule Missed Appointment (TRMA) and Meter Reading Performance Metrics (MRPM).

2. The average for TRMA was 97.0% in 2021 and 93.8% in 2022. The TRMA is a Service Quality Requirement (SQR) with a performance target of 100% which means customers must receive a call to reschedule work within two hours after the end of the original appointment window. Enbridge Gas historically has never achieved 100% for the TRMA measure. The 100% target does not consider factors like emergency response, human error and technical error. In the event of an emergency, technicians and dispatch team members are redirected from non-emergency customer appointments, responding to emergencies including blowing gas or odour calls, which can impact the ability of Enbridge Gas to meet a booked customer appointment within the rescheduled timeline. Missed TRMA are a result of emergency work volumes, oversight due to increased focus on priorities and high volumes of work, and when the appointment is met outside the two hour window.

3. Enbridge Gas management continues to improve 2023 results, implementing action plans addressing report and process challenges. In March 2023, a new reporting feature was developed which logs attempts to contact a customer (CCON) by flagging a rescheduled workorder. Process enhancements were also implemented for Field Reps to document and communicate to Dispatch, requesting attempts to contact customers (CCON) when an appointment will not be attended within two hours following the original appointment window. Additionally, Enbridge Gas developed a tool to capture reasons for missing rescheduled appointments for further assessment of trends and improvements. Communication of these

requirements including reports of attempts to contact the customer and reasons for a missed reschedule were also communicated to external vendors. To further demonstrate our commitment, weekly reporting of all missed reschedules are provided to the accountable Operations Director for review and escalation as required.

4. Additionally, on a consistent basis Enbridge Gas exceeds the Appointments Met target, demonstrating commitment and success to overall customer service. By meeting more appointments than targeted, the Company reduces the absolute number of calls that require rescheduling which promotes greater customer satisfaction. Enbridge Gas exceeds the Scheduled Appointments Met on Time target of 85% with actual results of 98.5%, 98.8%, 94.5% and 95.4% for years 2019 to 2022 respectively.

5. As part of the Company's Rebasing application, Enbridge Gas has requested a performance target that aligns to the electric utilities or re-scheduling 98% of missed appointments within one business day.

6. Meter Reading Performance Measurement (MRPM) represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. As set out in the GDAR, the annual standard for MRPM is not to exceed 0.5%. In mid-2021, the OEB compliance staff commenced a review of Enbridge Gas's SQR results following an increased number of customer complaints to the OEB after the Company's July 2021 integration of customers to the CIS system. Following the OEB's compliance review, Enbridge Gas shared its mitigation plans with the OEB and proposed SQR targets for 2022, as part of an Assurance of Voluntary Compliance (AVC)[1] signed in September 2022. In the

[1] EB-2022-0188, EGI-Assurance-of-Voluntary-Compliance-20220912.pdf (oeb.ca)

MRPM mitigation plan[2], Enbridge Gas committed to aim for 4% for 2022 (3% when accounting for meters that Enbridge Gas cannot access). For 2022, Enbridge Gas was able to significantly decrease the number of meters with consecutive estimates and reached an annual MRPM of 4.1% or 2.5% when accounting for meters that Enbridge Gas could not access. These results are very close to the target (missing by 0.1%) and exceeds the AVC when accounting for meters where access is limited by the customer. Enbridge Gas continues to follow the MRPM plan for 2023, finding various methods to obtain reads, including: working with field staff to obtain reads during service visits, working additional hours and knocking on doors to obtain reads, customer outreach through social media, monthly emails and texts to customers asking to submit a reading, requesting a reading from customers when they contact the call centre, and engaging the Enbridge Gas Quality Assurance team to review consecutive estimates.

7. As part of the Company's Rebasing application, Enbridge Gas has requested a performance target of no more than 2% of meters with consecutive estimates for four months or more. Further details are available in the Rebasing evidence, noting that one of the main reasons for adjusting this metric is that customer behaviour and expectations have changed since the SQRs were added to the GDAR in January 2007.[3]

8. In the 2019 and 2020 Utility Earnings and Disposition of Deferral and Variance Account Balances proceedings, the OEB found that "the performance scorecard continues to provide valuable information during the deferred rebasing period"[4] , and that "the OEB is informed of issues faced by Enbridge Gas and may potentially adjust the metrics as the industry and its customers evolve"[5] , and "Enbridge Gas's

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[2] EB-2022-0200, Exhibit 1, Tab 7, Schedule 1, pp. 18-21; and Attachment 4.
[3] EB-2022-0200, Exhibit 1, Tab 7, Schedule 1, pp. 14-17.
[4] EB-2021-0149, Decision and Order, p. 12.
[5] EB-2020-0134, Decision and Order, p. 18.

2024 rebasing proceeding would be the appropriate time to review historical performance trends and consider the customer implications before making any adjustments to the performance scorecard."[6] Considering the OEB's decisions for both 2019 and 2020, Enbridge Gas filed evidence in the Rebasing proceeding to have the GDAR metrics reviewed. The scorecard evidence can be found in the Rebasing application, EB-2022-0200, at Exhibit 1, Tab 7, Schedule 1.

[6] EB-2021-0149, Decision and Order, p. 12.

EGI OEB SCORECARD 2018 - 2022

#	Performance Measure	Target	Actual 2022 EGI	Actual 2021 EGI	Actual 2020 EGI	Actual 2019 EGI	Actual 2018 LEGD	Actual 2018 LUG
#	**CUSTOMER FOCUS (Service Quality & Customer Satisfaction)**							
1	**Reconnection Response Time (# of days to reconnect a customer)** (# of reconnections completed within 2 business days/# of reconnections completed)	85.0%	98.1%	96.9%	98.9%	98.1%	97.3%	90.7%
2	**Scheduled appointments met on time (appointments met within designated time period)** (# of appointments met within 4hrs of the scheduled date/# of appointments scheduled in the month)	85.0%	95.4%	94.5%	98.8%	98.5%	94.7%	98.8%
3	**Telephone calls answered on time (call answering service level)** (# of calls answered within 30 seconds / # of calls received)	75.0%	75.9%	64.3%	75.2%	79.0%	82.0%	77.6%
4	**Customer Complaint Written Response (# of days to provide a written response)** # of complaints requiring response within 10 days / # of complaints requiring a written response	80.0%	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
5	**Billing accuracy** 'The requirement states that utilities should complete manual checks of their bills to verify data when a meter read demonstrates excessively high or low usage.'		390,246 manual checks completed as per QAP	384,858 manual checks completed as per QAP	427,524 manual checks completed as per QAP	429,386 manual checks completed as per QAP	224,316 manual checks completed as per QAP	218,700 manual checks completed as per QAP
6	**Abandon Rate (# of calls abandon rate)** (# of calls abandoned while waiting for a live agent / # of calls requesting to speak to a live agent)	10.0%	7.1%	16.0%	5.4%	2.50%	1.9%	2.6%
7	**Time to Reschedule Missed Appointments** (% of rescheduled work within 2 hours of the end of the original appointment time)	100.0%	93.8%	97.0%	97.3%	97.0%	98.7%	99.8%
	OPERATIONAL EFFECTIVENESS (Safety, System Reliability, Asset Management & Cost Control)							
8	**Meter Reading Performance** # of meters with no read for 4 consecutive months / # of active meters to be read	0.5%	4.1%	5.0%	4.4%	0.7%	0.5%	0.4%
9	**% of Emergency Calls Responded within One Hour** (# of emergency calls responded within 60 minutes / # of emergency calls)	90.0%	94.1%	95.2%	96.7%	96.7%	96.6%	99.3%
10	**Compression Reliability** % reliable for transmission compression		100.0%	99.7%	99.7%	99.9%	NA	99.8%
11	**Damages per 1000 locate requests**		2.31	1.95	2.22	1.97	1.85	2.28
12	**Total Cost per Customer** ($ / Customer)		683.18	643.94	658.2	653.6	530.7	756.7
13	**Total Cost per km of Distribution Pipe** ($ / km of Distribution Pipe)		17,480.7	16,639.6	16,928.5	16,735.4	15,123.1	16,947.5
	PUBLIC POLICY RESPONSIVENESS (Conservation & Demand Management & Connection of Renewable Generation)							
14	**Total Cumulative Cubic Meters of Natural Gas Saved (Net)** (Millions)		N/A[1]	1,707.5 [2]	1,632.2	2,075.9	807.5	1,124.5
	FINANCIAL PERFORMANCE (Financial Ratios)							
15	**Current Ratio** (Current Assets / Current Liabilities)		0.84	0.71	0.66	0.75	0.93	0.69
16	**Debt Ratio** (Total Debt / Total Assets)		0.42	0.41	0.40	0.40	0.49	0.51
17	**Debt to Equity Ratio** (Total Debt / Shareholders' Equity)		1.10	1.06	1.01	0.98	1.67	2.12
18	**Interest Coverage** (EBIT / Interest Charges)		2.54	2.55	2.34	2.53	2.52	2.69
19	**Financial Statement Return on Assets** (Net Income / Total Assets)		2.03%	2.07%	1.97%	2.25%	2.98%	3.20%
20	**Financial Statement Return on Equity** (Net Income / Shareholders' Equity)		5.37%	5.32%	4.96%	5.56%	10.20%	13.25%

[1] 2022 results will be available in 2024

[2] 2021 results are audited and to be approved in the DSM Clearance Proceeding

Integrated Resource Planning (IRP)

2022 Annual Report

Section 1 - Introduction

This Enbridge Gas Inc. ("Enbridge Gas" or the "Company") 2022 IRP Annual Report (the "Report") encompasses the period from January 1, 2022, through to December 31, 2022. This Report complies and is consistent with the Ontario Energy Board ("OEB") Integrated Resource Planning ("IRP") Decision and Order (dated July 22, 2021) establishing an IRP Framework for Enbridge Gas (the "Framework"), where the OEB directed:[1]

> "Enbridge Gas shall file an Annual IRP Report with the OEB as part of its annual Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application, the proceeding in which it may seek disposition of balances in the IRP Costs deferral accounts.
>
> The OEB does not intend to approve the annual IRP report, but it could impact the OEB's findings on the disposition of amounts in the IRP Costs deferral accounts or inform future proceedings.
>
> The annual IRP report and the report from the IRP Technical Working Group are to be filed for information regardless of whether Enbridge Gas is seeking approval to clear any balances in the IRP Costs deferral accounts. The annual IRP report should include the following information:
>
> - A summary of IRP stakeholdering activities from the past year
> - A summary of IRP engagement or consultation activities with Indigenous peoples
> - Updates on IRP pilot projects underway
> - Updates on incorporating IRP into asset management planning
> - Updates on the status of potential IRP Plans
> - Updates on the status of approved IRP Plans, including details of adjustments made by Enbridge Gas
> - Annual and cumulative summaries of actual peak demand reductions/energy savings generated by each IRP Plan to date, including comparisons to the initial forecast reduction/energy savings and the actual amount of expenditure on each IRP Plan to-date
> - The most recent results of Enbridge Gas's IRP Assessment Process for system needs, including reporting on those system needs where a negative binary screening or technical/economic evaluation resulted in no further assessment of IRPAs
> - A summary of best available information on demand-side IRPAs, including types of IRPAs, estimates of cost, peak demand savings, status in Ontario, the potential role and relevance to Enbridge Gas's system, and learnings from pilot projects and other jurisdictions
> - Efforts taken to explore the use of interruptible rates for meeting system needs, including how customers have been provided the opportunity to consider this option
> - Any other IRP-related matters established by the OEB."[2]

[1] EB-2020-0091, Decision and Order, Appendix A, p. 22
[2] IBID

Section 2 - IRP Integration

Throughout 2022, Enbridge Gas has built upon its progress from the latter half of 2021 regarding integrating IRP into its existing planning practices. This included hiring additional resources, referred to as full-time equivalents ("FTEs"), to take on the incremental workload attributed to IRP. To date, Enbridge Gas has added 13.5 additional IRP resources that are embedded within its Asset Management and system planning teams as well as the demand side management, financial analysis, regulatory, and stakeholder and community engagement departments. This is in addition to the 3 FTE IRP roles involved in IRP before the IRP Decision. The incremental work that has arisen for the organization because of implementing the OEB's IRP Decision, includes:

- Binary screening and technical evaluations of facility projects in the Asset Management Plan and optimization of the AMP to include IRP Plans;
- Economic analysis of those projects with a technically feasible IRPA(s);
- Support the technical and economic evaluation of ETEE and demand response IRPAs, as well as design and, once approved, support the delivery and ongoing evaluation of IRP Plans, including Pilot Projects;
- Development and implementation of regional, geo-targeted and pilot specific IRP stakeholder engagement activities, as well as an increased level of direct engagement with a number of key IRP stakeholders; and
- Regulatory support for IRP Plans, and for traditional Leave-to-Construct (LTC) proceedings.

To ensure that IRP is considered and supported within each of the departments, IRP resources have been hired directly into their respective teams. This ensures that a strong, ongoing, focus remains on the coordination and implementation of integrated resource planning across the organization. Further details on the roles and responsibilities of the additional FTEs can be found in EB-2023-0092 Exhibit C Tab 1, Table 2.

Section 3 – Integrated Resource Planning Alternatives (IRPAs) Evaluation and Asset Management Plan (AMP) Update

The 2023 to 2032 Asset Management Plan was completed in May 2022. From there, investments included in the capital plan advanced through the IRP Evaluation process, as described in EB-2022-0200, Exhibit 2, Tab 6, Schedule 2, Appendix B. Since EB-2022-0200 was filed, additional work has been completed to continue to evaluate investments in the 2023 to 2032 capital plan. Although Enbridge Gas is still reviewing the upcoming near-term leave to construct applications from an IRP perspective, in 2022 the IRP team began the more systematic and forward-looking processes detailed below.

The evaluation process began with removing non-gas-carrying asset investments from the list of 2023-2032 AMP investments that would proceed to the binary screening phase, followed by the binary screening. Once the binary screening was completed, Enbridge Gas began its technical evaluation. In order to evaluate whether an investment could have a technically feasible IRPA(s), Enbridge Gas determined which AMP investment categories the Company considered to be driven in part, or in full, by design hour/day demand. This includes projects with the asset class of "growth" or "distribution pipeline." Enbridge Gas then determined the level of design hour/day demand reduction required to meet a system need by calculating the total customer design hour/day demand for natural gas, and the total current design hour/day capacity, the difference between these two factors determined the design hour/day demand capacity required to meet the system needs. Enbridge Gas then assessed the technical potential of an IRPA(s) to meet a system need. Further details can be found in EB-2022-0200 Exhibit I.2.6-STAFF-81[3]. Projects that have passed technical evaluation will be evaluated economically to determine their feasibility. Projects that have passed the economic evaluation will be reviewed and selected for IRPA Plan Development. See Section 10 for updates on the DCF+ test that will be used for economic evaluations. Also see Section 6 for Non–Pilot IRP Plan Updates.

As of March 8, 2023, Enbridge Gas had completed the technical feasibility process for 552 projects, the results of which were filed in EB-2022-0200 Exhibit I.2.6 STAFF 82 as well as an updated 'IRP Appendix B', which provides the most recent results of Enbridge Gas's IRP Evaluation Process. Including reporting on those system needs where a negative binary screening, technical or economic evaluation resulted in no further assessment of IRPAs. Enbridge Gas will provide another update on these evaluations with the 2024 AMP Addendum, to be filed with the OEB in October 2023.

In addition to continuing to complete IRP evaluations, Enbridge Gas is also working to further integrate the IRP Evaluation process into its Asset Investment Planning Management (AIPM) processes. This further integration will allow for any technically and economically feasible IRP alternatives to be considered prior to, or as part of, the 2025-2034 AMP's optimization, and for the resultant impacts on the capital forecast to be identified.

Section 4 – IRP Pilot Plan Developments

In 2022, Enbridge Gas reviewed the AMP to select two IRP Pilot projects. The concept of developing and implementing two IRPA Pilots received universal support during the IRP Framework proceeding.[4] Parties recognized that these IRP pilots would be an effective approach to better understand and evaluate how IRPAs can be implemented to avoid, delay, or reduce facility projects. As outlined in more detail below,

[3] Exhibit I.2.6-STAFF-8 can be found on Page 288 of pdf
[4] EB-2020-0091, Decision and Order, p.90

Enbridge Gas has selected two IRP Pilot projects and is developing evidence and an application for filing with OEB in June 2023.

IRP Pilot Plans

In its Decision the OEB "expects that the IRP Pilot projects will be selected and deployed by the end of 2022 as proposed by Enbridge Gas".[5] Further, "the OEB finds that it is unnecessary for this decision to provide detailed direction on the pilot projects and recommends that the nature of the pilots should be responsive to the opportunities that arise."[6] As noted in Enbridge Gas's 2021 IRP Annual Report, the Company had insufficient time to review the AMP, select two pilot projects, and implement them by the end of 2022. On December 22, 2022, Enbridge Gas filed with the Ontario Energy Board a letter updating the status of the IRP Pilots. The letter indicated that Enbridge Gas had selected two IRP pilot plans and that it intends to file one or more applications with the OEB seeking approval to deploy and implement the projects in time to influence natural gas consumption for the winter of 2023/2024. Accordingly, Enbridge Gas plans to file an application in June 2023 (EB-2022-0335).

Selection of Pilots

The IRP Pilot selection process was undertaken by Enbridge Gas and input was sought from the IRP Technical Working Group ("TWG") during Q2 and Q3 2022. Specifically, this selection process included Enbridge Gas defining the objectives and developing a set of criteria to help guide the pilot project selection process. The objectives together with the criteria formed the basis for a 'Pilot Evaluation Criteria and Scoring Matrix' that was applied to potential pilot project options.

The objectives of the pilot projects are to:

- Develop an understanding of how to design, deploy and evaluate an enhanced targeted energy efficiency ("ETEE") and a demand response ("DR") program.
- Develop the ability and data to understand how ETEE and DR measures impact peak-hour demands.

Enbridge Gas reviewed the 10-year AMP to develop a list of potential pilot project options, and considered the following:

- The forecast system need should pass the binary screening set out in the IRP Framework for Enbridge Gas.
- The pilot project should have the potential to avoid, defer or reduce a forecasted system need identified in Enbridge Gas's most recent 10-year AMP.
- The pilot project should have the potential for effective data collection and measurement of the impact that IRPAs have on peak demand.
- The pilot project should act as a "proof-of-concept" project with potential for scalability & transferrable learnings.

[5] EB-2020-0091, Decision and Order, p.90
[6] EB-2020-0091, Decision and Order, p.90

- As Enbridge Gas is proposing to implement two pilot projects, one pilot should be focused on addressing a single system need, and the other should attempt to address multiple system needs.

The potential pilot project options were then evaluated and ranked using a weighted average scoring matrix, outlined in Table 4.1. Enbridge Gas selected the two projects the Company identified as scoring the highest on the matrix, Southern Lake Huron and Parry Sound. More details including presentations and the Enbridge Gas rationale behind each of the evaluation criteria can be found on the OEB IRP Technical Working Group web page.[7]

Table 4.1 – Pilot Evaluation Criteria and Scoring Matrix

		Multiple System Needs			Single System Need				
Criteria	**Weight**	**Sarnia**	**Ottawa**	**Brantford**	**Bayfield**	**Brooklin**	**Kemptville**	**Parry Sound**	**Southampton**
System configuration	15%	3	1	3	4	3	4	5	4
Balanced customer mix & potential for scalability	25%	4	5	4	2	2	3	2	2
Peak hourly flow data collection potential	25%	5	1	2	3	3	3	4	3
Feasibility of supply-side IRPA implementation in the short-term	15%	4	2	3	3	4	5	5	5
Feasibility for ETEE	20%	3	1	2	5	2	3	4	2
Weighted Average	100%	**3.9**	2.2	2.8	3.3	2.7	3.5	**3.8**	3.0

Southern Lake Huron Pilot

The Southern Lake Huron Pilot is in the southwest operating region of the Enbridge Gas franchise area and consists of the City of Sarnia and the Town of Plympton-Wyoming. The customer mix is well represented in the pilot area with approximately 28,000 residential, and 2,300 commercial/industrial customers with a 10-year growth forecast of an additional 1350 residential and 165 commercial connections.

The area is seeing an increase in growth along the Lakeshore region, which corresponds to a low point on the distribution system, requiring a pipe and station reinforcement project (originally identified for 2032 in the AMP). Located in the same region is a vintage steel main replacement project, originally identified to be undertaken in 2024. This customer mix in this region is predominately residential.

Across the rest of the Sarnia region, various system projects have been identified, including vintage steel main, bare unprotected pipe, and station projects, identified to occur in the next 10 years. While customers in this area do not directly impact the reinforcement projects identified in the Lakeshore

[7] Natural Gas Integrated Resource Planning (IRP) | Engage with Us (oeb.ca) (Meeting #'s 5,6,8,10,12, 14,16)

region, the scope of the pilot would include a subset of these customers to increase the sample size for the pilot and support learnings.

IRP Alternatives

The two demand-side IRP alternatives being tested as part of this pilot are a demand response (DR) program and an enhanced targeted energy efficiency (ETEE) program. Enbridge Gas has engaged other jurisdictions to better understand the learnings from their respective pilots and has engaged with the TWG on key IRP Plan design details.

Data Collection & Analysis

The Southern Lake Huron IRP pilot area is unique in that most residential customers are already equipped with Automated Meter Reading (AMR) technology via Encoder Receiver Transmitters (ERTs), which provide the capability to collect hourly interval data from the customers' meter. This significantly reduces the time and costs required to prepare and set up a system from a data collection perspective. Having adequate measurement in place is critical in supporting the analysis of the impact of IRP on peak hour and consistent with the objectives of the pilot project. ERT programming modifications have been completed to enable the hourly interval data recording and coordination with local district operations is underway to collect 2022/2023 winter baseline data. Additional details with regards to measurement and data analysis has been included in the IRP Pilot Application.

Stakeholder Engagement

Enbridge Gas initiated stakeholder engagement with representatives of the municipalities, Bluewater Power Distribution, Hydro One, and Independent Electricity System Operator ("IESO") in Q4 2022 and has continued engagement into Q1/Q2 2023. Public outreach initiatives will be held in 2023 and interested parties can register to participate in these sessions on the Enbridge regional planning website.

Parry Sound Pilot

The Parry Sound Pilot is in the Enbridge Gas Northern operating area of the Town of Parry Sound. The customer mix is approximately 1,800 residential and 270 commercial customers, with a 10-year growth forecast of an additional 500 residential and 70 commercial connections.

The current distribution system in this area is fed by TransCanada (TC) Energy with an existing NPS 4 and 6 natural gas pipeline feeding into the town. A reinforcement project was originally identified in the Enbridge Gas AMP for 2032 due to the growth forecast in the area. Since this original inclusion in the AMP, Enbridge has learned that the existing rolling pressure elevation of 4,570 kPa may be terminated for Winter 2023/24, with a new guaranteed pressure of 4,000 kPa. The change in pressure will impact the timing of the forecast system reinforcement.

IRP Alternatives

The IRP alternatives being explored for this pilot include supply and demand side alternatives.

Enbridge Gas is exploring the following supply-side alternatives:

- Potential for increased delivery pressure from TC Energy
- Development of a Compressed Natural Gas (CNG) plan as a bridging solution.

From a demand-side perspective, Enbridge Gas plans to implement an enhanced targeted energy efficiency (ETEE) program to reduce the design hour demand on the system.

Data Collection & Analysis

To inform and support the analysis of the impact of IRP on peak hour, consistent with the objectives of the pilot project, measurement of hourly data from customers within the Parry Sound area is critical. Stratification of customers was applied to help prioritize areas for installations of ERTs on residential customers in 2023 to allow for initial collection of 2023/2024 winter baseline data. Request for additional metering budget, including for larger commercial customers, will be included in the pilot application, as well as additional details around measurement and data analysis.

Stakeholder Engagement

Enbridge Gas began the stakeholder engagement for this pilot and met with representatives of the Town of Parry Sound, Lakeland Power, Hydro One, and the IESO in Q4 2022. Public outreach initiatives will be held in 2023 and interested parties can register to participate in these sessions on the Enbridge regional planning website.

A single application for both IRP Pilot Plans will be submitted to the Ontario Energy Board in June 2023 (EB-2022-0335). These IRP Pilot Plans seek approval to invest in the implementation of the above-noted two pilot plans beginning in 2023. The application includes details on the project area and need, baseline facility alternatives, design of IRP alternatives, associated budget and evaluation plans, an illustrative DCF+ test, and stakeholder engagement.

Please see Enbridge Gas' IRP Pilot Application (EB-2022-0335) for additional details on the IRP Pilots.

Section 5 - IRP Stakeholder and Indigenous Engagement Update

As part of the Decision in the IRP Framework proceeding "The OEB has determined that the components of Enbridge Gas's proposed Stakeholder Engagement Process will provide valuable input into Enbridge Gas's IRP activities and shall be incorporated in the IRP Framework. The OEB also directs the establishment of a website by Enbridge Gas to facilitate the broad sharing of information on IRP stakeholdering efforts."[8]

Regional Engagement

Enbridge Gas is planning its first regional engagement sessions in April 2023. This timing allowed for the 2023 to 2032 AMP to be completed and optimized, and it also allowed Enbridge Gas to complete the binary screening process and some technical evaluations before the stakeholder engagement sessions. The timing of Enbridge Gas's first regional engagement sessions was also chosen as the Ontario municipal elections were held in October 2022, which meant that many key municipal stakeholders were unavailable to participate in stakeholder sessions in the fall/winter of 2022 and early 2023. Municipalities' awareness, support, and involvement in these sessions is critical, and so delaying them to allow for their participation

[8] EB-2020-0091, Decision and Order, p. 66

was determined to be prudent. In preparation for the regional stakeholder engagement sessions, Enbridge Gas met with the IESO to obtain lessons learned and advice on how to run successful regional engagement sessions.

Enbridge Gas notes that the regional engagement sessions are not the best forum to discuss government climate policies that should (or should not) be adopted. There exist established processes through the OEB by which policy or government directives or mandates can be proposed, discussed, and debated.

As mentioned previously, initial geotargeted stakeholder engagement to support the IRP Pilots has begun in both the Parry Sound and Southern Lake Huron areas, and these engagements will continue through the first half of 2023. As part of these engagements, Enbridge Gas has held meetings with the local municipalities, local electricity distribution companies, Hydro One, and the IESO to discuss alignment on forecasts and potential IRPA opportunities. Upon completion of these meetings, Enbridge Gas will start both public geotargeted engagement activities and Indigenous engagement in the pilot regions.

Municipal Outreach

Throughout 2022, Enbridge Gas also focused its stakeholder engagement efforts on municipalities. Enbridge Gas attended the 2022 Association of Municipalities of Ontario ("AMO") conference in August, the Ontario Professional Planners Institute conferences in September, and the Rural Ontario Municipal Association (ROMA) conference in January 2023 to raise awareness amongst municipalities about natural gas integrated resource planning (IRP) and how they can be further involved in the regional planning process. Enbridge Gas is working with AMO to increase awareness of natural gas IRP and regional planning with notifications in their organization's Watchfile[9] Newsletter.

Figure 5.1 - Example of the information shared with participants at events.

[9] Watchfile Newsletter | AMO

Enbridge Gas also continues to work directly with municipalities to understand the impact of their community energy plans on the Company's demand forecasts. Enbridge Gas's participation in the Regional Planning Process Advisory Group ("RPPAG"), which looks specifically at electricity planning in the province, is aligned with this ongoing work. As part of the RPPAG process, a subgroup was formed to develop a document that could help electric utilities interpret and allow community energy plans to be considered in the electricity planning processes. Where appropriate and transferrable Enbridge Gas will consider adopting similar natural gas-focused metrics. [10]

IRP Web Content

Many considerations go into developing a webpage at Enbridge Gas, including content and business requirements that drive the design and wireframing of the web pages. Enbridge Gas worked with a creative agency to develop IRP Web content, design webpage wireframes, and complete the build-out of the web pages. Reviews are conducted by Enbridge Gas and the creative agency for quality assurance and to confirm compliance with the Accessibility for Ontarians with Disabilities Act ("AODA") and privacy laws, and to ensure the Company's cyber security protocols were met. Enbridge Gas uses a content management system to build and manage its website.

In December 2021, Enbridge Gas IRP Regional Planning and Engagement webpages went live.[11] The webpages allow individuals to learn about Enbridge Gas's IRP activities and to register, by region, for email updates on the area and the region's stakeholder engagement sessions. The registration process is quick and allows for the registration of multiple regions. By registering an email address with Enbridge Gas, individuals give permission to receive emails from the Company in the future, which meets the requirements of Canada's Anti-Spam Legislation ("CASL").

Figure 5.2 - Example of the Social Media Campaign to highlight the IRP web page

[10] The RPPAG reviewed Municipal Information document can be found on the OEB web site: https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/regional-planning-process-review#municipal

[11] Regional Planning & Engagement | Enbridge Gas

The IRP website was recently updated to provide information on the IRP Pilots in the Parry Sound[12] and Southern Lake Huron[13] areas. The IRP website will be the primary source of information including dates for the regional engagement sessions, IRP pilot webinars, and information on how to sign up and participate. As more engagement and content are rolled out in the various operating regions, more of the planned IRP website components will be brought online.

Indigenous Engagement

In 2022, Enbridge Gas met with Indigenous groups or representative organizations when requested to discuss not only IRP but also Energy Transition ("ET"). For instance, in November 2022, Enbridge Gas met with representatives of the Three Fires Group to provide an overview of both natural gas IRP and the Pathways to Net-Zero Emissions in Ontario Report.

Informational materials have been developed for use by the Enbridge Gas Indigenous Engagement group during informal discussions, and during their normal course of engagements to highlight the Regional Engagement sessions and to promote registrations for engagement events that may be happening in their areas.

Section 6 – Non–Pilot IRP Plan Updates

Throughout the review of the AMP projects, Enbridge Gas will ensure that all details related to IRPA investments, and the underlying system needs they are intended to address are continuously monitored. At the end of 2022, Enbridge Gas identified that 3 projects had IRP technical potential. As of March 8, 2023, Enbridge Gas has identified 25 projects that have IRP technical potential and will complete the economic evaluation as soon as possible.

In 2022 Enbridge Gas did not file any Non-Pilot IRP Plans (i.e., IRPA Plan applications) with the OEB, however, Appendix D: IRP Screening Results for LTC Projects Filed in 2022 includes a list of leave-to-construct projects where Enbridge Gas has completed an IRP screening in 2022. It is important to recognize that not all identified IRPAs will result in an IRP Plan application being brought forward to the OEB. For instance, in 2022, an IRP review of facility-related capital projects resulted in the deferral and elimination of a system reinforcement project in Kingston, Ontario. Although this project did not result in an IRPA Plan application being brought forward to the OEB for decision, the review of potential IRP alternatives led to the identification of a technically feasible IRPA, and to the project being deferred. As IRP is further integrated into the planning processes, such instances are expected to increase.

Kingston Reinforcement Project

The East Kingston Creekford Rd Reinforcement project was a 6.2km NPS 8 6895 kPa relocation project off the lateral feeding the town of Kingston, Ontario, with a project in-service date of 2024 (Investment

[12] Parry Sound Project - Regional Planning & Engagement | Enbridge Gas
[13] Southern Lake Huron Project - Regional Planning & Engagement | Enbridge Gas

#100703). The drivers of this project included growth and system integrity issues. Enbridge Gas reviewed this project for IRP alternatives including:

- Supply-side alternatives: Incremental pressure from TC Energy and Compressed Natural Gas ("CNG")
- Demand-side alternatives: Enhanced Targeted Energy Efficiency (ETEE), and Contract & Interruptible Rates review

Enbridge Gas implemented an In-Franchise Binding Reverse Open season, which offered contract customers within the proposed project service area an opportunity to "turnback" or reduce their existing contracted capacity and the Company also considered a CNG option. One response was received from a Contract Customer to reduce their firm contracted capacity, reducing the total peak demand on the system. This alternative resulted in an annual revenue reduction for Enbridge Gas. The Company will be seeking recovery of the IRP alternative and lost revenue for the Kingston reinforcement project as part of the 2022 Non-Commodity Deferral Disposition proceeding. Please see Exhibit C, Tab 1 for further details on this IRPA.

Section 7 - Integrated Resource Planning Alternatives Update

In its Decision and Order establishing an IRP Framework for Enbridge Gas, the OEB found that a "...document on best available information for demand-side alternatives would promote more timely development of IRP Plans and directs Enbridge Gas to include a listing in its annual IRP Report."[14]

Appendix B: Integrated Resource Planning Alternatives lists the integrated resource planning alternatives and includes information on these specific IRPAs as suggested by OEB Staff including "types of IRPAs, estimates of cost, peak demand savings, status in Ontario, the potential role and relevance to Enbridge Gas's system, and learnings from pilot projects and other jurisdictions." Enbridge Gas also expects the IRPA pilot projects to provide more information allowing for refinement and updating of the impacts of some of the IRPAs listed.

Section 8 - Technical Working Group Summary

The OEB directed that an IRP Technical Working Group be established and led by OEB staff, to provide input on IRP issues that will be of value to both Enbridge Gas in implementing IRP, and to the OEB in its oversight of the IRP Framework.

All documents and presentations concerning the IRP Technical working group can be found on the OEB website.[15]

[14] EB-2020-0091, Decision and Order, page 36

[15] Natural Gas Integrated Resource Planning (IRP) | Engage with Us (oeb.ca)

Attached in Appendix E: Technical Working Group Report is a report prepared by the IRP Technical Working Group

Section 9 - Interruptible Rates Update

The use of interruptible rates as an IRPA was reviewed as part of the IRP Framework proceeding. The discussion centered around a few key issues: "Customers on interruptible rates pay a lower rate in exchange for the ability of Enbridge Gas to curtail delivery if capacity is not available on the system. Interruptible volumes are not included in Enbridge Gas's design day assumptions. Therefore, increased use of interruptible rates could potentially reduce the amount of firm peak demand Enbridge Gas is obligated to serve, helping address a system need. For this reason, Enbridge Gas indicated that it does consider interruptible rates to be a type of IRPA."[16]

In response, Enbridge Gas indicated that it would "investigate the drivers for recent declines in the use of interruptible services and could potentially file revised interruptible and firm seasonal services/rates to make them more attractive to customers as part of its 2024 rebasing application."[17] In the OEB Decision[18], Enbridge Gas was directed to study its interruptible rates to determine how they might be modified to increase customer adoption of this alternative service, which may reduce peak demands.

The Interruptible Rate Study[19] was filed as part of the Enbridge Gas' rebasing application in late 2022.[20] The interruptible Rate Study found that "Enbridge Gas's proposal to use negotiated rates within the context of an IRP plan application is prudent as it allows for a targeted approach to provide further incentives for customers to adopt interruptible service. This approach is more efficient than reducing interruptible rates beyond what has been calculated through the harmonized cost allocation methodology for all customers. The proposed approach will limit cross-subsidies between firm and interruptible to situations where there is a demonstrated benefit of doing so. This proposal also provides transparency as any proposed rate reduction can be evaluated against alternatives proposed through the IRP plan application."[21]

As outlined in the IRP Framework Decision, and as an outcome to the interruptible rates review, Enbridge Gas will evaluate the use of demand response (i.e., shift peak demands to an off-peak period), in the context of future IRP Plan Applications where applicable. A demand response project could take several different forms, including a negotiable interruptible rate, or a customer is provided with an onsite CNG station to utilize when a peak hour/day event is called. Implementing these approaches will allow for a targeted approach to providing additional incentives for customers to adopt interruptible service or shift their peak demands to an off-peak period.

[16] EB-2020-0091, Decision and Order, p,3
[17] IBID, p. 30-31
[18] DECISION AND ORDER EB-2020-0091, page 35
[19] The Interruptible Rates Study can be found on page 1399 to 1424 in the pdf.
[20] EB-2022-0200 Exhibit 8 Tab 4 Schedule 7, pages 1399-1424 in pdf.
[21] EB-2022-0200 Exhibit 8 Tab 4 Schedule 7 Plus Attachment Page 25 - 26

Section 10 - DCF+ Review

As part of the IRP Framework Decision, the OEB found that "the OEB accepts the categories of benefits and costs proposed by Enbridge Gas for the three phases of the DCF+ test for the use of this test in the IRP Framework. The OEB recognizes that the DCF+ test could be improved to better identify and define the costs and benefits of Facility Alternatives and IRPAs and clarify how these costs and benefits should be considered within the DCF+ test. This could include expanding the inputs to recognize increasing carbon costs, the risk that a constraint remains unresolved, and the impact on gas supply costs. The OEB directs Enbridge Gas to study improvements to the DCF+ test for IRP."[22]

The OEB further recognized that "this test could be improved to better list and define the costs and benefits of facility projects and IRP Alternatives and clarify how these costs and benefits should be considered within the test. Enbridge Gas is expected to study improvements to the Discounted Cash Flow-plus test for IRP, in consultation with the IRP Technical Working Group that will be established as part of the IRP Framework and using IRP pilot projects as a testing ground. Enbridge Gas shall file an enhanced Discounted Cash Flow-plus test for approval as part of the first non-pilot IRP Plan."[23]

Enbridge Gas engaged Guidehouse to develop recommendations on how the currently approved Discounted Cash Flow-plus (DCF+) test could be improved to better identify and define the costs and benefits of Facility Alternatives and Integrated Resource Planning Alternatives, including infrastructure, supply-side, and demand-side IRPAs. The summation of the Guidehouse proposed recommendations and enhancements to all three phases of the DCF+ cost-benefit analysis test. Specifically, Guidehouse recommended that Enbridge Gas include the following:

Phase 1:
- Include avoided/incremental utility carbon costs

Phase 2:
- Include avoided/incremental participating customer carbon costs
- Specify incremental customer equipment costs
- Defined as the capital and operating and maintenance costs associated with the purchase of equipment that may be required as part of the Facility Alternative project (if any)

Phase 3:
- Implement a flooring mechanism that brings quantified Phase 3 non-energy benefits (NEBs) to at least 15% of Phases 1 and 2 benefits. If Phase 3 quantifiable benefits > 15% of Phases I and II benefits, then no flooring is needed
- Implement a Non-Energy Benefit Adder of 15% (Accentuating Mechanism) to be applied to quantified Phase 3 benefits to include qualitative parameters
- Further refine qualitative and quantitative parameters

[22] EB-2020-0091 Decision and Order, p.56-57
[23] EB-2020-0091 DECISION AND ORDER, p. 57

Enbridge Gas continued to work with the IRP Technical working group throughout the latter half of 2022 on enhancements to the DCF+ cost-benefit analysis. As this work is ongoing throughout 2023 the TWG will make available the DCF+ report when complete.

Enbridge Gas began the process of developing a DCF+ Handbook of Assumptions that will clarify, quantify, and detail the various inputs to the DCF+ test. This will allow for consistent application and transparency in assumptions assisting in the evaluation of energy efficiency, demand response options, and supply-side options. This DCF+ handbook intends to lay out a framework for calculating the benefits and costs of both facility projects and those IRPA solutions. As noted in the OEB Decision the Company will file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan.[24]

Section 11 - IRP Planning for 2023

This section provides a high-level summary of the work streams that Enbridge Gas expects to build upon and evolve further in 2023. These work streams are continuations of the work completed in 2022 as Enbridge continues to make strides regarding its Pilot and non-pilot IRP Plans, external stakeholder engagement initiatives, further integrating of IRP into the Asset Investment Planning Management (AIPM) process, and the evolution and filing of the Company's DCF+ Handbook of Assumptions.

External Stakeholder Outreach

Municipal

Enbridge Gas will continue its IRP outreach to municipalities across the province, this will involve one on one discussions along with webinars and outreach opportunities to reach wider audiences with the support and involvement of organizations such as the Association of Municipalities of Ontario (AMO) and the Rural Ontario Municipal Association (ROMA).

Electric Sector

Consultation with the IESO on best practices for Stakeholder Engagement and opportunities for Planning coordination will continue to be a priority for Enbridge Gas throughout 2023.

IRP Framework stakeholder plan

Roll out of the Regional Engagement Sessions will be based on the following schedule:

Region	Webinar Date
Southeast	April 4, 2023
Southwest	April 6, 2023
Northern	April 25, 2023
Eastern	April 11, 2023
GTA East	April 13, 2023

[24] EB-2020-0091 DECISION AND ORDER, page 57

Toronto	April 18, 2023
GTA West	May 4, 2023

Feedback received from these Regional Stakeholder engagement sessions will be reviewed and considered in the load forecasting process which will inform the 2024 AMP Addendum[25].

Implementation of geotargeted engagement to support the IRP Pilots in both Parry Sound and South Lake Huron geographic areas will continue through the first half of 2023. Enbridge has held a series of meetings with the impacted municipalities, local electricity distribution companies, Hydro One, and the IESO to ensure alignment on forecasts and potential IRPA opportunities as well as held public information sessions in Parry Sound on May 10, 2023, and in the Southern Lake Huron pilot area on May 17, 2023.

Enbridge Gas also reached out and engage with Indigenous groups in both pilot areas, separate from the geotargeted public engagement process, although Indigenous groups are welcome to attend all public engagement initiatives.

Enhancements to the Regional Planning webpage such as specific pilot and regional pages as well as a "Have your say" function, will roll out throughout 2023 as content becomes available

Continued IRP Evaluations

Enbridge Gas will continue to review the projects identified in the AMP and assess these projects through the technical and economic evaluation processes. Based on its review of the AMP projects, Enbridge Gas expects to develop and subsequently file a stand-alone Non-Pilot IRP Plan application and supporting evidence with the OEB for approval. An update on the projects reviewed has been provided as part of EB-2022-0200. Please refer to Exhibit I.2.6 STAFF 82 for the updated list in Appendix B as well as JT5.36[26] for an explanation of the binary and technical screening process. An update will also be provided as part of the 2024 AMP Addendum being filed with the OEB in October 2023.

DCF+ Test

Enbridge Gas anticipates that the discussion and work with the IRP TWG concerning the DCF+ enhancements will continue throughout the first half of 2023 and Enbridge Gas will file a submission on the DCF+ components as part of the first non-pilot IRP proceeding. [27] Notes and presentations that continue during the IRP TWG meetings can be found on the OEB IRP TWG web page. [28]

Pilot projects

Two Pilot projects will be filed with the OEB in June 2023 see EB-2022-0335. The regulatory process to support these two pilot projects will continue through at least the end of Q3 2023.

[25] EB-2022-0200 Exhibit 1 Tab 10 Schedule 4 Pages 14 - 16
[26] JT5.36 starts on page 2178 of the pdf
[27] EB-2020-0091, Decision and Order, page 56-57
[28] Natural Gas Integrated Resource Planning (IRP) | Engage with Us (oeb.ca)

Appendix A: OEB IRP Directives

The table below provides Enbridge Gas' progress toward meeting the Directives as ordered by the OEB in the IRP Decision.

Directive Item	Directive	Status
Interruptible rates	The OEB directs Enbridge Gas to study its interruptible rates to determine how they might be modified to increase customer adoption of this alternative service.	Completed and filed with Enbridge Gas Rebasing Application EB-2022-0200 Exhibit 8, Tab 4, Schedule 7
Documentation of demand-side IRPAs	The OEB concludes that a document on the best available information for demand-side alternatives would promote more timely development of IRP Plans and directs Enbridge Gas to include a listing in its annual IRP Report. The OEB agrees with Enbridge Gas that supply-side alternatives require case-by-case examination and therefore are not required to be included in the listing.	Completed – list included in 2021 IRP Annual Report. Updates included in the 2022 Annual Report Appendix B Integrated Resource Plan Alternatives.
Asset Management Plan	The OEB directs that the AMP include information about Enbridge Gas' system needs. This includes providing the status of consideration of IRP Plans regarding meeting system needs, the result of the binary screening, and details on the evaluation.	Completed and filed with Enbridge Gas Rebasing Application EB-2022-0200 Exhibit 2, Tab 6, Schedule 2, Appendix B
DCF+ test enhancement	The OEB directs Enbridge Gas to study improvements to the DCF+ test for IRP and, as applicable, file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan.	In progress Natural Gas Integrated Resource Planning (IRP) | Engage with Us (oeb.ca)

Directive Item	Directive	Status
IRP Website	The OEB also directs the establishment of a website by Enbridge Gas to facilitate the broad sharing of information on IRP stakeholder engagement efforts.	Phase 1 – Completed Phase 2 - Completed
Technical Working Group	Establishment of a TWG with the OEB directing that membership should include Enbridge Gas, OEB staff, independent experts, and experienced non-utility stakeholders	Completed Natural Gas Integrated Resource Planning (IRP) | Engage with Us (oeb.ca)
IRP Deferral accounts	The OEB directs Enbridge Gas to prepare a Draft Accounting Order for the two IRP Costs deferral accounts, consistent with the direction of this decision.	Completed
IRP Pilot projects	The OEB expects that the IRP pilot projects will be selected and deployed by the end of 2022 as proposed by Enbridge Gas. The detailed consideration of IRP pilot projects should commence shortly after the issuance of the IRP Framework with input being sought from the IRP Technical Working Group described in chapter 10 (“Stakeholder Outreach and Engagement Process”).	In progress

Appendix B: Integrated Resource Planning Alternatives

As per the IRP Decision, the IRP Annual Report is to include "a summary of the best available information on demand-side IRPAs, including the types of IRPAs, estimates of cost, peak demand savings, status in Ontario and learnings from pilot projects and other jurisdictions". Additionally, a summary of the best available information on supply-side IRPAs has been included below.

Demand Side IRP Alternatives

Enhanced Targeted Energy Efficiency (ETEE)

IRPA Overview
Enhanced targeted energy efficiency (ETEE) programs focus on achieving necessary reductions in a specific geographical area to reduce peak period system demands. ETEE programs could include enhancing existing broad-based Demand Side Management ("DSM") offerings through additional incentives and targeted marketing, or introducing new geo-targeted programs not offered through broad-based DSM. The mix of offerings and measures utilized in an ETEE program is dependent on the scope of the facility investment project under consideration, customer characteristics in the specific project services area, past DSM participation, etc. Broad-based DSM programs have been offered to natural gas customers across Ontario since 1993. The Company's 2023-2027 DSM Plan (EB-2021-0002) was recently reviewed and approved by the OEB to guide ongoing broad-based DSM programming and includes a joint whole home residential program with Natural Resources Canada ("NRCan") delivered by Enbridge. As defined by the Ontario Energy Board in their DSM Letter, the objective of broad-based DSM is "assisting customers in making their homes and businesses more efficient in order to help better manage their energy bills". As ETEE Programs focus on peak hour reductions, ETEE measures would focus on enhancing existing broad-based DSM measures such as space heating equipment, water heating equipment and building envelope upgrades. Additional measures being considered are new technologies, including thermal energy storage, hybrid heating and gas heat pumps. Enbridge will be undertaking IRP Pilots to review and understand the potential impacts of energy efficiency programs on peak period system demands within a geo-targeted area, and whether the impacts are significant enough to be considered an infrastructure alternative. The learnings from these IRP Pilots, as well as any non-pilot IRP Plans, will be incorporated into future iterations of the IRP Annual Report's Appendix B, "Demand Side Alternatives".
IRPA Peak Impacts
Forecast peak impacts will be estimated on a case-by-case basis depending on the ETEE program. Enbridge Gas worked with Posterity Group to build an end-use model of its service territory with the 2019 Achievable Potential Study (APS) being the starting point for the model creation. First, a mirror model of the APS was created and then several adjustments were made to better reflect EGI's knowledge and experience of the Ontario DSM market, EGI's current TRM assumptions and known changes to applicable standards. Posterity Group then worked with EGI to develop peak factors which were added to the model so that enhanced targeted energy efficiency peak hour impact estimates could be developed for each region, sector, segment, and end use. Posterity Group and EGI plan to

continue to evolve this model by refining assumptions and assessment methodologies to refine and improve forecasting of peak hourly flow reduction potential [29].
IRPA Cost Details
Costs will be determined on a case-by-case basis depending on the ETEE program. The Posterity model described above also includes cost assumptions for ETEE programs. Posterity Group and EGI plan to continue to evolve this model by refining assumptions and assessment methodologies so it can be used to assess project specific costs for an ETEE program.
IRPA Deployment Strategy
The selection of energy efficiency measures for an ETEE program and the deployment strategy would be dependent upon the scope of the facility investment project under consideration, customer characteristics in the specific project service area, past DSM participation, etc. The IRP Pilots will provide insights that could guide the deployment strategy of future IRP ETEE programs. The pilots could also provide insights on the deployment strategy into the richness of customer ETEE incentive levels and the intensity of the ETEE program delivery approaches for various customer groups to drive the participation uptake levels necessary to meet peak demand reduction requirements.
IRPA Solution Timing
Timing on an ETEE IRPA solution is dependent upon the scope of the facility system need under consideration, the type of ETEE program(s) being considered, and the customer characteristics in the specific project service area. A high-level estimate of a 3-to-5-year minimum lead time would be required with about three years for deployment and about two years for performance measurement.
IRPA Operational Risks
There are several operational risks related to ETEE: • Principle of universality (offering different DSM programing and incentives to different customers). • Undersubscription of ETEE programming to meet peak demand requirements to delay or avoid the facility system need. • Uncertainty on the reliability of cost-effective ETEE performance for facility planning. • Coordination of timing between fully effective ETEE IRPAs and meeting the system needs. • Current lack of experience in implementing ETEE programming; DSM expertise in delivery programming has been broad-based.
Learnings from Pilot Projects/Other Jurisdictions
Enbridge Gas engaged Guidehouse to undertake a jurisdictional review of ETEE and DR natural gas pilots implemented for general service customers, where the pilots' objectives were to defer or avoid infrastructure [30]. Guidehouse focused on three jurisdictions, summarizing the pilot objectives, marketing activities, costs, findings and challenges faced. Additionally, Guidehouse noted challenges in data availability in completing the jurisdictional review.

[29] Posterity Group, Enbridge's Navigator End-Use Model Presentation: Posterity (Enbridge's Navigator End-Use Model)
[30] IRP ETEE-DR Pilot Review April 8, 2022 Guidehouse (IRP ETEE-DR Pilot Review)

Enbridge Gas filed a Geo-Target Demand Side Management Case Study in EB-2020-0091 at Exhibit C, Appendix A. The objectives of the case study were:

1. Assessment of the impacts of geo-targeted DSM programs on reducing peak hour demand.
2. Assessment of the costs of geo-targeted DSM program implementation.

The results from this case study only illustrate the impacts geo-targeted DSM had on the town of Ingleside and although informative and directional, the results cannot be generally applied due to the specific nature of customer composition.

Demand Response (DR)

IRPA Overview
Natural gas demand response aims to reduce demand by natural gas customers during peak periods. For residential and commercial customers, this is usually heating demand reduction during DR program events via thermostat control or water heater temperature settings. For contract customers, this can be done through leveraging interruptible rates. Enbridge will be undertaking IRP Pilots to review and understand the potential impacts of residential DR on peak period system demands within a geo-targeted area, and whether the impacts are significant enough to be considered an infrastructure alternative. The learnings from these IRP Pilots, as well as any non-pilot IRP Plans, will be incorporated into future iterations of the IRP Annual Report's Appendix B, "Demand Side Alternatives". Demand response would include: 1. Negotiable interruptible rate - as detailed in Section 9, the use of interruptible rates was reviewed as part of the IRP Framework Decision, and Enbridge Gas filed an Interruptible Rate Study that evaluated the use of demand response in the context of future IRP Plan Application where applicable 2. Utilization of another alternative (i.e., onsite CNG) when a peak hour/day event is called 3. Incentives to shift peak hourly demands to off-peak periods
IRPA Peak Impacts
Peak impacts will be determined on a case-by-case basis depending on the DR program.
IRPA Cost Details
DR IRPA costs will be determined on a case-by-case basis depending on the DR program.
IRPA Deployment Strategy
The deployment strategy will be determined on a case-by-case basis depending on the customer mix and characteristics in the project area. The IRP Pilot residential DR program will provide insights that could guide the deployment strategy for future programming.

For contract rate customers, as part of the IRP evaluation process, Enbridge Gas will engage with all contract customers in the project area to assess whether those customers could reduce their peak demands, convert their firm demand service to interruptible service or leverage another fuel source.
IRPA Solution Timing
DR IRPAs are dependent upon the scope of the facility system need under consideration, the type of DR program being considered, and the customer characteristics in the specific project service area. The IRP Pilot residential DR program would provide insight on the time required to design a DR program and to deliver a DR program to reach participation levels required of the specific facility IRPA. Engagement of contract rate customers will occur as part of the detailed technical assessment.
IRPA Operational Risks
There are several operational risks related to a residential DR program: • Principle of universality (offering DR programing/incentives to different geographically specific customers) • Undersubscription and lack of persistent participation of DR programming to meet peak demand requirements of the delay or avoidance of facility system need • Uncertainty on the reliability of cost-effective DR performance for facility planning • Coordination of timing between fully effective DR IRPAs and meeting the system needs • Current lack of experience in implementing DR programming; Enbridge Gas has not previously implemented a gas-DR program for general service customers.
Learnings from Pilot Projects/Other Jurisdictions
Enbridge Gas engaged Guidehouse to undertake a jurisdictional review of ETEE (Enhanced Targeted Energy Efficiency) and DR (demand response) gas pilots implemented for general service customers, where the pilots' objectives were to defer or avoid infrastructure [31]. Guidehouse focused on three jurisdictions, summarizing the pilot objectives, marketing activities, costs, findings and challenges faced. Additionally, Guidehouse noted challenges in data availability in completing the jurisdictional review.

[31] IRP Working Group Meetings | Natural Gas Integrated Resource Planning (IRP) | Engage with Us (oeb.ca)

Supply Side IRP Alternatives

Compressed Natural Gas (CNG)

IRPA Overview
CNG is a mobile solution that can be used in place of traditional pipeline reinforcement to meet customer demands at peak hours on peak days. Natural gas is compressed into large tube trailers and moved by trucks from the "mother" compression station to a "daughter" decompression station where the gas is delivered into the pipeline. This is an active control best utilized in long, single feed pipe networks with cold weather peaking loads. Mother stations are situated in relative proximity to daughter stations (within 200 kms) to minimize driving distance.
IRPA Peak Impacts
CNG targets peak hours on peak demand days, where the injection of gas back into the system at the daughter station would have an equivalent 1 for 1 offset of gas otherwise required to flow through the traditional pipeline bottleneck. Injecting near the low-pressure point on the system would magnify the benefit beyond 1 for 1 on a hydraulic basis. Although the trailered gas will need to be withdrawn from the system at the mother station, this can be done at off-peak times and locations and where capacity is available.
IRPA Cost Details
From a capital cost perspective: - Tube trailers typically have a capacity of 10,000 m^3 of natural gas (at standard conditions) and cost $700,000 per trailer with a 15-year useful life. - Daughter and mother stations costs can vary based on capacity requirements, but typically cost $300,000 and $3M per station respectively with a 20+ year useful life. From an operational cost perspective, the equipment requires regular maintenance and supervised operation. Drivers are also required to drive the trailers between mother and daughter station with highway tractors.
IRPA Deployment Strategy & Timing
The equipment is mobile and can be deployed in various locations throughout the province. CNG would be most ideal in areas where the gas demands are large enough to achieve economies of scale but small enough to be practical. For instance, the transmission pipeline scale is too large as it may require hundreds of trailers, but a few households would be too small as a single trailer will be underutilized. Additional consideration based on location would impact the suitability of CNG as a solution, such as urban versus rural and the number of trucks required. Depending on the system need and location, CNG can be a suitable bridging solution and can be deployed in a relatively short amount of time. This solution can be scalable by adding additional trailers and daughter stations into the fleet.
IRPA Operational Risks

The biggest risk associated with this solution is a potential disruption in the supply of trailers to the daughter station, for instance road closure due to weather or an accident while in transit. To mitigate this risk, extra trailers can be made available on-site at the daughter station and the associated additional costs would need to be considered when assessing the viability of this IRPA.

Market-Based Supply

IRPA Overview
Market-based supply-side IRP alternatives include incremental natural gas deliveries or pressure increases at specific interconnects or points between Enbridge's system and other pipelines such as the TC Energy Mainline and US based pipelines such as Panhandle Eastern Pipeline Company and Vector. Contracting for market-based supply-side alternatives into Enbridge's franchise area, where applicable and available, can reduce, defer or mitigate traditional infrastructure by meeting incremental natural gas demands in a defined area with incremental deliveries or pressure.
IRPA Peak Impacts
Incremental deliveries or increased pressure must be delivered in the project's area to impact peak hour demands. Therefore, market-based supply side alternative options are limited to interconnects with TC Energy along the mainline and Enbridge's system or with interconnects with other pipelines that connect to Enbridge's system such as Parkway, Ojibway and Dawn.
IRPA Cost Details
Market-based supply-side alternative costs are based on market dynamics at the time of contracting. Enbridge cannot forecast the cost of market-based supply-side options on a long-term basis.
IRPA Deployment Strategy and Timing
Enbridge can contract and deploy market-based supply-side alternatives if the deliveries from a third party or pipeline are available. However, for US pipelines, the Federal Energy Regulatory Commission rules dictate that US pipelines cannot sell capacity more than "90 days from the contract start date". Given that many of Enbridge's interconnects are with US pipelines it may be difficult to utilize the market-based supply-side services for an IRP alternative.
IRPA Operational Risks
There are two primary operational risks with market-based supply-side alternatives: lack of renewal rights and failure to deliver. Most market-based supply-side alternatives are short-term (1-2 years) and lack renewal rights making it difficult to rely on long-term to reduce or mitigate a project need. In many instances, a market-based supply-side alternative will be used to defer a project in the short-term and then the need and IRP alternatives will need to be reassessed. While Enbridge may have contracted for a market-based supply side alternative, if the capacity underpinning the service is not firm, then natural gas market dynamics may cause the supplier to fail on its delivery obligations. For example, without firm capacity underpinning the market-based service, during peak weather events upstream pipeline systems may become constrained and non-firm

services can be curtailed. If the service provider is relying on non-firm services, it may be unable to supply natural gas to Enbridge. While contract penalties and other contract language may limit most events like the example above from happening, it remains a legitimate and material risk. If the contracted service was not delivered as planned, Enbridge could have insufficient gas supply deliveries to meet its market demands; potentially resulting in a system outage during the coldest periods of the year. While Enbridge would collect financial penalties, if applicable, after the event occurred, Enbridge would still need to deal with the physical and customer impacts that resulted due to the failed delivery of the incremental gas on that day.

Appendix C: Summary of IRP Evaluations

Refer to Exhibit I.2.6 STAFF 82 for the updated list in Appendix B, which provides the most recent results of Enbridge Gas's IRP Assessment Process for system needs, including reporting on those system needs where a negative binary screening, technical or economic evaluation resulted in no further assessment of IRPAs.

Appendix D: IRP Screening Results for LTC Projects Filed in 2022

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
EB-2022-0203	Ridge Landfill RNG	Fail			Enbridge Gas applied the IRP Binary Screening Criteria and determined that this Project meets the definition of a Customer-Specific Build, as defined in the IRP Framework: Customer-Specific Builds – If an identified system need has been underpinned by a specific customer's (or group of customers') clear request for a facility project and either the choice to pay a Contribution in Aid of Construction or to contract for long-term firm services delivered by such facilities, then an IRP evaluation is not required. The Project was driven solely by a specific customer's (Waste Connections) request for facilities to connect to Enbridge Gas's existing natural gas distribution system. Waste Connections has executed a long-term contract including a CIAC to fully fund the cost of the Project.	OEB Decision: the proposed Project falls under the customer-specific build category in the OEB's IRP framework, which obviates the need for an IRP evaluation.
EB-2022-0155	Crowland well upgrade replacement project				Enbridge Gas stated that it is not aware of any comparable alternative facility or non-facility solution that would enable gathering information on the rock properties of these specific geological formations	OEB Report of the Board: The OEB finds that there is a need for the Project. The OEB notes that any future conversion of EC 1 from a test well to an observation or injection/withdrawal well would be subject to Enbridge Gas receiving approvals from the MNRF.
EB-2022-0086	Dawn to Corunna Replacement Project		Fail		The Company applied the OEB-approved Binary Screening Criteria to the Project and determined that it is not possible to implement and resolve the identified system constraint within the timeframe required. As stated in the OEB's IRP Framework for Enbridge Gas: ii. Timing - If an identified system constraint/need must be met in under three years, an IRP Plan could not likely be implemented, and its ability to resolve the identified system constraint could not be verified in time. Therefore, an IRP evaluation is not required. Exceptions to this criterion could include consideration of supply-side IRPAs and bridging or market-based alternatives where such IRPAs can address a more imminent need.	The OEB finds that the assessment of alternatives was sufficient for the purpose of selecting the Project as the preferred option. The OEB finds that an Integrated Resource Planning assessment is not required in this case under the current Integrated Resource Planning Framework

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
					The cost of an ETEE program that could deliver 90 TJ/d of demand reduction in the most favorable market downstream (EGD rate zone – CDA) of the Project is estimated to be approximately $980 million. Further, this alternative would require additional expenditures of a similar magnitude every 10-15 years to maintain this reduction over the depreciable life of the proposed Project, which is currently anticipated to be approximately 40 years	
EB-2022-0003	NPS 20 Waterfront Relocation Project		Fail		Enbridge Gas applied the Binary Screening Criteria and determined that the need underpinning the Project does not warrant further IRP consideration, as the Project is driven by a need that must be met within 3 years: Timing - If an identified system constraint/need must be met in under three years, an IRP Plan could not likely be implemented and its ability to resolve the identified system constraint could not be verified in time. Therefore, an IRP evaluation is not required. Exceptions to this criterion could include consideration of supply-side IRPAs and bridging or market-based alternatives where such IRPAs can address a more imminent need.	The OEB finds that an IRP assessment is not required in this case given that the proposed Project is a like-for-like with no growth component and has a tight timeline.
EB-2022-0247	Metrolinx Scarborough Extension – Kennedy Station	Fail	Fail		Enbridge Gas applied the Binary Screening Criteria and determined that the need underpinning the Project does not warrant further IRP consideration based on the timing criteria, as the need must be met in under three years (the proposed project has in-service dates of December 2023 for Phase 1, and July 2025 for Phase 2). In addition, the Project is driven by a customer-specific build where Metrolinx will reimburse Enbridge Gas through a Contribution in Aid of Construction ("CIAC") for the actual Project costs.	In the OEB's Decision the OEB finds that the Project is the best alternative to meet the stated need. The Project is excluded from IRP considerations for the following reasons: the Project addresses a system need that must be met in under three years; Metrolinx will pay all project costs. The project is within the intent of the findings made by the OEB in the IRP Framework decision regarding customer specific builds where the customer fully pays for incremental infrastructure cost.

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
EB-2022-0248	Mohawks on the Bay of Quinte First Nation Community Expansion			Fail	Enbridge Gas applied the Binary Screening Criteria and determined that the proposed Project meets the definition of a community expansion project under the IRP Framework, as the Project has been approved by the Government of Ontario as part of the Phase 2 NGEP to provide access to natural gas distribution services in MBQFN and the Township. Consequently, the need underpinning the Project does not warrant further IRP consideration.	Decision not issued as of date of report
EB-2022-0249	Hidden Valley Community Expansion			Fail	As per the IRP Binary Screening Criteria (iv), the need underpinning the Project does not warrant further IRP consideration or assessment: iv. Community Expansion & Economic Development – If a facility project has been driven by government legislation or policy with related funding explicitly aimed at delivering natural gas into communities, then an IRP evaluation is not required.	Decision not issued as of date of report
EB-2022-0156	Selwyn Community Expansion Project			Fail	As per the IRP Binary Screening Criteria (iv), the need underpinning the Project does not warrant further IRP consideration or assessment: iv. Community Expansion & Economic Development – If a facility project has been driven by government legislation or policy with related funding explicitly aimed at delivering natural gas into communities, then an IRP evaluation is not required.	Decision not issued as of date of report
EB-2022-0088	Haldimand Shores Community Expansion Project			Fail	Enbridge Gas applied the Binary Screening Criteria and determined this Project meets the definition of a community expansion project defined in the IRP Framework as the Project has been approved by the Government of Ontario as part of the Phase 2 NGEP to provide access to natural gas distribution services in the community of Haldimand Shores. Consequently, the need underpinning the Project does not warrant further IRP consideration. iv. Community Expansion & Economic Development – If a facility project	OEB Decision: In EB-2020-0091 the OEB approved an integrated resource planning process for Enbridge Gas that required an evaluation and comparison of options to meet energy supply needs. To meet the Ontario Government's Natural Gas Expansion Program (NGEP) objective of bringing service to unserved communities the OEB provided that the consideration of such options or alternatives was not required for NGEP approved projects that have been designated in Ontario Regulation 24/19. The OEB's

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	**Timing**	**Community Expansion & Economic Development**		
					has been driven by government legislation or policy with related funding explicitly aimed at delivering natural gas into communities, then an IRP evaluation is not required.	decision in this proceeding is in accordance with its approved integrated resource planning process
EB-2022-0157	Panhandle Regional Expansion Project				Enbridge reviewed potential IRPA such as firm exchange between Dawn and Ojibway, a hybrid alternative, trucked CNG, and an ETEE These alternatives were found to not be technically feasible viable solutions.	The proceeding has been in abeyance since December 5, 2022. Decision not issued as of date of report.

Appendix E: Technical Working Group Report

Review of Enbridge Gas Inc. 2022 Integrated Resource Planning (IRP) Annual Report and Update on IRP Working Group Activities

From: Integrated Resource Planning Technical Working Group

May 30, 2023

Contents

1. Introduction & Overview of IRP Working Group

An Integrated Resource Planning (IRP) Framework for Enbridge Gas was established by the OEB through its *July 22, 2021 Decision and Order* (IRP Decision). The IRP Decision directed the OEB to establish an IRP Technical Working Group (Working Group) and required a Working Group report to be filed in the same proceeding in which Enbridge Gas's annual IRP report is filed.

This Working Group report provides comments on Enbridge Gas's implementation of the IRP Framework in 2022 (as described in Enbridge Gas's 2022 annual IRP report), including member comments or concerns with the implementation of the IRP Framework to date, and also discusses priorities for implementation of the IRP Framework in 2023. The Working Group report also provides a summary of activities undertaken by the Working Group over the previous year.

The Working Group report has been prepared by OEB staff with input from all Working Group members, and approved by all Working Group members, as an accurate summary of the Working Group's activities.[1] Where views expressed in the report do not reflect the views of all members, this is clearly indicated.

1.1. Overview of IRP Working Group

Membership to the Working Group was announced in a *letter* issued by the OEB on December 6, 2021. Members were determined through a *call for nomination* process where the OEB selected seven non-utility members, representatives from the OEB and Enbridge Gas, and observers from the Independent Electricity System Operator and EPCOR Natural Gas LP. The Working Group members have not changed since inauguration and are listed in **Table 1** below. Per the IRP Decision, the Working Group led by OEB staff, was instructed to provide input on IRP issues that will be of value to both Enbridge Gas in implementing IRP, and to the OEB in its oversight of the IRP Framework. Accordingly, a *Terms of Reference* was issued by the OEB on February 17, 2022, after considering the review and input from the Working Group.

Working Group meetings are typically held monthly. Considering the complexity of the discounted cash flow-plus (DCF+) test and as suggested by Working Group members in last

[1] The IRP Technical Working Group includes observers from the Independent Electricity System Operator and EPCOR Natural Gas LP. As noted in the Working Group's Terms of Reference, any materials authored by the IRP Working Group (including this report) should not be considered to represent the views of Working Group observers, or their organizations.

year's Working Group report, a DCF+ subgroup was formed with the first meeting held on July 5, 2022. As such, meetings occurred bi-weekly, generally alternating between the General Working Group and the DCF+ Subgroup. Meeting notes and meeting materials for all IRP Working Group meetings are published on the OEB's website following meetings to allow stakeholders to follow the Working Group's progress.[2] These materials can be found at: https://engagewithus.oeb.ca/irp

Table 1: IRP Working Group Membership

Name	Role
Michael Parkes	OEB staff representative (Working Group chair)
Stephanie Cheng	OEB staff representative
Chris Ripley	Enbridge Gas representative
Whitney Wong	Enbridge Gas representative
Amber Crawford, Association of Municipalities of Ontario	Non-utility member
John Dikeos, ICF Consulting Canada Inc.	Non-utility member
Tamara Kuiken, DNV Inc.	Non-utility member
Cameron Leitch, Enwave Energy Corporation	Non-utility member
Chris Neme, Energy Futures Group	Non-utility member
Dwayne Quinn, DR Quinn & Associates Ltd.	Non-utility member
Jay Shepherd, Shepherd Rubenstein Professional Corporation	Non-utility member
Kenneth Poon, EPCOR Natural Gas LP	Observer
Steven Norrie, Independent Electricity System Operator	Observer

[2] Meeting materials are typically posted online shortly after the meeting. Meeting notes are not typically posted until after the following meeting, to allow for members to review draft notes and identify any omissions or inaccuracies.

2. Review of Enbridge Gas's Annual IRP Report and Comments on IRP Framework Implementation

The IRP Decision notes that the Working Group is expected to review a draft of Enbridge Gas's annual IRP report. The review is coordinated by OEB staff, and Enbridge Gas should provide a draft of the annual IRP report to the Working Group far enough in advance of its planned filing to the OEB to allow the Working Group adequate time to review and comment. The IRP Decision also indicates that the Working Group report should include any comments on Enbridge Gas's annual IRP report, including material concerns that remain unresolved within the Working Group. The Working Group's review took the following steps:

STEP 1:

Enbridge Gas

Provided a draft of its 2022 IRP annual report to the Working Group for review

STEP 2:

Working Group Members

Provided suggested edits/ comments/ clarifying questions

- Member comments were generally aimed at improving the accuracy and completeness of Enbridge Gas's description of its IRP activities, and also suggested some content additions (e.g., listing facilities proceedings where IRP alternatives were considered but rejected, addition of descriptive information on supply-side IRP alternatives to the appendix)

STEP 3:

Enbridge Gas

Revised and finalized its annual report

- Enbridge Gas provided a revised draft of the annual report to the Working Group, documenting how it considered comments from Working Group members
- After a second round of review, Enbridge Gas finalized its annual report. Final determinations as to the contents of Enbridge Gas's IRP annual report were made by Enbridge Gas, not the Working Group

STEP 4:

Working Group Members

Provided final comments on implementation of the IRP Framework including the highest priority items for 2023, for inclusion in the Working Group report

Member comments are discussed further below in section 2.1

2.1. Working Group Comments on Implementation of the IRP Framework

Working Group members (with the exception of observers) were asked the following question:

> ***Having reviewed Enbridge Gas's final annual IRP report's description of Enbridge's IRP activities in the previous year and having also participated on the IRP Working Group, do you have any comments or concerns with the implementation of the IRP Framework to date? What do you think should be the highest priorities for the implementation of the IRP Framework in 2023?***

With regards to implementation of the IRP Framework, some Working Group members expressed concerns with the pace of Enbridge's IRP implementation to date, particularly given the need for the OEB to consider the impacts of IRP and the energy transition as they relate to key aspects of Enbridge's active rebasing application, such as Enbridge's forecast capital expenditures during the rebasing term. Members also noted some concerns with Enbridge's engagement with the Working Group, regarding the scope of IRP-related topics discussed with the Working Group, the level of information provided, and the stage at which the Working Group was engaged. Members noted that this limited the Working Group's ability to meaningfully contribute to improving Enbridge's IRP implementation. Priorities for 2023 are discussed in chapter 4 of this report.

More specifics are provided in the comments from individual members in Table 2, and the comments of Enbridge Gas Working Group members follow in Table 3.

Table 2: Individual Comments of IRP Working Group Members

Working Group Member	Comments (optional)
Amber Crawford (non-utility member)	While some progress has been made over the past year, there remain key concerns around whether the Working Group (WG) is being used in accordance with its intended purpose or being used to fulfill a regulatory requirement.

	1. WG brought in too late in the process: In my opinion, by the time feedback was sought from the WG, Enbridge was often too far along in the process for our contributions to have meaningful impact. For example, the WG felt limited in its ability to provide comprehensive and insightful advice around the technical evaluations of the pilots because there was minimal information or analysis on why particular pilots were selected and what justified the absence of others. 2. WG provided with information too slowly: The pace at which information was distributed to the WG has also been concerning given the speed at which Enbridge's Rebasing Application and its plan to add more than $7 billion of capital additions in 2024-2028 is proceeding. 3. WG members not apprised of certain IRP activities: Members of the WG were only apprised of the Kingston IRP after the fact, for reasons that Enbridge has not made clear. Additionally, there was a breakdown in communication, and promotion of the IRP webinar consultations were not shared broadly or with enough notice for most WG members to participate.
John Dikeos (non-utility member)	I generally agree with the feedback that other WG members have provided in terms of opportunities to make better use of WG member expertise and ensure broader communication on all of Enbridge's work related to IRP alternatives. Also, I believe that there is still room for improvement regarding the pace of the development and implementation of Enbridge's IRP pilots. Given the current pace of progress, it is increasingly unlikely that Enbridge Gas will be able to "deploy and implement the projects in time to influence natural gas consumption for the winter of 2023/2024", as noted in the 2022 IRP Annual Report. The timeline for the collection of baseline data further complicates the deployment of these pilots. Although the data that will be collected from the IRP pilots will help refine the evaluation of IRPA projects in the future (e.g., through access to more reliable estimates of costs, peak demand impacts, and customer participation), Enbridge should be encouraged to make parallel progress on the deployment of additional IRPA projects prior to the completion

	of the IRP pilots. Supply-side options, such as CNG, should be increasingly considered as bridge options to help address any near-term performance concerns with demand-side IRPA projects. In terms of upcoming priorities, I am in general agreement that WG members should support the evolution and refinements of Enbridge's processes and tools to consider IRPA projects. I also believe that Enbridge should continue to monitor relevant developments in other jurisdictions and communicate them with WG members so that they can be considered in the evolution of Enbridge Gas' IRPA strategy.
Tamara Kuiken (non-utility member)	{no additional comments}
Cameron Leitch (non-utility member)	Like Dwayne, having had the benefit of Jay and Amber's comments before writing my own, I do not believe there is a benefit in repeating them. Suffice to say, I also agree with their feedback and would defer to Chris Neme and others on another important topic: application of DCF+. There are two focus areas for 2023 that I would add to the feedback from other members. **1. Implementing and Refining IRP using Feedback** Now that the development of an IRP Framework is well underway, and having spent a considerable amount of the WG's time working through process, the next phase will hopefully be focused on implementation and refinement of these processes and tools. Having focused on developing the structure, the detailed application of IRP (and exposure of the WG to the application of it) will provide better insight into the effectiveness of the process. Having reviewed the draft IRP Annual Report prepared by Enbridge, and presuming I've understood Exhibit I.2.6 from the rebasing application correctly, it appears that there are nearly 2,300 investments in the AMP. Of these, 1,392 failed the binary screening with high-level reasons including "Dollar Threshold", "Emergent Safety", or "Timing". The "Dollar Threshold" reason accounts for 1,341 of the failed binary screening items, with forecasted spend ranging from $15.8M to under $1,000.

	Of those investments that passed binary screening, 25 (or approximately 1%) have passed the technical evaluation. And of those, presumably the majority will not pass the final economic evaluation. It is appreciated that the IRP process is relatively new, that additional resources have been hired to manage the process, and that the sheer volume of projects in the AMP requires a considerable amount of effort to evaluate, and so going forward in 2023 I am hoping to (a) see considerable progress toward the identification and implementation of feasible IRPAs, (b) witness the implementation of the processes and tools that the WG had input into so that refinements may be made, and (c) better understand the specific practices that go into defining the Facility Alternative and the IRPA (such as metric-based pricing, assumptions around ETEE/DR uptake, etc.) for the three “levels” of evaluation (binary screening, technical, and economic evaluation). In addition, the investments in the AMP are influenced by the existing customer base and growth, whether replacing/upgrading existing infrastructure or constructing new. Modelling is used to forecast these requirements, and with the changing climate and regulatory environment I would like to better understand how aspects such as global warming and customer upgrades and attrition have been factored into the model. Additionally understanding historical agreement between forecast models and actual system demand may help highlight whether historical perceived need reflects reality. **2. Proposed IRPA Solutions** Enbridge has identified several “conventional” options to consider when evaluating IRPAs, with demand-side options such as ETEE, DR, and supply-side options such as CNG injection. Additionally Enbridge alluded to the implementation of thermal storage and gas heat pumps (in the IRP Report), and the direct installation of these systems in a recent WG meeting. Given the potential challenges in the identification of feasible IRPAs as identified above, efforts to expand the list of opportunities to consider are valuable. That said, how those opportunities are implemented requires further discussion as the direct installation of gas-consuming systems would extend beyond simply bringing the service to the meter.

	Conclusions In 2023 I believe that implementation of IRP and refinement through a deliberate feedback loop, as well as continued scrutiny of the current and former demand modelling that informs the investments in the AMP, are most important.
Chris Neme (non-utility member)	Like many of the other members of the Working Group, I have concerns about how slowly Enbridge has moved to implement the IRP process. I do appreciate that it is somewhat complex and that there is a lot of work associated with assessing the applicability and ultimately cost-effectiveness of IRPAs. I suspect Enbridge is not adequately staffed to enable systemic and routine IRP assessments of hundreds of potential projects. However, as others have noted, given the massive scale of the system investments being proposed in the current AMP – and their implications for gas ratepayers and risks of creating stranded assets because of the energy transition – that cannot be considered an excuse. I also share concerns of others about Enbridge often not using the Working Group to collaboratively consider how best to apply IRP practices rather than informing the working group about decisions that have largely (or entirely) already been made. Going forward, I think there are five areas on which it would make sense to focus Working Group activities: 1. **Refining strategies for the IRPA pilots**. Experience in other jurisdictions suggests that things rarely go exactly as planned for such pilots. There is therefore a need to be closely tracking progress and being prepared to modify strategies quickly in response to market feedback and other factors such as revised estimates of load growth. In my view, this requires at least monthly check-ins initially on the roll-out of strategies. Over time, that could shift to quarterly. Of course, this is only useful, if the Company sees the WG almost as partners in the design, implementation and on-going refinement/adaptation of the pilots. 2. **Refining details of the revised DCF+ test**. There are key elements of our discussion of modifications to the DCF+ test framework that require further work. The devil really is in the details. To give just one

	example, we talked about the need to make estimates of job impacts more accurate and balanced, but haven't moved beyond that concept to actual application of the principle. It would be helpful to actually develop specifics for this issue, commission a jobs and economic development study to quantify things as other jurisdictions have, etc. This applies potentially to other DCF+ issues/impact categories too. 3. **Working through specific details of the Company's binary screening and, perhaps more importantly, its technical screening of IRPA applicability**. It would be super helpful to get more specifics from Enbridge on how these screens are being applied and for the WG to work through potential modifications to the Company's approach to such screening where appropriate and applicable. This needs to be done while the pilots are being implemented (not just afterwards) as we cannot afford to wait until the pilots are complete to revise current practices or we will be too late to influence hundreds of millions or billions of dollars of investments. 4. **Penalties and incentives for IRPAs**. I strongly suspect that Enbridge (like other utilities) will respond much more expeditiously and effectively to IRP requirements if shareholder dollars are at stake. Thus, I personally think it is important that there are both penalties for failing to adequately review IRPAs (or to review them early enough to enable them to proceed if cost-effective) and incentives for pursuit of IRPAs that are effectively deployed. The WG should endeavor to identify a short list of options and, ideally, a consensus recommendation for the Board (if not, at least a summary discussion of pros and cons of different options) on such penalties/incentives. I believe that the Board's order in the Gas IRP proceeding suggested this is a topic the WG should take up. Seems like it needs to happen soon. 5. **Modifications of Gas IRP Framework and/or approach to application of the framework to address the energy transition**. The current rebasing case has made clear that major changes are coming. We may disagree about exactly what those changes will be or how fast they will come, but they will be major in any case and are coming. This has huge

	implications for consideration of IRPAs. For one thing, I think at a minimum that IRPAs should be assessed under several different demand growth futures, so that we better understand the risks of creating stranded assets and better assess the risk mitigating potential of IRPAs. I appreciate that the above list is substantial, and it is probably not possible to tackle all of it within the current WG structure and process. But it is also all urgent. So maybe there needs to be a discussion about how to modify the WG process to better enable addressing more of these fundamental issues. as long as it addressed all of the aforementioned issues.
Dwayne Quinn (non-utility member)	Having the opportunity to follow Jay and Amber, I can state that I fully support their expressed concerns and will not restate them. Instead, we provide specific concerns as examples of the problems identified in their submissions. Many times, the WG asked about getting information on IRP processes or projects and were told that these items were "under review" or still being "developed" by EGI. These requested items were not being released until "signed off" by all of the pertinent areas of EGI. This approach clearly inhibited the opportunity for the WG to contribute to the development of approaches or projects where ideas from the group could have enhanced the process and outcome. One specific example is the Parry Sound project. Several times, I suggested ideas or requested information and it took months to get responses. When I did get information, it was limited to my specific ask and was not complete leading to my speculation on approaches (I would guess or estimate to get the requested information by being corrected). Three months ago, after making some progress, I was told that once EGI finished their USM model, it would be a good idea to have a meeting. That meeting has not been scheduled.
Jay Shepherd (non-utility member)	The Enbridge approach to IRP continues to be a disappointment, although there have been improvements over the 2022 year. ***Role of the Working Group.*** Enbridge and the Working Group appear to have different views of the role and value of

	the Working Group. The members of the WG generally agree, I think, that we should be seen as an expert resource that Enbridge can tap to a) improve the quality of their approach to IRP, and b) increase the speed with which they implement to meet the expectations of their customers and the OEB. That has not been the experience to date. Instead, the WG has been treated as a regulatory requirement that Enbridge must meet, but only on topics specifically set out in the IRP Decision. Information has been doled out in a limited manner, and input sought on only a few narrow items (pilot projects and DCF+, mainly). Thus, at no time did Enbridge share their strategic planning for the rollout of IRP with the WG. Effective use of the resource would have meant sharing final copies, or even drafts, of their staffing plan, their stakeholdering and communications plans, their technical assessment process, and their economic evaluation process, to name just a few components. None of that was done, despite the fact that around the WG table there are people who have considerable experience in those areas. For example, early on Enbridge made a decision that, in adding FTEs for IRP work, they would add those new people to the non-IRP functional areas, rather than create a cohesive team focused on IRP and interacting as a team with the other functional areas. The WG found out about this as a *fait accompli*, already finalized and implemented. Both staffing strategies have strengths and weaknesses, and the Enbridge approach may or may not be the best one. It is, though, surprising that the experience of the WG members was not tapped to provide input to that important decision. Another example is the technical evaluation process. Since the beginning the WG members have been asking for information on that process so that they could provide input. At this point, with the AMP going before the OEB in the rebasing proceeding in just a few weeks, we still do not have details on this process. This is particularly problematic since so few of the AMP projects have passed the technical evaluation. A more effective approach to the IRP function at Enbridge would have been to develop a comprehensive internal business plan/strategy for that initiative, and share that at all stages of the drafting with the WG. To the best of our knowledge, nothing like that has even been prepared, let

	alone shared, and certainly the Enbridge IRP strategy is opaque. It is also worth noting that Enbridge did implement one IRP in 2022, the Kingston project. The WG was not involved in that process, finding out about it only after the fact, for reasons that Enbridge has not made clear. ***Continued Resistance to Implementing Meaningful IRP.*** The pace remains very slow. In parallel, the Rebasing Application is proceeding at full speed, with Enbridge's plan to add more than $7 billion of capital additions in 2024-2028 a key element of that application. It now appears clear that the OEB will be required to make a determination on that application, and that capital plan, without any information on the ability of IRP to make a dent in that spending. This WG report itself will be made public the day before the ADR in that application, and less than a month before the oral hearing. At that point, the WG will have had limited ability to look at how IRP is being done this year, and the AMP will not include any IRP alternatives. This may have the effect of deferring the disciplined consideration of actual IRP implementation by the OEB for up to five more years. This is all against the backdrop of the Energy Transition, perhaps the most overarching issue in the Rebasing Application. We have seen no indication that Enbridge has any sense of urgency in their IRP rollout, despite the increasing intensity of the Energy Transition debate. It is as if the continuing additions to rate base, month after month, can continue indefinitely, with no "brakes" being applied through IRP or anything else. At the current pace of IRP planning and implementation at Enbridge, I believe it is unlikely that even 1% of the $7 billion of capital additions over the next five years will be avoided by IRP alternatives (i.e. less than $70 million). ***Stakeholder Engagement.*** It is of concern that members of the WG that would have attended community meetings hosted by Enbridge found that they were not invited, or that their invitations were "lost". This is particularly problematic in the context of municipal engagement, since past reports have suggested that stakeholder engagement could be used to "sell" more continued use of natural gas rather than other alternatives. Further, Enbridge presentations to municipal representatives routinely promote the gaseous fuels model for

	getting to Net Zero, and downplay the alternative, increased electrification. It would be helpful if Enbridge maintained a schedule of community engagement activities for IRP that was available to WG members – and members of the public - well in advance, so that those who wish to attend could do so.
Mike Parkes/ Stephanie Cheng (OEB staff representatives)	In OEB staff's view, Enbridge Gas made significant progress towards implementing the IRP Framework in 2022, as compared to 2021, although to date this has only resulted in one instance where Enbridge Gas has used IRP alternatives to defer a facility project (Kingston Reinforcement Project, section 6 of Enbridge Gas annual IRP report). In particular, Enbridge Gas's integration of IRP assessment into its Asset Management Plan (section 3) and study and proposal for interruptible rate design (section 9), are important steps towards implementing the IRP Framework in alignment with the IRP Decision,[3] as are the work done with Working Group input to refine IRP pilot proposals (section 4) and enhance the DCF+ test (section 10), although Enbridge Gas's key milestones for these items will not be reached until later in 2023. Enbridge Gas should build on this work and further leverage the expertise of the Working Group in 2023. OEB staff provides the following additional comments: • **Transferring Learnings from IRP Pilots:** In last year's comments, OEB staff noted that Enbridge Gas was not on track to have pilots deployed by the end of 2022, which was the expectation of the IRP Decision, and that it would therefore be important for Enbridge Gas to make use of learnings from the pilots while they are still in-flight, to inform Enbridge Gas's broader consideration of IRP alternatives in system planning decisions. As this year's annual report shows, the timing of pilots has been further delayed, and Enbridge will be filing its pilot application in June 2023. OEB staff recommends that Enbridge provide regular public updates on pilot progress, so that, in the context of non-pilot proceedings (e.g., Leave to Construct applications, IRP Plans), the OEB and other parties will have an up-to-date understanding of what Enbridge is

[3] Both of these items are part of the evidence in Enbridge Gas's rebasing proceeding (EB-2022-0200), which is active at the time of writing. OEB staff's acknowledgement of their importance for the IRP Framework should not be interpreted as taking a position on the substance of Enbridge's actions and proposals as they relate to the approvals requested in the rebasing proceeding.

	learning from its pilots, and how this has informed Enbridge's planning determinations. • **Scope of Input on Enbridge Gas's IRP Activities by the IRP Working Group:** In last year's comments, OEB staff noted a concern that the Working Group had not been provided with substantive advance details of IRP-related proposals in Enbridge Gas's rebasing application, and that any review by the Working Group in advance of Enbridge Gas's filing would be quite limited. This proved to be true, with limited consideration by the Working Group of some aspects after the filing of the rebasing application (e.g., IRP screening process applied to the Asset Management Plan), and no consideration of others (e.g., interruptible rate design). OEB staff recognizes that the timing of the rebasing application made it difficult for Enbridge Gas to seek advance input from the Working Group on all IRP-related proposals; going forward, OEB staff encourages Enbridge Gas to broadly share information on IRP-related developments with the Working Group, and work collaboratively with the Working Group to identify and prioritize areas where Working Group input at early stages will add the most value. • **2023 Priorities:** OEB staff generally agrees with the 2023 IRP priorities identified by Enbridge Gas. In particular, OEB staff agrees with the Working Group that understanding, refining, and improving the evaluation process used by Enbridge as it continues its IRP evaluations of system needs in the Asset Management Plan should be a high-priority item for Enbridge Gas and for the Working Group. Among the list of items in the IRP decision that were not identified as 2023 priorities by Enbridge Gas, OEB staff also believes that some consideration of performance metrics for IRP (at the level of an individual IRP Plan or for Enbridge's system-wide use of IRP) by Enbridge Gas and the Working Group may be valuable. This could include consideration of the metrics for non-wires alternatives discussed in the OEB's Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as Non-Wires Alternatives, and whether they are applicable or useful for natural gas IRP.

Table 3: Comments of Enbridge Gas IRP Working Group Members

Working Group Member	Comments (optional)
Chris Ripley/ Whitney Wong (Enbridge Gas representatives)	Enbridge Gas values the technical expertise and experience of each IRP TWG member and appreciates that their technical input can help facilitate an effective implementation of the OEB's IRP Decision. Enbridge Gas understands, via discussion at the IRP TWG and from the above noted comments, that TWG members have concerns with the pace by which Enbridge is implementing the IRP Framework Decision, as well as the scope and timing of information that Enbridge Gas has brought forward to the IRP TWG for input. Implementing IRP into a utility's established asset management planning process, as seen across other jurisdictions, is complex and time intensive. Over the course of 2022, Enbridge Gas has worked with the IRP TWG to confirm its IRP Pilots and to evolve the DCF+ Test. In addition, to ensure progress is not slowed, Enbridge has evolved its asset management planning process via the development of draft IRPA assessment processes, and by drafting and trialing stakeholder engagement processes for its seven planning regions. Enbridge believes this progress is reasonable given the many facets of Enbridge's Planning process that must be evolved, and that the advancement has happened in parallel to Enbridge Gas's 2024 Rebasing application and proceeding. In terms of the scope and timing of information that Enbridge Gas has brought forward to the IRP TWG for input, Enbridge has focused its time with the TWG on the areas that the Board noted as a priority, the IRP Pilots and the DCF+ Test. With significant progress made on these initial priorities, Enbridge Gas has highlighted the topics it would like to focus on with the IRP TWG in 2023 and these priorities are aligned with most of the topics that the TWG would like to have input into. There are a number of topics that TWG members would like to discuss that indicates some members view the scope of the TWG as more expansive than what Enbridge Gas understands it to be from the Board's IRP Decision and from the TWG's TOR. Enbridge Gas has included comments below to further address these key concerns as well as other comments that have been noted above.

	2022 IRP TWG Priorities as defined by the IRP Decision and the IRP TWG Terms of reference (TOR)
	The role of the IRP TWG was defined in both the IRP Decision and in the Terms of Reference (TOR). The OEB's IRP Decision indicated that "The OEB expects that the first priorities will be consideration and implementation of the IRP pilot projects, and enhancements or additional guidance in applying the DCF+ evaluation methodology.[4]" These initial priorities were reiterated in the Terms of Reference (TOR), "The OEB expects that the first priorities of the Working Group will be: Consideration of IRP pilot projects to better understand how IRP can be implemented to avoid, delay or reduce facility projects. Enbridge Gas is expected to select and deploy two IRP pilot projects by the end of 2022. Enhancements or additional guidance in using the Discounted Cash Flow-plus economic evaluation methodology to assess and compare the costs and benefits of using either facility solutions or IRP alternatives to meet system needs.[5]" Given this clear direction from the Board, the Pilots and the DCF+ Test have been the initial focus of the TWG and, therefore, what Enbridge has initially focused its TWG content on. In 2022, Enbridge was committed to developing and contributing a great deal of relevant TWG content and to obtaining the expertise of the TWG on these topics. To ensure there was sufficient time allocated to gathering input, Enbridge advocated to move the TWG meetings from monthly to bi-weekly. In addition, as outlined within its 2022 IRP Annual Report, Enbridge has identified new/additional topics that it would like the IRP TWG's input on given the status of the two initial areas of focus. This level of engagement does not align with some of the above noted TWG member comments, most specifically, comments noting that Enbridge treats the TWG process solely as a regulatory requirement. An overview of the work Enbridge Gas undertook in 2022 on the IRP Pilots and the DCF+ Test has been highlighted in its 2022 Annual IRP Report. To address the above noted comments regarding the IRP Pilots, Enbridge has added some additional details below.

[4] EB-2020-0091 Decision and Order, page 7

[5] IRP Working Group - Terms of Reference (oeb.ca)

	<u>*IRP Pilots*</u> In 2022, Enbridge Gas presented and requested input and expertise on a number of specific proposals and concepts related to the IRP Pilot projects, including: pilot objectives, pilot project selection criteria, eight potential pilot projects potential IRP alternatives for the projects and rationale for the selection of the two projects through a decision matrix. Throughout 2022, Enbridge continued to engage the TWG on the pilot projects to discuss the IRP alternatives considered and chosen, pilot budgets, ETEE programming, approach to cost benefit test for the pilot application, pilot stakeholder meeting objectives and outcomes and overall pilot project timing. The TWG reiterated to Enbridge Gas throughout 2022 that Enbridge Gas is responsible for the selection and implementation of the pilot projects. ***Advancing IRP Implementation in Parallel to working through the IRP TWG's Initial Areas of Focus (Pilots and DCF+ Test)*** While the IRP TWG has focused on the Board's initial two priorities, Enbridge Gas has moved other IRP implementation activities forward to ensure progress is not slowed. Working on other activities does not mean that TWG member contributions made in 2023 won't have a meaningful impact as some members have expressed. Rather, it means that Enbridge Gas is in a position to bring forward draft processes, for example the draft technical evaluation process, for both discussion and input. This feedback can and will be considered as these processes have and will continue to be iterative. Some IRP TWG members do not feel Enbridge Gas has moved fast enough with regards to implementing IRP; however, some members also believe that Enbridge Gas has moved things forward without fulsome consultation with the TWG. These two requests, to move more quickly and to bring all IRP activity underway to the IRP TWG would not have been feasible in 2022 given the magnitude of IRP implementation work required and that the IRP TWG had to move to biweekly meetings to create the capacity to address the two areas of focus identified by the Board. A complete list of areas that Enbridge Gas focused on in 2022 has been highlighted in its 2022 Annual IRP Report. To

	address comments made above by IRP TWG members, details regarding some of these areas are noted below. *Stakeholder engagement roll out:* The stakeholder engagement plan is being implemented per the Boards Decision [6]. As outlined in more detail within Enbridge's 2022 Annual IRP Report, Enbridge Gas focused its 2022 stakeholder engagement efforts on building its web page and webinar hosting capabilities, marketing to external stakeholders to garner interest and participation in the IRP / regional planning initiatives and on engaging municipalities to ensure awareness and understanding of IRP. The regional webinar sessions were rolled out in early 2023. TWG members have indicated that they were not invited to these webinars and that it would be helpful if Enbridge maintained a schedule of community engagement activities so that those who wish to attend could do so. As noted in the 2021 Annual Report and as socialized with the TWG during the TWG meetings starting in January 2022, the IRP website is the primary site for all communications related to upcoming IRP initiatives, pilot projects, regional webinars and presentations. It was noted in TWG meetings that dates of upcoming sessions would be posted on the web site and that to receive notifications and updates, individuals must register on the site, if not registered an individual would have to check back periodically. The IRP Regional Planning web page can be accessed here: Regional Planning & Engagement | Enbridge Gas Unfortunately, as sometimes happens when new digital initiatives are launched, Enbridge experienced a small technical issue that resulted in seven registrants, including one TWG member, not receiving emails regarding upcoming regional engagement sessions. Once notified of this issue Enbridge was able to rectify the situation immediately. Enbridge notes that although some TWG members have registered on Enbridge Gas's IRP web page no other non-utility TWG members attended the webinars. To ensure those that can't attend the IRP webinars have access to the information presented, the regional

[6] EB-2020-0091 Decision and Order, page 66

	presentations are posted on the IRP web page[7]. These presentations include an overview of Energy Transition to provide context about how Enbridge forecasts and plans its distribution system. Enbridge Gas disagrees with some working group members' comments that the inclusion of content related to Energy Transition is meant to sell more and/or continued use of natural gas, rather Enbridge Gas believes it provides context as to how IRP fits into the Energy Transition. *Ongoing IRP Alternative Assessments:* As noted above, Enbridge Gas has drafted an IRP Technical Assessment process. This draft process was iterated continually as Enbridge moved through its first AMP IRP review process. Despite this process occurring in parallel to the 2024 Rebasing proceeding, Enbridge Gas continued to progress its review and as it was able to provide additional information throughout the rebasing interrogatory and technical conference phase, it did so[8]. Enbridge Gas expects that with each AMP cycle the process will be refined, with input from the TWG and become more seamless and less time intensive. *Non-Pilot IRP Plans* In moving through its first IRP Alternative Assessment process Enbridge identified and implemented its first feasible IRPA, the Kingston Creekford project, as outlined in the 2022 Annual Report Section 6 – Non–Pilot IRP Plan Updates and in Enbridge Gas' 2022 Annual Deferral Disposition proceeding, Exhibit c, Tab 1. Some TWG members have noted that they were not, and had expected to be, made aware of the Kingston Creekford IRPA prior to its implementation. Enbridge Gas agrees that when identified IRPAs include new or unusual circumstances or technical considerations it would benefit from consultation with the IRP TWG. Enbridge Gas notes, however, that the Kingston project's IRP alternatives evaluation and implementation were straightforward. Enbridge Gas agrees with TWG members' comments regarding continuing to make progress on non-pilot IRP Plans

[7] Regional sessions were held on April 4, 6, 11, 13, 18, 25 and May 4, 2023 Regional Planning & Engagement | Enbridge Gas

[8] Section 3 – Integrated Resource Planning Alternatives (IRPAs) Evaluation and Asset Management Plan (AMP) Update & EB-2022-0200 Exhibit I.2.6-STAFF-81

	in parallel to the deployment of the IRP Pilots. Enbridge Gas has reviewed its 2023-2032 Asset Management Plan and is actively evaluating non-pilot IRP Plans. Enbridge Gas will continue to review facility projects for IRP alternatives and will engage the TWG on new technical issues. *Jurisdictional scan* Enbridge continues to monitor Natural Gas IRP in other jurisdictions on an ongoing basis to inform its own IRP progress. In 2022 Enbridge shared a jurisdictional review it had commissioned on ETEE / DR NG IRP programs with the TWG. Enbridge will continue to share any IRP learnings from other jurisdictions with the TWG and looks forward to further contribution from TWG members on any insights they have from other areas. Enbridge Gas notes that in moving these other areas of focus forward it has fulfilled the directives as outlined by the Board in its Decision, the status of which can be found in the 2022 Annual Report Appendix A: OEB IRP Directives. ***Scope of the IRP TWG 2023+*** Finally, comments received from IRP TWG indicate that some members view the scope of the IRP TWG as more expansive than what Enbridge Gas understands it to be from the Board's IRP Decision and from the TWG's TOR. The IRP Decision and the TWG TOR both note that the TWG's initial priority areas of focus are the Pilots and the DCF+ Test; other potential areas of focus for the Working Group may include addressing: • Learnings from natural gas IRP in other jurisdictions • Performance metrics for IRP • Accounting treatment of IRP costs • Treatment of stranded assets in system planning • Other activities relevant to the IRP Framework, as identified by the Working Group or as directed by the OEB[9] Some working group members have indicated that they interpret this list to include areas such as consultation and input into Enbridge Gas's hiring of IRP employees and the

[9] IRP Working Group - Terms of Reference (oeb.ca)

	associated staffing/organizational structure, internal strategic planning, review and input into each project within the AMP, and consultation on Enbridge Gas's broader demand forecast process; which was identified in the IRP Decision as a topic best addressed in the Rebasing proceeding[10]. Enbridge Gas, however, understands the IRP Decision and TOR to scope the IRP TWG's initial areas of focus to the Pilots and the DCF+ Test, and that other potential areas of focus would be those clearly defined items noted above, as well as processes and approaches that are new for Enbridge Gas as a result of the IRP Decision (e.g. technical evaluation, economic analysis / use of the DCF+ Test, IRP stakeholder engagement etc.) that benefit from the broad technical expertise of the TWG. It is important to note, that the topics that Enbridge Gas has highlighted as 2023 TWG priorities are aligned with most of the topics that TWG members have said that they would like to have input into. This illustrates that, contrary to some IRP TWG comments noted above, that Enbridge Gas is not opposed to, and values, the IRP TWG's expertise and insight in these areas.

[10] EB-2020-0091 Decision page 4

3. Description of Other Key Activities to Date

In accordance with the IRP decision, the Working Group's *Terms of Reference* confirmed the consideration of IRP pilot projects and guidance on the DCF+ economic evaluation methodology as the highest initial priorities for the Working Group (in addition to the review of Enbridge Gas's annual IRP report). The Working Group's efforts over the previous year focused primarily on these two items.

A high-level summary is provided below - refer to the Meeting Folders on the Engage with Us (EwU) IRP webpage[11] for meeting materials and meeting notes summarizing key discussion points and outcomes.

Consideration of IRP pilot projects to better understand how IRP can be implemented to avoid, delay or reduce facility projects.

Per the IRP Framework, Enbridge Gas is expected to develop and implement two IRP pilot projects. The pilots are expected to be an effective approach to understand and evaluate how IRP can be implemented to avoid, delay or reduce facility projects. The IRP Framework indicated that the OEB expects that the IRP pilot projects will be selected and deployed by the end of 2022.

The Working Group had several meetings to provide input to Enbridge Gas on the objective of the pilots, criteria to be used to select and prioritize pilots, and types of IRP alternatives (IRPAs) that should be of priority to test and learn from the pilots. IRPAs of notable interest to the Working Group include enhanced targeted energy efficiency (ETEE), peak shaving supply-side IRPAs including compressed or renewable natural gas (CNG or RNG) as a bridging solution, and demand response (DR) programs and/or interruptible rates focused on general service customer's heating loads and/or larger contract customers. After considering the Working Group's input, Enbridge Gas identified potential pilot areas based on specific system needs identified in its Asset Management Plan. Eight potential pilot areas were presented to the Working Group with an evaluation matrix of Enbridge Gas's ranking and weighting of criteria for each option. The Working Group provided input on the options presented by Enbridge Gas and this led to Enbridge Gas's decision to select:

[11] https://engagewithus.oeb.ca/irp

- Pilot # 1 Southern Lake Huron Pilot (a portfolio option targeting a larger area to offer a suite of IRPAs (ETEE and DR program)).
- Pilot #2 Parry Sound Pilot (a single option to address a specific need in a specific area (geotargeted ETEE and CNG as a bridging solution)).

Once Enbridge Gas determined which two pilot areas to proceed with, the Working Group had several meetings to provide input on Enbridge Gas's development of the pilot design and budget. Matters discussed included selection of specific energy efficiency measures/technologies; best practices and considerations regarding forecasting program participation and peak demand impact (including consideration of the use of derating factors, and the methodology for assessing peak demand impact developed for Enbridge Gas by Posterity Group), budgeting, and stakeholdering; mechanisms to potentially increase program uptake; collection of timely and sufficient baseline data using viable technologies; cost-effectiveness considerations including whether and how to use the DCF+ test; and tracking the effectiveness of the pilot program through monitoring, evaluation, and an audit plan. Throughout the year, members shared their experience, expertise, and research on the topics discussed during Working Group meetings and at individual member discussions when requested by Enbridge Gas. Enbridge Gas was also encouraged to reference previous pilots and IRP efforts in other jurisdictions for learnings. Members provided various examples and information sources like Con Edison, National Grid and Northwest Natural pilots they thought would be of value to Enbridge Gas.

In December 2022, Enbridge Gas filed a letter to inform the OEB that it would not be in a position to file a pilot application by the end of 2022, and anticipated filing an application in early 2023. At the time of writing, the Working Group is in the final stages of reviewing Enbridge Gas's pilot proposals, after which a pilot application is expected to be filed with the OEB by Enbridge Gas.

Enhancements or additional guidance in using the Discounted Cash Flow-plus economic evaluation methodology to assess and compare the costs and benefits of using either facility solutions or IRP alternatives to meet system needs.

Per the IRP Framework, a three-phase discounted cash flow-plus (DCF+) test was established as the economic evaluation that will be used to compare the costs and benefits of different approaches to meeting system need (IRP alternatives, facility alternatives, or a combination). The OEB concluded that the DCF+ test could be improved to better identify and define the costs and benefits of Facility Alternatives and IRP Alternatives, and clarify how these costs and benefits should be considered within the DCF+ test. This could include expanding the inputs to recognize increasing carbon costs, the risk that a constraint remains unresolved, and impact on gas supply costs. Enbridge Gas was directed to study improvements to the DCF+ test, and encouraged to consult with the Working Group, and use the IRP pilot projects as a testing ground. Enbridge Gas was directed to file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan.

The Working Group made significant progress in providing Enbridge with suggestions to arrive at an enhanced DCF+ test, resulting in a Working Group report, *Report of the IRP Working Group on the Discounted Cash Flow-Plus Test*, finalized and made public in May 2023.

Starting July 2022, a DCF+ subgroup was formed to focus discussions on this subject matter. During the first few meetings, the agenda was set out to address some foundational issues. This included defining the purpose of each phase, aligning categories of cost and benefits with the purpose of each phase, and addressing the concept of additivity of phases in conjunction with interpreting and assigning value to the results of the different phases. The DCF+ subgroup then examined more specific issues, such as the valuation of specific categories of cost and benefits like greenhouse gas emissions, gas supply costs, risk that a constraint remains unresolved, the cost impact of other energy sources including electricity, and the treatment of non-energy benefits, including the question of monetizing such impacts versus qualitative consideration. Throughout these meetings, members shared their knowledge and expertise including a second presentation done by Working Group member and cost-effectiveness expert Chris Neme on demand related commodity price effects and risk. The subgroup also provided suggestions for improvement of a simplified DCF+ sample calculation prepared by Enbridge Gas and provided input on Guidehouse's recommendations to Enbridge Gas on matters like how to quantify and account for non-energy benefits.

Although consensus could not be reached for all items discussed during subgroup meetings, documentation of differing perspectives along with any items where consensus was reached have been captured in the Working Group's DCF+ Report. The next step will be for Enbridge Gas to develop an enhanced DCF+ Test and accompanying handbook, giving consideration to the perspectives noted in the Working Group's DCF+ Report. Enbridge Gas will then file the enhanced DCF+ test for approval with the OEB, as part of its first non-pilot IRP Plan application, as required by the IRP Decision.

Other IRP Items Discussed by the Working Group: Apart from the two pilots and enhancements to the DCF+ test, the IRP Working Group briefly discussed some additional matters in 2022 related to Enbridge Gas's overall approach to identifying system needs and considering IRP alternatives, including Enbridge's approach to developing system reinforcement plans (including the approach to customer forecasting and the degree to which hydraulic modeling is used), and the evolution of its approach to binary screening and technical evaluation of IRP alternatives for identified system needs in its Asset Management Plan. As discussed in the next section, it is expected that some of these issues will receive further consideration by the Working Group in 2023.

4. IRP Priorities and Working Group Activities in 2023

The Working Group's role on its initial priority items (DCF+ test and pre-application review of pilots) is nearly complete. In May 2023, the Working Group held a preliminary discussion of subsequent priorities for implementation of the IRP Framework in 2023, and the role the Working Group should have. Several members also made suggestions for 2023 priorities in their individual comments (chapter 2).

The Working Group gave consideration to the activities Enbridge Gas identified as priorities in its annual IRP report:

- External stakeholder outreach (including broader discussions with municipalities and municipal organizations, collaboration with IESO on best practices, regional engagement sessions, and geotargeted engagement in pilot areas)
- IRP evaluations of system needs in Asset Management Plan through technical and economic evaluation process
- DCF+ Test (submission as part of first non-pilot IRP proceeding)
- Pilot projects (regulatory review and implementation)

Of Enbridge Gas's identified 2023 priorities, the Working Group agreed that understanding, refining, and improving the evaluation process used in Enbridge Gas's IRP evaluations of system needs in its Asset Management Plan should be a high-priority item for the Working Group. Several members expressed an interest in considering the approach to demand forecasting and energy transition assumptions that is embedded in the IRP assessment process. The Working Group also agreed that the stakeholder outreach process is an important IRP priority for Enbridge Gas. Enbridge Gas is seeking advice from other organizations in developing the stakeholder outreach process, so the Working Group's role may be more limited, but there could still be opportunities for the Working Group to add value. The Working Group also generally agreed that, as Enbridge Gas works towards its identified 2023 IRP priorities, Enbridge Gas should engage the Working Group earlier in the decision-making process, rather than as a group to report out to, to make better use of the Working Group's expertise.

The Working Group also considered the other potential areas of work for the Working Group that were identified in the IRP Decision and the Working Group Terms of Reference:

- Learnings from natural gas IRP in other jurisdictions
- Performance metrics for IRP
- Accounting treatment of IRP costs
- Treatment of stranded assets in system planning
- Other activities relevant to the IRP Framework, as identified by the Working Group or as directed by the OEB

At the May 2023 Working Group discussion and in written comments, some interest was expressed in the following topics: learnings from other jurisdictions, performance metrics and incentives/penalties for IRP, expanding the list of technologies/solutions that are considered as IRP Alternatives, and how broader co-ordination of gas and electricity planning may affect IRP. There was insufficient time to discuss these additional topics in depth at the initial meeting. While there were no specific work products/deliverables identified by the Working Group or Enbridge Gas related to these additional topics at this time, this is likely to change.

OEB staff will work with Enbridge Gas to develop an updated Work Plan for the Working Group, based on 2023 priorities, to outline workstreams and expected timing of key deliverables.