ENBRIDGE

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May 31, 2024

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-2024-0125
2023 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 2023 utility earnings and the disposition and recovery of certain 2023 deferral and variance account balances (the Application) for all Enbridge Gas rate zones.

Included with the application, Enbridge Gas is providing the OEB Scorecard and the Indigenous Working Group Report. No approval is being sought regarding these items.

Enbridge Gas is providing notification to the OEB that Exhibit H, the Integrated Resource Planning (IRP) Annual Report and the IRP Technical Working Group Report, will be filed separately. As per the OEB Decision and Order in the IRP Framework proceeding (EB-2020-0091), no approval is being sought regarding these reports. Enbridge Gas expects to file all the IRP Reports by early July.

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: Reports

Enbridge Gas proposes to dispose of the approved 2023 deferral and variance account balances with the first QRAM application following the OEB's approval, which is assumed to be January 1, 2025.

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 2022 Deferral & Variance Account Balances Application (see EB-2023-0092 Decision on Confidentiality, September 20, 2023).

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,

Richard Wathy

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		2023 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 , Rate Class and Service Class
		2	Customer Meters, Volumes and Revenues By Rate Class
		3	Revenue from Regulated Storage and Transportation of Gas
		4	Utility Other Revenue and Other Income

B- Utility Results and Earning Sharing

C- Enbridge Gas Inc Deferral and Variance Accounts

D - EGD Rate Zone Deferral and Variance Accounts

D - EGD Rate Zone Deferral and Variance Accounts

E – Union Rate Zones Deferral and Variance Accounts

F – Rate Allocation

G – OEB Scorecard

H –Reports

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.

<u>1. Earnings Sharing</u>

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 2023, 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.

<u>2. Enbridge Gas Inc.</u>

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. As 2023 is the last year of the deferred rebasing term, Enbridge Gas seeks approval to clear the final balances of certain Enbridge Gas deferral and variance accounts for 2023 as set out at Exhibit C, Tab 1, Schedule 1.

<u>3. EGD Rate Zone</u>

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

8. Enbridge Gas seeks approval to clear the final balances of certain EGD rate zone deferral and variance accounts for 2023 as set out at Exhibit C, Tab 1, Schedule 1.

4. Union Rate Zones

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

10. Enbridge Gas seeks approval to clear the final balances of certain Union rate zones deferral and variance accounts for 2023 as set out at Exhibit C, Tab 1, Schedule 1.

5. Relief Requested

11. 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 2023 deferral and variance accounts requested in Exhibit C, Tab 1, Schedule 1. This includes final disposition of certain accounts previously cleared on an interim basis. 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, 2025.

12. In conjunction with Enbridge Gas's proposed Fugitive Emissions Investigation Plan described at Exhibit D, Enbridge Gas requests approval of the new Fugitive Emissions Measurement Administration Deferral Account at Exhibit D, Attachment 2.

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:

The Applicant:

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 –

<u>The Applicant's counsel</u>:

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: May 31, 2024, at Chatham, Ontario

ENBRIDGE GAS INC.

Richard Wathy

Richard Wathy
Technical Manager, Regulatory Applications

2023 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 2023 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 2023 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: 2023 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: Reports

3. Enbridge Gas proposes that the impacts which result from the disposition of 2023 deferral and variance account balances be implemented with the first available QRAM application following the OEB's approval, as early as January 1, 2025, 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 2023 deferral and variance accounts. The balances of the 2023 deferral and variance accounts are set out at Exhibit C, Tab 1,

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

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 2023 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 2023 deferral and variance accounts as a one-time adjustment for all customers. Enbridge Gas proposes to dispose of the 2023 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 2025 bills that customers receive in February 2025.

3. 2021 and 2022 UFG-related Deferral and Variance Accounts final disposition

10. As part of both the 2021 (EB-2022-0110) and 2022 (EB-2023-0092) OEB-approved Deferral and Variance Account settlement agreements, UFG-related accounts were disposed of on an interim basis, as Enbridge Gas committed to providing additional information. Commitments made in the EB-2022-0110 settlement agreement with regards to UFG-related deferral and variance accounts were addressed in evidence filed in EB-2023-0092. In its submission on the EB-2023-0092 settlement agreement, OEB staff noted they were satisfied with Enbridge Gas's provision of this information in accordance with its commitments in the OEB-approved 2021 Deferral and Variance Account settlement proposal.

11. Included in this application, in Exhibit D, is the additional information Enbridge Gas has committed to filing as part of the EB-2023-0092 settlement agreement with regards to UFG-related deferral and variance accounts.

12. Having met the commitments of the 2021 and 2022 OEB-approved Deferral and Variance Account settlement agreements, Enbridge Gas requests that the prior interim dispositions of the 2021 and 2022 UFG-related deferral and variance accounts be declared final.

4. Deferral and Variance Account request

13. In the EB-2022-0200 OEB-approved settlement agreement (Phase 1, Rebasing Application), Enbridge Gas committed to providing a robust investigation plan related to fugitive emissions for consideration and determination in the 2023 deferral and variance account proceeding. Enbridge Gas has provided a robust Fugitive Emissions Investigation Plan, within Exhibit D. Assuming that Enbridge Gas will move forward with implementation of the Fugitive Emissions Investigation Plan, Enbridge Gas requests OEB approval to establish the Fugitive Emissions Measurement Administration Deferral Account to capture incremental costs incurred. The draft deferral account has been provided at Exhibit D, Attachment 2.

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, 2025			
	EGD Rate Zone Commodity Related Accounts						
1.	Storage and Transportation D/A	2023 S&TDA		18,705.8	1,572.8	20,278.6	D-1, Page 1
2.	Transactional Services D/A	2023 TSDA		(41,738.1)	(2,291.5)	(44,029.6)	D-1, Page 2
3.	Unaccounted for Gas V/A	2023 UAFVA		(6,922.7)	(266.5)	(7,189.2)	D-1, Page 5
4.	Total Commodity Related Accounts			(29,955.0)	(985.2)	(30,940.2)	
	EGD Rate Zone Non Commodity Related Accounts						
5.	Average Use True-Up V/A	2023 AUTUVA		14,307.1	785.5	15,092.6	D-1, Page 69
6.	Gas Distribution Access Rule Impact D/A	2023 GDARIDA		-	-	-	D-1, Page 79
7.	Deferred Rebate Account	2023 DRA		2,132.7	187.1	2,319.8	D-1, Page 71
8.	Transition Impact of Accounting Changes D/A	2023 TIACDA		-	-	-	D-1, Page 79
9.	Electric Program Earnings Sharing D/A	2023 EPESDA		-	-	-	D-1, Page 79
10.	Open Bill Revenue V/A	2023 OBRVA		-	-	-	D-1, Page 79
11.	Ex-Franchise Third Party Billing Services D/A	2023 EFTPBSDA		-	-	-	D-1, Page 79
12.	OEB Cost Assessment V/A	2023 OEBCAVA		3,732.8	302.1	4,034.9	D-1, Page 72
13.	Dawn Access Costs D/A	2023 DACDA		-	-	-	D-1, Page 79
14.	Incremental Capital Module D/A - EGD	2020-2023 ICMDA		(4,909.0)	(232.4)	(5,141.4)	D-1, Page 75
15.	RNG Injection Service V/A	2022-2023 RNGISVA		(331.5)	(28.7)	(360.2)	D-1, Page 77
16.	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Differential V/A	2023 P&OPEBFAVACPDVA		-	-	-	D-1, Page 79
17.	Total EGD Rate Zone (for clearance)			(15,022.9)	28.4	(14,994.5)	
	Union Rate Zones Gas Supply Accounts	OEB Account Number					
18.	Upstream Transportation Optimization	179-131	2023	8,087.2	444.0	8,531.2	E-1, Page 6
19.	Spot Gas Variance Account	179-107	2023	-	-	-	E-1, Page 55
20.	Unabsorbed Demand Costs Variance Account	179-108	2023	41.5	37.8	79.3	E-1, Page 1
21.	Base Service North T-Service TransCanada Capacity	179-153	2023	79.0	5.6	84.6	E-1, Page 45
22.	Total Gas Supply Accounts			8,207.7	487.4	8,695.1	
	Union Rate Zones Storage Accounts						
23.	Short-Term Storage and Other Balancing Services	179-70	2023	1,637.5	89.9	1,727.4	E-1, Page 8
	Union Rate Zones Other Accounts						
24.	Normalized Average Consumption	179-133	2023	(3,650.8)	(201.3)	(3,852.1)	E-1, Page 4
25.	Deferral Clearing Variance Account	179-132	2023	3,372.3	184.5	3,556.8	E-1, Page 19
26.	OEB Cost Assessment Variance Account	179-151	2023	1,630.3	131.1	1,761.4	E-1, Page 42
27.	Unbundled Services Unauthorized Storage Overrun	179-103	2023	-	-	-	E-1, Page 55
28.	Gas Distribution Access Rule Costs	179-112	2023	-	-	-	E-1, Page 55
29.	Conservation Demand Management	179-123	2023	-	-	-	E-1, Page 55
30.	Parkway West Project Costs	179-136	2023	(696.4)	(48.7)	(745.1)	E-1, Page 20
31.	Brantford-Kirkwall/Parkway D Project Costs	179-137	2022	(3.1)	(0.3)	(3.4)	E-1, Page 23
32.	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	179-142	2023	267.8	10.3	278.1	E-1, Page 33
33.	Lobo D/Bright C/Dawn H Compressor Project Costs	179-144	2023	66.0	(39.5)	26.5	E-1, Page 37
34.	Burlington-Oakville Project Costs	179-149	2023	(43.3)	(3.1)	(46.4)	E-1, Page 40
35.	Panhandle Reinforcement Project Costs	179-156	2023	(1,884.1)	(145.9)	(2,030.0)	E-1, Page 46
36.	Sudbury Replacement Project	179-162	2023	-	-	-	E-1, Page 55
37.	Parkway Obligation Rate Variance	179-138	2023	-	-	-	E-1, Page 55
38.	Unauthorized Overrun Non-Compliance Account	179-143	2023	(45.5)	(4.3)	(49.8)	E-1, Page 36
39.	Incremental Capital Module D/A - UGL	179-159	2019-2023	(383.7)	(504.0)	(887.7)	E-1, Page 52
40.	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Differential V/A	179-157	2023	-	(6,207.7)	(6,207.7)	E-1, Page 49
41.	Unaccounted for Gas Volume Variance Account	179-135	2023	-	-	-	E-1, Page 25
42.	Unaccounted for Gas Price Variance Account	179-141	2023	(629.1)	(132.3)	(761.4)	E-1, Page 30
43.	Total Other Accounts			(1,999.6)	(6,961.2)	(8,960.8)	
44.	Total Union Rate Zones (for clearance)			7,845.6	(6,383.9)	1,461.7	
	EGI Accounts						
45.	Earnings Sharing D/A	179-382	2023	-	-	-	C-1, Page 1
46.	Tax Variance - Accelerated CCA - EGI	179-383	2023	(28,483.3)	(2,715.0)	(31,198.3)	C-1, Page 11
47.	IRP Operating Costs Deferral Account	179-385	2023	3,081.2	247.3	3,328.5	C-1, Page 14
48.	IRP Capital Costs Deferral Account	179-386	2023	-	-	-	C-1, Page 22
49.	Green Button Initiative D/A	179-387	2023	-	-	-	C-1, Page 1
50.	Cloud Computing Implementation Costs D/A	179-332	2023	-	-	-	C-1, Page 1
51.	Getting Ontario Connected V/A	179-324	2023	31,902.6	1,736.2	33,638.8	C-1, Page 23
52.	Expansion of Natural Gas Distribution Systems V/A	179-380	2023	-	-	-	C-1, Page 1
53.	Accounting Policy Changes D/A - Other - EGI	179-381	2019-2023	5,511.3	36.2	5,547.5	C-1, Page 2
54.	Impacts Arising from the COVID-19 Emergency D/A - EGI	179-384	2020-2021	-	-	-	C-1, Page 1
55.	Total EGI Accounts (for clearance)			12,011.8	(695.3)	11,316.5	
56.	Total Deferral and Variance Accounts (for clearance)			4,834.5	(7,050.9)	(2,216.4)	

2023 ENBRIDGE GAS INC. EARNINGS SHARING AMOUNT AND DETERMINATION PROCESS

1. For the year ended December 31, 2023, 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 earnings sharing mechanism (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 utility's 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, $795.2 million (Line 4) divided by the level of utility rate base, $15,858.9 million (Line 5) generates a utility return on rate base of 5.014% (Line 6).

7. When compared to the Company's required rate of return for ESM determination, of 6.637% (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 1.623% (Line 8) on total rate base.

8. As shown in Lines 9 through 11, the deficiency of 1.623% multiplied by the rate base of $15,858.9 million, produces a net under earnings or deficiency of $257.4 million, which from a pre-tax perspective ($257.4 million divided by the reciprocal, 73.5%, of the corporate tax rate which is 26.5%), results in a $350.2 million gross amount of under earnings, and therefore nothing to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

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

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

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

10. The $834.6 million (Line 14) of utility income before income tax, less utility taxes of $39.4 million (Line 19), produces the $795.2 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) $795.2 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 $362.7 million, shown at Line 20.

13. The $362.7 million, divided by the deemed common equity level of $5,709.2 million (Line 21, calculated as 36% of the $15,858.9 million rate base) produces a return on equity of 6.352% (Line 23). When comparing the 6.352% achieved return on equity to the threshold ROE percentage of 10.860% (Line 22), which is the OEB-approved formula return on equity for 2023 of 9.360% plus the 150 basis point deadband before sharing, there is a deficiency in ROE of 4.508% (Line 24).

14. The 4.508% multiplied by the common equity level of $5,709.2 million (Line 21) produces a net under earnings or deficiency of $257.4 million, which from a pre-tax perspective ($257.4 million divided by the reciprocal, 73.5%, of the corporate tax rate), results in a $350.2 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 the 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 on December 31, 2023

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)	834.6
3	Less: Income Taxes	(Ex. B, Tab 1, Sch. 3)	39.4
4	Utility Income		795.2
5	Utility Rate Base	(Ex. B, Tab 1, Sch. 4)	15,858.9
6	Indicated Return on Rate Base %	(line 4 / line 5)	5.014%
7	Less: Required Rate of Return %	(Ex. B, Tab 1, Sch. 5)	6.637%
8	(Deficiency) / Sufficiency %		-1.623%
9	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	(257.4)
10	Provision for Income Taxes		(92.8)
11	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	(350.2)
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)	834.6
15	Less: Long Term Debt Costs	(Ex. B, Tab 1, Sch. 5)	399.7
16	Less: Short Term Debt Costs	(Ex. B, Tab 1, Sch. 5)	32.9
17	Less: Cost of Preferred Capital	(Ex. B, Tab 1, Sch. 5)	0.0
18	Net Income before Income Taxes		402.1
19	Less: Income Taxes	(Ex. B, Tab 1, Sch. 3)	39.4
20	Net Income Applicable to Common Equity	(line 18 - line 19)	362.7
21	Common Equity	(Ex. B, Tab 1, Sch. 5)	5,709.2
22	Approved ROE (including deadband before earning sharing) %	(Board-approved + 150bp)	10.860%
23	Achieved Rate of Return on Equity %	(line 20 / line 21)	6.352%
24	Resulting (Deficiency) / Sufficiency in Return on Equity %		-4.508%
25	Net Earnings (Deficiency) / Sufficiency	(line 21 x line 24)	(257.4)
26	Provision for Income Taxes		(92.8)
27	Gross Earnings (Deficiency) / Sufficiency	(line 25 / 73.5%)	(350.2)
28	50% Earnings sharing to ratepayers	(if line 27 > 1, line 27 x 50%)	-

EGI Utility Income
2023 Actual

Line No.		Reference	Col. 1 Corporate (a)	Col. 2 Unregulated Operations (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)	5,398.3	-	(32.6)	(i)	5,365.7
2	Transportation	(Ex. B, Tab 2, Sch. 3)	140.4	(0.4)	(0.8)	(ii)	140.0
3	Storage	(Ex. B, Tab 2, Sch. 3)	215.2	208.3	(0.3)	(iii)	6.5
4	Other operating revenue	(Ex. B, Tab 2, Sch. 4)	76.6	3.6	(15.2)	(iv)	57.8
5	Other income	(Ex. B, Tab 2, Sch. 4)	11.1	1.4	(2.6)	(viii)	7.1
6	Total operating revenue		5,841.6	212.8	(51.5)		5,577.1
7	Gas costs		2,873.4	70.7	(15.3)	(i)	2,787.4
8	Operation and maintenance	(Ex. B, Tab 3, Sch. 1)	1,303.2	24.1	(170.3)	(v)	1,108.8
9	Depreciation and amortization expense		756.6	19.5	(22.5)	(vi)	714.6
10	Fixed financing costs		4.0	-	2.8	(vii)	6.8
11	Municipal and other taxes		126.3	1.5	-		124.8
12	Cost of service		5,063.5	115.8	(205.2)		4,742.5
13	Utility income before income taxes						834.6
14	Income tax expense	(Ex. B, Tab 1, Sch. 3)					39.4
15	Utility income						795.2

Notes on Adjustments:

(i)	Reclassification of Union rate zone optimization revenue as a cost of gas reduction	(15.3)
	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues	(17.3)
		(32.6)
(ii)	Elimination of the Union rate zone shareholder portion of net optimization activity (before tax)	(0.8)
(iii)	Elimination of the Union rate zone shareholder portion of net short-term storage revenue (before tax)	(0.3)
(iv)	Adjust EGD rate zone OBA costs to reflect EB-2013-0099 approved unit costs agreed to be used for determining net revenue	(4.2)
	Elimination of EGD rate zone Open Bill shareholder incentive	0.4
	Elimination of EGD rate zone shareholder portion of transactional service revenues	(5.7)
	Elimination of demand-side management incentive	(5.0)
	Elimination of EGD rate zone net revenue from ABC T-service, considered to be non-utility	(0.8)
		(15.2)
(v)	Elimination of donations	(2.6)
	Elimination of Central Functions Corporate Allocation Methodology (CFCAM) charges	(11.2)
	Elimination of non-utility costs to support the EGD ABC T-Service program	(0.3)
	Elimination of pension impairment charge (Phase 1 Decision EB-2022-0200)	(156.1)
		(170.3)
(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	2.8
(viii)	Elimination of interest income from investments not included in utility rate base	(0.7)
	Elimination of interest income from affiliates	(1.8)
	Elimination of the revenue indemnification received from Enbridge Inc. related to a non-utility Corporate tax planning Part VI.1 tax transfer to EGI	-
		(2.6)

Calculation of EGI Utility Taxable Income and Income Tax Expense
2023 Actual

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1	Utility income before income taxes	834.6	834.6	
	Add			
2	Depreciation and amortization	714.6	714.6	
3	Accrual based pension and OPEB costs	7.3	7.3	
4	Other non-deductible items	130.1	130.1	
5	Total Add Back	852.1	852.1	
6	Sub-total	1,686.7	1,686.7	
	Deduct			
7	Capital cost allowance	878.7	878.7	
8	Items capitalized for regulatory purposes	207.3	207.3	
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	1.3	1.3	
12	Cash based pension and OPEB costs	18.0	18.0	
13	Total Deduction	1,105.4	1,105.4	
14	Taxable income	581.3	581.3	
15	Income tax rates	15.00%	11.50%	
16	Tax provision excluding interest shield	87.2	66.9	154.1
	Tax shield on interest expense			
17	Rate base	15,858.9		
18	Return component of debt	2.73%		
19	Interest expense	432.5		
20	Combined tax rate	26.50%		
21	Income tax credit			(114.6)
22	Total utility income taxes			39.4

EGI Utility Rate Base
2023 Actual

Line No.		Col. 1 2023 Actual	Col. 2 2022 Actual
		($Millions)	($Millions)
	Property, Plant, and Equipment		
1	Gross property, plant, and equipment	23,740.4	22,585.9
2	Accumulated depreciation	(8,748.0)	(8,320.1)
3	Net property, plant, and equipment	14,992.4	14,265.9
	Allowance for Working Capital		
4	Materials and supplies	110.9	102.6
5	ABC receivable	(22.1)	(19.4)
6	Customer security deposits	(59.7)	(61.0)
7	Prepaid expenses	7.2	6.1
8	Balancing gas	59.5	59.5
9	Gas in storage	748.6	1,005.1
10	Working cash allowance	22.1	22.6
11	Total Working Capital	866.5	1,115.5
12	Utility Rate Base	15,858.9	15,381.4

EGI Utility Property, Plant, and Equipment
Summary Statement - Average of Monthly Averages
2023 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	657.0	(170.6)	486.5
2	Distribution plant	10,728.0	(3,509.5)	7,218.5
3	General plant	525.7	(355.3)	170.4
4	Plant held for future use	1.7	(1.5)	0.2
5	EGD Rate Zone Total	11,912.4	(4,036.9)	7,875.5
	Union Rate Zones			
6	Intangible plant	1.7	(1.6)	0.1
7	Local storage plant	33.9	(19.7)	14.2
8	Underground storage plant	826.8	(372.1)	454.7
9	Transmission plant	4,052.8	(1,365.3)	2,687.5
10	Distribution plant - Southern operations	4,098.1	(1,658.9)	2,439.2
11	Distribution plant - Northern and Eastern operations	2,390.3	(1,097.8)	1,292.4
12	General plant	424.5	(195.7)	228.7
13	Union Rate Zones Total	11,828.0	(4,711.1)	7,116.9
14	EGI Total	23,740.4	(8,748.0)	14,992.4

EGI Utility Gross Plant
Year End Balances and Average of Monthly Averages
2023 Actual

Line No.		Col. 1 Opening Balance Dec.2022	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2023	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2023	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	(0.0)	48.9	(1.0)	47.9	47.9
2	Structures and improvements (452)	35.3	0.9	(0.1)	36.2	(0.1)	36.1	35.3
3	Wells (453)	95.8	(0.5)	(0.4)	94.9	-	94.9	94.3
4	Well equipment (454)	14.1	2.6	(0.1)	16.6	-	16.6	16.2
5	Field Lines (455)	134.7	136.2	-	270.9	-	270.9	137.4
6	Compressor equipment (456)	231.5	41.4	-	272.9	(0.5)	272.4	256.3
7	Measuring and regulating equipment (457)	11.2	175.5	-	186.7	-	186.7	37.3
8	Base pressure gas (458)	32.4	-	-	32.4	-	32.4	32.4
9	Sub-Total	603.9	356.1	(0.5)	959.5	(1.5)	958.0	657.0
	EGD Rate Zone Distribution Plant							
10	Renewable Natural Gas (461)	5.2	-	-	5.2	-	5.2	5.2
11	Land (470)	71.2	6.5	(0.5)	77.2	-	77.2	76.1
12	Offers to purchase (470)	-	-	-	-	-	-	-
13	Land rights intangibles (471)	63.8	0.3	-	64.0	-	64.0	63.9
14	Structures and improvements (472)	190.1	5.3	(4.5)	190.9	(0.3)	190.6	190.4
15	Services, house reg & meter install. (473/474)	3,679.5	236.8	(17.4)	3,899.0	-	3,899.0	3,766.0
16	Mains (475)	5,288.4	174.3	(47.6)	5,415.1	(2.2)	5,412.9	5,358.5
17	NGV station compressors (476)	5.2	0.7	-	6.0	-	6.0	5.6
18	Measuring and regulating equip. (477)	685.2	42.9	(2.5)	725.6	(0.5)	725.1	705.3
19	Meters (478)	554.2	37.9	(18.4)	573.8	-	573.8	557.1
20	Sub-Total	10,542.9	504.8	(90.9)	10,956.8	(3.1)	10,953.8	10,728.0
	EGD Rate Zone General Plant							
21	Investment in leased assets (101)	15.3	1.0	-	16.3	-	16.3	15.8
22	Lease improvements (482)	0.1	-	-	0.1	(0.2)	(0.1)	(0.1)
23	Office furniture and equipment (483)	26.9	1.2	(4.8)	23.2	-	23.2	26.7
24	Transportation equipment (484)	73.9	2.5	(0.2)	76.2	(0.1)	76.1	74.3
25	NGV conversion kits (484)	3.1	0.1	-	3.2	-	3.2	3.1
26	Heavy work equipment (485)	26.8	1.6	-	28.4	-	28.4	27.4
27	Tools and work equipment (486)	51.9	0.3	(1.5)	50.7	-	50.7	53.0
28	Rental equipment (487)	2.5	0.3	-	2.8	-	2.8	2.5
29	NGV rental compressors (487)	4.0	(0.0)	-	4.0	-	4.0	3.5
30	NGV cylinders (484 and 487)	0.6	-	-	0.6	-	0.6	0.6
31	Communication structures & equip. (488)	2.0	-	(0.1)	1.8	-	1.8	2.0
32	Computer equipment (490)	0.9	8.2	6.9	16.0	-	16.0	11.9
33	Software Aquired/Developed (491)	230.0	38.1	(134.1)	133.9	-	133.9	199.1
34	CIS (491)	12.2	2.0	(15.3)	(1.2)	-	(1.2)	18.3
35	WAMS (489)	92.0	-	(24.2)	67.9	-	67.9	87.4
36	Sub-Total	542.2	55.2	(173.4)	424.0	(0.3)	423.7	525.7
	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	11,690.7	916.1	(264.8)	12,342.0	(4.8)	12,337.1	11,912.4
	Union Rate Zones Intangible Plant							

EGI Utility Gross Plant
Year End Balances and Average of Monthly Averages
2023 Actual

Line No.		Col. 1 Opening Balance Dec.2022	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2023	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2023	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
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)	5.8	0.1	-	5.9	-	5.9	5.8
44	Gas holders - storage (443)	5.5	0.0	-	5.5	-	5.5	5.5
45	Gas holders - equipment (443)	20.2	0.2	-	20.5	-	20.5	20.3
46	Regulatory Overheads	2.3	0.5	-	2.8	-	2.8	2.4
47	Sub-Total	33.8	0.8	-	34.6	-	34.6	33.9
	Union Rate Zones Underground Storage Plant							
48	Land (450)	11.0	0.0	-	11.0	-	11.0	11.0
49	Land rights (451)	32.0	0.0	-	32.0	-	32.0	32.0
50	Structures and improvements (452)	70.7	0.5	(0.2)	71.0	-	71.0	70.8
51	Wells (453)	49.2	0.5	-	49.8	-	49.8	49.3
52	Field Lines (455)	54.3	5.2	(0.0)	59.5	-	59.5	55.7
53	Compressor equipment (456)	479.1	2.6	-	481.7	-	481.7	480.1
54	Measuring and regulating equipment (457)	63.1	0.3	-	63.5	-	63.5	63.2
55	Base pressure gas (458)	36.2	-	-	36.2	-	36.2	36.2
56	Regulatory Overheads	27.7	2.0	-	29.7	-	29.7	28.4
57	Sub-Total	823.4	11.2	(0.2)	834.4	-	834.4	826.8
	Union Rate Zones Transmission Plant							
58	Land (460)	85.7	(0.2)	-	85.4	-	85.4	85.6
59	Land rights (461)	68.6	(0.2)	-	68.4	-	68.4	68.5
60	Structures & improvements (462/463/464)	168.2	0.2	-	168.5	-	168.5	168.3
61	Mains (465)	2,066.3	17.2	-	2,083.6	-	2,083.6	2,071.9
62	Compressor equipment (466)	958.7	1.8	-	960.6	-	960.6	959.0
63	Measuring & regulating equipment (467)	418.8	12.0	-	430.8	-	430.8	422.2
64	Line Pack Gas	7.2	-	-	7.2	-	7.2	7.2
65	Regulatory Overheads	260.4	28.6	-	289.0	-	289.0	270.1
66	Sub-Total	4,033.9	59.5	-	4,093.4	-	4,093.4	4,052.8
	Union Rate Zones Distribution Plant - Southern Operations							
67	Land (470)	18.5	0.5	(0.3)	18.7	-	18.7	18.5
68	Land rights (471)	10.9	0.5	-	11.4	-	11.4	11.0
69	Structures and improvements (472)	155.8	0.8	(0.8)	155.8	-	155.8	155.9
70	Services - metallic (473)	139.3	4.1	-	143.5	-	143.5	140.4
71	Services - plastic (473)	1,038.5	47.3	-	1,085.8	-	1,085.8	1,061.1
72	Regulators (474)	112.2	8.6	(2.7)	118.1	-	118.1	112.8
73	House regulators & meter installations (474)	89.9	6.7	-	96.6	-	96.6	91.0
74	Mains - metallic (475)	724.6	37.1	-	761.6	-	761.6	730.9
75	Mains - plastic (475)	803.7	38.2	-	841.9	-	841.9	817.4
76	Measuring & regulating equipment (477)	91.3	12.6	-	103.9	-	103.9	93.6
77	Meters (478)	414.3	53.5	(9.4)	458.4	-	458.4	434.8
78	Regulator Overheads	406.6	74.5	-	481.1	-	481.1	430.8
79	Sub-total	4,005.6	284.5	(13.3)	4,276.8	-	4,276.8	4,098.1

EGI Utility Gross Plant
Year End Balances and Average of Monthly Averages
2023 Actual

Line No.		Col. 1 Opening Balance Dec.2022	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2023	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2023	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Union Rate Zones Distribution Plant - Northern & Eastern Operations							
80	Land (470)	6.3	0.3	-	6.6	-	6.6	6.4
81	Land rights (471)	11.3	0.2	-	11.5	-	11.5	11.5
82	Structures and improvements (472)	73.9	0.7	(3.2)	71.5	-	71.5	73.4
83	Services - metallic (473)	113.2	2.3	-	115.5	-	115.5	114.4
84	Services - plastic (473)	521.3	15.5	-	536.8	-	536.8	527.3
85	Regulators (474)	39.4	4.1	(0.6)	42.9	-	42.9	41.3
86	House regulators & meter installations (474)	45.9	0.9	-	46.8	-	46.8	46.3
87	Mains - metallic (475)	795.3	43.3	-	838.5	-	838.5	804.4
88	Mains - plastic (475)	251.2	12.3	-	263.5	-	263.5	252.1
89	Measuring & regulating equipment (477)	161.8	6.9	-	168.7	-	168.7	162.8
90	Meters (478)	108.8	8.9	(2.1)	115.6	-	115.6	110.6
91	Regulator Overheads	238.3	0.5	-	238.8	-	238.8	239.7
92	Sub-total	2,366.9	95.8	(5.9)	2,456.8	-	2,456.8	2,390.3
	Union Rate Zones General Plant							
93	Land (480)	0.5	-	-	0.5	-	0.5	0.5
94	Structures & improvements (482)	98.5	0.1	-	98.5	-	98.5	98.5
95	Office furniture and equipment (483)	7.8	0.0	-	7.8	-	7.8	7.7
96	Office equipment - computers (483)	100.4	6.8	(70.6)	36.7	-	36.7	97.8
97	Transportation equipment (484)	68.5	1.6	(2.4)	67.7	-	67.7	68.3
98	Heavy work equipment (485)	23.8	1.1	(0.1)	24.9	-	24.9	24.1
99	Tools and work equipment (486)	33.4	1.1	-	34.4	-	34.4	33.8
100	NGV fuel equipment (487)	4.5	0.0	-	4.5	-	4.5	4.5
101	Communication equipment (488)	9.3	0.0	(0.2)	9.2	-	9.2	9.3
102	Regulatory Overheads	79.3	3.6	(17.2)	65.6	-	65.6	79.9
103	Sub-total	426.1	14.2	(90.4)	350.0	-	350.0	424.5
104	Union Rate Zones Total	11,691.4	466.0	(109.8)	12,047.7	-	12,047.7	11,828.0
105	EGI Total	23,382.1	1,382.1	(374.6)	24,389.6	(4.8)	24,384.8	23,740.4

EGI Utility Plant
Continuity of Accumulated Depreciation
Year End Balances and Average of Monthly Averages
2023 Actual

Line No.		Col. 1 Opening Balance Dec.2022	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2023	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2023	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)	(27.6)	(0.5)	-	-	(28.1)	-	(28.1)	(27.8)
2	Structures and improvements (452)	(3.4)	(0.6)	-	(0.0)	(4.0)	0.1	(4.0)	(3.7)
3	Wells (453)	(16.9)	(1.4)	0.4	-	(17.9)	-	(17.9)	(17.7)
4	Well equipment (454)	(9.3)	(1.1)	0.1	-	(10.4)	-	(10.4)	(9.9)
5	Field Lines (455)	(35.9)	(2.1)	-	-	(38.0)	-	(38.0)	(36.9)
6	Compressor equipment (456)	(63.0)	(6.0)	-	-	(69.0)	0.3	(68.7)	(65.7)
7	Measuring and regulating equipment (457)	(8.6)	(1.0)	-	-	(9.6)	-	(9.6)	(8.8)
8	Sub-Total	(164.8)	(12.7)	0.5	(0.0)	(177.0)	0.4	(176.6)	(170.6)
	EGD Rate Zone Distribution Plant								
9	Renewable Natural Gas (461)	(0.0)	-	-	-	(0.0)	-	(0.0)	(0.0)
10	Land rights intangibles (471)	(7.2)	(0.8)	-	-	(8.0)	-	(8.0)	(7.6)
11	Structures and improvements (472)	(51.2)	(11.7)	12.9	(11.2)	(61.2)	0.3	(60.8)	(54.3)
12	Services, house reg & meter install. (473/474)	(1,182.5)	(84.2)	17.4	35.2	(1,214.1)	-	(1,214.1)	(1,200.3)
13	Mains (475)	(1,585.2)	(118.5)	11.0	13.7	(1,679.0)	2.2	(1,676.8)	(1,624.7)
14	NGV station compressors (476)	(3.9)	(0.4)	-	-	(4.2)	-	(4.2)	(4.1)
15	Measuring and regulating equip. (477)	(247.4)	(16.1)	2.5	0.4	(260.5)	0.5	(260.0)	(252.7)
16	Meters (478)	(354.3)	(45.1)	18.4	0.0	(381.0)	-	(381.0)	(365.8)
17	Sub-Total	(3,431.7)	(276.7)	62.2	38.2	(3,608.1)	3.1	(3,605.0)	(3,509.5)
	EGD Rate Zone General Plant								
18	Investment in leased assets (101)	(0.4)	(0.5)	-	-	(0.9)	-	(0.9)	(0.6)
19	Lease improvements (482)	(0.1)	-	-	-	(0.1)	0.2	0.1	0.1
20	Office furniture and equipment (483)	(18.3)	(2.2)	0.8	-	(19.8)	-	(19.8)	(18.8)
21	Transportation equipment (484)	(44.1)	(7.9)	0.2	-	(51.8)	0.1	(51.7)	(47.9)
22	NGV conversion kits (484)	(0.1)	(0.3)	-	-	(0.4)	-	(0.4)	(0.3)
23	Heavy work equipment (485)	(7.5)	(1.0)	-	-	(8.6)	-	(8.6)	(8.1)
24	Tools and work equipment (486)	(9.7)	(2.1)	1.5	-	(10.3)	-	(10.3)	(10.5)
25	Rental equipment (487)	(0.1)	(0.0)	-	-	(0.1)	-	(0.1)	(0.1)
26	NGV rental compressors (487)	(3.1)	(2.1)	1.2	-	(4.0)	-	(4.0)	(3.4)
27	NGV cylinders (484 and 487)	(0.6)	(0.0)	-	-	(0.6)	-	(0.6)	(0.6)
28	Communication structures & equip. (488)	(0.1)	(0.2)	0.1	-	(0.1)	-	(0.1)	(0.1)
29	Computer equipment (490)	0.4	(6.1)	(7.4)	-	(13.1)	-	(13.1)	(11.1)
30	Software Aquired/Developed (491)	(199.7)	(53.2)	119.0	-	(133.9)	-	(133.9)	(185.1)
31	CIS (491)	(9.3)	4.7	5.8	-	1.2	-	1.2	(10.6)
32	WAMS (489)	(56.8)	(10.6)	18.5	-	(48.9)	-	(48.9)	(58.2)
33	Sub-Total	(349.5)	(81.6)	139.8	-	(291.3)	0.3	(291.0)	(355.3)
	EGD Rate Zone Plant held for future use								
34	Inactive services (102)	(1.5)	(0.0)	-	-	(1.5)	-	(1.5)	(1.5)
35	EGD Rate Zone Total	(3,947.5)	(371.0)	202.5	38.2	(4,077.9)	3.7	(4,074.2)	(4,036.9)
	Union Rate Zones Intangible Plant								
36	Franchises and consents (401)	(1.0)	(0.1)	-	-	(1.1)	-	(1.1)	(1.1)
37	Other intangible plant (402)	(0.5)	(0.0)	-	-	(0.5)	-	(0.5)	(0.5)
38	Sub-Total	(1.5)	(0.1)	-	-	(1.6)	-	(1.6)	(1.6)

EGI Utility Plant
Continuity of Accumulated Depreciation
Year End Balances and Average of Monthly Averages
2023 Actual

Line No.		Col. 1 Opening Balance Dec.2022	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2023	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2023	Col. 8 Average of Monthly Averages
	Union Rate Zones Local Storage Plant								
39	Structures and improvements (442)	(2.7)	(0.2)	-	-	(2.9)	-	(2.9)	(2.8)
40	Gas holders - storage (443)	(4.1)	(0.1)	-	-	(4.2)	-	(4.2)	(4.1)
41	Gas holders - equipment (443)	(11.7)	(0.7)	-	-	(12.4)	-	(12.4)	(12.1)
42	Regulatory Overheads	(0.6)	(0.1)	-	-	(0.7)	-	(0.7)	(0.7)
43	Sub-Total	(19.1)	(1.1)	-	-	(20.2)	-	(20.2)	(19.7)
	Union Rate Zones Underground Storage Plant								
44	Land rights (451)	(19.4)	(0.7)	-	-	(20.1)	-	(20.1)	(19.8)
45	Structures and improvements (452)	(45.6)	(1.8)	0.2	-	(47.2)	-	(47.2)	(46.5)
46	Wells (453)	(35.4)	(1.2)	-	0.0	(36.6)	-	(36.6)	(36.0)
47	Field Lines (455)	(30.9)	(1.4)	0.0	-	(32.2)	-	(32.2)	(31.6)
48	Compressor equipment (456)	(180.7)	(12.9)	-	0.0	(193.6)	-	(193.6)	(187.1)
49	Measuring & regulating equipment (457)	(44.9)	(1.9)	-	-	(46.9)	-	(46.9)	(45.9)
50	Regulatory Overheads	(4.8)	(0.9)	-	-	(5.7)	-	(5.7)	(5.2)
51	Sub-Total	(361.8)	(20.7)	0.2	0.0	(382.3)	-	(382.3)	(372.1)
	Union Rate Zones Transmission Plant								
52	Land rights (461)	(20.5)	(1.2)	-	-	(21.7)	-	(21.7)	(21.1)
53	Structures & improvements (462/463/464)	(50.2)	(3.4)	-	-	(53.6)	-	(53.6)	(51.9)
54	Mains (465)	(733.0)	(41.2)	-	0.1	(774.1)	-	(774.1)	(753.5)
55	Compressor equipment (466)	(354.9)	(31.0)	-	0.0	(385.9)	-	(385.9)	(370.4)
56	Measuring & regulating equipment (467)	(125.5)	(11.3)	-	0.3	(136.5)	-	(136.5)	(131.2)
57	Regulatory Overheads	(34.0)	(6.7)	-	-	(40.7)	-	(40.7)	(37.3)
58	Sub-Total	(1,318.0)	(94.8)	-	0.4	(1,412.5)	-	(1,412.5)	(1,365.3)
	Union Rate Zones Distribution Plant - Southern Operations								
59	Land rights (471)	(2.6)	(0.2)	-	-	(2.8)	-	(2.8)	(2.7)
60	Structures and improvements (472)	(50.7)	(3.4)	0.4	-	(53.7)	-	(53.7)	(52.3)
61	Services - metallic (473)	(110.2)	(4.0)	-	4.2	(109.9)	-	(109.9)	(111.4)
62	Services - plastic (473)	(457.1)	(26.8)	-	36.2	(447.6)	-	(447.6)	(457.3)
63	Regulators (474)	(41.0)	(5.6)	2.7	0.2	(43.7)	-	(43.7)	(43.5)
64	House regulators & meter installations (474)	(34.6)	(2.5)	-	0.0	(37.1)	-	(37.1)	(35.9)
65	Mains - metallic (475)	(392.8)	(20.7)	-	0.3	(413.2)	-	(413.2)	(402.9)
66	Mains - plastic (475)	(317.9)	(18.9)	-	0.0	(336.7)	-	(336.7)	(327.2)
67	Measuring & regulating equipment (477)	(26.1)	(3.4)	-	0.2	(29.4)	-	(29.4)	(27.8)
68	Meters (478)	(124.6)	(16.3)	9.4	(0.2)	(131.6)	-	(131.6)	(127.3)
69	Regulator Overheads	(64.5)	(12.4)	-	-	(76.9)	-	(76.9)	(70.7)
70	Sub-Total	(1,622.0)	(114.1)	12.5	40.9	(1,682.7)	-	(1,682.7)	(1,658.9)
	Union Rate Zones Distribution Plant - Northern & Eastern Operations								
71	Land rights intangibles (471)	(4.7)	(0.2)	-	-	(4.9)	-	(4.9)	(4.8)
72	Structures and improvements (472)	(30.1)	(1.8)	0.0	-	(31.8)	-	(31.8)	(31.0)
73	Services - metallic (473)	(84.4)	(3.7)	-	0.7	(87.3)	-	(87.3)	(86.0)
74	Services - plastic (473)	(242.8)	(13.8)	-	0.7	(255.9)	-	(255.9)	(249.5)
75	Regulators (474)	(15.3)	(2.1)	0.6	0.0	(16.7)	-	(16.7)	(16.2)
76	House regulators & meter installations (474)	(18.8)	(1.4)	-	0.1	(20.1)	-	(20.1)	(19.5)
77	Mains - metallic (475)	(386.9)	(24.3)	-	(0.0)	(411.2)	-	(411.2)	(399.0)
78	Mains - plastic (475)	(125.3)	(6.0)	-	0.0	(131.3)	-	(131.3)	(128.3)
79	Measuring & regulating equipment (477)	(88.6)	(6.1)	-	0.1	(94.6)	-	(94.6)	(91.5)
80	Meters (478)	(31.5)	(4.4)	2.1	0.0	(33.7)	-	(33.7)	(32.6)
81	Regulator Overheads	(36.2)	(6.7)	-	-	(42.9)	-	(42.9)	(39.4)
82	Sub-Total	(1,064.5)	(70.4)	2.8	1.7	(1,130.5)	-	(1,130.5)	(1,097.8)

EGI Utility Plant
Continuity of Accumulated Depreciation
Year End Balances and Average of Monthly Averages
2023 Actual

Line No.		Col. 1 Opening Balance Dec.2022	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2023	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2023	Col. 8 Average of Monthly Averages
	Union Rate Zones General Plant								
83	Structures & improvements (482)	(19.1)	(2.0)	-	-	(21.1)	-	(21.1)	(20.1)
84	Office furniture and equipment (483)	(4.7)	(0.5)	-	-	(5.2)	-	(5.2)	(4.9)
85	Office equipment - computers (483)	(35.2)	(17.5)	26.7	-	(26.0)	-	(26.0)	(42.9)
86	Transportation equipment (484)	(57.2)	(9.2)	2.4	(0.7)	(64.7)	-	(64.7)	(61.5)
87	Heavy work equipment (485)	(6.9)	(1.7)	0.1	-	(8.6)	-	(8.6)	(7.8)
88	Tools and work equipment (486)	(14.9)	(2.3)	-	-	(17.1)	-	(17.1)	(16.0)
89	NGV fuel equipment (487)	(1.7)	(0.2)	-	-	(1.9)	-	(1.9)	(1.8)
90	Communication equipment (488)	(5.5)	(0.6)	0.1	-	(6.0)	-	(6.0)	(5.8)
91	Regulatory Overheads	(31.2)	(8.0)	7.9	-	(31.3)	-	(31.3)	(34.8)
92	Sub-Total	(176.4)	(42.0)	37.2	(0.7)	(181.9)	-	(181.9)	(195.7)
93	Union Rate Zones Total	(4,563.5)	(343.3)	52.7	42.3	(4,811.7)	-	(4,811.7)	(4,711.1)
94	EGI Total	(8,511.0)	(714.3)	255.2	80.5	(8,889.6)	3.7	(8,885.9)	(8,748.0)

EGI Working Capital Components
Month End Balances and Average of Monthly Averages
2023 Actual

Line No.		Col. 1 Materials and Supplies	Col. 2 ABC Receivable	Col. 3 Customer Security Deposits	Col. 4 Prepaid Expenses	Col. 5 Balancing Gas	Col. 6 Gas in Storage	Col. 7 Working Cash Allowance	Col. 8 Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1	January 1	96.2	(18.5)	(59.9)	(0.1)	59.5	1,422.9	22.1	1,522.2
2	January 31	100.1	8.3	(59.8)	(9.7)	59.5	978.9	22.1	1,099.3
3	February	103.1	(25.5)	(59.8)	(1.1)	59.5	875.4	22.1	973.8
4	March	107.9	(51.9)	(57.3)	3.4	59.5	634.8	22.1	718.5
5	April	110.6	(40.0)	(57.8)	7.6	59.5	395.1	22.1	497.1
6	May	116.7	(37.8)	(58.4)	7.0	59.5	448.7	22.1	557.9
7	June	109.3	(44.9)	(56.4)	11.4	59.5	561.7	22.1	662.7
8	July	112.3	(22.7)	(57.2)	9.7	59.5	613.0	22.1	736.8
9	August	114.5	(13.8)	(58.5)	14.9	59.5	738.8	22.1	877.4
10	September	114.7	(18.0)	(61.3)	18.8	59.5	857.9	22.1	993.8
11	October	115.7	(0.6)	(65.3)	15.1	59.5	936.4	22.1	1,082.9
12	November	118.8	(0.0)	(63.5)	10.3	59.5	835.6	22.1	982.7
13	December	118.5	(18.8)	(63.3)	(0.8)	59.5	791.0	22.1	908.3
14	Avg. of monthly avgs.	110.9	(22.1)	(59.7)	7.2	59.5	748.6	22.1	866.5

EGI Summary of Capital Structure & Cost of Capital
2023 Actual

Line No.		Col. 1 Utility Capital Structure Principal ($Millions)	Col. 2 Utility Capital Structure Component %	Col. 3 Cost Rate %	Col. 4 Return Component %	Col. 5 (Col. 1x Col. 3) Interest & Return ($Millions)
1	Long and Medium-Term Debt	9,498.1	59.89	4.21	2.520	399.7
2	Short-Term Debt	651.6	4.11	5.04	0.207	32.9
3	Total Debt	10,149.7	64.00		2.727	432.5
4	Common Equity	5,709.2	36.00	10.86	3.910	620.0
5	Total Rate Base	15,858.9	100.00		6.637	1,052.6

Calculation of Cost Rates
for EGI Capital Structure Components
2023 Actual

Line No.			Col. 1 Average of Monthly Averages ($Millions)	Col. 2	Col. 3 Carrying Cost ($Millions)
	Long and Medium-Term Debt				
1	Debt Summary		9,792.9		410.7
2	Unamortized Finance Costs		(33.2)		-
3	(Profit)/Loss on Redemption		-		-
4			9,759.7		410.7
5	Percentage Allocation of Debt to Unregulated	2.68%	(261.6)		(11.0)
6	Net Regulated Long and Medium-Term Debt		9,498.1		399.7
7	Calculated Cost Rate			4.21%	
	Short-Term Debt				
8	Calculated Cost Rate			5.04%	
	Common Equity				
9	Board Formula ROE			9.36%	
10	Threshold before earnings sharing			1.50%	
11	ROE for earnings sharing determination			10.86%	

EGI Summary Statement of Principal and Carrying Cost of Term Debt

2023 Actual

Line No.	Coupon Rate	Maturity Date	Col. 1 Average of Monthly Averages Principal	Col. 2 Effective Cost Rate	Col. 3 Carrying Cost
			($Millions)		($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	135.4	3.87%	5.2
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	-	4.91%	-
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	54.2	6.38%	3.5
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	325.0	3.15%	10.2
39	4.55%	August 17, 2052	325.0	4.52%	14.7
40	5.46%	October 6, 2028	52.1	5.54%	2.9
41	5.70%	October 6, 2033	83.3	3.70%	3.1
42	5.67%	October 6, 2053	72.9	5.08%	3.7
43			9,707.9		402.3
Long-Term Debentures					
44.	9.85%	December 2, 2024	85.0	9.910%	8.4
45.			85.0		8.4
46.	Total Term Debt		9,792.9		410.7

EGI Unamortized Debt Discount and Expense
Average of Monthly Averages
2023 Actual

Line No.		Col. 1 Unamortized Debt Discount and Expense
		($Millions)
1	January 1	69.5
2	January 31	68.6
3	February	67.7
4	March	66.8
5	April	65.9
6	May	65.0
7	June	64.1
8	July	63.2
9	August	62.4
10	September	61.8
11	October	(80.2)
12	November	(94.7)
13	December	(94.6)
14	Average of Monthly Averages	33.2

Reconciliation of Audited Enbridge Gas Inc. Income (Per Financial Statements)
to Corporate Income for Utility Income Determination Purposes
2023 Actual

		Col. 1	Col. 2	Col. 3	Col. 4
Line No.	($ millions)	Audited Income (as per Financial Statements)	Corporate Income (as per Utility Income Schedule)	Variance	Reference
	Operating Revenues				
1	Gas sales and distribution	4,797.2	5,398.3		
2	Storage, transportation and other	1,045.5	-		
3	Transportation	-	140.4		
4	Storage	-	215.2		
5	Other operating revenue	-	76.6		
6	Other Income	47.5	11.1		
7	Total operating revenue	5,890.3	5,841.6	(48.7)	(a)
	Operating Expenses				
8	Gas Costs	2,873.4	2,873.4	(0.0)	
9	Operation and maintenance	1,196.7	1,303.2	106.5	(b)
10	Depreciation and amortization expense	756.6	756.6	(0.0)	
11	Impairment of long-lived assets	281.5	-	(281.5)	(b)
12	Fixed financing costs	-	4.0	4.0	(c)
13	Municipal and other taxes	-	126.3	126.3	(d)
14	Cost of service	5,108.2	5,063.5	(44.7)	
15	Income before interest and income taxes	782.1	778.1	(4.0)	
16	Interest and financing expenses	439.5	-	(439.5)	(e)
17	Income before income taxes	342.6	778.1	435.5	
18	Income taxes	1.5	-	(1.5)	(f)
19	Net Income	341.1	778.1	437.0	

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

a)	Audited Total Operating Revenue	5,890.3
	Reclassify pension related other revenue to O&M	(37.0)
	Reclassify EGD rate zone Open Bill and ABC T-service O&M against program revenues in other revenue	(12.3)
	Reclassify other expenses out of other income to O&M	0.6
	Corporate Total Operating Revenue	5,841.6
b)	Audited Operation and Maintenance	1,196.7
	Reclassify pension related other revenue to O&M	(37.0)
	Reclassify Municipal & Property Taxes out of O&M	(126.3)
	Reclassify Impairment Charges to O&M	281.5
	Reclassify EGD rate zone Open Bill and ABC T-service O&M against program revenues in other revenue	(12.3)
	Reclassify other expenses out of other income to O&M	0.6
	Corporate Operation and Maintenance	1,303.2
c)	Audited Fixed Financing Costs	-
	Reclassify fixed financing costs from interest and financing expenses	4.0
	Corporate Fixed Financing Costs	4.0
d)	Audited Municipal and Other Taxes	-
	Reclassify Municipal and other taxes included within O&M costs	126.3
	Corporate Municipal and Other Taxes	126.3
e)	Audited Interest and Financing expenses	439.5
	Reclassify fixed financing costs from interest and financing expenses	(4.0)
	Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure	(435.5)
	Corporate Interest and Financing expenses	(0.0)
f)	Audited Income Taxes	1.5
	Elimination of corporate income taxes which will be calculated on a utility stand-alone basis	(1.5)
	Corporate Income Taxes	-

Delivery Revenue by Service, Rate Class and Service Class
Enbridge Gas Inc.

For the Year Ending December 31, 2023

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	995.1	13.6	-	0.0	-	1,008.7
3	Rate 6	312.8	83.7	-	28.3	-	424.7
4	Rate 9	-	-	-	-	-	-
5	Total EGD Rate Zone	1,307.9	97.2	-	28.3	-	1,433.4
6	Rate M1	508.6	18.2	-	1.7	-	528.5
7	Rate M2	37.8	28.2	-	17.7	-	83.8
8	Rate 01	190.5	8.2	-	1.0	-	199.7
9	Rate 10	11.9	7.4	-	5.3	0.2	24.7
10	Total Union Rate Zones	748.8	62.1	-	25.7	0.2	836.7
11	Total General Service Sales & T-Service	2,056.7	159.3	-	54.0	0.2	2,270.1
12	Wholesale - Utility						
13	Rate M9	0.7	-	-	1.3	-	2.0
14	Rate M10	0.0	-	-	-	-	0.0
15	Total Wholesale - Utility	0.7	-	-	1.3	-	2.0
16	Contract Sales						
17	Rate 100	0.8	0.6	-	1.5	-	2.9
18	Rate 110	4.4	7.1	-	28.8	-	40.3
19	Rate 115	0.0	-	-	6.5	-	6.5
20	Rate 125	-	-	-	-	12.7	12.7
21	Rate 135	0.2	0.2	-	1.5	-	1.8
22	Rate 145	0.0	0.3	-	3.5	-	3.8
23	Rate 170	0.0	0.2	-	2.5	-	2.7
24	Rate 200	3.3	-	-	1.6	-	5.0
25	Rate 300	-	-	-	-	0.0	0.0
26	Rate 315	-	-	-	-	0.0	0.0
27	Total EGD Rate Zone	8.7	8.3	-	46.0	12.7	75.7
28	Rate M4	4.0	3.1	-	28.2	-	35.2
29	Rate M7	1.5	1.4	-	26.2	-	29.1
30	Rate 20	0.9	0.1	-	3.3	27.3	31.7
31	Rate 100	-	-	-	-	11.1	11.1
32	Rate T-1	-	-	-	-	14.0	14.0
33	Rate T-2	-	-	-	-	82.3	82.3
34	Rate T-3	-	-	-	-	7.6	7.6
35	Rate M5	0.2	0.2	-	2.3	-	2.7
36	Rate 25	2.2	-	-	-	7.1	9.3
37	Rate 30	-	-	-	-	-	-
38	Total Union Rate Zones	8.9	4.8	-	60.0	149.5	223.2
39	Total Contract Sales	17.6	13.1	-	106.0	162.2	298.9
40	Subtotal	2,075.0	172.4	-	161.2	162.4	2,571.0
41	Accounting Adjustments:						
42	EGI Tax Variance						(27.2)
43	EGI Accounting Policy Change						(40.3)
44	EGD Average Use / Normalized Average Consumption						9.8
45	EGD Dawn Access COS (DACDA)						
46	EGD Incremental Capital Module						4.1
47	EGD LRAM						(0.0)
48	EGD Febderal Carbon Program						0.9
49	EGI Greenhouse Gas Emissions Administration						0.1
50	Union Average Use / Normalized Average Consumption						(4.1)
51	Union Incremental Capital Module						1.8
52	Union Capital Pass-through						(1.7)
53	Union Parkway Obligation						(0.0)
54	Union LRAM						0.5
55	Union DSM						1.4
56	Union Federal Carbon Program						2.3
57	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues						(17.3)
58	Total Utility Revenue						2,501.2

Delivery Revenue by Service, Rate Class and Service Class
Enbridge Gas Inc.

For the Year Ending December 31, 2022

		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	982.7	15.0	-	0.1	-	997.8
3	Rate 6	319.0	82.8	-	31.7	-	433.6
4	Rate 9	(0.0)	-	-	-	-	(0.0)
5	Total EGD Rate Zone	1,301.7	97.8	-	31.8	-	1,431.4
6	Rate M1	500.6	18.5	-	1.7	-	520.7
7	Rate M2	38.2	26.4	-	16.5	-	81.2
8	Rate 01	188.2	8.2	-	1.0	-	197.4
9	Rate 10	11.6	6.9	-	5.0	0.3	23.8
10	Total Union Rate Zones	738.6	59.9	-	24.1	0.3	823.0
11	Total General Service	2,040.3	157.7	-	56.0	0.3	2,254.4
12	Wholesale - Utility						
13	Rate M9	0.7	-	-	1.3	-	1.9
14	Rate M10	0.0	-	-	-	-	0.0
15	Total Wholesale - Utility	0.7	-	-	1.3	-	2.0
16	Contract Sales						
17	Rate 100	0.7	0.4	-	1.2	-	2.3
18	Rate 110	3.6	5.5	-	27.3	-	36.5
19	Rate 115	0.0	-	-	6.8	-	6.9
20	Rate 125	-	-	-	-	12.2	12.2
21	Rate 135	0.2	0.3	-	1.1	-	1.6
22	Rate 145	0.1	0.2	-	1.4	-	1.7
23	Rate 170	0.1	0.2	-	3.2	-	3.5
24	Rate 200	3.3	-	-	1.5	-	4.8
25	Rate 300	-	-	-	-	0.1	0.1
26	Rate 315	-	-	-	-	0.0	0.0
27	Total EGD Rate Zone	8.0	6.7	-	42.6	12.3	69.6
28	Rate M4	4.7	2.8	-	27.6	-	35.1
29	Rate M7	2.6	1.2	-	23.3	-	27.0
30	Rate 20	0.9	0.1	-	3.1	23.7	27.8
31	Rate 100	-	-	-	-	11.9	11.9
32	Rate T-1	-	-	-	-	14.3	14.3
33	Rate T-2	-	-	-	-	80.8	80.8
34	Rate T-3	-	-	-	-	7.5	7.5
35	Rate M5	0.2	0.2	-	2.3	-	2.7
36	Rate 25	2.4	-	-	-	3.7	6.1
37	Rate 30	-	-	-	-	-	0.0
38	Total Union Rate Zones	10.8	4.4	-	56.3	141.9	213.4
39	Total Contract Sales	18.8	11.1	-	98.9	154.2	282.9
40	Subtotal	2,059.8	168.8	-	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

Customer Meters, Volumes and Revenues by Rate Class
Enbridge Gas Inc.

For the Year Ending December 31, 2023

Line No.		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		Customer Meters			Throughput Volumes (103M3)			Revenues ($ Millions)		
		Sales	T-Service	Total	Sales	T-Service	Total	System Sales	T-Service	Total
1	General Service									
2	Rate 1	2,124,994	27,310	2,152,304	4,614,491	62,856	4,677,347	2,069.6	15.6	2,085.2
3	Rate 6	148,013	23,197	171,210	2,800,585	1,649,573	4,450,159	968.3	157.9	1,126.2
4	Rate 9							-	-	-
5	Total EGD Rate Zone	2,273,007	50,507	2,323,514	7,415,076	1,712,429	9,127,506	3,037.9	173.5	3,211.4
6	Rate M1	1,168,590	28,454	1,197,044	2,744,946	180,673	2,925,618	1,062.7	19.9	1,082.6
7	Rate M2	4,902	3,715	8,617	503,869	646,755	1,150,624	135.8	45.9	181.8
8	Rate 01	358,646	10,192	368,838	869,052	62,730	931,782	428.4	14.1	442.5
9	Rate 10	1,435	959	2,394	137,667	167,581	305,249	45.1	23.1	68.2
10	Total Union Rate Zones	1,533,573	43,320	1,576,893	4,255,534	1,057,739	5,313,273	1,672.0	103.0	1,775.0
11	Total General Service Sales & T-Service	3,806,580	93,827	3,900,407	11,670,610	2,770,168	14,440,778	4,709.9	276.5	4,986.4
12	Wholesale - Utility									
13	Rate M9	1	3	4	17,445	80,435	97,880	4.2	1.3	5.5
14	Rate M10	3		3	427		427	0.1	-	0.1
15	Total Wholesale - Utility	4	3	7	17,872	80,435	98,307	4.4	1.3	5.6
16	Contract Sales									
17	Rate 100	6	13	19	13,666	36,350	50,015	4.0	3.1	7.1
18	Rate 110	90	376	466	120,157	1,134,071	1,254,228	28.6	50.5	79.1
19	Rate 115		18	18	158	354,870	355,028	0.0	9.3	9.3
20	Rate 125		4	4		1,106,860	1,106,860	-	12.7	12.7
21	Rate 135	2	41	43	1,651	65,218	66,869	0.4	1.9	2.3
22	Rate 145	2	15	17	(138)	50,022	49,883	(0.1)	4.5	4.5
23	Rate 170		20	20	1,559	242,401	243,960	0.2	1.9	2.1
24	Rate 200	1		1	133,901	54,540	188,441	34.7	2.7	37.4
25	Rate 300		1	1		0	0	-	0.0	0.0
26	Rate 315							-	0.0	0.0
27	Total EGD Rate Zone	101	488	589	270,954	3,044,331	3,315,285	68.0	86.6	154.5
28	Rate M4	25	196	221	51,991	512,604	564,595	13.9	31.3	45.2
29	Rate M7	1	68	69	18,856	750,681	769,537	5.6	27.7	33.3
30	Rate 20	5	60	65	8,870	1,065,356	1,074,225	3.6	37.3	40.9
31	Rate 100		11	11		942,952	942,952	-	11.1	11.1
32	Rate T-1		38	38		397,887	397,887	-	14.0	14.0
33	Rate T-2		27	27		5,069,101	5,069,101	-	82.4	82.4
34	Rate T-3		1	1		255,245	255,245	-	7.6	7.6
35	Rate M5	4	31	35	1,767	57,200	58,966	0.6	2.5	3.1
36	Rate 25	29	22	51	54,615	201,050	255,665	12.8	7.1	19.9
37	Rate 30							-	-	
38	Total Union Rate Zones	64	454	518	136,098	9,252,076	9,388,174	36.5	220.9	257.4
39	Total Contract Sales	165	942	1,107	407,052	12,296,407	12,703,459	104.5	307.5	412.0
40	Subtotal	3,806,749	94,772	3,901,521	12,095,534	15,147,010	27,242,544	4,818.8	585.3	5,404.0
41	Accounting Adjustments:									
42	EGI Tax Variance									(27.2)
43	EGI Accounting Policy Change									(40.3)
44	EGD Average Use / Normalized Average Consumption									16.9
45	EGD Dawn Access COS (DACDA)									-
46	EGD Incremental Capital Module									4.1
47	EGD LRAM									(0.0)
48	EGD Febderal Carbon Program									0.9
49	EGI Greenhouse Gas Emissions Administration									0.1
50	EGD Transactional Services Revenue									12.0
51	Union Average Use / Normalized Average Consumption									(3.7)
52	Union Incremental Capital Module									1.8
53	Union Capital Pass-through									(1.7)
54	Union Parkway Obligation									(0.0)
55	Union LRAM									0.5
56	Union DSM									1.4
57	Union Federal Carbon Program									2.3
58	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues									(17.3)
59	Miscellaneous									11.9
60	Total Utility Revenue									5,365.7

Weather Normalized Customer Meters, Volumes and Revenues by Rate Class
Enbridge Gas Inc.

For the Year Ending December 31, 2023

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		Customer Meters			Throughput Volumes (103M3)			Revenues ($ Millions)		
Line No.		Sales	T-Service	Total	Sales	T-Service	Total	System Sales	T-Service	Total
1	General Service									
2	Rate 1	2,124,994	27,310	2,152,304	4,851,862	66,140	4,918,002	2,148.0	16.0	2,164.0
3	Rate 6	148,013	23,197	171,210	2,947,451	1,730,393	4,677,845	1,012.6	163.2	1,175.8
4	Rate 9	-	-	-	-	-	-	-	-	-
5	Total EGD Rate Zone	2,273,007	50,507	2,323,514	7,799,314	1,796,533	9,595,847	3,160.6	179.2	3,339.8
6	Rate M1	1,168,590	28,454	1,197,044	2,976,358	195,904	3,172,262	1,127.3	20.5	1,147.8
7	Rate M2	4,902	3,715	8,617	540,935	694,331	1,235,266	146.2	49.0	195.2
8	Rate 01	358,646	10,192	368,838	930,548	67,169	997,717	452.7	14.8	467.5
9	Rate 10	1,435	959	2,394	144,968	176,469	321,437	47.8	24.3	72.1
10	Total Union Rate Zones	1,533,573	43,320	1,576,893	4,592,809	1,133,872	5,726,681	1,774.0	108.7	1,882.7
11	Total General Service Sales & T-Service	3,806,580	93,827	3,900,407	12,392,123	2,930,406	15,322,528	4,934.6	287.9	5,222.5
12	Wholesale - Utility									
13	Rate M9	1	3	4	17,445	80,435	97,880	4.2	1.3	5.5
14	Rate M10	3	-	3	427	-	427	0.1	-	0.1
15	Total Wholesale - Utility	4	3	7	17,872	80,435	98,307	4.4	1.3	5.6
16	Contract Sales									
17	Rate 100	6	13	19	13,666	36,350	50,015	4.0	3.1	7.1
18	Rate 110	90	376	466	120,157	1,134,071	1,254,228	28.6	50.5	79.1
19	Rate 115	-	18	18	158	354,870	355,028	0.0	9.3	9.3
20	Rate 125	-	4	4	-	1,106,860	1,106,860	-	12.7	12.7
21	Rate 135	2	41	43	1,651	65,218	66,869	0.4	1.9	2.3
22	Rate 145	2	15	17	(138)	50,022	49,883	(0.1)	4.5	4.5
23	Rate 170	-	20	20	1,559	242,401	243,960	0.2	1.9	2.1
24	Rate 200	1	-	1	133,901	54,540	188,441	34.7	2.7	37.4
25	Rate 300	-	1	1	-	0	0	-	0.0	0.0
26	Rate 315	-	-	-	-	-	-	-	0.0	0.0
27	Total EGD Rate Zone	101	488	589	270,954	3,044,331	3,315,285	68.0	86.6	154.5
28	Rate M4	25	196	221	51,991	512,604	564,595	13.9	31.3	45.2
29	Rate M7	1	68	69	18,856	750,681	769,537	5.6	27.7	33.3
30	Rate 20	5	60	65	8,870	1,065,356	1,074,225	3.6	37.3	40.9
31	Rate 100	-	11	11	-	942,952	942,952	-	11.1	11.1
32	Rate T-1	-	38	38	-	397,887	397,887	-	14.0	14.0
33	Rate T-2	-	27	27	-	5,069,101	5,069,101	-	82.4	82.4
34	Rate T-3	-	1	1	-	255,245	255,245	-	7.6	7.6
35	Rate M5	4	31	35	1,767	57,200	58,966	0.6	2.5	3.1
36	Rate 25	29	22	51	54,615	201,050	255,665	12.8	7.1	19.9
37	Rate 30	-	-	-	-	-	-	-	-	-
38	Total Union Rate Zones	64	454	518	136,098	9,252,076	9,388,174	36.5	220.9	257.4
39	Total Contract Sales	165	942	1,107	407,052	12,296,407	12,703,459	104.5	307.5	412.0
40	Subtotal	3,806,749	94,772	3,901,521	12,817,046	15,307,248	28,124,294	5,043.5	596.6	5,640.1
41	Accounting Adjustments:									
42	EGI Tax Variance									(27.2)
43	EGI Accounting Policy Change									(40.3)
44	EGD Average Use / Normalized Average Consumption									16.9
45	EGD Dawn Access COS (DACDA)									-
46	EGD Incremental Capital Module									4.1
47	EGD LRAM									(0.0)
48	EGD Febderal Carbon Program									0.9
49	EGI Greenhouse Gas Emissions Administration									0.1
50	EGD Transactional Services Revenue									12.0
51	Union Average Use / Normalized Average Consumption									(3.7)
52	Union Incremental Capital Module									1.8
53	Union Capital Pass-through									(1.7)
54	Union Parkway Obligation									(0.0)
55	Union LRAM									0.5
56	Union DSM									1.4
57	Union Federal Carbon Program									2.3
58	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues									(17.3)
59	Miscellaneous									11.9
60	Total Utility Revenue									5,601.7

Customer Meters, Volumes and Revenues by Rate Class
Enbridge Gas Inc.

For the Year Ending December 31, 2022

		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	2,094,144	30,288	2,124,432	5,029,401	76,913	5,106,314	2,358.5	17.6	2,376.1
3	Rate 6	148,947	21,213	170,160	3,031,974	1,755,703	4,787,677	1,145.4	163.9	1,309.4
4	Rate 9	0	0	0	(1)	0	(1)	(0.0)	0	(0.0)
5	Total EGD Rate Zone	2,243,091	51,501	2,294,592	8,061,374	1,832,617	9,893,991	3,504.0	181.5	3,685.5
6	Rate M1	1,155,352	29,101	1,184,453	2,992,122	191,540	3,183,662	1,232.6	20.1	1,252.8
7	Rate M2	4,546	3,424	7,970	563,032	663,196	1,226,228	180.3	42.9	223.2
8	Rate 01	355,311	9,881	365,192	944,713	66,223	1,010,936	487.1	14.4	501.5
9	Rate 10	1,356	857	2,213	146,808	173,648	320,456	58.5	22.7	81.3
10	Total Union Rate Zones	1,516,565	43,263	1,559,828	4,646,675	1,094,606	5,741,281	1,958.6	100.2	2,058.8
11	Total General Service	3,759,656	94,764	3,854,420	12,708,049	2,927,223	15,635,272	5,462.5	281.7	5,744.2
12	Wholesale - Utility									
13	Rate M9	1	3	4	18,996	77,894	96,890	5.4	1.3	6.7
14	Rate M10	3	0	3	331	0	331	0.1	0	0.1
15	Total Wholesale - Utility	4	3	7	19,326	77,894	97,221	5.5	1.3	6.8
16	Contract Sales									
17	Rate 100	7	11	18	12,929	23,886	36,815	4.3	2.3	6.6
18	Rate 110	81	361	442	114,059	1,083,818	1,197,877	33.8	47.1	80.9
19	Rate 115	2	13	15	1,040	399,955	400,995	0.3	9.8	10.1
20	Rate 125		4	4		977,270	977,270	-	12.2	12.2
21	Rate 135	7	34	41	2,578	56,442	59,020	0.9	1.6	2.5
22	Rate 145	3	15	18	1,302	17,607	18,909	0.4	1.8	2.2
23	Rate 170	8	13	21	7,685	284,279	291,964	2.1	2.7	4.8
24	Rate 200	1	0	1	136,663	50,697	187,361	40.3	2.5	42.8
25	Rate 300	0	2	2		211	211	0	0.1	0.1
26	Rate 315	0	0	0	0	0	0	0	0.0	0.0
27	Total EGD Rate Zone	109	453	562	276,255	2,894,167	3,170,422	82.1	80.2	162.3
28	Rate M4	31	191	222	64,479	537,398	601,877	21.2	30.5	51.7
29	Rate M7	5	60	65	41,088	708,979	750,067	13.7	24.5	38.2
30	Rate 20	5	59	64	9,113	870,231	879,345	4.2	33.8	38.0
31	Rate 100	0	11	11	0	943,946	943,946	0	11.9	11.9
32	Rate T-1	0	38	38	0	440,944	440,944	0	14.3	14.3
33	Rate T-2	0	26	26	0	4,850,508	4,850,508	0	82.1	82.1
34	Rate T-3	0	1	1	0	278,032	278,032	0	7.5	7.5
35	Rate M5	4	33	37	1,835	58,974	60,809	0.7	2.5	3.2
36	Rate 25	40	25	65	68,669	82,612	151,281	21.2	3.7	24.9
37	Rate 30	0	0	0	0	0	0	0	0	0
38	Total Union Rate Zones	85	444	529	185,184	8,771,624	8,956,808	61.0	210.8	271.8
39	Total Contract Sales	194	897	1,091	461,440	11,665,791	12,127,231	143.1	290.9	434.0
40	Subtotal	3,759,854	95,664	3,855,518	13,188,815	14,670,908	27,859,723	5,611.2	573.9	6,185.1
41	Accounting Adjustments:									
42	EGI Tax Variance									(29.9)
43	EGI Accounting Policy Change									(2.8)
44	EGD Average Use / Normalized Average Consumption									6.9
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	EGD Transactional Services Revenue									12.0
51	Union Average Use / Normalized Average Consumption									8.8
52	Union Incremental Capital Module									(2.0)
53	Union Capital Pass-through									(2.9)
54	Union Parkway Obligation									(0.1)
55	Union LRAM									0.8
56	Union Federal Carbon Program									2.0
57	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues									(17.4)
58	Miscellaneous									8.9
59	Total Utility Revenue									6,164.5

Weather Normalized Customer Meters, Volumes and Revenues by Rate Class

Enbridge Gas Inc.

For the Year Ending December 31, 2022

		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	2,094,144	30,288	2,124,432	4,928,130	76,175	5,004,305	2,332.3	17.4	2,349.7
3	Rate 6	148,947	21,213	170,160	2,954,007	1,737,662	4,691,668	1,128.3	161.6	1,289.9
4	Rate 9	0	0	0	(1)	0	(1)	(0.0)	0	(0.0)
5	Total EGD Rate Zone	2,243,091	51,501	2,294,592	7,882,136	1,813,836	9,695,973	3,460.6	179.0	3,639.6
6	Rate M1	1,155,352	29,101	1,184,453	2,975,284	190,462	3,165,746	1,229.4	20.1	1,249.5
7	Rate M2	4,546	3,424	7,970	561,927	661,894	1,223,821	180.2	42.8	223.0
8	Rate 01	355,311	9,881	365,192	940,369	65,918	1,006,288	485.8	14.4	500.2
9	Rate 10	1,356	857	2,213	147,198	174,109	321,307	58.7	22.8	81.5
10	Total Union Rate Zones	1,516,565	43,263	1,559,828	4,624,779	1,092,383	5,717,162	1,954.0	100.1	2,054.1
11	Total General Service	3,759,656	94,764	3,854,420	12,506,915	2,906,220	15,413,135	5,414.6	279.1	5,693.7
12	Wholesale - Utility									
13	Rate M9	1	3	4	18,996	77,894	96,890	5.4	1.3	6.7
14	Rate M10	3	0	3	331	0	331	0.1	0	0.1
15	Total Wholesale - Utility	4	3	7	19,326	77,894	97,221	5.5	1.3	6.8
16	Contract Sales									
17	Rate 100	7	11	18	12,918	23,886	36,804	4.3	2.3	6.6
18	Rate 110	81	361	442	113,896	1,083,182	1,197,078	33.8	47.1	80.9
19	Rate 115	2	13	15	1,036	399,937	400,973	0.3	9.8	10.1
20	Rate 125	0	4	4	-	977,270	977,270	0	12.2	12.2
21	Rate 135	7	34	41	2,578	56,401	58,979	0.9	1.6	2.5
22	Rate 145	3	15	18	1,289	17,581	18,869	0.4	1.8	2.2
23	Rate 170	8	13	21	7,685	283,859	291,544	2.1	2.7	4.8
24	Rate 200	1	0	1	139,960	50,697	190,657	40.3	2.5	42.8
25	Rate 300	0	2	2	0	211	211	0	0.1	0.1
26	Rate 315	0	0	0	0	0	0	0	0.0	0.0
27	Total EGD Rate Zone	109	453	562	279,361	2,893,025	3,172,386	82.1	80.2	162.3
28	Rate M4	31	191	222	64,479	537,398	601,877	21.2	30.5	51.7
29	Rate M7	5	60	65	41,088	708,979	750,067	13.7	24.5	38.2
30	Rate 20	5	59	64	9,113	870,231	879,345	4.2	33.8	38.0
31	Rate 100	0	11	11	0	943,946	943,946	0	11.9	11.9
32	Rate T-1	0	38	38	0	440,944	440,944	0	14.3	14.3
33	Rate T-2	0	26	26	0	4,850,508	4,850,508	0	82.1	82.1
34	Rate T-3	0	1	1	0	278,032	278,032	0	7.5	7.5
35	Rate M5	4	33	37	1,835	58,974	60,809	0.7	2.5	3.2
36	Rate 25	40	25	65	68,669	82,612	151,281	21.2	3.7	24.9
37	Rate 30	0	0	0	0	0	0	0	0	0
38	Total Union Rate Zones	85	444	529	185,184	8,771,624	8,956,808	61.0	210.8	271.8
39	Total Contract Sales	194	897	1,091	464,545	11,664,649	12,129,194	143.1	290.9	434.0
40	Subtotal	3,759,854	95,664	3,855,518	12,990,787	14,648,763	27,639,549	5,563.2	571.3	6,134.5
41	Accounting Adjustments:									
42	EGI Tax Variance									(29.9)
43	EGI Accounting Policy Change									(2.8)
44	EGD Average Use / Normalized Average Consumption									6.9
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	EGD Transactional Services Revenue									12.0
51	Union Average Use / Normalized Average Consumption									8.8
52	Union Incremental Capital Module									(2.0)
53	Union Capital Pass-through									(2.9)
54	Union Parkway Obligation									(0.1)
55	Union LRAM									0.8
56	Union Federal Carbon Program									2.0
57	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues									(17.4)
58	Miscellaneous									8.9
59	Total Utility Revenue									6,114.0

EGI Revenue from Regulated Storage & Transportation of Gas
2023 Actual

Line No.	Particulars ($000s)	2021 Actual	2022 Actual	2023 Actual
		(a)	(b)	(c)
	Revenue from Regulated Storage Services:			
1	C1 Off-Peak Storage	433	138	1,046
2	Supplemental Balancing Services	640	1,053	905
3	Gas Loans	1	(1)	(1)
4	C1 Short Term Firm Peak Storage	1,536	2,108	2,634
5	Short Term Storage and Balancing Services Deferral	3,577	3,732	2,352
6	Rate 325: Transmission, Compression, & Storage	2,169	2,303	2,174
7	Less: Elimination of charges between EGD and Union rate zones	(2,226)	(2,344)	(2,238)
8	Total Regulated Storage Revenue Net of Deferral	6,130	6,988	6,871
	Revenue from Regulated Transportation Services:			
9	M12 Transportation	206,637	213,050	216,935
10	M12-X Transportation	21,527	20,769	14,839
11	C1 Long Term Transportation	19,934	21,023	20,013
12	Rate 332: Gas Transmission	18,107	18,313	19,186
13	C1 Short Term Transportation	7,226	8,365	7,024
14	Gross Exchange Revenue	1,729	1,127	636
15	Rate 331: Gas Transmission	165	170	172
16	Rate 401: RNG Injection Service	0	111	521
17	M13 Local Production	157	173	173
18	M16 Transportation	926	986	859
19	M17 transportation	545	511	529
20	S&T:Transportation Carbon Facility Collection	2,692	4,196	5,167
21	Other S&T Revenue	1,440	1,407	1,633
22	Less: Elimination of charges between EGD and Union rate zones	(138,489)	(144,576)	(147,672)
23	Total Regulated Transportation Revenue Net of Deferral	142,597	145,627	140,015

EGI Utility Other Revenue and Other Income
2023 Actuals

Line No.	Particulars	Col. 1 2022 Utility Revenue ($Millions)	Col. 2 2023 Utility Revenue ($Millions)
1	Late Payment Penalties	20.9	23.0
2	Account Opening Charges	9.8	9.3
3	Other Billing Revenue	9.7	11.0
4	Customer Billing Revenue	40.4	43.3
5	Open Bill Revenue	5.4	5.4
6	Distributor Consolidated Billing and Direct Purchase Administration Charges	2.3	2.2
7	Mid Market Transactions	1.4	1.7
8	CNG Rental Revenue	1.6	2.1
9	Other Operating Revenue	2.6	3.1
10	Total Other Revenue	53.6	57.8
11	Other Income (1)	(2.1)	7.1
12	Total Other Revenue and Other Income	51.5	64.9

UTILITY OPERATING AND MAINTENANCE

1. This evidence explains the drivers in the Utility Operating and Maintenance (O&M) expense change from 2022 to 2023.

2. The Utility O&M schedule for 2023 preserves the presentation from the 2022 ESM Proceeding (EB-2023-0110) to provide transparency to all expense categories and in particular, segregating Corporate Shared Services (CSS), Demand Side Management (DSM), and Integration-related costs. The Company recognizes that this O&M presentation is useful to inform stakeholders about operating costs, and as such, has maintained the presentation to allow the driver explanations to be comparable between years.

3. Table 1 presents 2023 O&M expenses relative to the prior year. Appendix A is provided as required and agreed to by Enbridge Gas. As in 2022, Enbridge Gas provided an appendix reconciling 2023 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 purposes.

4. Overall, O&M expenses increased by $106.5 million primarily due to higher Miscellaneous Expense, Compensation and Benefits, DSM, Materials and Supplies. These increases were partially offset by decreases primarily in CSS, integration related costs and increased Allocations and Recoveries as well as capitalization recovery on Non-CSS.

Table 1
Utility O&M
2022-2023 Actuals

Line No.	Col. 1 Expense Categories	Col. 2 2022 Actual ($M)	Col. 3 2023 Actual ($M)	Col. 4 $ change	Col. 5 % change
1	Compensation and Benefits	398.9	425.9	26.9	6.8%
2	Employee Related Services and Development	2.1	2.2	0.2	8.2%
3	Materials and Supplies	31.7	37.1	5.4	16.9%
4	Outside Services	271.3	270.6	(0.6)	-0.2%
5	Transportation Related Repairs and Maintenance	7.4	9.7	2.3	30.6%
6	Vehicle Related Repairs and Maintenance	19.9	22.8	2.9	14.5%
7	Rents and Leases	12.6	12.2	(0.4)	-3.4%
8	Telecommunications	0.2	0.1	(0.1)	-53.2%
9	Travel and Entertainment	8.1	8.9	0.8	9.9%
10	Donations and Memberships	3.6	5.4	1.7	46.8%
11	Admin Expenses	2.9	2.4	(0.5)	-18.4%
12	Allocations & Recoveries	(12.1)	(17.8)	(5.6)	46.4%
13	Corporate Shared Services (CSS)	285.2	273.8	(11.5)	-4.0%
14	DSM	132.1	142.3	10.2	7.7%
15	Integration-Related Costs	30.8	17.2	(13.8)	-44.7%
16	Miscellaneous Expense	16.4	299.8	283.4	1729.7%
17	Capitalization on Non-CSS	(183.1)	(209.4)	(26.3)	14.4%
18	O&M Subtotal before Eliminations	1028.1	1,303.2	275.1	26.8%
19	Donations	(1.1)	(2.5)	(1.4)	122.0%
20	CDM Program	0.0	-	0.0	
21	ABC T-service Program	(0.3)	(0.3)	(0.0)	2.3%
22	CF utility adjustment	(8.4)	(11.2)	(2.8)	
23	Other Eliminations	(0.3)		0.3	-100.0%
24	Unregulated Adjustments	(15.6)	(24.2)	(8.6)	54.7%
25	Pension Impairment Eliminations		(156.1)	(156.1)	0.0%
26	Total Unregulated/Non-Utility Eliminations	(25.8)	(194.3)	(168.6)	48.4%
27	Total Net Utility O&M Expense	1002.3	1108.8	106.5	26.2%

5. Miscellaneous Expense (Line 16) increased $283.4 million over the prior year primarily due to impairment charges related to the OEB Settlement and Phase 1 rebasing decisions driven by the pension balance write-off ($156.1 million), write-off of net capital integration costs ($84.3 million), and GTA/WAMS capital write-offs ($41.0 million). The pension write-off of $156.1 million is considered non-utility cost and is eliminated on Line 25.

6. Corporate Shared Services (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.

7. CSS costs were $11.5 million lower than the prior year primarily due to: lower CSS benefits and higher CSS capitalization partially offset by higher CSS allocations.

8. Compensations and Benefits (Line 1) increased by $26.9 million over the prior year from an $11.0 million increase in merit. An increase of $5.3 million was driven by higher Operations and Customer Care FTEs. The increased Operations FTEs were to address COVID-19 induced labour shortages, and reflect requirements for the transition to pre COVID-19 work volume. An increase in Customer Care FTEs were required to increase focus on meeting SQR targets. In addition, the business unit benefits increased by $9 million due to higher FTEs and higher pension expense.

9. The Company’s multi-year DSM Plan Application was filed with the OEB on May 3, 2021, and is designed to make homes and businesses more energy efficient, help lower average annual gas usage, and help meet Ontario’s GHG reduction goals. The $10.2 million increase in DSM (Line 14) are a pass-through component of utility O&M and are included in total recoverable amounts although part of a separate proceeding.

10. Materials and Supplies (Line 3) increased $5.4 million over the prior year primarily due to inflation, increased spend on integrity management programs and additional purchase of odourant.

11. Allocation and Recoveries (Line 12) increased by $5.6 million driving lower O&M due to higher direct charges to capital projects in Operations and Engineering and offset by higher allocation charges to the unregulated business. All unregulated business costs are removed in unregulated adjustments (Line 24).

12. Integration-related costs (Line 15) decreased by $13.8 million as integration initiatives winded down and ended with 2023 being the final year of integration.

13. Unregulated Adjustments (Line 24) increased by $8.5 million driving lower O&M due to incremental unregulated costs primarily related to Enbridge RNG projects, Enbridge Sustain, and the Carbon Capture project.

1. 2023 Overhead Capitalization

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

15. Overhead capitalization applies to all expense categories except integration-related costs, which are fully expensed. Total combined overhead capitalization was $35.3 million more than the prior year (Table 2).

16. Non-CSS overhead capitalization increased by $26.3 million driven by the increases in O&M expenses noted in the previous section.

17. CSS overhead capitalization increased by $9.0 million from the prior year driven by the increases in CSS capitalization rate and loading rate from the annual update to the overhead capitalization methodology.

Table 2
Total Overhead Capitalization Impact on O&M

Line No.	Categories	2022 Actual ($M)	2023 Actual ($M)	2023-2022 Variance ($M)
1	CSS-related Capitalization	(86.7)	(95.7)	(9.0)
2	Capitalization on Non-CSS	(183.1)	(209.4)	(26.3)
3	Total Overhead Capitalization	(269.7)	(305.0)	(35.3)

18. 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
CF Cost Allocations and CSS

Line No.	Categories	2022	2023	2022-2023 Variance
1	CF Cost Allocations	371.9	369.4	(2.5)
2	Less: Utility adjustment	(8.4)	(11.2)	(2.8)
3	Utility CF cost Allocations	363.5	358.2	(5.3)
4	Less: Capitalization of CSS	(86.7)	(95.7)	(9.0)
5	Net Utility CSS	276.8	262.6	(14.3)

Table 1

Reconciliation of Utility O&M Schedule
2022 & 2023 Results

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
		2022 ACTUAL				2023 ACTUAL				2022-2023	2022-2023
Line No.	Expense Categories ($M)	2022 Previous Format	Central Functions Costs	DSM & Integration Costs	2022 Revised	2023 Previous Format	Central Functions Costs	DSM & Integration Costs	2023 Revised	$ change	% change
1	Compensation and Benefits	493.8	(69.6)	(25.3)	398.9	519.1	(72.2)	(20.9)	425.9	27.0	6.8%
2	Employee Related Services and Development	6.2	(3.3)	(0.8)	2.1	7.5	(5.1)	(0.2)	2.2	0.2	8.2%
3	Materials and Supplies	52.2	(1.7)	(18.8)	31.7	66.3	(2.2)	(27.0)	37.1	5.4	16.9%
4	Outside Services	440.0	(50.8)	(117.9)	271.3	452.0	(71.0)	(110.3)	270.6	(0.6)	-0.2%
5	Transportation Related Repairs and Maintenance	9.4	(2.0)	(0.0)	7.4	9.7	(0.1)	(0.0)	9.7	2.3	30.6%
6	Vehicle Related Repairs and Maintenance	20.0	(0.0)	(0.0)	19.9	22.9	(0.0)	(0.0)	22.8	2.9	14.5%
7	Rents and Leases	14.9	(2.3)	0.0	12.6	15.1	(2.9)	-	12.2	(0.4)	-3.4%
8	Telecommunications	0.2	0.0	(0.0)	0.2	0.2	(0.1)	(0.0)	0.1	(0.1)	-53.2%
9	Travel and Entertainment	9.6	(1.0)	(0.6)	8.1	11.3	(1.3)	(1.1)	8.9	0.8	9.9%
10	Donations and Memberships	4.7	(0.3)	(0.8)	3.6	5.2	0.7	(0.5)	5.4	1.8	49.6%
11	Admin Expenses	0.0	(0.2)	3.1	2.9	(0.3)	0.1	2.5	2.4	(0.5)	-18.4%
12	Allocations & Recoveries	230.6	(242.2)	(0.5)	(12.1)	199.4	(216.6)	(0.6)	(17.8)	(5.6)	46.4%
13	Corporate Shared Services (CSS)	0.0	285.2		285.2	0.0	275.1	(1.3)	273.8	(11.5)	-4.0%
14	DSM	0.0		132.1	132.1	0.0	-	142.3	142.3	10.2	7.7%
15	Integration-Related Costs	(0.0)	1.3	29.5	30.8	0.0	-	17.2	17.2	(13.7)	-44.3%
16	Miscellaneous O&M Expense	16.2	0.1		16.4	299.8	(0.0)		299.8	283.4	1729.7%
17	Capitalization on non-CSS	(269.7)	86.7		(183.1)	(305.0)	95.7		(209.4)	(26.3)	14.4%
18	O&M Subtotal before Eliminations	1028.1	(0.0)	0.0	1028.1	1303.2	0.0	(0.0)	1303.2	275.2	26.8%
19	Donations	(1.1)			(1.1)	(2.5)			(2.5)	(1.4)	122.0%
20	CDM Program	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)	2.3%
22	CF utility adjustment	(8.4)			(8.4)	(11.2)			(11.2)	(2.8)	32.9%
23	Other Eliminations	(0.3)			(0.3)	0.0			0.0	0.3	-100.0%
24	Unregulated Adjustments	(15.6)			(15.6)	(24.2)			(24.2)	(8.6)	54.7%
25	Pension Impairment Eliminations					(156.1)			(156.1)	(156.1)	
26	Total Unregulated/Non-Utility Eliminations	(25.8)			(25.8)	(194.3)			(194.3)	(168.6)	654.3%
27	Total Net Utility O&M Expense	1002.3			1002.3	1108.8			1108.8	106.5	10.6%

UTILITY CAPITAL EXPENDITURES

1. The purpose of this evidence is to provide information on Enbridge Gas' 2023 utility capital expenditures within the EGD and Union rate zones.

Table 1
Summary of Capital Expenditures 2023 Actual
($millions)

Line No.	Particulars	Col 1 EGD	Col 2 UG	Col 3 Total EGI
1	Distribution Plant	473.1	399.4	872.5
2	Transmission Plant	-	101.9	101.9
3	General & Other Plant	115.5	15.3	130.8
4	Underground Storage Plant	324.7	13.0	337.8
5	Total	913.4	529.6	1,442.9

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)

Line No.	Asset Class	2022	2023	Variance
1	Compression Stations	73.4	314.0	240.6
2	Customer Connections	183.8	210.3	26.5
3	Distribution Pipe	205.2	110.5	(94.7)
4	Distribution Stations	54.8	25.4	(29.4)
5	Fleet & Equipment	15.0	6.4	(8.6)
6	Growth - Distribution System Reinforcement	10.2	9.4	(0.8)
7	Real Estate & Workplace Services	46.5	62.9	16.4
8	Technology Information Services (TIS)	18.2	39.1	21.0
9	Transmission Pipe and Underground Storage	9.1	10.8	1.7
10	Utilization	44.6	87.3	42.6
11	EA Fixed Overhead	22.2	19.3	(2.9)
12	Capitalized Overheads	-	-	-
13	Integration Capital	24.0	7.0	(17.0)
14	Community Expansion	9.3	8.1	(1.3)
15	Other	1.6	2.9	1.3
16	Total	718.0	913.5	195.5

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

Line No.	Asset Class	2022	2023	Variance
1	Compression Stations	33.4	16.5	(16.9)
2	Customer Connections	113.2	131.6	18.4
3	Distribution Pipe	272.3	138.4	(133.9)
4	Distribution Stations	42.3	25.0	(17.3)
5	Fleet & Equipment	15.5	4.6	(10.9)
6	Growth - Distribution System Reinforcement	59.2	28.0	(31.2)
7	Real Estate & Workplace Services	17.9	10.1	(7.8)
8	Technology Information Services (TIS)	9.9	8.2	(1.7)
9	Transmission Pipe and Underground Storage	87.7	74.4	(13.3)
10	Utilization	53.7	84.5	30.8
11	EA Fixed Overhead	4.8	3.2	(1.6)
12	Capitalized Overheads	-	-	-
13	Integration Capital	4.7	1.5	(3.2)
14	Community Expansion	4.9	1.9	(3.0)
15	Other	(0.5)	1.5	2.0
16	Total	719.1	529.5	(189.6)

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 primarily due to the continuation of the Dawn to Corunna Replacement project ($266 million).

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 2023 compared to 2022. In addition, the average cost for customer connection increased for both rate zones due to the inflation pressures for labor and materials.

c) Distribution Pipe

- 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 decreased in 2023 due to significant capital allocated to the completion of NPS 20 Lake Shore Replacement Cherry to Bathurst project in 2022 and less Integrity spend in 2023 compared to 2022.
- The Union rate zone decreased due to the completion of projects executed in 2022 including the London Lines project ($32.1 million) and the Kirkland Lake Lateral project ($26 million) combined with less Integrity spend in 2023 compared to 2022.

d) Distribution Stations

- 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 decreased due to completion of Brampton Gate Rebuild ($9.6 million), Dale Gate Rebuild ($5.8 million) and Martin Grove Feeder ($4.3 million).
- The Union rate zone decreased due to the pacing of station replacements and rebuilds including Leamington North Gate ($5.7 million) and others to offset 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.
- Decreases in the Fleet, Equipment and Tools asset class across both rate zones, between 2023 and 2022, are attributed to expenditure reductions in Tools ($5.9 million) and Vehicles and Equipment ($15.3 million).

f) Growth – Distribution System Reinforcement

- The Growth asset class includes reinforcements driven by customer and load growth.
- The EGD rate zone had little variance year over year.
- The Union rate zone decreased due to the completion of a number of reinforcement projects executed in 2022: Ingersoll Transmission Station ($10.6 million), Byron Transmission Station ($8.9 million), Greenstone Mine ($5.7 million), and Staples Reinforcement ($4.0 million).

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 Ottawa Building ($27.0 million).
- The Union rate zone decreased due to the pacing of Chatham Building renovation located at 50 Keil to offset the inflationary pressures for labor and materials in other asset classes.

h) <u>Technology Information Services</u>

- 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 increases were largely due to the start of Contract Market Modernization project ($18.1 million) in 2023. The Union rate zone did not experience a significant variance from 2022 to 2023.

i) <u>Transmission Pipe and Underground Storage</u>

- 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.
- EGD rate zone did not experience a significant variance from 2022 to 2023. The UG rate zone decreased due to the completion of Dawn to

Cuthbert NPS 42 Replacement ($17.1 million) combined with less integrity spend ($6.4 million) which was offset by the increase in the Panhandle Regional Expansion Project ($17.2 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 decrease in the 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 are 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).

[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.

- Total combined capitalized overheads increased by $38.3 million which includes a $4.2M increase to IDC as a result of increases to the OEB prescribed rate. The indirect overhead increases of $34.1 million are explained in Exhibit B, Tab 3, Schedule 1.

m) Integration Capital

- Integration capital included expenditures required to integrate the two legacy companies. Enbridge Gas evaluated projects to determine if they met the criteria of integration capital: a one time incremental cost related to the amalgamation of the legacy utilities. Projects were identified to address integration needs, or they were driven by a need to replace an asset due to obsolescence. In either case, the project was classified as integration as it drove a harmonized solution that added value to the integrated utility. These expenditures were excluded when calculating the thresholds for ICM capital.
- The decrease in both the EGD and UG rate zones are due to higher spend for Cost of Gas and Asset and Work Management System in 2022 and write-off of completed projects in 2023, as a result of the OEB's 2024 Phase 1 Rebasing Decision[2].

n) Community Expansion

- Community expansion provides natural gas services to communities not currently using natural gas. In response to 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.

[2] EB-2022-0200, OEB Decision and Order, December 21, 2023, p. 74.

- 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 decrease is due to higher contributions recognized 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 2023 Actual
($millions)

Line No.	Asset Class	Regulated	Unregulated
1	Compression Stations	313.9	(0.5)
2	Transmission Pipe and Underground Storage	10.8	6.2
3	Total Capital Expenditures	324.7	5.7

6. EGD Rate Zone Compression Stations – significant projects related to EGD's regulated assets include Dawn to Corunna Replacement ($303.2 million), SCOR:60004-Fdn-Blk-Replace ($3.0 million), SSOM:K-802 Iso Valves-Replace ($1.1 million), SSOM: V-0805 Iso Valves - Rep ($1.0 million) and SCOR:61008Top End-O/H ($1.0 million).

7. EGD Rate Zone Transmission Pipe and Underground Storage – significant projects related to EGD's regulated assets include NPS 16 Wilkesport P and C ($2.9 million), NPS 16 WLK Trans Retrofit ($1.8 million), PCRW:Wells-Upgrade ($1.5 million) and NPS 20 SK Loop P&C ($1.0 million) and Dow Moore MOP Remediation ($1.0 million). Significant unregulated projects include TPS-Wells SE24 PMKC ($1.7 million), LLAD: Pipeline and Meter Station ($1.4 million) and SE 21/22 LDOW ($1.2 million) and PLAD:TL8 A1 Obs Well-Drill ($1.1 million) 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 2023 Actual
($millions)

Line No.	Asset Class	Regulated	Unregulated
1	Compression Stations	16.6	6.8
2	Transmission Pipe and Underground Storage	74.4	2.7
3	Total Capital Expenditures	91.0	9.5

8. UG Rate Zone Compression Stations – significant projects related to UG's regulated assets include Dawn:5985 CV Piping & Improvements ($3.3 million), STO Convert High Bleed devices to Low/no bleed ($2.1 million) and Bright B PLC Upgrade ($1.2 million). Unregulated projects include the Dawn Dehy Plant – Process Tank Replacement ($5.9 million) and Dawn I Plant Glycol Line Replacement ($0.9 million).

9. UG Rate Zone Transmission Pipe and Underground Storage – significant projects related to UG's regulated assets include the Panhandle Regional Expansion Project ($50.1 million), Trafalgar NPS 26 Integrity Digs ($7.4million), Panhandle NPS 20 AC Mitigation ($4.9 million), Dawn-Cuthbert – NPS 42 replacement ($1.1 million),

Trafalgar NPS 26 Line Lowering ($1.9 million) and NPS 20 Bickford Sombra IFK Repairs ($1.0 million). The SE21/22-NPS24/TIE IN/STN , Mandaumin A1 observation well and Bluewater A1 Well($2.7million) are unregulated projects and part of the 2nd phase of the Storage Enhancement project (EB-2021-0079) described in paragraph 7.

Enbridge Gas Inc.
Summary of Capital Cost Allowance (CCA)

Line No.		Particulars ($000s)	Col. 1 UCC at Prior Year Filing EB-2023-0092 (a)	Col. 2 True-up from Filing to Tax Return (b)	Col. 3 UCC At Beginning of Year (c)	Col. 4 Total Additions (d)	Col. 5 Total Additions Qualifying for Accel. CCA (e)	Col. 6 Less: Lessor of Cost or Proceeds (f)	Col. 7 Eligible CCA Additions** (g)	Col 8 Depreciable UCC Balance (h)	Col. 9 Rate (%) (i)	Col. 10 CCA FY2023 (j)	Col. 11 Ending UCC (k)
	Class												
1	1	Buildings, structures and improvements, services, meters, mains	2,118,476.9	-	2,118,476.9	-	-	-	-	2,118,476.9	4%	84,739.1	2,033,737.8
2	1	Non-residential building acquired after March 19, 2007	153,170.0	112.7	153,282.7	3,236.8	3,236.8	-	4,855.3	158,138.0	6%	9,488.3	147,031.3
3	2	Mains acquired before 1988	143,339.5	-	143,339.5	-	-	-	-	143,339.5	6%	8,600.4	134,739.2
4	3	Buildings acquired before 1988	2,704.7	-	2,704.7	-	-	-	-	2,704.7	5%	135.2	2,569.4
5	6	Other buildings	63.4	-	63.4	-	-	-	-	63.4	10%	6.3	57.1
6	7	Compression equipment acquired after February 22, 2005	371,124.6	-	371,124.6	4,446.1	4,446.1	-	6,669.2	377,793.8	15%	56,669.1	318,901.6
7	8	Compression assets, office furniture, equipment	200,767.9	(6,970.9)	193,797.0	125,909.3	125,909.3	-	188,864.0	382,661.0	20%	76,532.2	243,174.1
8	10	Transportation, computer equipment	30,593.4	(512.6)	30,080.7	3,253.9	3,253.9	-	4,880.9	34,961.7	30%	10,488.5	22,846.2
9	12	Computer software, small tools	780.1	(221.8)	558.4	33,766.4	33,766.4	-	33,766.4	34,324.7	100%	34,324.7	-
10	13	Leasehold improvements	139.6	-	139.6	-	-	-	-	139.6	0%	107.8	31.9
11	14.1	Intangibles	12,826.0	0.0	12,826.0	564.0	564.0	-	846.0	13,672.0	5%	683.6	12,706.4
12	14.1	Intangibles (pre 2017)	40,458.5	-	40,458.5	-	-	-	-	40,458.5	7%	2,832.1	37,626.4
13	17	Roads, sidewalk, parking lot or storage areas	425.4	-	425.4	-	-	-	-	425.4	8%	34.0	391.4
14	38	Heavy work equipment	11,178.4	(168.0)	11,010.4	2,462.7	2,462.7	-	3,694.1	14,704.5	30%	4,411.3	9,061.8
15	41	Storage assets	81,607.6	(653.0)	80,954.6	98,405.5	98,405.5	-	147,608.3	228,562.9	25%	57,140.7	122,219.4
16	45	Computers - Hardware acquired after March 22, 2004	1.9	-	1.9	-	-	-	-	1.9	45%	0.9	1.0
17	49	Transmission pipeline additions acquired after February 23, 2005	755,358.0	142.4	755,500.4	25,124.4	25,124.4	-	37,686.6	793,187.0	8%	63,455.0	717,169.9
18	50	Computers hardware acquired after March 18, 2007	6,966.8	(691.9)	6,274.9	17,057.2	17,057.2	-	25,585.7	31,860.6	55%	17,523.3	5,808.7
19	51	Distribution pipelines acquired after March 18, 2007	6,201,229.7	(31,916.7)	6,169,313.0	908,359.9	908,359.9	(4,738.9)	1,360,170.4	7,524,744.5	6%	451,484.7	6,621,449.3
20	Total		10,131,212.4	(40,879.7)	10,090,332.7	1,222,586.3	1,222,586.3	(4,738.9)	1,814,626.8	11,900,220.5		878,657.1	10,429,522.9

ACCOUNTS NOT BEING REQUESTED FOR CLEARANCE

1. The following accounts of Enbridge Gas have zero balances and are therefore not requested for clearance:

   - Earnings Sharing Mechanism Deferral Account – EGI
   - Green Button Initiative Deferral Account – EGI
   - Cloud Computing Implementation Costs Deferral Account – EGI
   - Expansion of Natural Gas Distribution Systems Variance Account – EGI
   - Impacts Arising from the COVID-19 Emergency Deferral Account - EGI

2. With respect to the Impacts Arising from the COVID-19 Emergency Deferral Account, Enbridge Gas was approved to clear the balance as part of the OEB's EB-2022-0200 Interim Rate Order, and therefore, Enbridge Gas has no further balance to dispose of in this proceeding.

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. In the EB-2022-0200 Phase 1 Decision and Order dated December 21, 2023, the OEB approved the clearance of deferral and variance accounts as proposed by Enbridge Gas including the balance in the APCDA, with the exception of the former Union Gas pre-2017 amortized actuarial gains/losses[4]. The balance approved within that application was comprised of actual & forecast amounts. Within this application, Enbridge Gas is seeking final disposition of the remaining balance in the APCDA, reflecting the variance between the forecast balance approved in the EB-2022-0200 Phase 1 Decision and Order, and associated Interim Rate Order dated April 11, 2024, and the final actual balances calculated through December 31, 2023.

3. The Company tracked the annual revenue requirement impact of accounting policy changes made as of the amalgamation date, January 1, 2019, or at other points throughout the deferred rebasing term. The cumulative actual balance of the APCDA

[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-2022-0200, Decision and Order dated December 23, 2023, pp. 101-107.

as of December 31, 2023 is a credit, or payable of $7.445 million, as compared to the forecast balance payable of $ 12.956 million which was approved in the EB-2022-0200 Interim Rate Order. Please refer to Exhibit C, Tab 1, Schedule 2, Table 1 which categorizes each of the accounting policy changes, provides the cumulative opening balance as of the beginning of the period, details the current period revenue requirement impact being added to the cumulative balance, provides the ending cumulative balance as of the end of the current period, and finally provides the residual balances being requested as part of this filing. The details of each item within Table 1 are described further in the remaining evidence presented.

4. Exhibit C, Tab 1, Schedule 2, Table 2 provides an additional detailed breakdown of the changes by rate zone between what was originally approved through the EB-2022-0200 Interim Rate Order and the final cumulative balances recorded for each item. The variance, and amount requested for disposition as part of this proceeding is a debit (or receivable) of $5.511 million, plus interest of $0.036 million.

5. Please refer to Exhibit C, Tab 1, Schedule 2, Table 3 for the detailed 2023 revenue requirement calculation of the items presented above.

1. Capitalization vs Expense

6. 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

7. 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 2023 between UGL and EGD Rate Zones of:
   - Lower O&M expense of approximately $8.256 million, offset by higher capitalization; and,
   - Gross revenue requirement decrease, or sufficiency of $7.260 million.

8. On a cumulative basis, this policy alignment resulted in a gross revenue requirement decrease, or sufficiency of $20.319 million, however, the forecast balance approved for clearance as part of the Rebasing Decision was an $11.666 million sufficiency, resulting in a residual sufficiency (or credit) balance of $8.653 million that is proposed for disposition as part of this 2023 ESM Proceeding. The variance results primarily from a larger amount of integrity dig inspections in the Union Rate Zone that were capitalized on an actual basis as compared to the forecast.

2. Interest During Construction

9. 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.

	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

10. Upon amalgamation, it was necessary for Enbridge Gas to align its accounting treatment of IDC. The policy alignment resulted in the following for 2023:
    - Total 2023 net gross revenue requirement decrease, or sufficiency of $1.352 million.

11. On a cumulative basis, this policy alignment resulted in a gross revenue requirement decrease, or sufficiency of $0.751 million, however, the forecast balance approved for clearance as part of the Rebasing Decision was a gross revenue requirement increase, or deficiency of $1.533 million, resulting in a residual sufficiency balance of $2.284 million that is proposed for disposition as part of this 2023 ESM Proceeding. The variance results primarily from larger amounts closing into service and a much larger increase in the OEB prescribed interest rate vs the weighted average cost of debt rate since Q3 2022 as compared to the forecast.

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

3. Depreciation Expense

12. Depreciation rates for Union and EGD, in place at the time of amalgamation and used over the deferred rebasing term, were based on depreciation studies that were approved by the OEB in prior proceedings.

13. 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

14. 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.

15. The policy alignment resulted in an impact in 2023 specific only to the UGL Rate Zone of:
    - A decrease in depreciation expense of approximately $5.427 million; and,
    - A gross revenue requirement decrease, or sufficiency of $5.731 million.

16. On a cumulative basis, this policy alignment resulted in a gross revenue requirement decrease, or sufficiency of $24.190 million, however, the forecast balance approved for clearance as part of the Rebasing Decision was a gross sufficiency of $31.229 million, resulting in a variance, or balance for recovery, of $7.039 million that is proposed for disposition as part of this 2023 ESM Proceeding. The variance is a result of the mix between the amount and timing differences of in-service additions between actual and forecast. The lower amount of additions in the year and going

into service later result in a smaller gap between Union Rate Zone depreciation on a half year basis compared to monthly after in-service.

4. Overhead Capitalization

17. 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.

18. 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.

19. The APCDA isolated the impact of the overhead capitalization policy change. The calculation took the annual O&M spend with the new harmonized rates and subtracted from it O&M spend using the legacy rates to determine the APCDA impact. The policy change resulted in a decrease in O&M and offsetting increase in capitalized overheads, with the revenue requirement impact recorded in the APCDA. The net impact in 2023 between UGL and EGD Rate Zones was:

- Lower net OM&A expenses of $22.512 million (offset by higher capitalization of overheads); and,
- A gross revenue requirement decrease, or sufficiency of $25.450 million

20. On a cumulative basis, this policy alignment resulted in a gross revenue requirement decrease, or sufficiency of $24.339 million, however, the forecast balance approved for clearance as part of the Rebasing Decision was a gross sufficiency of $36.494 million, resulting in a variance in the deficiency balance of $12.155 million that is proposed for disposition as part of this 2023 ESM Proceeding. The variance is primarily the result of applying the harmonized capitalization rates to the mix of O&M spend on an actual basis over 2022 and 2023 that differed from the legacy approach, resulting in a lower amount of overhead capitalization when compared to the forecast.

5. Amortized Gas Supply Storage and Transportation Costs

21. 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.

22. 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 over the calendar year. In the EGD rate zone, these monthly invoiced charges are initially accrued 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

[6] EB-2022-0200, Exhibit 9, Tab 2, Schedule 1, pp. 14-16.

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.

23. 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.

24. 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), was transferred to the APCDA resulting in no amounts being required to be amortized to gas cost expense in 2023. At the time of the Enbridge Gas Rebasing filing, the forecast balance for this account was $64.9 million, which was subsequently approved for clearance. The Company now requests disposition of the residual sufficiency balance of $2.745 million, the difference between the forecast amount filed as part of the Rebasing Application and the final balance recorded to the account, as part of this application.

25. The amount transferred to the APCDA represents costs incurred by Enbridge Gas in providing service to customers and does not reflect any material 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

26. As part of Enbridge Gas's 2024 Rates Phase 1 Decision and Order, the OEB denied the proposed recovery of the remaining Pension and OPEB expenses recorded in the APCDA (Union pre-2017 unamortized actuarial gains/losses), and as such the amounts were written off leaving no balance to be disposed of[7].

[7] EB-2022-0200, OEB Decision and Order, December 23, 2023, pp. 101-107.

ENBRIDGE GAS - TAX VARIANCE DEFERRAL ACCOUNT (TVDA)

1. Establishment of the Enbridge Gas Inc. - Tax Variance Deferral Account was approved by the OEB in Enbridge Gas'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 2023 is comprised of the following:

Table 1
Details of 2023 TVDA Balances

Line No.		Amount ($ millions)
1	2022 True up to T2 Filing balance[2]	1.816
2	2023 Non-integration related balance[3]	(30.299)
3	Total Balance	(28.483)

[1] EB-2018-0305, Final Rate Order dated October 24, 2019, Appendix I, p. 10.
[2] Represents the true-up to Accelerated CCA impact between the 2022 Earnings Sharing amount submitted and the amount reflected as per the 2022 T2 Corporate Income Tax return filed after 2022 Earnings Sharing submission.
[3] Represents the Acclerated CCA impact for 2023 in-service additions exclusive of ICM, CPT and Integration related.

3. As noted above, the balance requested for clearance within this proceeding is a credit of $28.483 million, plus forecast interest of $2.715 million, for a total credit of $31.198 million. Of the principal balance in the account, a debit of $1.816 million relates to a true-up of the 2022 accelerated CCA impact which reflects the impact of a variance between the 2022 qualifying additions captured in the 2022 Enbridge Gas Tax Variance Deferral Account examined in the EB-2023-0092 proceeding, and the final 2022 qualifying additions supporting Enbridge Gas's 2022 tax filing. The 2023 balance of $30.299 million relates to the 2023 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 2023. Please refer to Exhibit C, Tab 1, Schedule 3 for details of the Tax Variance Account calculation.

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.

5. Consistent with the OEB's EB-2022-0200 Decision and Order, dated December 21, 2023[4], the entire balance related to integration capital projects in the TVDA shall be disposed of in favour of Enbridge Gas. As per the direction in the Decision and Order, Enbridge Gas has no remaining integration related balance to bring forward in this account.

<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 – 2023 total annual capital additions which have qualified for accelerated CCA, and then removed the annual additions related to capital pass-through, incremental capital module, and integration projects. For the remaining qualifying additions, the cumulative annual CCA has been calculated utilizing the accelerated rates and compared against the cumulative

[4] EB-2022-0200, Decision and Order dated December 21, 2023, p.77.

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 2023 accelerated CCA impact.

ENBRIDGE GAS – INTEGRATED RESOURCE PLANNING 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 2023 IRP Operating Costs Deferral Account that is being requested for clearance within this proceeding is a debit of $3.081 million, plus forecast interest of $0.247 million, for a total debit of $3.328. This amount is attributable to incremental Enbridge Gas staff salaries including expenses for IRP related work performed in 2023, the implementation of Integrated Resource Plan Alternatives (IRPA(s)) 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, OEB Decision and Order, July 22, 2021, p. 71.
[2] Ibid, p. 75.

5. Table 1 provides details and a breakdown of the expenditures included in the 2023 IRP Operating Costs Deferral Account.

Table 1
Details of Expenditures – IRP Operating Costs

Line No.	Item	Description	Millions ($)
1	Incremental FTE's	Salaries, loadings and expenses	$2.680
2	East Kingston Creekford Rd Project	Project costs	$0.278
3	Posterity Group	Model enhancement costs	$0.113
4	Stakeholder Engagement	Promotion and materials	$0.010
5	Total Requested for Clearance		$3.081
6	IRP Pilot Projects	Not Requested for Clearance	$0.061
7	Total in IRP Operating Cost DA		$3.142

1. Incremental Full Time Equivalent's and expenses:

6. In 2023, there were 16 Full Time Equivalent (FTE) positions and employee expenses associated with IRP, all of which are accounted for in the 2023 IRP Operating Costs Deferral Account. This is in addition to the 3 FTE IRP roles that are already captured in O&M. These 16 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);
   - 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;

[3] EB-2020-0091.

- 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, Municipal Energy Solutions, Distribution Optimization Engineering (DOE), Asset Management, Demand Side Management (DSM), Regulatory, Storage and Transmission, 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 FTEs included in the 2023 IRP Operating Costs Deferral Account. The work completed as of the end of 2023 is outlined in the 2023 IRP Annual Report which will be filed with the OEB by early July 2024.

Table 2
Description of FTE Additions – IRP

Line No.	Role	Number of FTEs	Department	Responsibilities
1	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.

Table 2 (Continued)
Description of FTE Additions – IRP (Continued)

Line No.	Role	Number of FTEs	Department	Responsibilities
2	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.
3	Supervisor	1	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.
4	Advisor	2	IRP	Support the development and filing of the annual IRP Report. Support the IRP Technical Working Group. Support IRP stakeholder engagement, including related 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.
5	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 (Continued)
Description of FTE Additions – IRP (Continued)

Line No.	Role	Number of FTEs	Department	Responsibilities
6	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.
7	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.
8	Engineer	0.5	Storage & Transmission	Perform technical evaluations on potential LTC projects. This includes providing modelling and analysis of how each IRPA option, or combination of options, impacts the project needs and design to support IRP technical feasibility evaluations (i.e., IRPA for Transmission Systems include: usage of Supply-side, CNG, LNG, ETE, PDO from Empress or other supply points, Contract customer Firm to IT conversions).
9	Advisor	2	Municipal Energy Solutions	Execute IRP engagement activities with municipalities, inclusive of contact identification, outreach, and ongoing engagement requirements. Involvement across forums to communicate with stakeholders on IRP activities such as conferences and open houses. Geo-targeted outreach with municipalities regarding IRP projects assessed for their communities as required, inclusive of the Pilot Projects ensuring municipal support.

[5] Ibid.

Table 2 (Continued)
Description of FTE Additions – IRP (Continued)

Line No.	Role	Number of FTEs	Department	Responsibilities
10	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.
11	Director	0.5	IRP	This role is responsible for the integration strategy and implementation of IRP.

2. East Kingston Creekford Rd Project

10. Enbridge Gas is proposing to recover $0.278 million in the IRP Operating Costs Deferral Account related to the IRP alternative that was implemented to defer a pipeline reinforcement project in the Kingston, Ontario area.

11. The East Kingston Creekford Rd Reinforcement project was a planned $24.3 million capital reinforcement. Enbridge Gas determined that this project could be deferred by implementing a supply side IRP alternative in the form of CNG beginning in 2022.[6] Without the CNG injection, the Kingston system was anticipated to fall below its minimum pressure requirements as early as the Winter of 2022/2023. An

[6] For a detailed description of the pipeline project and IRP alternatives please see EB-2023-0092, Exhibit C, Tab 1, pp. 20 – 24.

agreement for CNG in 2022 ensured Enbridge Gas maintained a safe and reliable system for customers in the Kingston project service area. The CNG agreement was executed July 1, 2022, for the winters of 2022/2023 and 2023/2024 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. The 2022 charges for the CNG Agreement were approved for recovery in the IRP Operating Costs Deferral Account[7] and the $0.278 is the 2023 cost of the CNG agreement.

12. The CNG agreement provided time for Enbridge Gas to implement a Contract turnback to reduce contract demand avoiding the facilities project. The turnback provided, 2,200 m^3/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 back-up solution. Enbridge Gas is no longer seeking recovery of the lost revenue associated with the contract demand reduction for this project.[8] In the event foregone revenue is a consideration when assessing a future facility project, Enbridge Gas will file evidence on the recovery of such amounts at that time.

13. Enbridge Gas will monitor the demands in this area to ensure the CNG solution and contract reduction realized continue to meet the needs. CNG was 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 depth of cover and class location issues to determine if a future facility or IRP alternative will be required in this area.

[7] EB-2023-0092, OEB Decision and Settlement Proposal and Rate Order, February 6, 2024, p.4.
[8] EB-2023-0092, Settlement Proposal, Exhibit N1, Tab 1, Schedule 1, November 28, 2023, p. 7.

3. Posterity – General Model Enhancements

14. Enbridge Gas is proposing to recover $0.113 million in the IRP Operating Costs Deferral Account related to enhancements made to Posterity's proprietary model.

15. 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)[9] as a basis; where additional calibration and development of load shapes were layered onto the "mirror model" to create the IRPA Model.

16. 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. This work continued through 2023 and will be completed in 2024.

17. 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.
    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.

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

4. Stakeholder Engagement

18. Enbridge Gas is proposing to recover $0.010 million in the IRP Operating Costs Deferral Account related to the stakeholder activities completed in 2023. General stakeholder efforts included the promotion of regional webinars in the spring and fall. Enbridge Gas also developed print materials for engagement at Conferences throughout 2023.

5. IRP Pilot Projects

19. Additional operating costs of approximately $0.061 million and capital costs of $0.015 million have been incurred in 2023 related to the IRP Pilot Project application (EB-2022-0335). Recovery of these amounts will be requested after the OEB Decision on the Pilot Project application.

ENBRIDGE GAS – GETTING ONTARIO CONNECTED ACT VARIANCE ACCOUNT

1. Establishment of the Getting Ontario Connected Act (GOCA) variance account was approved by the OEB in EB-2023-0143[1]. The purpose of the GOCA variance account is to track incremental pipeline locate costs resulting from the enactment of Bill 93 on April 14, 2022. Bill 93 included amendments to the Ontario *Underground Notification System Act, 2012*[2] and the *Building Broadband Faster Act, 2021*[3]*.* The GOCA variance account is intended to continue for each year of the current IR term (2024 to 2028).

2. Based on 2021 external contractor costs Enbridge Gas was expecting to pay approx. $34 per locate in 2023, however the actual cost paid for a locate rose to $72 a 111% increase over expectation. The increase in cost was a direct result of Bill 93 which imposed a five-business-day deadline for completing standard locate requests and introduced administrative penalties for failing to comply. Bill 93 has resulted in incremental locating costs to meet this compliance mandate that are not covered by current rates. This evidence outlines the drivers behind Bill 93 cost increases as well as the incremental cost calculations.

3. The balance of the 2023 GOCA account that is being requested for clearance is $31.903 million plus interest of $1.736 million for a total debit balance of $33.639 million. The background and methodology employed on arriving at this amount are outlined in detail below.

4. In its EB-2023-0143 decision, the OEB issued an accounting order for gas utilities to establish the GOCA variance account to record the variance between locate costs resulting from Bill-93 and the approved cost included in base rates.

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[1] EB-2023-0143, Decision and Order, October 31, 2023.
[2] Bill 8, Ontario Underground Infrastructure Notification System Act, 2012, June 19, 2012. https://www.ola.org/en/legislative-business/bills/parliament-40/session-1/bill-8
3 Bill 257, Supporting Broadband and Infrastructure Expansion Act, April 12, 2021 https://www.ola.org/en/legislative-business/bills/parliament-42/session-1/bill-257

5. According to the OEB,

> "This account includes costs incurred to enable the locate activities. Utilities are expected to track costs at a sufficiently detailed level to assist in a review of the costs incurred, materiality, and causation related to Bill 93 at the time of disposition. Specifically, utilities are to demonstrate that recorded amounts in their accounts are both incremental to the base rates and are a direct result of Bill 93."[4]

   The OEB also indicated that only amounts incurred on or after April 1, 2023, were to be recorded in this account. Following OEB guidance, Enbridge Gas has employed a methodology to capture incremental locating costs that are directly attributable to Bill 93 on or after April 1, 2023.

6. Bill 93 has directly resulted in incremental costs outside of base rates in two areas: the cost of the locate itself, and in vital main standby (VMS) costs – a locate-related service requiring an experienced locator skillset and therefore provided by the same locate service providers (LSP).

<u>1. Drivers Behind Bill 93 Cost Increases</u>

7. Locate costs have increased due to the new legislated locate delivery timelines resulting from Bill 93. Enbridge Gas's average locate delivery times were 13 days and 15 days in 2021 and 2022 respectively. Bill 93 legislates a 5 day locate delivery mandate and introduces administrative penalties for non-compliance. This change in timeline is analogous to checking customers out of a grocery store. If the volume of customers stays the same and you want to speed up the check out times, more registers are needed. To meet the 5 day locate delivery timeline, LSPs were required to onboard a significant amount of new locators, as well as increase locator wages to attract and retain qualified talent under tight labour market conditions. Bill 93 put legislation in place recognizing locators as a highly skilled industry requirement. LSPs renewed unionized labour contracts in 2022, and based on the new operating environment and industry recognition of locating as a highly skilled trade, unionized wages increased significantly. This increased wage cost resulted in

[4] EB-2023-0143, OEB Decision and Order, October 31, 2023, Schedule B, p. 17.

higher contract service costs for Enbridge Gas and the other ~15 utilities in the Locate Alliance Consortium (LAC).

8. As a result of LSPs onboarding additional locators and locator wage increases, locating costs are up significantly for Enbridge Gas. Quite simply, Bill 93 required Enbridge Gas to shave an average of 10 days off its locate delivery time and the only way to achieve this was to have more locators. This coincided with LSP union negotiations where labour rates increased significantly to match the new industry skillset requirements and to attract/retain more specialized talent. This increase in locators and rates have caused the Enbridge Gas cost per locate to double. As mentioned above, the 2021 average external contractor cost per locate was $34 and the 2023 average external contractor cost per locate was $72, a 111% increase. Enbridge Gas has included incremental external locating costs related to Bill 93 in the GOCA variance account.

9. VMS is a program, requiring a LSP skillset, designed to ensure public safety when excavations take place within the vicinity of vital natural gas infrastructure in the public right of way. The VMS program prevents damages, energy outages, and protects the public and excavators by ensuring locates are recognized and proper procedures and safety controls are followed throughout the excavation process within the vicinity of the located vital assets.

10. As previously noted, Bill 93 has resulted in increased labour rates for LSPs which has created parallel incremental costs in the Enbridge Gas VMS program since this service is performed by the same contractors. The 2021 average external contractor cost per hour was $82 and the 2023 average external contractor cost per hour was $146, a 78% increase. Enbridge Gas has therefore included incremental external locator costs for the VMS program in the GOCA variance account.

2. Incremental Bill 93 cost calculations

11. Enbridge Gas has calculated incremental costs directly related to Bill 93 using 2021 actual locate costs adjusted for inflation and 2023 locate volumes as a baseline. 2021 actual locate costs were used as they provide an accurate calculation of pre Bill 93 locating costs.

12. The EGI locates budget included in base rates with OEB approved Price Cap Index (PCI)[5] was $26.4 million for 2021, in comparison to actual 2021 costs of $34.5 million. Enbridge Gas will not seek to recover the increased spend from base rates as it was deemed unrelated to Bill 93.

13. Actual 2021 locating costs were $34.5 million. To incorporate inflationary impacts, the PCI values for 2022 and 2023 were applied resulting in an inflation adjusted cost of $36.2 million[6]. After adjusting for 2023 actual locate volumes, the calculated annual base locate cost for 2023 is $33.1 million. Please refer to Table 1 outlining the calculations.

Table 1
Base Locates Costs

Line No.		Particulars	Amount
1	A	2021 Actual Locate Costs	$ 34,464,465
2	B	PCI Inflation (2022, 2023)	$ 1,740,593
3	C = A*B	Inflation Adjusted Locate Costs	$ 36,205,058
4	D	2021 Locate Volumes	1,068,953
5	E = C/D	Inflation Adjusted Costs per Locate	$33.87
6	F	2023 Actual Locate Volumes	975,919
7	G = E*F	Base Locate Costs (full year)	$33,054,030

14. The same logic was used to calculate VMS costs which are contractually billed to Enbridge Gas hourly. Actual 2021 VMS costs were $3.3 million resulting in an inflation adjusted cost of $3.5 million[7]. After adjusting for 2023 actual VMS hours, the

[5] PCI percentages were 1.4% for 2022 and 3.6% in 2023.
[6] $34.5 million x 1.014 x 1.036 = $36.2 million.
[7] $3.3 million x 1.014 x 1.036 = $3.5 million.

calculated annual base VMS cost for 2023 is $4.9 million. Please refer to Table 2 outlining the calculations.

Table 2
Base VMS Costs

Line No.		Particulars	Amount
1	A	2021 Actual VMS Costs	$ 3,300,909
2	B	PCI Inflation (2022, 2023)	$ 166,709
3	C = A*B	Inflation Adjusted VMS Costs	$ 3,467,618
4	D	2021 Volumes (VMS Hours)	40,086
5	E = C/D	Inflation Adjusted VMS Costs per Hour	$ 86.50
6	F	2023 Actual Volumes (VMS Hours)	57,046
7	G = E*F	Base VMS Costs (full year)	$ 4,934,734

15. The calculated annual base locate and VMS costs for 2023 were $33.1 million and $4.9 million respectively. To determine costs incurred on or after April 1, 2023, these costs were separated using a weighted cost approach to determine monthly costs for these expenditures. This weighted cost approach results in base locate & VMS costs for April 1, 2023 - December 31, 2023 of $29.2 million for locates and $4.4 million for VMS. Actual locate and VMS costs for this same period in 2023 resulted in $58.1 million for locates and $7.4 million for VMS. Please refer to Table 3 and Table 4 outlining the calculations.

Table 3
Locates Monthly Profile
($millions)

Line No.		Particulars	Amount Jan to Mar	Apr to Dec
1	A	2023 Actual Locate Costs	$7.7 M	$58.1 M
2	B	% of Year Total	11.7%	88.3%
3	C= B*$33.1M	Locates Base Costs	$3.9 M	$29.2 M
4	A-C	2023 Actual less Base Costs	$3.8 M	$28.9 M

Table 4
VMS Monthly Profile
($millions)

Line No.		Particulars	Amount Jan to Mar	Amount Apr to Dec
1	A	2023 Actual VMS Costs	$0.9 M	$7.4 M
2	B	% of Year Total	10.9%	89.1%
3	C= B*$4.9M	VMS Base Costs	$0.5 M	$4.4 M
4	A-C	2023 Actual less Base Costs	$0.4 M	$3.0 M

16. 2023 total actual costs less the weighted base costs are $28.9 million[8] for locates and $3 million[9] for VMS, as per Table 3 and Table 4 ($31.9 million total). The balance of the 2023 GOCA account that is being requested for clearance is $31.903 million plus interest of $1.736 million for a total debit balance of $33.639 million.

17. The proposed split of the GOCA variance account balance ($33.639 million) between the EGD rate zone, Union North rate zone and Union South rate zone is based on the number of locates completed within each rate zone during 2023. Please refer to table 5 for the proposed breakdown.

Table 5
2023 Completed Locate Weighting
($millions)

Line No.	Description		Amount
1	EGD Total	62.0%	$20.9 M
2	Union North Total	7.3%	$2.5 M
3	Union South Total	30.7%	$10.3 M
4	Total		$33.639 M

18. The proposed cost allocation methodology to dispose of the GOCA variance account to rate classes in each rate zone is described at Exhibit F, Tab 1, page 4.

[8] $58.1 million – $29.2 million = $28.9 million.
[9] $7.4 million - $4.4 million = $3.0 million.

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, 2025			
	EGD Rate Zone Commodity Related Accounts						
1.	Storage and Transportation D/A	2023 S&TDA		18,705.8	1,572.8	20,278.6	D-1, Page 1
2.	Transactional Services D/A	2023 TSDA		(41,738.1)	(2,291.5)	(44,029.6)	D-1, Page 3
3.	Unaccounted for Gas V/A	2023 UAFVA		(6,922.7)	(266.5)	(7,189.2)	D-1, Page 5
4.	Total Commodity Related Accounts			(29,955.0)	(985.2)	(30,940.2)	
	EGD Rate Zone Non Commodity Related Accounts						
5.	Average Use True-Up V/A	2023 AUTUVA		14,307.1	785.5	15,092.6	D-1, Page 69
6.	Gas Distribution Access Rule Impact D/A	2023 GDARIDA		-	-	-	D-1, Page 79
7.	Deferred Rebate Account	2023 DRA		2,132.7	187.1	2,319.8	D-1, Page 71
8.	Transition Impact of Accounting Changes D/A	2023 TIACDA		-	-	-	D-1, Page 79
9.	Electric Program Earnings Sharing D/A	2023 EPESDA		-	-	-	D-1, Page 79
10.	Open Bill Revenue V/A	2023 OBRVA		-	-	-	D-1, Page 79
11.	Ex-Franchise Third Party Billing Services D/A	2023 EFTPBSDA		-	-	-	D-1, Page 79
12.	OEB Cost Assessment V/A	2023 OEBCAVA		3,732.8	302.1	4,034.9	D-1, Page 72
13.	Dawn Access Costs D/A	2023 DACDA		-	-	-	D-1, Page 79
14.	Incremental Capital Module D/A - EGD	2020-2023 ICMDA		(4,909.0)	(232.4)	(5,141.4)	D-1, Page 75
15.	RNG Injection Service V/A	2022-2023 RNGISVA		(331.5)	(28.7)	(360.2)	D-1, Page 77
16.	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Differential V/A	2023 P&OPEBFAVACPDVA		-	-	-	D-1, Page 79
17.	Total EGD Rate Zone (for clearance)			(15,022.9)	28.4	(14,994.5)	
	Union Rate Zones Gas Supply Accounts	OEB Account Number					
18.	Upstream Transportation Optimization	179-131	2023	8,087.2	444.0	8,531.2	E-1, Page 6
19.	Spot Gas Variance Account	179-107	2023	-	-	-	E-1, Page 55
20.	Unabsorbed Demand Costs Variance Account	179-108	2023	41.5	37.8	79.3	E-1, Page 1
21.	Base Service North T-Service TransCanada Capacity	179-153	2023	79.0	5.6	84.6	E-1, Page 45
22.	Total Gas Supply Accounts			8,207.7	487.4	8,695.1	
	Union Rate Zones Storage Accounts						
23.	Short-Term Storage and Other Balancing Services	179-70	2023	1,637.5	89.9	1,727.4	E-1, Page 8
	Union Rate Zones Other Accounts						
24.	Normalized Average Consumption	179-133	2023	(3,650.8)	(201.3)	(3,852.1)	E-1, Page 12
25.	Deferral Clearing Variance Account	179-132	2023	3,372.3	184.5	3,556.8	E-1, Page 19
26.	OEB Cost Assessment Variance Account	179-151	2023	1,630.3	131.1	1,761.4	E-1, Page 42
27.	Unbundled Services Unauthorized Storage Overrun	179-103	2023	-	-	-	E-1, Page 55
28.	Gas Distribution Access Rule Costs	179-112	2023	-	-	-	E-1, Page 55
29.	Conservation Demand Management	179-123	2023	-	-	-	E-1, Page 55
30.	Parkway West Project Costs	179-136	2023	(696.4)	(48.7)	(745.1)	E-1, Page 20
31.	Brantford-Kirkwall/Parkway D Project Costs	179-137	2022	(3.1)	(0.3)	(3.4)	E-1, Page 23
32.	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	179-142	2023	267.8	10.3	278.1	E-1, Page 33
33.	Lobo D/Bright C/Dawn H Compressor Project Costs	179-144	2023	66.0	(39.5)	26.5	E-1, Page 37
34.	Burlington-Oakville Project Costs	179-149	2023	(43.3)	(3.1)	(46.4)	E-1, Page 40
35.	Panhandle Reinforcement Project Costs	179-156	2023	(1,884.1)	(145.9)	(2,030.0)	E-1, Page 46
36.	Sudbury Replacement Project	179-162	2023	-	-	-	E-1, Page 55
37.	Parkway Obligation Rate Variance	179-138	2023	-	-	-	E-1, Page 55
38.	Unauthorized Overrun Non-Compliance Account	179-143	2023	(45.5)	(4.3)	(49.8)	E-1, Page 36
39.	Incremental Capital Module D/A - UGL	179-159	2019-2023	(383.7)	(504.0)	(887.7)	E-1, Page 52
40.	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Differential V/A	179-157	2023	-	(6,207.7)	(6,207.7)	E-1, Page 49
41.	Unaccounted for Gas Volume Variance Account	179-135	2023	-	-	-	E-1, Page 25
42.	Unaccounted for Gas Price Variance Account	179-141	2023	(629.1)	(132.3)	(761.4)	E-1, Page 30
43.	Total Other Accounts			(1,999.6)	(6,961.2)	(8,960.8)	
44.	Total Union Rate Zones (for clearance)			7,845.6	(6,383.9)	1,461.7	
	EGI Accounts						
45.	Earnings Sharing D/A	179-382	2023	-	-	-	C-1, Page 1
46.	Tax Variance - Accelerated CCA - EGI	179-383	2023	(28,483.3)	(2,715.0)	(31,198.3)	C-1, Page 11
47.	IRP Operating Costs Deferral Account	179-385	2023	3,081.2	247.3	3,328.5	C-1, Page 14
48.	IRP Capital Costs Deferral Account	179-386	2023	-	-	-	C-1, Page 22
49.	Green Button Initiative D/A	179-387	2023	-	-	-	C-1, Page 1
50.	Cloud Computing Implementation Costs D/A	179-332	2023	-	-	-	C-1, Page 1
51.	Getting Ontario Connected V/A	179-324	2023	31,902.6	1,736.2	33,638.8	C-1, Page 23
52.	Expansion of Natural Gas Distribution Systems V/A	179-380	2023	-	-	-	C-1, Page 1
53.	Accounting Policy Changes D/A - Other - EGI	179-381	2019-2023	5,511.3	36.2	5,547.5	C-1, Page 2
54.	Impacts Arising from the COVID-19 Emergency D/A - EGI	179-384	2020-2021	-	-	-	C-1, Page 1
55.	Total EGI Accounts (for clearance)			12,011.8	(695.3)	11,316.5	
56.	Total Deferral and Variance Accounts (for clearance)			4,834.5	(7,050.9)	(2,216.4)	

Table 1
Revenue Requirement
($millions)

Line No.			Interest During Construction	Depreciation Expense	Overhead Capitalization	Amortized Gas Supply Storage and Transportation Costs	Subtotal	Pension Expense	Total
1	Balance at December 31, 2022	(13.059)	0.601	(18.459)	1.110	62.155	32.348	160.289	192.638
2	Impact to 2023 revenue requirement:								
3	Expense	(8.043)	0.268	(5.427)	(22.188)		(35.390)	(160.289)	(195.679)
4	Cost of capital	1.067	0.273	1.421	0.567		3.328	-	3.328
5	Income tax	(0.284)	(1.893)	(1.725)	(3.828)		(7.730)	-	(7.730)
6	Total	(7.260)	(1.352)	(5.731)	(25.450)	-	(39.793)	(160.289)	(200.082)
7	Balance at December 31, 2023	(20.319)	(0.751)	(24.190)	(24.339)	62.155	(7.445)	(0.000)	(7.445)
8	Balances previously approved for disposition	(11.666)	1.533	(31.229)	(36.494)	64.900	(12.956)	-	(12.956)
9	Balances proposed for Disposition	(8.653)	(2.284)	7.039	12.155	(2.745)	5.511	(0.000)	5.511

Table 2
Summary of Accounting Policy Changes Deferral Account (No. 179-381)
Amounts Requested for Clearance In 2023 ESM Proceeding

Line No.	($millions)	Actual & Forecast Balances Approved for Disposition (EB-2022-0200)[1]			Final Cumulative Balances[2]			Amounts Proposed for Disposition (2023 ESM and Deferral Disposition)[3]		
		Principal	Interest	Total	Principal	Interest	Total	Principal	Interest	Total
	EGD Rate Zone									
1	Capitalization vs Expense	7.899	0.193	8.092	9.058	0.340	9.398	1.159	0.147	1.306
2	Interest During Construction	2.360	0.058	2.418	0.790	0.030	0.820	(1.570)	(0.028)	(1.598)
3	Depreciation Expense	-	-	-	-	-	-	-	-	-
4	Overhead Capitalization	22.627	0.554	23.181	17.114	0.643	17.757	(5.513)	0.089	(5.424)
5	Amortized Gas Supply Storage & Transportation Costs	64.900	1.588	66.488	62.155	2.335	64.490	(2.745)	0.748	(1.997)
6	Total EGD Rate Zone APCDA	97.786	2.392	100.178	89.117	3.348	92.465	(8.669)	0.956	(7.713)
	UGL Rate Zone									
7	Capitalization vs Expense	(19.565)	(0.478)	(20.043)	(29.378)	(1.104)	(30.482)	(9.813)	(0.625)	(10.438)
8	Interest During Construction	(0.827)	(0.020)	(0.847)	(1.542)	(0.058)	(1.6)	(0.715)	(0.038)	(0.753)
9	Depreciation Expense	(31.229)	(0.764)	(31.993)	(24.190)	(0.909)	(25.1)	7.039	(0.145)	6.894
10	Overhead Capitalization	(59.121)	(1.446)	(60.567)	(41.452)	(1.6)	(43.0)	17.669	(0.112)	17.557
11	Amortized Gas Supply Storage & Transportation Costs	-	-	-	-	-	-	-	-	-
12	Total UGL Rate Zone APCDA	(110.742)	(2.708)	(113.450)	(96.562)	(3.628)	(100.190)	14.180	(0.920)	13.260
13	Total APCDA	(12.956)	(0.316)	(13.272)	(7.445)	(0.280)	(7.725)	5.511	0.036	5.547

Notes:
(1) EB-2022-0200 Rate Order, Working Papers, Schedule 27, pages 1 & 2; approved in Interim Rate Order dated April 11, 2024.
(2) Reflects 2019 through 2023 actuals.
(3) Represent variances between amounts approved for disposition in the Interim Rate Order and the final cumulative balances based on actuals.

Table 3
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	(8,774.4)	22,068.1	13,293.7	(1,527.5)	5,034.6	3,507.1	19,465.2	(3,930.4)	11,100.9	7,170.5	-	43,436.5	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*	(544.0)	1,611.0	1,067.0	(94.7)	367.5	272.8	1,421.0	(243.7)	810.4	566.7	-	3,327.5	-
	Cost of service													
4	Gas costs	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Operation and Maintenance	2,116.2	(10,372.2)	(8,256.0)	-	-	-	-	13,519.4	(36,031.3)	(22,511.9)	-	(30,767.9)	(4,268.0)
6	Depreciation and amortization	(216.3)	429.3	213.0	(43.1)	311.0	267.9	(5,427.2)	(110.5)	434.4	323.9	-	(4,622.4)	-
7	Municipal and other taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Cost of service	1,899.9	(9,942.9)	(8,043.0)	(43.1)	311.0	267.9	(5,427.2)	13,408.9	(35,596.9)	(22,188.0)	-	(35,390.3)	(4,268.0)
	Income taxes on earnings													
9	Excluding tax shield	(415.9)	2,221.9	1,806.0	(742.5)	(750.5)	(1,493.0)	-	(2,388.4)	5,391.7	3,003.3	-	3,316.3	1,131.0
10	Tax shield provided by interest expense	67.9	(233.9)	(166.0)	11.8	(53.4)	(41.6)	(206.3)	30.4	(117.7)	(87.3)	-	(501.2)	-
11	Income taxes on earnings	(348.0)	1,988.0	1,640.0	(730.7)	(803.9)	(1,534.6)	(206.3)	(2,358.0)	5,274.0	2,916.0	-	2,815.1	1,131.0
	Taxes on (def) / suff.													
12	Gross (def.) / suff.	(1,371.7)	8,632.1	7,260.4	1,181.6	170.6	1,352.2	5,731.0	(14,703.9)	40,153.6	25,449.7	-	39,793.3	4,268.0
13	Net (def.) / suff.	(1,008.2)	6,344.6	5,336.4	868.5	125.4	993.9	4,212.3	(10,807.4)	29,512.9	18,705.5	-	29,248.1	3,137.0
14	Taxes on (def.) / suff.	363.5	(2,287.5)	(1,924.0)	(313.1)	(45.2)	(358.3)	(1,518.7)	3,896.5	(10,640.7)	(6,744.2)	-	(10,545.2)	(1,131.0)
15	Revenue requirement	1,371.7	(8,632.1)	(7,260.4)	(1,181.6)	(170.6)	(1,352.2)	(5,731.0)	14,703.9	(40,153.6)	(25,449.7)	-	(39,793.3)	(4,268.0)
16	Gross revenue (def.) / suff.	(1,371.7)	8,632.1	7,260.4	1,181.6	170.6	1,352.2	5,731.0	(14,703.9)	40,153.6	25,449.7	-	39,793.3	4,268.0

*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.	Class	2022 Year-End Particulars ($000s)	Opening UCC Accel. CCA (a)	Opening UCC Regular CCA (b)	Total Additions Qualifying for Accel. CCA (c)	ICM, Capital Pass-Through and Integration Additions (d)	Additions Net of ICM, Capital Pass-Through and Integration (e)	Accel. CCA Depreciable UCC Balance (f)	Regular CCA Depreciable UCC Balance (g)	Rate (%) (h)	Accelerated CCA (i)	Regular CCA (j)	Closing UCC Accel. CCA (k)	Closing UCC Regular CCA (l)
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	23,294.4	(0.9)	23,295.3	73,541.4	52,791.1	6%	4,395.2	3,161.7	57,498.6	61,277.0
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	79,647.5	-	79,647.5	166,136.2	99,821.4	20%	33,214.5	19,960.0	93,097.9	119,685.2
8.	10	Transportation, computer equipment	14,261.9	22,041.2	20,296.7	-	20,296.7	44,707.0	32,189.5	30%	13,380.7	9,646.4	21,177.9	32,691.5
9.	12	Computer software, small tools	-	4,027.7	45,365.2	32,350.8	13,014.3	13,014.3	10,534.8	100%	12,456.0	10,255.7	558.4	6,786.3
10.	13	Leasehold improvements	-	-	-	-	-	-	-	N/A	-	-	-	-
11.	14.1	Intangibles	5,879.8	6,197.6	890.9	6.6	884.3	7,206.2	6,639.7	5%	360.3	332.0	6,403.7	6,749.9
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	6,480.3	-	6,480.3	18,555.6	16,894.5	30%	5,555.4	5,064.6	9,760.0	15,070.0
15.	41	Storage assets	48,703.6	68,185.0	42,923.7	-	42,923.7	113,089.2	89,646.9	25%	28,272.3	22,411.7	63,355.0	88,697.0
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	65,636.2	-	65,636.2	250,720.3	198,926.4	8%	20,057.6	15,914.1	197,844.6	215,830.4
18.	50	Computers hardware acquired after March 18, 2007	4,292.4	17,782.6	13,744.0	1,936.4	11,807.6	22,003.7	23,686.4	55%	12,048.1	13,009.5	4,051.8	16,580.6
19.	51	Distribution pipelines acquired after March 18, 2007	1,594,705.5	1,699,850.9	870,196.3	95,445.4	774,751.0	2,756,831.9	2,087,226.4	6%	165,409.9	125,233.6	2,204,046.5	2,349,368.3
20.		Total	$ 1,923,428.3	2,109,994.1	1,187,456.5	129,738.3	1,057,718.2	3,503,498.4	2,638,853.2		$ 300,803.9	$ 228,063.7	2,680,342.6	2,939,648.6
											72,740.2			

Line No.	Class	2023 Year-End Particulars ($000s)	Opening UCC Accel. CCA (a)	Opening UCC Regular CCA (b)	Total Additions Qualifying for Accel. CCA (c)	ICM, Capital Pass-Through and Integration Additions (d)	Additions Net of ICM, Capital Pass-Through and Integration (e)	Accel. CCA Depreciable UCC Balance (f)	Regular CCA Depreciable UCC Balance (g)	Rate (%) (h)	Accelerated CCA (i)	Regular CCA (j)	Closing UCC Accel. CCA (k)	Closing UCC Regular CCA (l)
1.	1	Buildings, structures and improvements, services, meters, mains	-	-	-	-	-	-	-	4%	-	-	-	-
2.	1	Non-residential building acquired after March 19, 2007	57,498.6	61,277.0	3,236.8	2.5	3,234.3	62,350.0	62,894.2	6%	3,741.0	3,773.7	56,991.9	60,737.7
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	22,548.1	26,912.3	4,446.1	-	4,446.1	29,217.3	29,135.3	15%	4,382.6	4,370.3	22,611.6	26,988.1
7.	8	Compression assets, office furniture, equipment	93,097.9	119,685.2	125,909.3	-	125,909.3	281,961.9	182,639.8	20%	56,392.4	36,528.0	162,614.8	209,066.5
8.	10	Transportation, computer equipment	21,177.9	32,691.5	3,253.9	-	3,253.9	26,058.9	34,318.5	30%	7,817.7	10,295.5	16,614.2	25,649.9
9.	12	Computer software, small tools	558.4	6,786.3	33,766.4	15,561.0	18,205.4	18,763.8	15,889.0	100%	18,763.8	15,889.0	-	9,102.7
10.	13	Leasehold improvements	-	-	-	-	-	-	-	N/A	-	-	-	-
11.	14.1	Intangibles	6,403.7	6,749.9	564.0	-	564.0	7,249.8	7,031.9	5%	362.5	351.6	6,605.3	6,962.3
12.	14.1	Intangibles (pre 2017)	-	-	-	-	-	-	-	7%	-	-	-	-
13.	17	Roads, sidewalk, parking lot or storage areas	-	-	-	-	-	-	-	8%	-	-	-	-
14.	38	Heavy work equipment	9,760.0	15,070.0	2,462.7	-	2,462.7	13,454.1	16,301.4	30%	4,036.2	4,890.4	8,186.5	12,642.3
15.	41	Storage assets	63,355.0	88,697.0	98,405.5	-	98,405.5	210,963.3	137,899.8	25%	52,740.8	34,474.9	109,019.7	152,627.6
16.	45	Computers - Hardware acquired after March 22, 2004	-	-	-	-	-	-	-	45%	-	-	-	-
17.	49	Transmission pipeline additions acquired after February 23, 2005	197,844.6	215,830.4	25,124.4	-	25,124.4	235,531.1	228,392.6	8%	18,842.5	18,271.4	204,126.4	222,683.4
18.	50	Computers hardware acquired after March 18, 2007	4,051.8	16,580.6	17,057.2	1,669.3	15,387.9	27,133.7	24,274.6	55%	14,923.5	13,351.0	4,516.2	18,617.5
19.	51	Distribution pipelines acquired after March 18, 2007	2,204,046.5	2,349,368.3	908,359.9	25,855.2	882,504.7	3,527,803.6	2,790,620.6	6%	211,668.2	167,437.2	2,874,883.0	3,064,435.8
20.		Total	$ 2,680,342.6	2,939,648.6	1,222,586.3	43,087.9	1,179,498.3	4,440,487.4	3,529,397.7		$ 393,671.1	$ 309,633.1	3,466,169.8	3,809,513.8

	2018	2019	2020	2021	2022	2023
CCA Variance (i) - (j)	13,580.7	70,503.0	47,308.8	55,163.5	72,740.2	84,038.0
Tax Rate	26.5%	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	19,276.1	22,270.1
Earnings Impact Grossed-up for Taxes Recorded in the TVDA	4,896.4	25,419.5	17,056.9	19,888.9	26,226.0	30,299.4
Balances as filed in EB-2023-0092	4,896.4	25,133.9	16,588.8	18,694.4	28,042.2	N/A
variance	-	285.6	468.2	1,194.5	(1,816.2)	-
Include adjustment to 2019 balance in 2020 TVDA	-	(285.6)	285.6	-	-	-
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	-
Include adjustment to 2022 balance in 2023 TVDA	-	-	-	-	1,816.2	(1,816.2)
Revised Balances	4,896.4	25,133.9	16,874.3	19,162.6	29,236.7	28,483.3

1 - Balance for 2019 was updated based on the change from EB-2020-0134 and Tax Filing on June 30, 2020.
2 - Balance for 2020 was updated based on the change from EB-2021-0149 and Tax Filing on June 30, 2021.
3 - Balance for 2021 was updated based on the change from EB-2022-0110 and Tax Filing on June 30, 2022.
4 - Balance for 2022 was updated based on the change from EB-2023-0092 and Tax Filing on June 30, 2023.

2023 STORAGE & TRANSPORTATION DEFERRAL ACCOUNT
EGD RATE ZONES

1. The purpose of the 2023 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 2023 S&TDA that the Company is proposing to collect from customers is $18.7 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 2023 S&TDA is higher than forecasted transportation prices, higher than forecasted market-based storage costs in 2023 and a $5.9 million collection from the Union rate zone as part of Enbridge Gas's 2021 Deferral and Variance disposition as approved by the OEB in EB-2022-0110. Transportation prices are determined by the OEB-approved M12 Rate Schedule.

5. The market-based storage costs in 2023 were $23.8 million, which is $3.7 million higher than the OEB approved market-based storage costs of $20.1 million. The increase in 2023 market-based storage costs is primarily driven by the higher average storage cost in 2023 of $0.91/GJ compared to the average storage cost in the OEB approved market-based storage costs of $0.78/GJ.

6. As outlined in the 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 September 21, 2022, 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 5 years commencing April 1, 2023 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.

7. 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 October 11, 2022. 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.

2023 TRANSACTIONAL SERVICES DEFERRAL ACCOUNT (TSDA) 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 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 2023, the Company generated a total of $ 59.5 million in net Transactional Services revenue, of which the ratepayer portion represents $ 53.6 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, $41.7 million, proposed to be credited to customers through the disposition of the 2023 TSDA. For comparison purposes, the schedule also includes amounts recorded in the applicable TSDA accounts for years 2022, 2021, 2020, and 2019.

5. The transactions that Enbridge Gas entered into in 2023 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 influenced by the lack of pipeline infrastructure serving US Northeast markets.

2023 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 (UFG)[1] and the OEB approved UFG volumetric forecast. 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 UFG volumes. This evidence provides details regarding 2023 balances recorded in the UAFVA.

2. In the EGD Rate Zone, actual UFG was determined to be 79,232 10^3m^3. The forecast volume of UFG was 106,677 10^3m^3. The variance between actual and forecasted UFG volumes of 27,445 10^3m^3 resulted in a credit balance of $6.9 million in the UAFVA, plus interest. Exhibit D, Tab 1, Schedule 3 provides the detailed calculations of the UAFVA balance.

3. Table 1 provides historical UFG volumes for the EGD Rate Zone from 1991 to 2023.

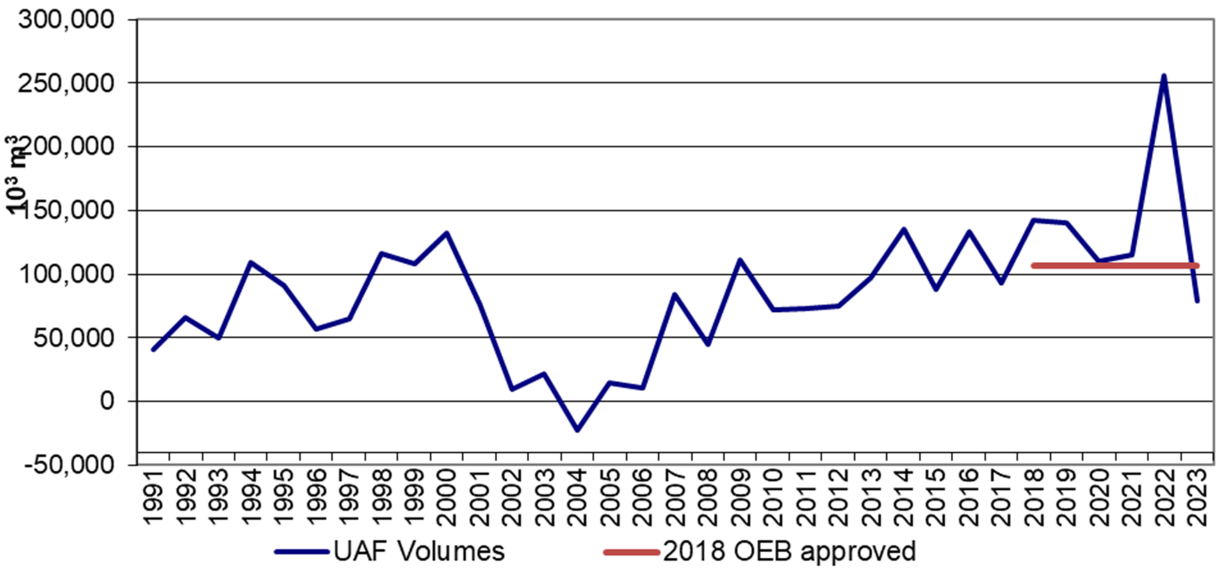
[1] "UAF" is the term historically used in reference to distribution related gas losses in the EGD rate zone. All references to unaccounted for gas will be harmonized to be "UFG" effective January 2024, as described in the Company's 2024 Rebasing Application, EB-2022-0200, Exhibit 4, Tab 3, Schedule 1.

Table 1
Historical UAF Volumes for EGD Rate Zone

Line No.	Calendar Year	UAF Volumes (10^3 m^3)
1	1991	40,662
2	1992	66,028
3	1993	49,782
4	1994	108,765
5	1995	90,655
6	1996	56,739
7	1997	65,228
8	1998	116,376
9	1999	108,201
10	2000	132,021
11	2001	75,606
12	2002	9,284
13	2003	21,412
14	2004	-22,406
15	2005	14,815
16	2006	10,274
17	2007	83,823
18	2008	44,424
19	2009	110,917
20	2010	72,104
21	2011	73,355
22	2012	74,762
23	2013	97,361
24	2014	135,380
25	2015	88,438
26	2016	133,112
27	2017	93,077
28	2018	142,086
29	2019	140,594
30	2020	110,234
31	2021	115,553
32	2022	256,333
33	2023	79,232

4. Figure 1 shows historical UFG volumes for the EGD Rate Zone from 1991 to 2023 and includes the 2018 OEB-approved UFG volume forecast.

Figure 1: Historical Unaccounted-For Gas Volumes (10^3m^3)



5. In the Settlement Proposal for the Company's 2022 Deferral and Variance Account and Earnings Sharing proceeding (EB-2023-0092),[2] Enbridge Gas agreed to address the following items in the current Application:

> Detailed evidence will be filed about the items learned and future plans arising from the ongoing review and investigation of UFG (see Exhibit I.Staff.6), including (without limitation):
>
> - the work completed by Enbridge Gas during 2023 and 2024 and the resulting observations and learnings,
> - the impact on UFG from "no bill" customers / volumes that are later billed,
> - the role, if any, played by Linepack in transmission and other high pressure systems in the incidence and determination of UFG, and
> - the Company's investigation plan for assessing fugitive emissions.[3]

6. Accordingly, to support the relief sought by Enbridge Gas and to satisfy commitments previously made regarding UFG volumes, Enbridge Gas is providing additional detail surrounding recent learnings and observations made regarding UFG, the impact of No Bills and transmission and high-pressure system Linepack on UFG, and the Company's Fugitive Emissions Measurement Project. The additional

[2] EB-2023-0092, OEB Decision on Settlement Proposal and Rate Order, February 6, 2024, p.4.
[3] As agreed in the EB-2022-0200 Settlement Proposal, Exhibit O1, Tab 1, Schedule 1, June 28, 2023, pp.36-37.

detail broadly applies to all rate zones unless otherwise indicated and is organized as follows:

Section 1: UFG-related Works, Observations, and Learnings
Section 2: Impact of No Bill Customer Volumes on UFG
Section 3: Impact of Transmission & Other High-Pressure System Linepack on UFG
Section 4: The Fugitive Emissions Measurement Plan Project

7. In all instances set out below, it is important to consider the relative range of uncertainty associated with any estimated volumetric impacts (e.g., the accuracy of measurement assets, estimated volumetric gas losses or emissions, etc.). Additionally, any quantification set out below carries a degree of uncertainty that must be considered when evaluating the magnitude of impacts to UFG.

8. As detailed in Section 3.3, Enbridge Gas is also seeking OEB approval to establish a Fugitive Emissions Measurement Administration Deferral Account (FEMADA) to record administrative costs associated with the implementation of the Company's fugitive emissions investigation plan.

Section 1: UFG-related Works, Observations and Learnings

Section 1.1 – Background

9. As discussed in the Company's 2022 Deferral and Variance Account Clearance Application (EB-2023-0092), in response to the elevated levels of UFG experienced in 2022, Enbridge Gas has taken the initial steps to establish a 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. Since initially filing its evidence in that proceeding, two subsequent settlement negotiations have focused the Company's efforts and strategic trajectory in this regard:

(i) On July 12, 2023, the Company filed a partial Settlement Proposal for its 2024 Rebasing Application that included a novel harmonized regulatory mechanism to recover UFG costs for all rate zones effective January 2024.[4] This mechanism further incents the Company to reduce both overall UFG volumes relative to approved forecast and inter-year volatility of UFG volumes. Enbridge Gas also agreed to determine and report on an appropriate way to identify, measure, and mitigate fugitive emissions and to file a robust investigation plan for consideration and determination as part of the current Application (see Section 4 for additional detail). The OEB accepted the Settlement Proposal on August 17, 2023.[5]

(ii) On November 28, 2023, the Company filed a Settlement Proposal for its 2023 Deferral and Variance Account Clearance Application that included a commitment to investigate the impact of No Bill customers/volumes that are later billed on UFG and to investigate the role of Linepack in transmission and other high-pressure systems in the incidence and determination of UFG.[6]

10. Accordingly, Enbridge Gas began preparation of analysis and evidence relating to the above changes and commitments. Learnings and observations made regarding recent investigations into the impact of No Bills, and high-pressure pipeline system Linepack on UFG are addressed in Sections 2 and 3, respectively. The existing systems and processes underlying derivation of UFG balances, including No Bills and Linepack, are complex in nature so the Company is providing additional foundational explanation and illustrative examples to assist with understanding.

11. As noted in response to interrogatories in the Company's 2023 Deferral and Variance Account Clearance proceeding, as of October 31, 2023, a manager was selected to determine resource requirements to support these efforts. As of Q1

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[4] EB-2022-0200, Updated Settlement Proposal, July 12, 2023, pp. 11, & 36-37.
[5] EB-2022-0200, OEB Decision on Settlement Proposal, August 17, 2023.
[6] EB-2023-0092, Settlement Proposal, November 28, 2023, pp. 19-20.

2024, resources have been allocated and the long-term scope of the UFG initiative remains consistent with the Project Charter previously filed with the OEB.[7]

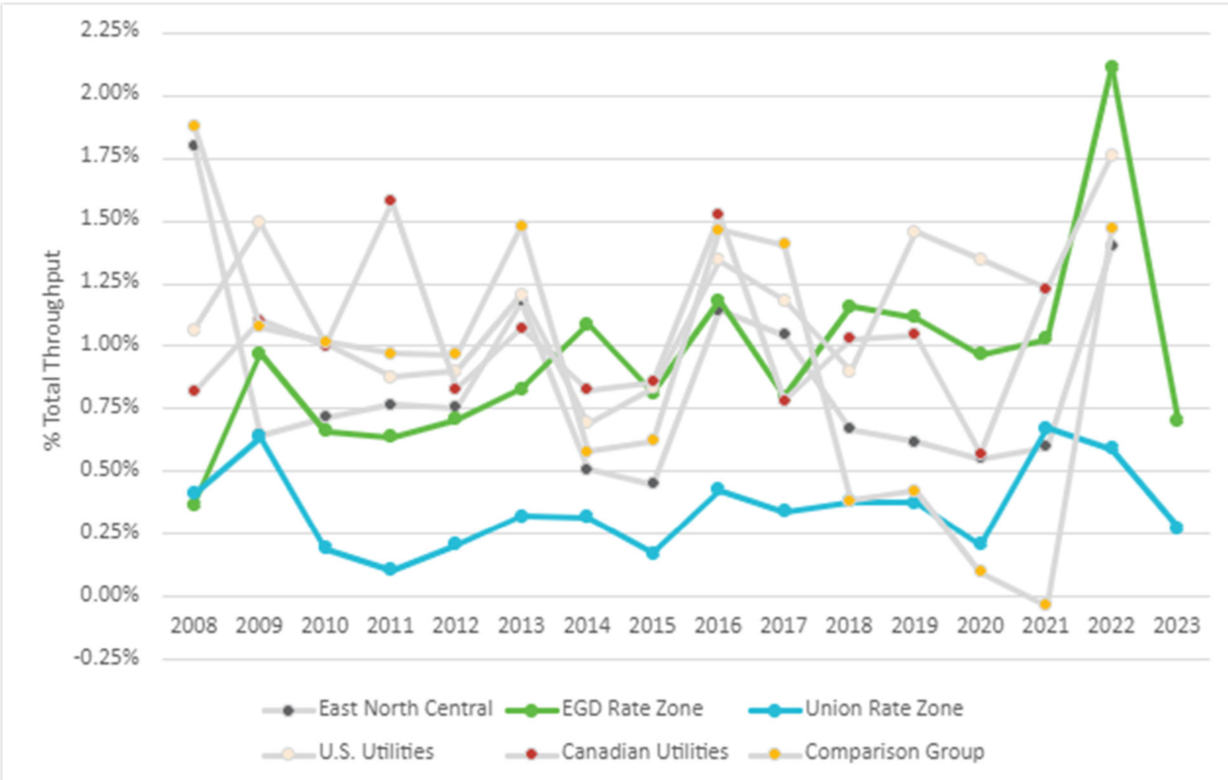
Section 1.2 – Benchmarking

12. 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 from 2008-2017 Enbridge Gas had demonstrated lower average UFG volumes than comparative gas utilities.[8]

13. 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 2022 for comparative utilities and 2023 for the Company) and updated the benchmark analysis set out in the 2019 UFG Report.[9] Figure 2 reflects the best available data regarding UFG volumes for each of the comparative utilities. To put these volumes into perspective, total system UFG in 2023 amounted to approximately 201,845 10^3m^3 (79,232 10^3m^3 in the EGD Rate Zone and 122,613 10^3m^3 in the Union Rate Zones) compared to total system throughput for that same year of approximately 56,645,986 10^3m^3 (0.36%).

[7] EB-2023-0092, Exhibit I.STAFF.6, Attachment 1.
[8] EB 2019-0194, Report on Unaccounted for Gas, December 19, 2019, pp. 3-4.
[9] Refer to EB 2019-0194, Report on Unaccounted for Gas, page 15 for details regarding comparative utilities included in Benchmark Analysis.

Figure 2: UFG Benchmark Analysis



14. Figure 2 demonstrates that all utilities included in the benchmark analysis experienced similar volatility in UFG over the period from 2008-2022, with material increases recorded in any one year generally reversing in subsequent years. This was the case for Enbridge Gas's UFG volumes in 2022 compared to those experienced in 2023. As noted in its most recent Decisions regarding UFG costs and related rate riders for AltaGas and ATCO, the Alberta Utilities Commission stated: [10]

> In prior decisions, the Commission recognized that UFG is an expected element of operating a natural gas distribution system. The Commission also recognized that, due to the many factors that impact UFG, the UFG amount will fluctuate over time.

[10] Alberta Utilities Commission, Decision 27552-D01-2022 (September 12, 2022), 2022-2023 Unaccounted-For Gas Rider E and Rider H. (Apex Utilities Inc.), pp. 2-4; and Alberta Utilities Commission, Decision 28406-D01-2022 (October 17, 2022), 2023 Unaccounted-For Gas Rider D and Rider P. (ATCO Gas and Pipelines Inc.), pp. 2-4.

15. Figure 2 reflects certain industry-wide trends across comparative utilities, such as a general decline in UFG volumes recorded in each of 2014, 2015 and 2020 followed by increases in UFG volumes recorded in subsequent years. Importantly, nearly all comparable utility groups set out in Figure 2 also experienced a significant increase in UFG volumes in 2022. It is reasonable to assume that such trends in UFG volumes or related trends in UFG costs may be reflective of common macro-economic, geo-political, and/or national/continental weather trends, which have the potential to impact UFG volumes or costs broadly across the industry. Such trends highlight the value of comparing UFG volumes and costs experienced by a single utility to relevant peer groups over time.

16. Finally, Figure 2 also shows that the EGD and Union Rate Zones' UFG volumes and annual fluctuations are generally consistent with other gas utilities. It also demonstrates that while Enbridge Gas has experienced recent increases in UFG volumes in the Union Rate Zones (2021) and in the EGD Rate Zone (2022), UFG volumes for 2023 were far lower in all rate zones.

Section 1.3 – Derivation of Balances

17. Throughout 2023 and 2024, Enbridge Gas assessed many complex systems and processes that contribute to the derivation of UFG balances. The details set out within this section of evidence serve to educate and inform the reader of those relevant systems and processes and to provide the necessary foundation to support understanding of the topics discussed within subsequent sections of evidence. This section of evidence describes the Company's processes and methodologies to derive annual UFG volumes and to calculate resulting balances in UFG-related variance accounts for the EGD Rate Zone and the Union Rate Zones. More specifically, this section describes how the Company's UFG Forecast is determined, and the monthly and annual processes for determining actual UFG volumes.

Determination of UFG Forecast –

EGD Rate Zone

18. The current method to forecast UFG volumes in the EGD Rate Zone estimates the relationship between historical calculated UFG and the total historical unlocked/active customers based on the presumption that UFG volume is directly correlated to the scale of the distribution system.

19. Historically, the UFG volume forecast was updated annually and approved by the OEB as part of the Company's annual rate setting proceedings. Since the amalgamation of EGD and Union, the UFG 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 UFG volume forecast is an annual amount, which is split into monthly volumes in proportion to the monthly profile of forecasted total throughput for the EGD Rate Zone.

Union Rate Zones

20. 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%).

21. The ratio of UFG volumes to total system throughput used to forecast UFG volumes for the period of 2013 to 2023 of 0.219% was established based on the weighted average of actual UFG and total system throughput volumes from 2009-2011.[11] This OEB-approved ratio is multiplied by the annual total system throughput forecast for a given year to derive an annual forecast of UFG volumes. Similarly, the UFG volume

[11] As approved by the OEB as part of Union's 2013 Cost of Service Application - EB-2011-0210, Exhibit D3, Tab 2, Schedule 2, Updated; EB-2011-0210, OEB Decision and Order, October 24, 2012.

currently included in rates is calculated by multiplying the 0.219% ratio by the 2013 OEB approved forecast total system throughput volumes.

2024+ Harmonized Methodology

22. Effective January 1, 2024, Enbridge Gas will rely upon a consolidated OEB-approved methodology to forecast annual UFG volumes across all rate zones, based on the average annual actual UFG volumes calculated for all rate zones from 2018-2020 of 243,681 10^3m^3.[12]

Determination of Actual UFG – Monthly Processes

23. For the purposes of deriving UFG-related costs, UFG volumes are calculated by determining the difference between net gas sendout volumes (Sendout) and actual in-franchise customer consumption volumes (Consumption). In a theoretical system with no UFG, Sendout volumes would match Consumption volumes.

Sendout

24. Sendout is the net volume of natural gas delivered into the Enbridge Gas distribution system to serve in-franchise customer demands after accounting for receipts and deliveries across Enbridge Gas' integrated storage, transmission, and distribution systems.

25. Receipts are the volumes of gas received into the distribution system from various interconnects and measured via custody transfer measurement, including:
    - ex-franchise transmission pipelines,
    - local Ontario production (Producers), from traditional natural gas production wells and renewable natural gas (RNG), as well as hydrogen,
    - net withdrawals from Ontario storage pools, and
    - injections into the distribution system from liquified natural gas (LNG) and compressed natural gas (CNG) facilities.

[12] EB-2022-0200, Partial Settlement Proposal, Exhibit O1, Tab 1, Schedule 1, June 28, 2023, p. 37.

26. Deliveries are the volumes of gas delivered by Enbridge Gas from its integrated storage, transmission, and distribution systems to various interconnects and measured via custody transfer measurement, including:
    - ex-franchise transmission pipelines,
    - net injections into Ontario storage pools,
    - injections into LNG and CNG facilities,
    - Company use fuel (e.g., line heaters, space heating, etc.), and
    - Company blowdown gas (i.e., an estimate of volumes typically purged or flared for operational maintenance purposes).

27. At custody transfer points, there is custody transfer measurement and often check measurement both of which utilize Measurement Canada approved equipment.[13] Custody transfer measurement, as it is the official system of record for billing purposes, is required to comply with Measurement Canada's +/- 3% overall volume measurement error tolerance.[14]

28. Further, Enbridge Gas operates within more stringent measurement error tolerances. The Company maintains up to a +/- 1% measurement error tolerance for testing and sealing a meter within a controlled test environment. Enbridge Gas investigates any monthly volume variance between custody transfer and check metering volumes that exceeds +/- 2%. 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. It is important to consider such measurement error tolerances together with other uncertainties when

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[13] Check measurement is not required to comply with Measurement Canada's standards.
[14] At custody transfer points where gas is delivered to the Company, the interconnecting operator (third-party) has custody transfer measurement while Enbridge Gas often has check measurement. Ownership of measurement is reversed at custody transfer points where Enbridge Gas delivers gas to an interconnecting operator (third party). A small number of exceptions to this rule exist wherein Enbridge Gas regularly analyzes and validates sole source measurement data for consistency to ensure a consistent "quality" of information across all custody transfer points.

assessing contributing sources of actual UFG volumes observed annually (0.36% for 2023 as discussed in Section 1.0).

Consumption

29. The nature of available customer Consumption data, whether it is measured or estimated and whether it is billed or not billed, impacts the calculation of UFG. In general, the Consumption volumes used in the calculation of UFG include both billed Consumption and unbilled Consumption. Billed Consumption volumes are sourced from the billing system and interfaced to the financial accounting system. Unbilled Consumption volumes are calculated and recorded within the financial accounting system only.

30. Consumption is billed monthly and is calculated within the billing system based on a combination of actual and estimated meter reads. Most contract rate customers have actual daily measurement recorded, using telemetry devices (see Section 1.4 for additional discussion of the nature of telemetry for contract rate customers), which is used to calculate their billed Consumption. The remaining customers, which are mainly residential and small commercial customers, have periodic meter reads completed and rely on a combination of actual and estimated meter reads to calculate their billed Consumption. Estimated meter reads are calculated for each customer based on the Consumption history for their respective premises. When insufficient Consumption history exists to derive an accurate estimated meter read, the billing system uses a combination of heating degree day data (HDD) and standard factors, depending upon the nature of the customer and premises, to derive an estimate.

31. In instances where a customer's billed Consumption is based on an estimated meter read, a subsequent true up will occur once an actual meter read is next recorded. After obtaining an actual meter read, Enbridge Gas performs a volumetric billing adjustment by allocating the Consumption over the estimated period using HDDs, the number of days in each billing period, and the customer's actual Consumption

for the same period in the prior year.[15] In situations where the customer's Consumption pattern varies by season, Enbridge Gas works with the customer to understand the nature of their Consumption. When a volumetric adjustment spans more than a single fiscal quarter, the Company also ensures that the appropriate quarterly QRAM rate is applied to consumed volumes. See the example set out in Table 2 for the accounting treatment of an illustrative Estimated Meter Read scenario:

[15] Re-allocation of volumes to previous months are completed in following with Enbridge Gas policy as required under section 7.3.2 of GDAR.

Table 2

"Estimated Meter Read" Example

Line No.	Particulars (units of Consumption)	Month 1	Month 2
		(a)	(b)
1	Sendout	100	100
	Billed Consumption		
2	Estimated Read	95	-95
3	Actual Read	0	200
	Finance Estimate		
4	No Bills	0	0
5	Unbilled	0	0
6	Total Consumption (Billing + Finance) (lines 2 + 3 + 4 + 5)	95	105
7	Monthly UFG (line 1 - 6)	5	-5
8	Cumulative UFG (1)	5	0

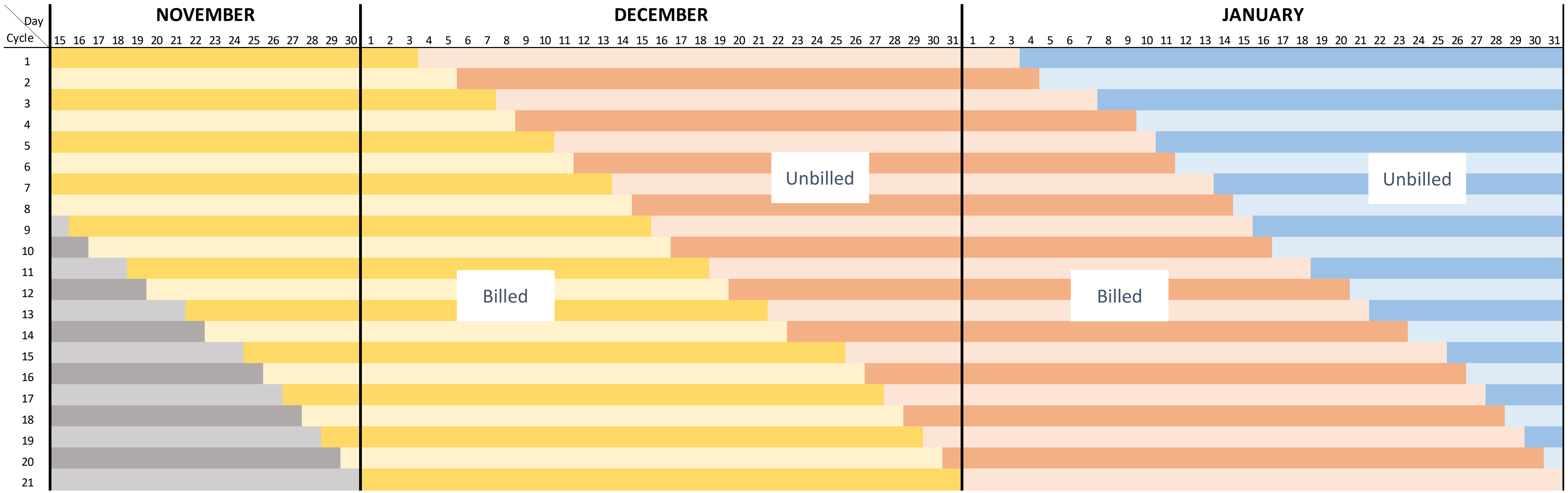
Notes:
(1) Cumulative UFG for Month 1 equals line 7 column (a). Cumulative UFG for Month 2 equal line 7 column (a) plus line 7 column (b).

32. The billing system ensures that any volumetric billing adjustment to the customer applies the appropriate QRAM rate for the period in which Consumption occurred. To the extent that a volumetric billing adjustment is recorded, it is reflected in the financial accounting system in the period in which the final billing adjustment ultimately occurred.

33. Consumption volumes for the purposes of calculating UFG also includes an estimation of gas consumed but not yet billed (unbilled Consumption). This includes customers who are billed on a staggered schedule throughout the month (Cycle Billed) as well as customers who have not been issued a bill in a specific accounting period (referred to as "No Bills").

34. Cycle billing is a common industry practice whereby customers are billed based on a schedule that is staggered throughout the month rather than billing all customers on the same date. As a result of cycle billing, a portion of customer Consumption at any point in time has not been billed. Figure 3 provides an illustrative example of the Company's cycle billing practices. In this instance, for the calendar month of December, the yellow-highlighted portions of cycles 1-21 represent Consumption that occurred within the month of December and that will be billed within that same month. The orange-highlighted portions of cycles 1-21 represent Consumption that occurred within the month of December and that will be billed in the following month (January).

Figure 3: Graphical Depiction of Cycle Billing



35. To align the reporting of monthly customer Consumption with calendar month reporting periods for accounting purposes, it is necessary to record an estimate of gas delivered but not yet billed at the end of every monthly reporting period. This estimate is recorded in the financial accounting system and is calculated at the rate class level. This estimate considers factors such as number of customers per billing cycle, number of days for each cycle which have not been billed, average use per HDD, actual HDDs, and demand coefficients. The unbilled Consumption estimate that is recorded in each reporting period in the accounting system 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 volumetric adjustment is performed and recorded to reflect the difference. See the example set out in Table 3 for the accounting treatment of an illustrative Cycle Billing scenario:

Table 3
"Cycle Billed" Example

Line No.	Particulars (units of Consumption)	Month 1	Month 2
		(a)	(b)
1	Sendout	100	100
	Billed Consumption		
2	Estimated Read	45	-45
3	Actual Read	0	200
	Finance Estimate		
4	No Bills	0	0
5	Unbilled	50	-50
6	Total Consumption (Billing + Finance) (lines 2 + 3 + 4 + 5)	95	105
7	Monthly UFG (line 1 - 6)	5	-5
8	Cumulative UFG (1)	5	0

Notes:
(1) Cumulative UFG for Month 1 equals line 7 column (a). Cumulative UFG for Month 2 equal line 7 column (a) plus line 7 column (b).

36. "No Bills" refers to the scenario where a bill has not been issued to a customer in a given accounting period. In these instances, Enbridge Gas' financial practice is to record an estimate of gas volumes delivered but not yet billed, which follows a process very similar to the "cycle-billed" unbilled estimation process described above. The No Bills estimate is calculated at the rate class level and recorded within the financial accounting system. This estimate considers factors such as billing cycles, number of customers, number of billing periods which have not been billed, average use per HDD, actual HDDs, and demand coefficients. The No Bills Consumption estimate that is recorded in each reporting period in the financial accounting system is reversed in the following reporting period and replaced by actual billed Consumption. To the extent that the estimate of the Consumption recorded in the accounting system differs from the actual billed Consumption, a

volumetric adjustment is completed in the financial accounting system and recorded to reflect the difference. Section 2 provides additional discussion on the incidents of No Bills, and their impact on UFG volumes.

37. If the estimation of unbilled and No Bills Consumption recorded in the financial accounting system was determined to be understated, the effect is a temporary increase to cumulative UFG in the period that the Unbilled and No Bills estimation was recorded. That same increase to cumulative UFG is then reversed when the estimate is replaced with actual billed Consumption in a subsequent period. The inverse is also true. See the example set out in Table 4 for an illustrative No Bills scenario:

Table 4
"No Bill" Example

Line No.	Particulars (units of Consumption)	Month 1 (a)	Month 2 (b)
1	Sendout	100	100
	Billed Consumption		
2	Estimated Read	0	0
3	Actual Read	0	200
	Finance Estimate		
4	No Bills	80	-80
5	Unbilled		
6	Total Consumption (Billing + Finance) (lines 2 + 3 + 4 + 5)	80	120
7	Monthly UFG (line 1 - 6)	20	-20
8	Cumulative UFG (1)	20	0

Notes:
(1) Cumulative UFG for Month 1 equals line 7 column (a). Cumulative UFG for Month 2 equal line 7 column (a) plus line 7 column (b).

38. Measurement errors also result in a difference between actual and metered customer Consumption volumes and can be attributable to meter failure, meters that do not accurately correct for temperature or pressure variations, or Consumption that is no longer appropriate for the size of meter installed.[16] Like adjustments made to correct billing estimates, to the extent that measurement errors occur and are quantifiable, a volumetric billing adjustment is performed and recorded to reflect the difference between actual and metered customer Consumption volumes (see Sections 1.4 and 2 for further discussion regarding measurement errors). Measurement errors result in a UFG loss/(gain) in the period when the error occurs and an equal and offsetting UFG (gain)/loss when a volumetric billing adjustment is performed and recorded.

[16] EB-2019-0194, Report on Unaccounted for Gas, December 19, 2019, p. 28.

39. On a monthly basis, the calculation of UFG volumes is recorded based on an annual forecasted heat value for natural gas delivered to customers.[17] In the following month, when the actual heat values are available, the difference between the actual and annual forecasted heat value is recorded in UFG deferral and variance accounts.

40. On a monthly basis, the determination of Sendout includes an entry to record operational blowdowns or flaring associated with compressor facilities as noted in the discussion on Sendout above. By accounting for the volumes associated with these operational blowdowns or flaring, these volumes are removed from Sendout and as such do not contribute to calculated UFG volumes. A similar entry is recorded, where necessary, for blowdowns or flaring associated with capital projects.

41. In summary, the monthly determination of UFG is derived as the difference between Sendout and Consumption. The residual difference between Sendout and Consumption represents a combination of actual physical gas losses/gains as well as temporary variances resulting from estimation used in both the billing and accounting processes described in this section. The temporary variances are reversed when the appropriate true ups are recorded in a subsequent accounting period. The treatment of these true ups when they occur in a subsequent fiscal year relative to the period of time in which the true ups pertain to is addressed in the next section.

Determination of Actual UFG – Annual Processes

42. The monthly processes described above are normal course of business for each monthly accounting reporting period, including the end of the calendar fiscal year. However, there are additional processes that occur on an annual basis.

[17] Heat value is the amount of energy per volume of the natural gas stream. As discussed in Enbridge Gas' 2024 Rebasing Application EB-2022-0200, Exhibit 3 Tab 6, Schedule 1, p. 2, conversion of volumes to energy is required as the natural gas industry measures natural gas transactions in energy units (GJ) however Enbridge Gas measures consumption in meters cubed (m^3).

43. For the EGD Rate Zone, there is an additional step that is completed after the end of the calendar fiscal year. The current accounting order for the UAFVA states that, "An adjustment will be made to the UAFVA in the subsequent year to record any differences between the estimated UFG and actual UFG."[18] In the EGD Rate Zone, the variance between the unbilled and No Bills estimated consumption recorded in December and the associated billed Consumption recorded in the following year is included in the calculation of the UAFVA balance for the fiscal year during which the unbilled and No Bills estimate(s) were recorded. This ensures that any such adjustment(s) is recorded in the UAFVA for the reporting period that the Consumption pertains to and eliminates a timing variance across fiscal years.

44. No such provision to record an adjustment(s) relating to unbilled and No Bills estimated Consumption across fiscal years exists for the Union Rate Zones or the associated UFGVDA. As such, to the extent that a variance exists between estimated Consumption and actual Consumption, any adjustment(s) made after December will be recorded in the deferral account in the subsequent fiscal year.

45. In its 2024 Rebasing Application,[19] Enbridge Gas proposed to harmonize UFG-related deferral and variance accounts for the EGD and Union Rate Zones into a single UFG Volume Variance Account (UFGVVA) (Account No. 179-203). Like the accounting treatment currently applicable to the EGD Rate Zone UAFVDA, the proposed harmonized accounting order includes a provision enabling the Company to adjust for differences in estimated UFG and actual UFG to minimize timing variance(s) across fiscal years for all rate zones. The OEB accepted the Company's proposed accounting order and treatment effective January 1, 2024.[20]

46. There are exceptional circumstances that may occur where true-ups are recorded in a year subsequent to the period that the consumption pertains to, beyond the timing

[18] EB-2019-0194, Exhibit D, Tab 3, Accounting Order, Appendix B, p. 9.
[19] EB-2022-0200, Exhibit 9, Tab 1, Schedule 1, Attachment 3, p. 7.
[20] EB-2022-0200 Exhibit O1, Tab 1, Schedule 1, pp. 54-55, and EB-2022-0200, OEB Decision and Order, December 21, 2023.

that allows for inclusion in the annual adjustment as discussed in the previous paragraph. Furthermore, the adjustment that is made to the UAFVA is limited to true-ups associated with unbilled and no bill estimates. As described above, true-ups also occur in relation to scenarios such as estimated meter reads, billing disputes or measurement errors. These true-ups are generally referred to as prior period adjustments (PPAs) and are normal course of business. As an example, a delayed meter reading would result in consecutive estimates, which is not trued-up until the actual meter read ultimately takes place. If the actual read and associated true-up occurs in a different fiscal year than the period which the consumption occurred, the true-up has the effect of impacting the current year UFG volumes. As UFG volumes are recorded in the respective deferral/variance accounts and are disposed of, the appropriate customers and rate classes are allocated a portion of the relevant UFG deferral/variance account based on OEB approved allocation methodologies. If a PPA associated with those volumes is recorded in a subsequent fiscal year, the PPA would result in a corresponding offsetting impact to the relevant deferral/variance account balance in that year and would subsequently be disposed of in the same manner keeping ratepayers whole.

47. On an annual basis, an adjustment is made to remove monetary recoveries of gas loss amounts resulting from third-party damages from the UAFVA balance for the EGD rate zone. No similar adjustment is made for the UFGVA for the Union rate zones. See section 1.4 for further detail on the harmonization of gas loss calculations and harmonization of treatment of gas loss damage recoveries within the harmonized UFGVVA starting in 2024.

48. Each year for the Union Rate Zones, the Company allocates UFG to its unregulated business(s) based on gross unregulated storage activity as a percentage of total actual gross storage and transportation activity. This ensures that no costs or volumes associated with unregulated business activities are included in the amounts recorded in the UFGVDA.

49. For the EGD Rate Zone, the Company recovers UFG volumes and costs relating to storage operations volumetrically in delivery rates based on a fixed OEB-approved provision, and no variances are recorded in a variance account. An allocation of storage related UFG volumes is made to unregulated storage operations, using a capacity-based allocation, as determined in EGD's 2016 Rate Application.[21]

50. A detailed description of the current methodology and a modified methodology proposed to become effective January 1, 2024, was filed as part of the Company's 2024 Rebasing Application and is being reviewed by the OEB as part of Phase 2 of that proceeding.[22]

51. Enbridge Gas also undergoes an annual audit of storage inventory to identify inventory variances as described in Section 1.4. In the Union Rates Zones, adjustments to inventory resulting from the storage inventory audit are recorded in the UFGVDA. In the EGD Rate Zone, as described above, the Company recovers UFG volumes and costs related to storage operations based on a fixed OEB-approved provision, and no variances are recorded in a variance account. Adjustments to inventory from the storage inventory audit in the EGD Rate Zone are not recorded in the UAFVA, which recovers distribution related gas losses only. As a single harmonized UFGVVA was approved as part of the Company's 2024 Phase 1 Rebasing proceeding, adjustments to inventory resulting from storage inventory audits for both legacy rate zones will be recorded in the UFGVVA as of 2024.

[21] EB-2015-0114, Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, December 1, 2015, pp.14-15.
[22] EB-2024-0111, Phase 2 Exhibit 1, Tab 13, Schedule 2.

Section 1.4 – 2023/2024 UFG Learnings and Observations

52. In response to interrogatories in its 2023 Deferral and Variance Account Clearance proceeding, the Company described several recent and ongoing initiatives with the potential to provide insights into UFG volumes experienced or potential UFG mitigation activities.[23] Despite the recent adjusted priorities of the UFG team described above, some further progress has been made to better understand the implications of those recent and ongoing initiatives, to assess the materiality of certain known contributing sources of UFG, to mitigate certain known contributing sources of UFG, and to identify additional potential contributing sources of UFG for future investigation and mitigation.

Participation in Industry Groups/Associations, & Cross-Functional Measurement Groups

53. As discussed in the Company's 2024 Rebasing application and associated UFG Progress Report,[24] the Company is continuing its work with interconnecting pipelines through participation in industry associations and remains focused on increasing internal cross-functional collaboration related to measurement.

54. In terms of its participation in Industry Groups and Associations, representatives of Enbridge Gas participate in the Canadian Gas Association's Measurement & Regulation Committee and Steering Group as well as its Gas Process Advisory Committee which is chaired by Measurement Canada. Enbridge Gas and other industry stakeholders also meet regularly with Measurement Canada, as part of various working groups, to support revisions to Measurement Canada's specifications with the goal of increasing measurement accuracy across the industry. In 2023, the Company supported revisions to the specifications for compliance sampling used for seal extension and is currently working with Measurement

[23] EB-2023-0092, Exhibit I.STAFF.6, p. 2.
[24] EB-2022-0200, Exhibit 4, Tab 3, Schedule 1, p. 20, and Attachment 3. p. 15.

Canada on pressure factor metering (PFM) specifications modernization and on specifications for ultrasonic meters.

Work to Update Gas Quality Parameters

55. As discussed in the Company's 2024 Phase 1 Rebasing application and associated UFG Progress Report and Supplemental UFG Progress Report, in 2020 the Company initiated a project to address outdated and non-representative gas quality parameters in more than 6,000 electronic volume corrector (EVCs) devices across the EGD Rate Zone.[25] Whereas EVCs in the Union Rate Zones were historically (since 2002) periodically updated, EVCs in the EGD Rate Zone were found to not have been updated to reflect the characteristics of the current natural gas supply mix entering Ontario, resulting in undercalculation of supercompressibility,[26] under measurement of volumes, and unaccounted for gas volumes.[27] At the time, Enbridge Gas concluded that the impacts of reliance on outdated gas quality parameters could have resulted in undermeasurement of volumes, which would have contributed to UFG volumes/costs recorded for the EGD Rate Zone, ranging from 0.05% at 60 psig to 0.67% at 700 psig, resulting in estimated potential annual volumetric impacts of approximately 2,116 10^3m^3.[28]

56. As of June 2019, all new EVC installations are made with updated parameters. As of the date of this filing, more than 6,000 EVCs have been updated. The Company expects that all remaining EVCs in the EGD Rate Zone will be configured with more

[25] EB-2022-0200, Exhibit 4, Tab 3, Schedule 1, Attachment 3, pp. 13-14. Please also see the response at EB-2022-0200, Exhibit I.4.3-FRPO-153.
[26] Supercompressibility factor is a factor to compensate for the compressibility of the flow gas, what is sometimes termed the deviation from Boyle's law. The factor is derived based on compressibility factors of the gas at base pressure and at flow conditions. (U.S. National bureau of Standards)
[27] Conversion of natural gas volumes from line conditions to standard conditions (101.325 kPa and 15 ˚C) requires a supercompressibility correction via a supercompressibility factor applied in the field via EVCs and remote terminal units (RTUs) to obtain accurate values of natural gas volume. Enbridge Gas uses the NX-19 method to calculate supercompressibility, which requires measures of specific gravity, N_2 concentration, and CO_2 concentration.
[28] More precise calculation would require comparison of results through meters for both historic and updated parameters using exact replication of real-time historic flows, atmospheric pressures, and gas temperature.

representative gas quality parameters by 2025 through the course of routine pressure regulation and measurement inspections. Going forward, gas quality parameters will be updated at a minimum on a 5-year cycle (for those with a lower maximum operating pressure (MOP) and flow rate) and as frequently as annually (for those with a higher MOP and flow rate). Further, the Large Volume Measurement Integration initiatives described below (namely the deployment of new measurement systems) are expected to improve the Company's ability to manage supercompressibility parameters as it will be possible to adjust them over-the-air (remotely).

Work to Eliminate a Backlog of Leaks

57. As discussed in the Company's 2024 Phase 1 Rebasing application and associated UFG Progress Report, in 2021 the Company initiated a project to eliminate 3,274 class-C leaks identified within the Union Rate Zones following the integration of Union and EGD.[29] The project was completed on December 31, 2023, and was successful in resolving all identified leaks either via repair (1,563 instances), close-out (1,701 instances),[30] or request for variance (10 instances of outstanding leaks). The Company intends to mitigate the 10 outstanding leaks that currently remain as part of planned replacement works over the course of 2024 and 2025. Going forward, all class-C leaks will be monitored every 12 months and will be repaired within 18 months of discovery, in accordance with the new integrated Enbridge Gas Leak Standard.

58. At this time, the Company does not measure flow rates from leaks within the distribution system and is not able to accurately estimate the actual impact of the backlog of leaks on calculated annual UFG volumes. However, using published

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[29] Union had previously maintained an operating standard that required class-C leaks to be monitored every 12 months (if not otherwise repaired) to ensure that they did not progress to more sever class-A or class-B leaks that required more urgent mitigative action. Class-C leaks are defined as, a leak on any non-plastic asset that is nonhazardous at the time of detection and can be reasonably expected to remain nonhazardous.
[30] Certain of the leaks closed out included duplicative reported leaks or data errors that were subsequently investigated and resolved.

industry-average emission factors as prescribed by the provincial and federal GHG reporting programs, it is estimated that the reduction of the backlog of leaks has resulted in a reduction in the annual loss of natural gas of approximately 1,100 10^3m^3. As discussed in Section 4, Enbridge Gas has initiated the Fugitive Emissions Measurement Plan Project to develop an investigation plan to quantify fugitive emissions more accurately.

Various Meter Reading Campaigns & Initiatives

59. In 2019, a key meter reading vendor terminated its service contract with Enbridge Gas, resulting in the need to hire a new vendor. The impacts of this issue persisted into 2020 and 2021 as the new vendor continued to learn Enbridge Gas's unique business requirements, dealt with extreme weather events (freezing rain, polar vortex, heavy snowfall, and flooding, all of which impacted access to certain properties), and struggled to maintain service standards and staffing levels throughout the COVID-19 pandemic due to events beyond the Company's control, including closed businesses and storefronts, and increased customer opposition to providing physical access to premises.[31]

60. As noted in Enbridge Gas's 2024 Phase 1 Rebasing evidence, as of the time of that filing (September 2022) the Company had initiated a variety of campaigns to improve meter reading frequency and efficiency, including:[32]

- Consecutive estimate campaign – working with meter reading vendors to hire additional readers and conduct meter reading and communication campaigns.
- Inbound calls – educating customers on the importance of providing access to meters and aiding them to read their own meters.

[31] Enbridge Gas was required to follow Public Health guidelines during the COVID-19 pandemic, including observation of lockdown, quarantine, and social distancing requirements. During periods of lockdown, Enbridge Gas faced several challenges with meter reading and directed its meter reading partners to ensure that all staff were working as safely as possible, and to avoid close contact with the public and customers.
[32] EB-2022-0200, Exhibit 1, Tab 7, Schedule 1, pp. 10-14 and Exhibit 1, Tab 7, Schedule 1, Attachment 4.

- Customer outreach – targeted customer communications to engage customers to arrange for meter access and submit own meter reads (including incentive programs).
- Meter reading processes – review and continuous improvement to increase attainment and efficiency.

Since that time, Enbridge Gas has seen significant improvements in meter reading frequency, as noted in Exhibit G, having reduced the proportion of meters with no read for 4 months or more from 5.0% in 2021 to 1.3% in 2023. Similarly, the Company's annual meter reading performance (MRP), a measure of total planned vs. actual meters read,[33] increased from 89.6% for 2022 to 93.7% for 2023.

61. As discussed in greater detail in Section 1.3, improvements in meter reading frequency reduce the Company's reliance on estimated customer Consumption and related temporary variances in the billing and financial reporting processes.

Vacant Premises Backlog

62. According to Enbridge Gas's Conditions of Service,[34] customers are required to notify the Company before taking possession of a new home, otherwise the premises are considered to be vacant and eligible for discontinuance of service. In this context, vacant premises encompass properties with existing natural gas service and an existing customer account that is sold or vacated, which continue to consume natural gas and for which no new customer account is established.

63. As previously noted in response to interrogatories in Enbridge Gas's 2023 Deferral and Variance Account Clearance proceeding, the Company is continuing its work to resolve a backlog of vacant premises that accumulated over the course of the COVID 19 pandemic.[35] Whereas under normal circumstances Enbridge Gas would

[33] MRP relates to general service customer classes (e.g., Rates 1, 6, 10, & M2) and does not include large volume telemetered customers.
[34] https://www.enbridgegas.com/en/conditions-of-service
[35] EB-2023-0092, Exhibit I.STAFF.6, p. 2.

discontinue services to such premises via lockout at the customer meter after warning the property owner in advance, the Company temporarily halted all such lockouts beginning in 2020 for safety reasons related to the ongoing COVID-19 pandemic and to provide exceptional relief to customers made economically vulnerable.[36] The Company only recommenced lockouts for non-compliance in Q2 2023.

64. In instances where vacant premises cases weren't resolved within the fiscal calendar year, as the Company has not historically estimated or accrued volumes for such circumstances, Enbridge Gas presumes that they may have contributed to UFG volumes. The number of such vacant premises with the potential to have caused intra-period UFG volatility (i.e., via billing adjustments in subsequent fiscal periods) increased beginning in 2020 from historic levels. For context, Table 5 contains the historic number of lockouts issued for vacant premises from 2018 to 2023 and reflects a sharp decrease beginning in 2020, consistent with the timing and circumstances discussed above.

Table 5
Historical Vacant Premises Lockouts

Line No.	Year	No. of Vacant Premises Lockouts
1	2018	3,504
2	2019	9,465
3	2020	809
4	2021	7
5	2022	813
6	2023	3,589

65. At this time, the Company is not able to accurately estimate the actual impact that vacant premises had on UFG volumes recorded given the need to investigate the circumstances of each instance to understand its duration and to develop a unique and accurate Consumption estimate. However, since recommencing its normal

[36] EB-2022-0200, Exhibit 4, Tab 4, Schedule 2, p. 29.

warning notice and lockout procedures in Q2 2023 (with a focus on resolving the longest duration and highest potential Consumption instances), and by leveraging property ownership search functionality available via GeoWarehouse,[37] Enbridge Gas has resolved approximately 6,800 instances of vacant premises as of the date of this filing.

66. The Company recommenced seasonal lockouts associated with vacant premises in 2024 on May 1 and is targeting to achieve 200% more locks than 2023 between May and October until the earlier of all outstanding cases are resolved or the commencement of 2024/2025 winter season (when customer lockouts are halted). Additionally, seasonal resources have been assigned to complete GeoWarehouse searches on lower consumption premises and premises with inside meters. Through the initiatives described above, Enbridge Gas expects to return to pre-pandemic lockout levels by 2025. Enbridge Gas also intends to investigate the viability of developing a process in 2024 to report annually on vacant premises instances, estimate their respective Consumption, and accrue for that Consumption at year-end (like the processes for unbilled estimates described in Sections 1.3 and 2). Together, these activities are expected to improve the Company's understanding of and to mitigate the impact of vacant premises in the future.

Assessment of Storage Inventory Audits and Adjustments

67. As discussed in response to interrogatories in the Company's 2024 Phase 1 Rebasing proceeding,[38] inventories in all Enbridge Gas storage pools are monitored via observation wells (for pressure) and custody transfer quality measurement (for volumetric flows). Following spring and fall stabilization periods, which allow pressures to equalize across storage reservoirs, an audit of inventories is routinely conducted to identify inventory variances. Variances in inventories are typically

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[37] GeoWarehouse is the single source of authoritative property information in Ontario. Subscribers can verify property ownership information by searching an address in GeoWarehouse. Enbridge Gas uses this to verify owner information during winter months in order to avoid service disruptions during this time.
[38] EB-2022-0200, Exhibit I.4.3-FRPO-150.

attributable to measurement error or natural gas migration within a storage reservoir. Adjustments are made to inventories based on the results of these audits. All such adjustments and related inventory analysis are reviewed by an external auditor on an annual basis. Additional detail regarding the accounting treatment of storage inventory adjustments, including their impact on UFG, is discussed in Section 1.3.

68. In 2023, Enbridge Gas reviewed the process for tracking, adjusting, and auditing storage inventories and found that total adjustments to underground storage inventories made in 2021, 2022 and 2023 were not a material source of UFG for Enbridge Gas. This conclusion is supported by the data set out in Table 6, which contains details of all historical adjustments to storage inventories made from 2002 to 2023.

Table 6
Storage Pool Inventory Adjustments

		Union Rate Zone		EGD Rate Zone	
		Adjustments	Percentage	Adjustments	Percentage
Line No.	Year	(103m3)	(%)	(103m3)	(%)
		(a)	(b)	(c)	(d)
1	2002	8,677	0.21%	0	0.00%
2	2003	17,458	0.43%	0	0.00%
3	2004	0	0.00%	0	0.00%
4	2005	-8,055	-0.20%	0	0.00%
5	2006	0	0.00%	0	0.00%
6	2007	0	0.00%	0	0.00%
7	2008	0	0.00%	0	0.00%
8	2009	-11,751	-0.28%	0	0.00%
9	2010	-23,196	-0.56%	0	0.00%
10	2011	6,669	0.16%	0	0.00%
11	2012	20,621	0.49%	-54,209	-1.73%
12	2013	-747	-0.02%	0	0.00%
13	2014	-20,218	-0.48%	0	0.00%
14	2015	120	0.00%	0	0.00%
15	2016	5,168	0.12%	0	0.00%
16	2017	0	0.00%	0	0.00%
17	2018	1,652	0.04%	-60,225	-1.85%
18	2019	0	0.00%	-13,746	-0.42%
19	2020	0	0.00%	0	0.00%
20	2021	-2,601	-0.06%	0	0.00%
21	2022	-2,834	-0.06%	-1,116	-0.03%
22	2023	4,853	0.11%	0	0.00%

Notes:
1 'Negative sign indicates that measured inventory was reduced.
2 Adjustments can be attributed to either measurement error or a change in the reservoir index.
3 EGD meter upgrade project was completed in 2012. 2018/19 adjustments based on 2013-2017 measurements

69. Further, Enbridge Gas has recently drilled and constructed several stratigraphic test wells and A-1 observation wells. These wells and the associated monitoring equipment provide further information on the geological properties of the Company's underground storage pools. Additionally, the pressure data from the A-1 Observation

wells improve the Company's understanding of how gas moves within these geological formations.[39] The potential benefits of these investments may include more efficient operation of storage facilities and improved understanding of storage inventory variances and adjustments. The Company intends to continue investing similarly to better understand and operate its underground storage pools in the future, as appropriate.

Advanced Metering Infrastructure

70. As noted in its 2024 Phase 1 Rebasing application,[40] Enbridge Gas is committed to Advanced Metering Infrastructure (AMI) and advised that it plans to file a stand-alone AMI application as soon as practicable that will request approval from the OEB for funding and to implement an AMI solution. In its 2023-2032 Asset Management Plan,[41] the Company went on to explain that AMI is expected to provide significant customer benefits including, but not limited to, reducing meter reading and call centre costs and eliminating estimated bills, while providing customers insight into their gas usage. The Company advised that an AMI Proof of Concept (PoC) project is currently underway which will inform the scope of the AMI program and any future AMI-related application to the OEB. In its Decision and Order, the OEB noted that the AMI PoC project is a positive step in managing meter reading performance and directed the Company to provide an update on the project in Phase 3 of the 2024 Rebasing proceeding.[42]

71. The Company has progressed through several key deliverables and design activities as part of the development of a strategic business case, it has built strong working relationships with AMI vendors, and it has developed a deeper understanding of key AMI technologies. The Company's AMI PoC went "live" on December 1st, 2023, and

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[39] Recent stratigraphic test wells include at the Ladysmith Storage Pool (EB-2019-0012/EB-2020-0256), and at the Crowland Storage Pool (EB-2022-0155). Recent A-1 observation wells include at the Corunna and Ladysmith Storage Pools (EB-2021-0079) and at the Coveny and Kimball-Colinville Storage Pools (EB-2021-0248).
[40] EB-2022-0200, Exhibit 2, Tab 7, Schedule 2, p. 6.
[41] EB-2022-0200, Exhibit 2, Tab 6, Schedule 2, p. 170.
[42] EB-2022-0200, OEB Decision and Order, December 21, 2023, p. 135.

will practically demonstrate and validate the benefits of AMI systems. The objectives of the PoC currently include:

- Showcase AMI capabilities, safety features and qualitative benefits of the meter technology in both laboratory and real-world settings.
- Demonstrate and validate advanced AMI communication use cases including collecting detailed data sets.
- Demonstrate and validate network functionality and system security.

Next steps regarding the PoC are to further evaluate AMI through several Enbridge Gas stakeholder test cases over the remainder of 2024.

72. AMI is anticipated to positively impact future UFG volumes/costs in multiple ways, including:
    - In terms of physical loss and theft of gas, AMI meters with internal sensors/alarms will detect and enable near real-time remote monitoring of distribution system performance at the customer premises level. AMI meters at customer premises fitted with automated tamper alarms will also alert the Company to instances of theft. When combined with flow and pressure data up to and including at gate stations, the Company expects to amass more precise measured Consumption data on an hourly basis which should translate to reduced variability in UFG volumes.
    - In terms of measurement quality, AMI can lay the foundation to enable Enbridge Gas to remotely monitor and manage the meter population, ensuring that appropriate and properly functioning assets are deployed and maintained to ensure a high degree of measurement data accuracy. The improved accuracy and reliability of hourly Consumption data is expected to contribute to the resolution of backlogs of unbilled and No Bills incidents and to eliminate billing based on estimated Consumption in the future. An anticipated consequence of these improvements is a reduction in UFG volatility.

Pressure Elevation Factors

73. For communities that fall within more than one elevation zone (with an elevation difference exceeding 110 m between maximum/minimum elevations), unique elevation factors (e.g., air pressure, barometric pressure area) may need to be established in the Company's billing systems to adjust for the effect of atmospheric pressure on volumes of natural gas delivered. Absent such elevation-specific factors, UFG loss/(gain) can result. The Company is currently reviewing pressure elevation factors for existing customer premises across the system to ensure such factors are set consistent with Measurement Canada standards and has taken steps to ensure that all new premises are set up with compliant factors at the time of account creation. The Company expects that this initiative will result in more accurate gas consumption and billing data and may result in reduced UFG (overall).

74. The Company is not currently able to accurately estimate the net impact that erroneous pressure elevation factors had on UFG volumes recorded in recent years given the need to investigate the circumstances of each instance to understand its magnitude and duration.

Loss of Containment (Gas Loss Due to Damage Events)

75. An initiative was launched in 2023 to assess and improve emission mitigation practices and the accuracy of gas loss calculations associated with instances of facility damage from third parties. By comparing legacy EGD and Union processes, the Company concluded that it was not consistently calculating and charging third parties (e.g., construction contractors) for such damage events and any associated gas loss (Damage Recoveries) across the EGD and Union Rate Zones. Furthermore, differences existed in how Damage Recoveries were recorded in the relevant UFG deferral/variance accounts in the EGD and Union Rate Zones. In the UAFVA for the EGD Rate Zone, Damage Recoveries were removed from the

UAFVA balance, whereas in the UFGVA for the Union Rate Zones, there was no adjustment made.

76. Enbridge Gas estimates that annual volumetric gas loss associated with third-party damage events have exceeded 1,000 10^3m^3 consistently since 2021 as shown in Table 7. While annual gas loss volume attributed to such events have been declining over that same period, the Company sought to better understand and mitigate such losses, to the extent possible.

Table 7
Estimated Natural Gas Loss Due to Third-Party Damages

Line No.	Year	Gas Losses (10^3m^3)
1	2021	2,380
2	2022	1,348
3	2023	1,173

77. Accordingly, Enbridge Gas assessed current processes and best practices to develop a common set of guidelines for field reporting during damage events (i.e., damage size, location, nature of facilities damaged, duration of methane release, system pressures, provide scale photos, etc.) and for charging for the associated gas loss. As part of its 2024 Phase 1 Rebasing Application, the Company proposed a standard set of Loss of Containment Cost Recovery Charges based on the pipeline diameter, operating pressure, duration of loss of containment, and cost of gas volume lost. Depending upon the specific circumstances surrounding damage events in the future, third parties may face no charges, flat rate charges or specific calculations using Rate 320. Currently, Enbridge Gas is working to establish a standard form and process to gather the information necessary to support these changes and expects to implement the new guidelines and processes by the end of 2024, including system upgrades, and updated training and education. In addition, with the implementation in 2024 of the harmonized UFGVVA, adjustments to remove gas loss recoveries will be consistently made going forward.

Measurement Integration

78. As previously noted in its 2024 Phase 1 Rebasing evidence and in response to interrogatories in Enbridge Gas's 2023 Deferral and Variance Account Clearance proceeding, the Company continues to align applications and equipment used for large volume customer measurement to ensure consistency in volume measurement data validation for all contract large volume customers.[43] In 2023, Enbridge Gas aligned on a solution to migrate from a near-obsolete measurement system that transmits pulse counts, to a new endpoint connectivity device that transmits serial measurement data.[44] This initiative is planned to be completed by 2025, and will result in a single measurement system for all large volume contract rate customers.

79. The Company expects that this work could contribute to related initiatives in the future to deploy remote interval metering solutions to commercial and General Service customers as it could eliminate the need for manual meter readings of customer consumption.[45]

80. At this time, the Company is exploring technological alternatives for commercial and General Service customers that would enable the installation of endpoint connectivity devices that are compatible with existing metering assets. Should such an initiative proceed, other considerations would include preferentially targeting General Service customers with the highest annual Consumption rates and that are served by existing systems that are currently or are forecast to be at capacity. Given the magnitude of natural gas volumes consumed by General Service customers, the Company expects that replacement of manual meter reading with an automated and remote process for those customers could significantly reduce incidence of billing based on estimated Consumption and related UFG volumes.

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[43] EB-2022-0200, Exhibit I.1.9-CCC-25, Attachment 1, p. 1; EB-2023-0092, Exhibit I.STAFF.6, p. 2.
[44] Pulse counts refers to electrical pulses from which the volume of customer consumption is derived (i.e., counting each instance that a corrected unit of measure has flowed). Serial measurement data refers to actual measured customer consumption volume data (including corrected or uncorrected measurement, temperature, pressure, correction factors, flow time, etc.) received directly from EVCs.
[45] Large multi-residential, manufacturing, office and other commercial General Service customers numbered approximately 10,000 and consumed more than 3 million m^3 as of 2021.

Large Volume Customer Measurement for Power Generation

81. Given their inherent physical limitations, aligning customer measurement facilities accurately with changing customer consumption patterns over time is a common challenge for utilities across the natural gas industry. For example, some of Enbridge Gas's large volume natural gas-fired power generator customers' operations have changed over time. Many natural gas-fired power generators that originally operated at high load factors as a base load power generator (constantly consuming large volumes of gas) now operate at much lower load factors as peaking plants (consuming large volumes for short, infrequent periods) and often remain idle until called upon by the IESO to generate electricity. Such facilities can have large properties, often including administrative offices, maintenance buildings, and turbine buildings which also use natural gas for building space and water heating throughout the year, even when not generating electricity. While the measurement facilities originally designed and installed by Enbridge Gas for these customers continue to measure accurately under their original high load factor conditions, they do not measure Consumption accurately under low-flow conditions (i.e., when turbines are not running).

82. Enbridge Gas has completed a high-level assessment of the capabilities of the existing measurement facilities installed for such customers and has determined that several were not designed to accurately measure natural gas volumes under low-flow conditions. In other words, the measurement facilities currently on site may be oversized relative to some current operating conditions. Work on this initiative is preliminary in nature and a project team is being formed to assess: (i) customer site-specific measurement station capabilities, layouts, and physical constraints; (ii) the estimated magnitude of unmeasured volumes; and (iii) engineering solutions (e.g., installation of low-flow measurement) for these facilities.

83. The Company intends to work closely with these customers to determine what ancillary natural gas appliances exist on-site as a first step towards estimating unmeasured volumes. Where applicable, the Company intends to apply lessons learned through this investigation to other large volume customer sites to ensure that measured and billed Consumption volumes are as accurate as possible. The Company has also developed a harmonized Measurement Design Standard to avoid instances of inaccurate measurement under low-flow conditions going forward. Similarly, as the issue of managing measurement limitations across dynamic customer groups over time is common across the North American natural gas industry, Enbridge Gas will monitor such issues identified by other utilities as well as any solutions implemented in case there is opportunity to apply lessons learned or best practices to the Company's engineering design standards or internal processes/systems.

Operational Emission Reductions

84. As discussed in its 2024 Phase 1 Rebasing Application,[46] to support achievement of federal and provincial GHG reduction targets Enbridge Gas has identified a number of emission reduction opportunities (some of which have already been included in the Company's Asset Management Plan).[47] Certain of these opportunities also have the potential to impact UFG volumes. At this time, the Company has not assessed the respective impacts of each opportunity on UFG volumes. However, going forward the Company will consider such impacts, where quantifiable, when prioritizing such investments.

<u>Section 2: Impact of No Bill Customer Volumes on UFG</u>

85. As discussed in Section 1.3, the Consumption volumes used to calculate UFG include both billed Consumption and unbilled Consumption volumes:

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[46] EB-2022-0200, Exhibit 1, Tab 10, Schedule 8, pp. 1-7.
[47] 66,100 tCO_2e per year of scope 1 and 2 GHG emissions are expected to be reduced by initiatives already being undertaken as part of the Company's Asset Management Plan or operational maintenance programs. Up to an additional 351,000 tCO_2e per year of emissions reductions are possible subject to economic assessment and prioritization.

- Billed Consumption Volumes – customer Consumption calculated based on a combination of actual meter reads and estimated meter reads interfaced from the Company's billing system into its financial accounting system.
- Unbilled Consumption Volumes – an estimate of gas delivered but not yet billed, calculated at the rate class level at the end of every monthly accounting period and recorded within the financial accounting system based on factors such as number of customers per billing cycle, number of days for each cycle which have not been billed, average use per HDD, actual HDDs, and demand coefficients.

86. No Bills are categorized as Unbilled Consumption Volumes that occur as a result of extenuating circumstances such as unexpected Consumption or charges being generated on customer bills that exceed established volumetric and monetary thresholds and trigger manual intervention before any bill can be issued to a customer(s).

87. As detailed in response to undertakings in its 2024 Rebasing proceeding,[48] the Company has several mechanisms in place to validate meter reading and billing accuracy that can trigger manual review and/or intervention before any bill can be issued to customers, including:

    - Validation that meter readings are within accepted tolerances and manual review of exceptions relative to factors such as historical readings, known natural gas appliances in service, and geographic weather zone.
    - Validation that commodity and supply-related costs are being appropriately applied according to the customer's specific rate class. For residential customers, a monetary threshold of $800 for such costs ensures that any bills exceeding this amount are manually reviewed before being issued.

[48] EB-2022-0200, Exhibit JT3.35.

- Validation that the total dollar value of bills is within established thresholds. For residential customers, a monetary threshold of $2,100 ensures that any bills exceeding this amount are manually reviewed before being issued.

88. In No Bills scenarios, while no bill is generated for the affected customer(s) in line with its particular monthly billing cycle, the Company's financial practice is to record an estimate of volumes delivered but not yet billed in the financial accounting system for the relevant monthly accounting period. Typically, this estimate is reversed in a subsequent accounting period and replaced with actual billed Consumption (contingent upon its availability) at the applicable QRAM rate, and any difference is corrected via volumetric adjustment in the financial accounting system. If the Company's estimate of No Bills recorded in the financial accounting system for any monthly accounting period is understated relative to actual billed Consumption, it creates a UFG loss in the period that the estimate was recorded and creates a UFG gain in the subsequent period when the estimate is reversed and replaced with actual billed Consumption. The inverse is true in instances when No Bills estimates are overstated.

89. As noted in Section 1.3, UFG is calculated as the monthly difference between Sendout and Consumption volumes and is composed of a combination of actual physical gas losses/gains and temporary variances resulting from estimation in billing and accounting processes, including No Bills. Therefore, while No Bills do not impact actual UFG volumes in the long-term, they can contribute to intra-period UFG volume volatility via variances in the short-term. Further, intra-period volatility that is not resolved (estimates reversed and replaced with actual Consumption) before annual fiscal accounting records are closed can result in lasting timing variances to UFG levels spanning fiscal periods (i.e., under or overstated No Bills estimate and commensurate UFG loss or gain).

90. Table 8 provides the historical impact of No Bills true-ups for 2022 and 2023 for the Union and EGD rate zones.

Table 8

Historical Impact of No Bills True-ups (10^3m^3)

Line No.	Particulars (10^3m^3)	2022	2023
1	Union Rate Zones	27,405	(25,031)
2	EGD Rate Zone	36,563	(27,373)
3	Impact to UFG Volumes: Increase/(Decrease)[1]	27,405	(25,031)

Notes:

(1) UFG Impacts of No Bills in 2022 and 2023 are limited to the Union Rate Zones impacts as the EGD Rate Zone volumes displayed in row 2 were trued-up and did not contribute to reported UFG volumes in each year.

91. As discussed in Section 1.3, for the EGD Rate Zone Enbridge Gas has the ability to eliminate timing variances that span two fiscal years related to unbilled estimated Consumption (including No Bills) via an accounting adjustment in the subsequent fiscal year to record differences between estimated and actual UFG. However, no such provision to record any adjustments related to unbilled estimated Consumption across fiscal years has historically existed for the Union Rate Zones. Said differently, to the extent that a variance existed between estimated Consumption and actual Consumption for the Union Rate Zones, any adjustment(s) made after December have historically been recorded in the subsequent fiscal year. As a result, unbilled estimate-related UFG volumes for the Union Rate Zones increased UFG volumes in 2022 and subsequently suppressed UFG volumes in 2023.

92. Effective January 2024, the accounting treatment for all rate zones will be harmonized, including the use of a single UFGVVA that includes a provision enabling the Company to uniformly adjust for differences in estimated UFG and actual UFG to avoid timing variances across fiscal years. As a result, the Company expects that intra-year volatility experienced in the Union Rate Zones from No Bills true-ups will be markedly reduced.

93. Between December 2022 and March 2023, multiple system changes were implemented to reduce the number of No Bills exceptions created by bills that were outside of pre-determined thresholds. These changes targeted 6 common scenarios with clear paths to resolution. Programs were developed to automate these scenarios and remove the need for agent intervention in order to release the bill to the customer. In addition, a comprehensive review of work prioritization was completed resulting in the implementation of process improvements that reduced the time to correct No Bills scenarios.

94. Going forward, Enbridge Gas intends to continue the initiatives discussed in Section 1.3, including its consecutive estimate campaign, inbound calls campaign, customer outreach campaign, and meter reading processes campaign, all of which have the potential to significantly reduce the impact of No Bills in the future. Similarly, the Company is also investigating a variety of system enhancements tied to the No Bills estimation process, including refinements to the determination of the number of missing billing periods, determining the relevant HDDs for each respective missing billing period rather using a common HDD for all periods, and differentiation of QRAM pricing used when No Bills periods span multiple quarters.

Section 3: Impact of Transmission & Other High-Pressure System Linepack on UFG

95. The term “Linepack” generally refers to the quantity (volume) of natural gas or inventory in a pipeline system at a given time. Pipeline systems are, in a way, storage facilities and the Linepack contained in these systems relates directly to the size of the facility, or its physical volume, which is based on its diameter and length. The physical volume of a pipeline can be calculated using the following equation:[49]

[49] Equation 3.30, Gas Pipeline Hydraulics by E. Shashi Menon (2005).

$$\mathrm{Vp} = \frac{\pi}{4}\mathrm{D}^2\mathrm{L}$$

Where:

V_p = physical volume (ft^3)

D = pipe inside diameter (ft)

L = pipe segment length (ft)

96. Since natural gas is compressible, the amount of gas a pipeline contains can vary depending upon the physical conditions it is stored under, including pressure, gas temperature, and the chemical properties of the gas stored. Generally, Linepack is positively correlated with increases in pipeline diameter, pipeline length, pipeline pressure, and colder gas temperatures. Linepack volume can be calculated using the following equation:[50]

$$\mathrm{Vb} = 0.7854\left(\frac{\mathrm{Tb}}{\mathrm{Pb}}\right)\left(\frac{\mathrm{Pavg}}{\mathrm{ZavgTavg}}\right)\mathrm{D}^2\mathrm{L}$$

Where:

V_b = Linepack in pipe segment (standard ft^3)

D = pipe inside diameter (ft)

L = pipe segment length (ft)

Tb = base temperature (°R)

Pb = base pressure (psig)

P_{avg} = average gas pressure in pipeline segment (psig)

T_{avg} = average gas temperature in pipe segment (°R)

Z_{avg} = average gas compressibility factor at T_{avg} and P_{avg}

97. Except for certain maintenance-related purposes, pipelines are normally never completely emptied of natural gas volumes.

98. Typically, natural gas customers consume gas in a diurnal (24 hour) cycle; the

[50] Equation 3.33, Gas Pipeline Hydraulics by E. Shashi Menon (2005).

lowest demands occur overnight while most customers are sleeping/inactive, and the highest (peak) demands occur during the morning and afternoon/evening while most customers are starting or ending their day. Operating pressures (including Linepack) on pipeline systems fluctuate in response. The highest pressures occur overnight, and the lowest pressures occur during the morning and afternoon/evening.

99. While the definition of Linepack set out above applies to all forms of Linepack, for the purposes of modeling and managing its pipeline systems Enbridge Gas commonly refers to two distinct forms of Linepack: (i) “Minimum Linepack”, and (ii) “Operational Linepack”.

100. Enbridge Gas generally defines Minimum Linepack as the volume of natural gas required to fill a pipeline to the minimum level required to make the system operational.

101. Enbridge Gas generally defines Operational Linepack as the volume of natural gas required to operate a particular pipeline system. Operational Linepack ranges between minimum system pressure and MOP of a particular pipeline system. Operational Linepack is required to operate the pipeline system and provide reliable service to customers, because higher pressures (above Minimum Linepack) are needed to provide the “push” required to move gas through the pipeline system from high to low pressure.

102. Enbridge Gas draws further pipeline system-specific distinctions between Minimum Linepack and Operational Linepack for the purposes of modelling and managing Linepack across its high-pressure storage and transmission pipeline systems,[51] and its high-pressure distribution pipeline systems. Accordingly, the sections of evidence that follow explain those system-specific distinctions and describe the

[51] For the purposes of this evidence, Enbridge Gas classifies “transmission pipeline systems” as specifically being the Dawn to Parkway transmission system, the Panhandle transmission system, the Sarnia transmission system, and the Albion Line.

Company's work to assess the effects of all forms of Linepack upon UFG.

103. In all instances of Linepack (i.e., Minimum and Operational), the Company has assessed the related factors considered in calculating Sendout (see description set out in Section 1.3) and has determined that changes in Linepack did not significantly impact UFG levels in 2022 or 2023.

Section 3.1 – Minimum Linepack

104. Minimum Linepack for transmission pipelines and high-pressure storage pipelines is calculated annually using system-specific models that consider the Linepack factors discussed above as well as reduced supply pressure, either to lowest anticipated level (minimum pressure of gas supply available) or to the level required to meet minimum contractual obligations.

105. Minimum Linepack for distribution pipelines is also calculated annually using system-specific models that consider the Linepack factors discussed above, balanced on a peak hour design condition according to temperature zone,[52] that assume that interruptions are called, and that producer injections are restricted. A further distinction of Minimum Linepack modelling for distribution pipelines is that the pressures near system source stations or takeoffs are highest, while the system extent pressures (or system constraints) are near or at their design conditions. Accordingly, Enbridge Gas views distribution pipeline Minimum Linepack as the volume of gas in a particular distribution pipeline system that is not forecasted to be consumed and billed on a design day. Accordingly, distribution system Minimum Linepack varies annually depending on forecasted demand changes (general service or contract rate volumes), forecasted new in-service pipelines, and forecasted abandonments.

[52] Using peak morning demands and resulting pressures for unsteady state models.

106. In Enbridge Gas's experience, Minimum Linepack typically does not change drastically from year to year because of updates made to the Linepack factors discussed above. Minimum Linepack is most often influenced by circumstances wherein pipeline facilities are added/removed to/from a modelled pipeline system. In 2024, Enbridge Gas completed an assessment of recent adjustments to Minimum Linepack for all pipeline systems and concluded that all such adjustments were adequately accounted for and directly attributable to specific and intended changes to the Company's facilities and/or operations and were not significant contributors to UFG volumes in 2022 or 2023. Table 9 provides historical Minimum Linepack data from 2021 to 2023:

Table 9

Historic Minimum Linepack 10^3m^3

Line No.		2021	2022	2023
1	Union Rate Zones			
2	Transmission	28,273	28,250	28,382
3	Storage	1,329	1,507	1,494
4	Distribution	7,346	7,240	7,309
5	Total Union Rate Zones	36,947	36,997	37,185
6	EGD Rate Zones			
7	Transmission	926	926	926
8	Storage	1,168	1,125	1,804
9	Distribution	8,072	8,317	6,780
10	Total EGD Rate Zone	10,166	10,367	9,509

107. A net increase in total calculated Minimum Linepack of 251 10^3m^3 observed from 2021 to 2022 is attributable to various annual updates to inputs and assumptions across many storage and distribution system Linepack models. A net reduction in total calculated Minimum Linepack of 670 10^3m^3 observed from 2022 to 2023 is attributable to various annual updates to inputs and assumptions across many

distribution system Linepack models, and increases to transmission minimum Linepack associated with gas property adjustments.

108. In all instances (transmission, storage, and distribution pipelines), Enbridge Gas treats Minimum Linepack as a fixed asset which cannot be sold or otherwise used and as a non-depreciable "property, plant, and equipment" valued at historical gas costs. In this regard, minimum Linepack in a pipeline is comparable in its purpose and accounting treatment to "cushion gas" volumes that are maintained within underground storage reservoirs.

109. If there is a change in Minimum Linepack, there is a corresponding change in the determination of Sendout. As described in Section 1.3, Sendout is the net volume of natural gas delivered into the Enbridge Gas distribution system to serve in-franchise customer demands after accounting for receipts and deliveries across Enbridge Gas' integrated storage, transmission, and distribution systems. Since there is no corresponding billed consumption associated with the change in Sendout resulting from the change to Minimum Linepack, it results in amounts recorded as UFG as part of the Sendout side of the equation discussed in Section 1.3. As such, an adjustment is recorded to remove the cost associated with the change in Minimum Linepack from UFG and the offsetting amount is recorded as a fixed asset.

Section 3.2 – Operational Linepack

Transmission and Storage Pipeline Systems

110. For Enbridge Gas's transmission and storage pipelines, Operational Linepack ranges between minimum and maximum operating pressures above the Minimum Linepack up to the maximum Linepack based on the MOP of a particular pipeline system. Transmission and storage system Operational Linepack varies,[53] as system pressures change to serve customer demands.

[53] Operational Linepack will fluctuate daily, weekly, monthly, seasonally, and annually.

111. As described in the Company's 2024 Phase 1 Rebasing evidence,[54] certain Enbridge Gas transmission pipeline systems are designed using transient hydraulic modelling techniques to partially serve design day demand via Operational Linepack:

> The Dawn Parkway System and Panhandle System are sized to serve the design day demand with the hourly demand changes served from the system's linepack. Linepack is the amount of natural gas storage within a pipeline and occurs because gas is compressible and becomes a usable asset in facilities design in large diameter, high pressure pipelines. When the hourly demand is greater than the design day demand the system pressure is dropping or known as "drafting" or losing linepack and when the hourly demand is less than the average daily demand the system pressure is increasing or known as 'packing" or gaining linepack. The ability to use linepack in transmission systems reduces the need for facilities as the facilities can be sized for the daily demand rather than the design hour demand.

112. The daily use of Operational Linepack for these purposes does not impact UFG volumes as any resulting variance in Linepack, either draft or pack, is typically recovered and balanced by the end of the gas day. Each segment of the Dawn Parkway Transmission System has pressure telemetry at mainline valve sites that provide sufficient data for the Company to calculate the Operational Linepack for the system on a daily basis. On a monthly basis, an entry is recorded to reflect the net increase or decrease to Operational Linepack as a movement between working inventory and Linepack inventory. Accordingly, the variation in Operational Linepack for each month for this system is accounted for in the determination of Sendout, discussed in Section 1.3, ensuring that it does not cause any variation in monthly or annual UFG calculations.[55]

113. Enbridge Gas assessed Operational Linepack changes observed on the Dawn Parkway Transmission system from 2022 and 2023 to gauge the significance of such changes relative to calculated UFG volumes. The largest month over month

[54] EB-2022-0200, Exhibit 2, Tab 7, Schedule 1, p. 16.
[55] Enbridge Gas does not have comparable pressure telemetry on its other transmission and high-pressure pipeline systems, and thus does not have the data needed to calculate and track system Operational Linepack similarly. However, the Company expects the proportional magnitude of impacts due to Operational Linepack adjustments to be similar in all instances to those discussed in Table 11.

Operational Linepack changes observed, set out in Table 10, were found to be negligible. As shown in Table 10, the Linepack adjustments for each of August 2022 and September 2022, and October 2023 and November 2023 represented 0.03-0.1% of the respective month's system activity.

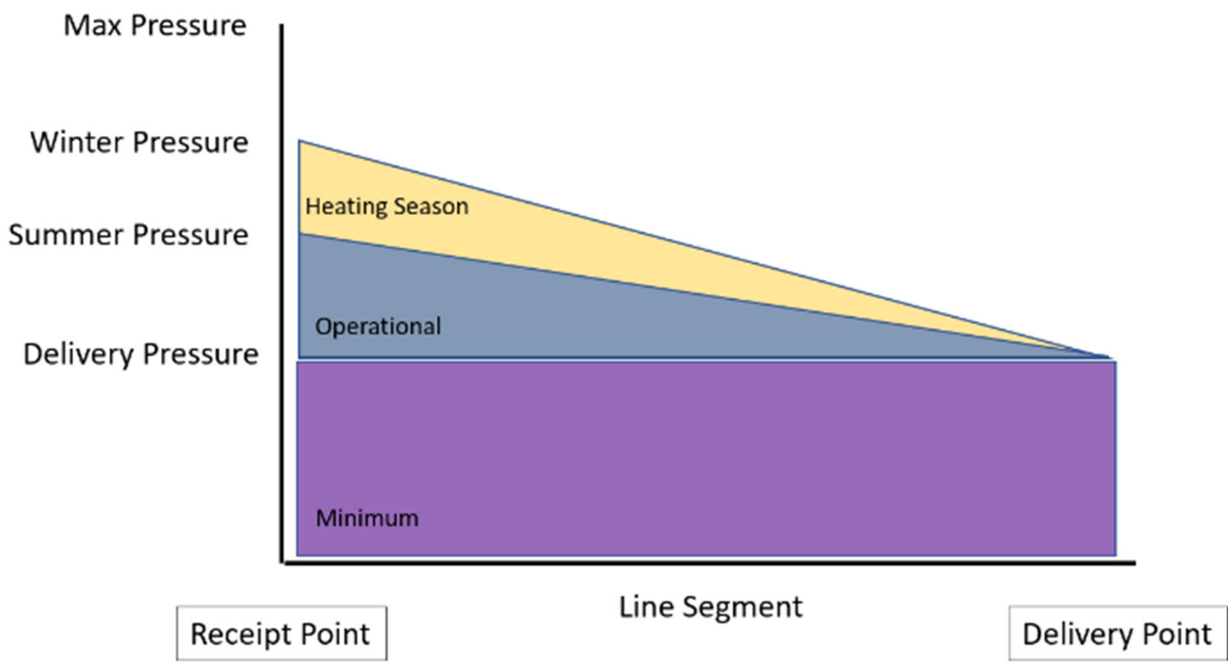
Table 10
Dawn-Parkway Operational Linepack Adjustments

Line No.	Particulars (10^3m^3)	Aug 2022	Sep 2022	Oct 2023	Nov 2023
		(a)	(b)	(a)	(b)
1	Absolute Activity	4,075,901	3,321,413	2,529,696	4,721,557
2	Total Receipts	2,386,408	1,977,352	1,669,918	2,946,788
3	Total Deliveries	1,689,492	1,344,061	859,779	1,774,769
4	Dawn Parkway System Linepack Receipts	2,093	-	2,288	-
5	Dawn Parkway system Linepack Deliveries	-	3,427	-	1,404
6	Dawn Parkway System Linepack Adjustment *(% of absolute activity)*	0.05%	0.10%	0.09%	0.03%

114. While Operational Linepack also varies by season for transmission pipeline systems, the adjustments discussed below are offsetting:

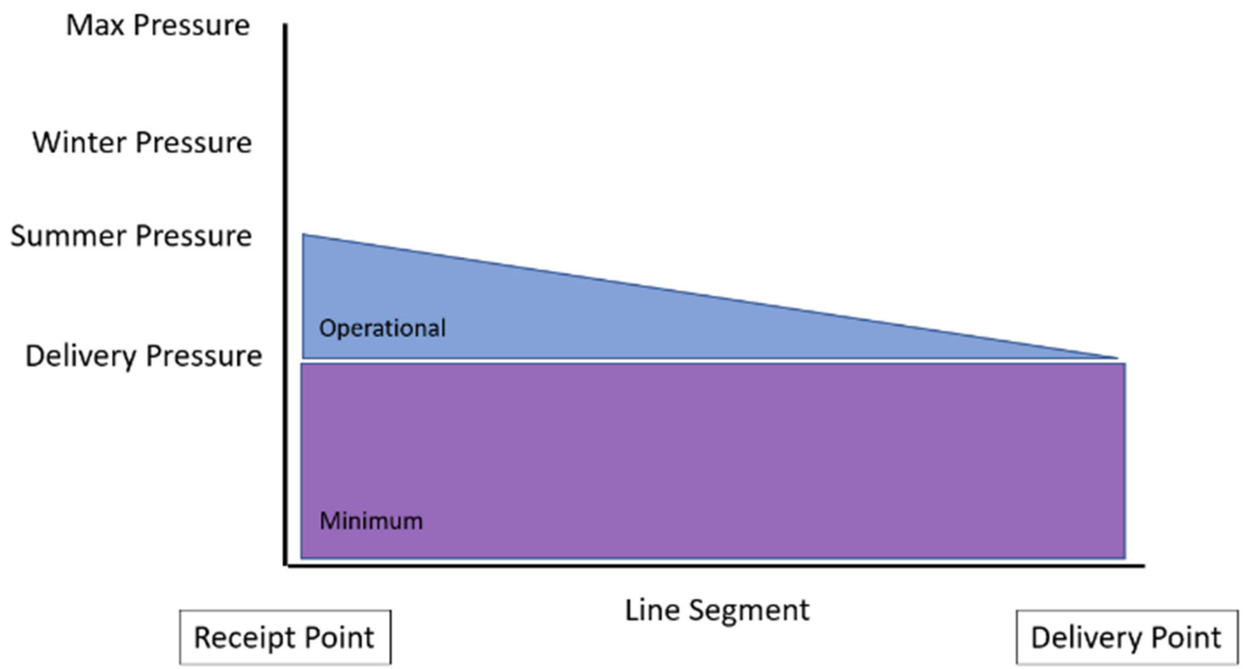
(i) Transmission pipeline operating pressures (including Operational Linepack) are increased in the fall, by way of increased system set pressures or by turning on compression, in advance of winter season conditions to serve anticipated increased customer demands. See Figure 4 for an illustrative example of this relationship.

Figure 4: Winter Transmission Pipeline Linepack



(ii) Transmission pipeline operating pressures (including Operational Linepack) are reduced in the spring, by way of decreased system set pressures or by turning off compression, in response to lower needs of summer season conditions to serve anticipated reduced customer demands. See Figure 5 for an illustrative example of this relationship.

Figure 5: Summer Transmission Pipeline System Linepack

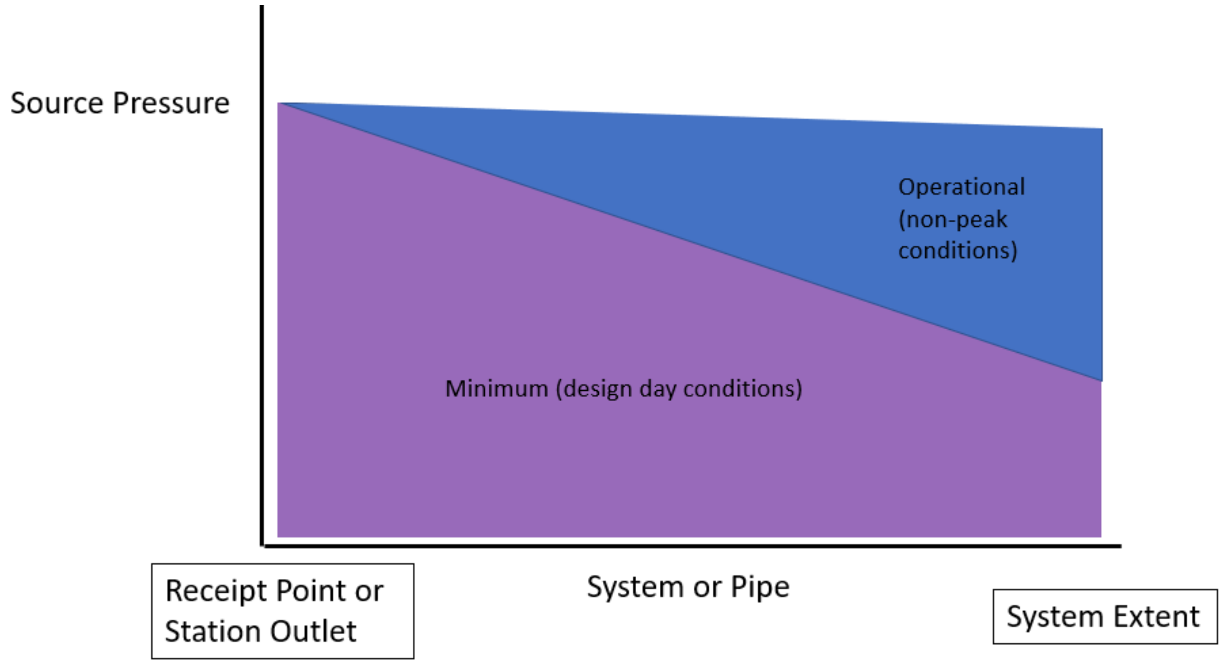


Distribution Pipeline Systems

115. For the Company's high-pressure distribution pipelines, Operational Linepack also varies between minimum and maximum operating pressures. Distribution pipeline system station pressures are typically held constant year-round and demands reduce over the length of each segment. As a result, the proportion of natural gas volumes deemed to be Operational Linepack on the system fluctuates throughout the year. Generally, distribution pipeline Operational Linepack increases in the summer, and spring/fall (shoulder months) seasons since customer demands are reduced relative to winter.[56] See Figure 6 for an illustrative example of this relationship.

[56] The caveat to this is when systems are undergoing maintenance, pipelines are isolated, during emergency work, or when station set pressures are modified or a station is taken out of service.

Figure 6: Linepack for Other High Pressure Pipeline Systems



116. Certain distribution pipeline systems that are directly connected and supplied by transmission pipelines that provide supply at variable pressures may at times experience reduced inlet/system station pressures, even during summer season and shoulder months. In such circumstances, similar to the discussion above regarding transmission pipeline system Linepack, any seasonal variability in operating pressures (including Operational Linepack) is offsetting (Operational Linepack increases made in advance of winter are reduced the following spring).

Section 4: The Fugitive Emissions Measurement Plan Project

117. In the Partial Settlement Proposal for Enbridge Gas's 2024 Phase 1 Rebasing proceeding,[57] the Company agreed to:

> …investigate and determine an appropriate way to accurately measure fugitive emissions, including consideration of top-down measurements (i.e., by aircraft, satellite, and/or towers), with the goals of: (a) confirming the volume of fugitive emissions, (b) determining if recent UFG increases could be due to fugitive emissions, and (c) attempting to locate specific fugitive sources that can be mitigated. This would include all kinds of assets (transmission, rural & urban distribution, and storage). Enbridge Gas will file a robust investigation plan for

[57] EB-2022-0200 Partial Settlement Proposal, Exhibit O1, Tab 1, Schedule 1, July 12, 2023, p. 37.

> consideration and determination in the 2023 deferral and variance account proceeding, which filing shall include justification of the planned approach including, without limitation, whether it will include aerial (i.e., top-down) investigation.

The Company's commitments to determining if recent UFG increases could be due to fugitive emissions was reiterated in the Settlement Proposal for the 2022 Earnings Sharing and Deferral and Variance Account Clearances proceeding.[58]

118. Enbridge Gas determined that in order to satisfy its commitments made above, the first step to meeting goals (a) through (c) would be to expand the Company's actual measurement of fugitive emissions to more accurately quantify volumes.[59] Methane measurements will allow Enbridge Gas to more accurately determine the contribution of fugitive emissions to UFG moving forward and to identify material contributors to the fugitive emissions inventory. This will support the implementation of targeted reduction strategies that are both efficient and effective. Accordingly, Enbridge Gas initiated the Fugitive Emissions Measurement Plan (FEMP) Project in August 2023 and commissioned a third-party expert consultant, Highwood Emissions Management Inc. (Highwood), to support its work to investigate and analyze fugitive emission sources and support the development of an investigation plan. Highwood's final report is set out at (Attachment 1 to this exhibit) (the "Highwood Report").

119. Highwood's investigation included:
    a) Evaluating and confirming the Company's 2022 fugitive emissions inventory –
        - Highwood's analysis (Highwood Report, Section 7.2) showed that 84% of Enbridge Gas's fugitive emissions arose from Distribution Operations (DO) with the remaining 16% from Storage and Transmission Operations (STO).
        - Highwood's analysis (Highwood Report, Section 7.5) showed that DO fugitive emissions were calculated using default published emission

[58] EB-2023-0092 Settlement Proposal Exhibit N1, Tab 1, Schedule 1, November 28, 2023, pp. 19-20.
[59] Fugitive emissions were understood to mean the unintended release of natural gas due to leaks or third-party damages. They do not include emissions from venting, combustion, or flaring.

factors (EFs), while the majority (>70%) of STO fugitive emissions were calculated through direct measurement of emissions using Optical Gas Imaging, followed by flow rate measurement using Hi-Flow samplers.
- Highwood referenced a 2021 uncertainty analysis (Highwood Report, Section 7.6) that estimated the uncertainty in Enbridge Gas's STO fugitive emissions to be <10%, while the uncertainty in DO emissions was estimated to be >115%. This is likely due to the fact that DO emissions are calculated using default published EFs while the majority of STO emissions are measured directly.

b) Reviewing fugitive emissions quantification methodologies and measurement technologies –
- Highwood's review (Highwood Report, Section 5.3) identified potential methodologies to more accurately calculate fugitive emissions, including developing company-specific EFs using representative sample measurements and directly measuring system-wide emissions. Highwood's review focused on the DO segment, due to its larger contribution to overall fugitive emissions and the higher uncertainties associated with the current emission calculation methods.
- Highwood conducted a review of potential emissions measurement technologies (Highwood Report, Section 6.2) and identified the suitability of hand-held and mobile (vehicle) measurement solutions. As previously mentioned, Highwood's review focused on the DO segment, due to its larger contribution to overall fugitive emissions and higher uncertainty.
- Highwood advised against adopting aerial and satellite technologies (Highwood Report, Section 9.4) since they lack the sensitivity to detect smaller leak sizes characteristic of downstream operations and are unlikely to enhance the accuracy of fugitive emissions from DO assets.

c) Recommendations –

Highwood recommended the following to improve the accuracy of the fugitive emissions inventory:

- The development of company-specific EFs for DO, prioritizing sources with high materiality and high levels of uncertainty.
- Piloting a Mobile Ground Detection (vehicle) measurement strategy for DO, and using the outcomes and lessons learned from the pilot to

direct future measurement efforts to improve the accuracy of the emissions inventory. It was suggested to evaluate the piloted mobile technology with respect to its ability to accurately detect and quantify leaks.

- Working towards the development of a measurement-informed inventory, using data obtained through the first two recommendations.
- Monitoring advances in aerial and satellite performance and evaluating emerging technology capabilities for suitability for deployment on distribution systems.

High-level cost estimates for system-wide implementation of different measurement scenarios were provided by Highwood (Highwood Report, Section 8.4)[60]

Table 11

Highwood High-level Cost Estimates *($millions)*

Line No.	Method	Upfront Cost[a,b]	Survey Cost[a]	Subscription Costs[a]	Annual Total[a]
1	Annual Handheld	$ 1.7	$ 28.0	-	$ 29.7
2	Annual Vehicle	$ 22.7	$ 4.7	$ 5.7	$ 33.1
3	Annual Aerial	-	$ 12.0	-	$ 12.0
4	Annual Satellite	-	$ 10.0	-	$ 10.0

a. Costs are in USD based on available information from US vendors and other sources.
b. Upfront costs are annualized over five years. Total upfront costs for the Annual Handheld is $8.5 million and the total upfront costs for the Annual Vehicle is $113.5 million.

Section 4.1 – Investigation Plan

120. Enbridge Gas' 2022 leak volumes were 18,118 10^3m^3 (including leak volumes related to both DO and STO), representing 4% of the Company's 2022 UAF/UFG volumes (EGD and Union Rate Zones combined). As previously discussed, these volumes were primarily due to leaks from DO which were calculated using default published EFs, with an estimated uncertainty of >115%. Emission factors can underestimate or overestimate emissions. However, measurement-informed inventories are generally more accurate than emission factor methods as they utilize measurement in place of generic assumptions.

[60] These high-level cost estimates were not based on vendor quotes for Enbridge Gas' system and will need to be validated. Highwood's cost estimate did not include internal resourcing to repair leaks.

121. Improving the accuracy of fugitive emissions reporting in a transparent and credible manner will require the implementation of a combination of technological, procedural, and operational enhancements. Based on Highwood's findings and recommendations, Enbridge Gas will prioritize the measurement of DO fugitive emissions, due to their higher contribution to overall emissions and since the majority of STO fugitive emissions are already being measured and quantified three times per year. Given the magnitude of the costs associated with the Highwood system wide implementation of measurement technologies and the fact that these technologies are rapidly evolving, Enbridge Gas is proposing to begin development of company-specific emission factors on a subset of assets and to pilot a mobile ground technology on a portion of the distribution system, as part of the Investigation Plan outlined below. The results of this mobile ground pilot and preliminary company-specific emission factor work, proposed to begin in 2025, will help inform next steps in the development of a broader fugitive emissions measurement program to support the development of a measurement-informed inventory.

122. The following outlines the key details of the Enbridge Gas Investigation Plan:

- Begin developing a measurement informed inventory, prioritizing the most material emission sources with the highest uncertainties in the Distribution segment.
- As part of this process, company-specific emission factors will be developed on a subset of assets, which will be an iterative and evolving process. Repeat programs may demonstrate consistency or highlight where further investigation is required. The outcomes of this work will be used to inform next steps in developing company-specific DO fugitive emission factors. This will include:
    - developing a robust, statistically valid sampling strategy,
    - implementing a measurement plan, and

    - data analysis and statistical modeling to develop company-specific emission factors and determine confidence intervals.
- Piloting a mobile ground (vehicle) technology for detecting and measuring DO fugitive emissions on a limited portion of the DO system. Enbridge Gas plans to evaluate the selected technology's suitability for both detecting and quantifying leak flow rates which will require comparison against baseline walking surveys and flow rate measurements. The outcomes and lessons learned from the pilot will be used to direct future measurement efforts.
- Given the diversity of GDS assets and the rapidly evolving technologies, it is expected that a variety of different measurement technologies may eventually need to be evaluated and adopted.
- A pilot will provide real-world, in-field evaluation of the recommended technology. This will include:
    - designing a pilot program (goals, location, duration),
    - deploying a mobile ground (vehicle) measurement technology,
    - validating mobile technology performance against known methods,
    - conducting the required follow-up investigations by foot to confirm and locate leaking components, and
    - managing and repairing leaks found during pilot program.
- Begin configuration and assessment of IT systems. This will include:
    - configuration of Enbridge Gas's existing emissions management database to integrate company-specific data obtained through the piloted measurement plans, and
    - Assess implications of potential system-wide integration on current IT systems
- Continue monitoring developments in aerial and satellite technologies to keep up with rapidly evolving industry and academic research. This will include:
    - attending training and conferences to keep up with emerging technologies and advancements in methane measurement research, and

- evaluation of new technologies as they become available.

Section 4.2 – Administration and Pilot Costs

123. As discussed above, based on Highwood's recommendations Enbridge Gas is seeking to pilot a mobile ground emissions measurement technology on a limited portion of the DO system and to initiate the development of company-specific emission factors. The anticipated incremental administration and pilot program costs are detailed below. It is anticipated that if the measurement pilot program is expanded for wider coverage in the future, further incremental costs will be incurred.

Table 12
2025 Forecast FEMADA Administration and Pilot Costs *($millions)*

Line No.	Cost Element	Total 2025 Forecasted Costs
1	Technology Pilot	1.7
2	IT System	0.2
3	Staffing Resources	0.4
4	Consulting Support	0.2
5	Other Miscellaneous Costs	0.1
6	Total	2.6

Technology Pilot

124. Based on Highwood's recommendations, in order to accurately and credibly measure fugitive emissions and meet the goal of confirming the value of fugitive emissions, Enbridge Gas is seeking to pilot a mobile ground (vehicle) emissions measurement technology and initiate the development of company-specific emission factors. Enbridge Gas anticipates the incremental costs associated with the pilot program to be $1.7 million. The mobile ground pilot program will require designing study parameters, deploying a mobile technology, validating and comparing performance of the technology against known methods, and conducting follow-up investigations by foot to locate and confirm leaking components. Incremental management and repair of leaks located during this pilot are not

included in this cost estimate as they would be covered by the Company's existing integrity programs. The development of company-specific emission factors will require creating a statistically valid sampling strategy, implementing a measurement campaign, and performing data analysis and statistical modeling to arrive at emission factors with confidence intervals. Enbridge Gas intends to use learnings from these pilots to inform the next steps in the development of a fugitive emissions measurement program.

IT System

125. Enbridge Gas has determined that additional IT system functionality will be required to support the integration of measurement into existing emissions management and other IT databases. Incremental funding will be required to reconfigure the emissions management database to utilize company-specific data obtained through pilot studies. Enbridge Gas anticipates the incremental costs associated with updating and reconfiguring IT systems for the pilot program to be $0.2 million.

Staffing Resources

126. The Carbon Strategy team currently comprises five full time equivalents (FTEs). This level of staffing reflects the current level of work Enbridge Gas has experienced to-date. With the implementation of a measurement program, Enbridge Gas expects to require additional incremental staffing resources to support the increased data management and analysis requirements, to oversee the deployment of new technology measurement campaigns on Enbridge Gas' systems, and to offer increased operational support. Enbridge Gas anticipates incremental staffing costs to be $0.4 million. It is anticipated that if the measurement pilot program is expanded for wider coverage in the future, further incremental operational support will be required.

127. Enbridge Gas anticipates that it will incur $0.2 million in external consulting costs for work supporting the development of company-specific emission factors and a

measurement pilot program, and related analyses. These expenditures are required to ensure that Enbridge Gas is well-informed of best practices and procedures for developing robust and credible measurement procedures. Enbridge Gas may incur additional consulting costs associated with other measurement pilots, depending on the outcomes and learnings from these early studies, and should new emerging technologies become viable for testing on Enbridge Gas' systems.

Other Miscellaneous Costs

128. Enbridge Gas expects to incur approximately $0.1 million in miscellaneous costs for training, conferences, and memberships associated with methane measurement technologies and methodologies. Methane measurement technologies for midstream and downstream segments of the value chain are still very new and are rapidly evolving in their sensitivity and capabilities. Based on Highwood's recommendations (Highwood Report, Section 9.1) to monitor advances in aerial and satellite performance, Enbridge Gas expects that incremental funding will be required to keep up with rapidly emerging new technologies, and to evaluate the suitability of new technologies for the improvement of Enbridge Gas's reported fugitive emissions accuracy.

Section 4.3 – New Deferral Account Request

129. To support implementation of the Fugitive Emissions Investigation Plan, Enbridge Gas is seeking OEB approval to establish a Fugitive Emissions Measurement Administration Deferral Account (FEMADA) to record the incremental administration costs, inclusive of Pilot costs, incurred to implement the plan. The account is proposed to be effective commencing January 1, 2025. Enbridge Gas will incur costs related to the technology pilot, configuration of IT systems, incremental staffing, consulting support and other miscellaneous costs, including training, conferences, and memberships associated with methane measurement technologies and methodologies. Assuming Enbridge Gas receives approval to

establish a deferral account for these purposes, the Company will record actual costs in the FEMADA annually until such time that these costs are incorporated into rates. Enbridge Gas is providing forecasted 2025 FEMADA costs for informational purposes only and will seek recovery of its actual 2025 administration and pilot costs in a future proceeding.

130. The Filing Requirements for Natural Gas Rate Applications (Filing Requirements) require a new D&VA request be accompanied by evidence on how the following eligibility criteria will be met:[61]

- Causation – the forecasted expense must be clearly outside the base upon which rates were derived;
- Materiality – the forecasted amounts must exceed the OEB-defined materiality threshold and have a significant influence on the operation of the distributor, otherwise they must be expensed in the normal course and addressed through organizational productivity improvements;[62] and,
- Prudence – the nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for ratepayers

131. Enbridge Gas has assessed the causation, materiality, and prudence of the FEMADA Deferral Account:

a) Causation: All costs that Enbridge Gas intends to record in the proposed FEMADA are outside of the base upon which rates are derived.

b) Materiality: Enbridge Gas's forecasted spend exceeds the $1 million materiality threshold for the establishment of a new account. As detailed in Table 12, the Company is forecasting to spend approximately $2.6 million in FEMADA administration and pilot costs in 2025.

c) Prudence: As noted above, the costs to be incurred are required to support the Fugitive Emissions Investigation Plan which was developed as agreed to in the OEB-approved Phase 1 Settlement Proposal. The Fugitive Emissions Investigation Plan will allow the Company to develop a more thorough understanding of how to more accurately identify, measure, and potentially

[61] OEB Filing Requirements for Natural Gas Rate Applications, February 16, 2017, p. 38.
[62] The materiality threshold is set at $1 million for a utility with a revenue requirement of more than $200 million, as defined in the OEB's Filing Requirements for Natural Gas Rate Applications, February 16, 2017, p.38.

address/reduce fugitive emissions. Details of the respective cost elements are set out in Section 4.2.

132. The proposed Accounting Order for the new deferral account is provided at Attachment 2 to this exhibit.

2023 ACTUAL AVERAGE USE TRUE-UP VARIANCE ACCOUNT
EGD RATE ZONE

1. The purpose of this evidence is to provide information in support of the 2023 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 $14.307 million, plus interest of $0.786 million for a total debit from ratepayers of $15.093 million. The collection is attributable to actual Rate 1 (residential) and Rate 6 (apartment, small commercial and industrial) average uses being lower than 2023 forecast levels.

3. Lower weather-normalized average uses are primarily attributable to higher actual natural gas prices and worse economic conditions in 2022 and 2023 than were forecast. Higher gas prices have led to lower consumption for both Rate 1 and Rate 6 customers. Lower GDP growth and high commercial vacancy rates than were expected have been other factors which have also contributed to lower average use for Rate 6 customers.

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 2023 DSM activities will not be available until a later date an estimate is used. Given the timing of the DSM Plan Proceeding, the 2023 DSM volumes from Enbridge's Application for Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027), EB-2021-0002, are used as an estimate of 2023 actuals. Without the exclusion of a DSM volumetric variance in the AUTUVA calculation, the impacts of DSM are inherently included. As a result, 2023 LRAM amounts which will be filed at a later date, will exclude the impact of Rate 1 and Rate 6 customers.

2023 DEFERRED REBATE ACCOUNT
EGD RATE ZONE

1. The purpose of the 2023 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. The balance in this variance account is a debit from EGD rate zones ratepayers of $2.133 million, plus interest to December 31, 2023, of $0.187 million, for a total debit of $2.320 million. The balance includes the residual amounts not disposed of from the following deferral dispositions: 2021 Earnings Sharing and Deferrals (EB-2022-0110) cleared effective January 2023, and 2021 Federal Carbon Pricing Program (EB-2022-0194) cleared effective April 2023. The total forecast disposition balance of these combined was a debit of $25.672 million, total recoveries were a credit of $23.539 million, resulting in a net residual debit balance of $2.133 million. A summary is provided in Table 1.

Table 1
Deferral Summary: Deferral Clearing Variance Account

Line No.	Proceeding	Amount ($ millions)
1	2021 Earnings Sharing and Deferrals (EB-2022-0110)	23.329
2	2021 Federal Carbon Pricing Program (EB-2022-0194)	2.343
3	Subtotal – Approved for Disposition in 2023	25.672
4	Amounts disposed of in 2023 through one-time billing adjustments	(23.539)
5	Residual balance to Deferral Clearing Variance Account	2.133

3. The residual balance reflects the outstanding amount resulting from the clearance of deferral and variance accounts in the EGD rate zone which occurred during 2023 and the inability to locate and dispose of the approved amounts to all intended customers.

2023 ONTARIO ENERGY BOARD COST ASSESSMENT VARIANCE ACCOUNT EGD RATE ZONE

1. The purpose of the 2023 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 Enbridge Gas'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 2023 OEBCAVA is \$3.733 million, plus interest of \$0.302 million for a total debit balance of \$4.035 million. This amount reflects the variance between OEB costs assessed to Enbridge Gas (relevant to EGD rate zone) in each quarter of fiscal 2023, 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 2023 EGD rate zone OEBCAVA, the Company first needed to apportion the actual 2023 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, Enbridge Gas Inc. has been receiving one consolidated

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

quarterly bill for the amalgamated utility. To apportion the quarterly assessments received in 2023 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 Enbridge Gas Inc's 2023 assessed costs to the EGD rate zone, and the calculation of the amount recorded in the 2023 EGD rate zone OEBCAVA.

4. To calculate the amount for recovery through the 2023 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, and methodology subsequently approved through the EB-2021-0149, 2020 Earnings Sharing and Deferral and Variance Account Clearance proceeding, 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 2023 base comparator, the Company escalated the 2022 quarterly comparator of $0.821 million by the sum of the 2023 Price Cap Index (PCI) of 3.60%, and the EGD rate zone ICM threshold calculation Growth Factor (g) of 1.19%. The 2023 PCI was approved as part of Enbridge Gas's 2023 Rate Application, EB-2022-0133. The 2023 ICM threshold calculation Growth Factor was not filed as part of the 2023 Rate Application, as no ICM funding was requested, but has been calculated using the same methodology as the 2022 ICM threshold calculation Growth Factor, which was approved as part of Enbridge Gas's 2022 Rate Application, EB-2021-0147/0148. The escalation resulted in a 2023 quarterly comparator of $0.861 million ($0.821 million * (1 + (3.60% + 1.19%))). As noted above, Table 2 below shows the apportionment of Enbridge Gas's actual 2023 assessed costs to the EGD rate zone, and the calculation of the

amount recorded in the 2023 EGD rate zone OEBCAVA utilizing a base comparator of $0.861 million.

5. Within this proceeding, the Company is requesting clearance of the principal and interest balances recorded in the 2023 OEBCAVA, in the amount of $3.733 million and $0.302 million respectively, as shown in Exhibit C, Tab 1, Schedule 1.

Table 1

2018/2019 OEB Cost Assessments

Line No.		EGD	UGL	Total
1	Apr. 1 to Jun. 30, 2018	1,467,963	988,479	2,456,442
2	Jul. 1 to Sep. 30, 2018	1,356,860	913,873	2,270,733
3	Oct. 1 to Dec. 31, 2018	1,356,860	913,873	2,270,733
4	Jan. 1 to Mar. 31, 2019	1,356,860	913,873	2,270,733
5		5,538,543	3,730,098	9,268,641
6	Percentage of Total	59.76%	40.24%	100.00%

Table 2

Calculation of 2023 EGD RZ OEBCAVA

Line No.	Period	EGI Assessment	EGD Rate Zone Share (59.76%)	Average Cost assessment Comparator	Variance to EGD Rate Zone OEBCAVA
1	Jan. 1 to Mar. 31, 2023	2,738,849.00	1,636,736.16	860,577.71	776,158.45
2	Apr. 1 to Jun. 30, 2023	3,141,892.00	1,877,594.66	860,577.71	1,017,016.95
3	Jul. 1 to Sep. 30, 2023	3,062,860.00	1,830,365.14	860,577.71	969,787.43
4	Oct. 1 to Dec. 31, 2023	3,062,860.00	1,830,365.14	860,577.71	969,787.43
5		12,006,461.00	7,175,061.10	3,442,310.85	3,732,750.25

INCREMENTAL CAPITAL MODULE DEFERRAL ACCOUNT – EGD RATE ZONES

1. The Incremental Capital Module Deferral Account (ICMDA) records the difference between the actual revenue requirement for approved ICM projects, and the revenues collected through ICM rates approved by the OEB on a project-by-project basis.

2. In the EB-2022-0200 Phase 1 Decision on Settlement Proposal dated August 17, 2023, parties agreed to the clearance of deferral and variance accounts as proposed by Enbridge Gas including ICMDA balances. The balance approved at the time was comprised of actual & forecast amounts. Enbridge Gas is seeking final disposition of the remaining balance in the ICM Deferral Account in this proceeding representative of the variance between the forecast balance approved in the OEB approved Interim Rate Order dated April 11, 2024, and the final actual balances as calculated through December 31, 2023.

3. The balance in this deferral account is a credit to the EGD Rate Zone of $4.909 million plus interest of $0.232 million for a total credit balance of $5.141 million. The balance of $4.909 million represents the difference between the $2.031 million debit approved for disposition in the Interim Rate Order and the calculation of the final EGD Rate Zone ICMDA credit balance of $2.878 million as shown in Table 1.

4. The variance of $4.909 million the EGD Rate Zone projects is primarily the result of a $3.7 million reduction in the Cherry to Bathurst Project revenue requirement due to the timing of capital spend and project in-service date, as well as $1.3 million additional revenue collected in rates compared to forecast.

Table 1
Summary of Incremental Capital Module Deferral Account
Amounts Requested for Clearance in 2023 ESM Proceeding

Line No.	($000's)	Actual & Forecast Balances Approved for Disposition (EB-2022-0200)[1]			Final Cumulative Balances[2]			Amounts Proposed for Disposition (2023 ESM and Deferral		
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Principal	Interest	Total	Principal	Interest	Total	Principal	Interest	Total
	EGD Rate Zone									
1.	NPS 20 Don River Replacement Project	-	-	-	79.2	13.2	92.4	79.2	13.2	92.4
2.	NPS 20 Cherry to Bathurst Replacement Project	2,031.1	(247.7)	1,783.4	(2,957.1)	(493.4)	(3,450.4)	(4,988.2)	(245.7)	(5,233.8)
3.	Total EGD Rate Zone ICMDA	2,031.1	(247.7)	1,783.4	(2,877.9)	(480.1)	(3,358.0)	(4,909.0)	(232.4)	(5,141.4)

Notes:
(1) EB-2022-0200 Rate Order, Working Papers, Schedule 27, pages 1 & 2; approved in Interim Rate Order dated April 11, 2024.
(2) Reflects 2019 through 2023 actuals.
(3) Represent variances between amounts approved for disposition in the Interim Rate Order and the final cumulative balances based on actuals.

RENEWABLE NATURAL GAS (RNG) INJECTION SERVICE VARIANCE ACCOUNT (RNGISVA)

1. The purpose of the RNGISVA is to record the annual revenue deficiency/sufficiency related to the provision of RNG injection services to RNG producers. The annual revenue deficiency/sufficiency will be calculated as the difference between actual revenues generated under Rate 401 (RNG injection service) and the actual revenue requirement impact of the costs incurred, on a fully allocated basis, to provide those services. To ensure that ratepayers are not harmed by potential default of Rate 401 customers, the annual revenue deficiency/sufficiency calculation will not include any impacts of contract default by RNG injection service customers.

2. In the EB-2022-0200 Rebasing Application, Enbridge Gas did not have adequate certainty on the in-service timing of the RNG injection services, and furthermore the preliminary forecast was less than $1 million. Given the uncertainty and materiality, Enbridge Gas proposed bringing forth actual balances as part of the 2023 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding[1].

3. Enbridge Gas is seeking final disposition of the total balance in the RNGISVA which is a cumulative credit to ratepayers of $0.332 million (see Table 1 for details) plus interest of $0.029 million, for a total credit balance of $0.360 million.

[1] EB-2022-0200 2024 Rebasing Application, Exhibit 9, Tab 2, Schedule 1, Section 5, para. 84.

Table 1

Summary of RNGISVA Amounts Requested For Clearance

Line No.	($000's)	2022	2023
1	Revenue Requirement - Dufferin Injection	(77.1)	515.2
2	Annual Service fee - Dufferin Injection	82.1	687.5
3	Annual Sufficiency/(Deficiency)	159.2	172.3
4	Cumulative Sufficiency/(Deficiency)	159.2	331.5

ACCOUNTS WITH A ZERO BALANCE - EGD RATE ZONE

1. The following 2023 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 (EFTPBSDA) Deferral Account;
   - Dawn Access Costs (DACDA) Deferral Account; and
   - Transition Impact of Accounting Changes (TIACDA) 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 Purchase Gas Variance Account (PGVA), DSM related accounts and Federal Carbon Charge accounts.

3. The balance in the Transition Impact of Accounting Changes (TIACDA) Deferral Account remaining after the clearance of the 2022 amount was approved for disposition as part of the OEB's EB-2022-0200 Interim Rate Order approved on April 11, 2024. Therefore, there will be no further balance to dispose of in this account.

Technical Report

EGI Fugitive Emissions Measurement Report

Date
2024-05-21 Final Report

Team

Heather Isidoro – Highwood Emissions Management
Brendan Moorhouse – Highwood Emissions Management
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Prepared for

ENBRIDGE

Disclaimer

Highwood Emissions Management Inc. (Highwood) has prepared this report for Enbridge Gas Inc. based on an agreed scope of work. The report was commissioned by and prepared for the exclusive use of Enbridge Gas Inc Except where expressly stated, Highwood cannot guarantee the validity, accuracy, or comprehensiveness of any information presented in this report. Information presented in this report may be used to guide decision making but additional information or research may be required. While every effort is made by Highwood to ensure that accurate information is disseminated through this report, Highwood makes no representation about the content and suitability of this information for any purpose.

Table of Contents

1. Executive Summary

Enridge Gas Inc. (EGI), Canada's largest natural gas storage, transmission, and distribution company, has committed to developing a plan for improving the accuracy of its reported fugitive emissions as part of the partial settlement proposal that was filed with the Ontario Energy Board (OEB) on June 28, 2023, as part of its 2024 Rates Application. Highwood Emissions Management (Highwood) conducted a comprehensive assessment of EGI's 2022 inventory and practices and provided recommendations for technology deployment strategies to improve emissions accuracy.

The report begins with an overview of greenhouse gas emissions, EGI's business segments, and the regulatory frameworks governing emissions reporting in Canada. It discusses various emissions quantification methodologies, including bottom-up inventories and measurement-informed inventories (MII), and highlights the importance of uncertainty estimation and mitigation strategies.

A key focus of the report is on technology options for detecting and quantifying fugitive emissions. It covers a range of commercial methane (CH_4) detection technologies, deployment platforms, sensing principles, and controlled release testing methods. The emphasis is on selecting accurate, efficient, and compliant technologies that meet the unique needs of storage, transmission, and distribution operations.

EGI's current fugitive emissions inventory and calculation methodologies are reviewed, including materiality assessments and year-over-year trends. The report provides insights into higher-emitting sources, station sizes, and contribution analysis across storage, transmission, and distribution operations.

Highwood presents this report and recommendations to support EGI in increasing the accuracy of their fugitive emissions inventory. Highwood recommends that EGI initiate pilots to begin implementing a measurement strategy and to begin developing company-specific emission factors to complement or replace generic emission factors. Increased detection and measurement data will increase the accuracy of both the quantity and frequency (or presence) of fugitive emissions and displace generic emission factors, which will better represent EGI's asset base. Highwood does not recommend the deployment of aerial and satellite technologies on EGI's systems based on their current performance but recommends monitoring future development and pilot opportunities for aerial technology.

2. Glossary

Activity Factor (AF) -Typically refers to the population of emitting equipment. For example, activity factors could refer to kms of natural gas pipeline, the count of thief hatches on a facility or the mechanical power of gas turbines. Activity factor can also refer to other parameters that directly influence the rate of operation and therefore emissions. For example, the activity factor for combustion engines can be the amount of fuel consumed or the number of operating hours.

Aggregated Data: Emissions data collected from multiple sources and combined, usually for reporting or statistical analysis.

Anthropogenic - Of, relating to, or resulting from the influence of human beings on nature.

Audio, Visual, and Olfactory (AVO) surveys - Audio, visual, and olfactory (AVO) surveys are a type of methane detection survey performed using human senses. Regulations often have some form of AVO requirement that is equipment or site specific.

Bottom-up Emissions Inventory - A list of emission sources by category and quantity, providing detailed information on individual sources. Bottom-up inventories can use generic emission factors derived from industry averages, company specific emission factors, direct measurements, engineering calculations, or manufacturer data.

Bottom-up Measurement: A measurement that occurs at a granular scale (e.g., component) used to estimate emissions more broadly. Bottom-up measurements can be averaged into emission factors and combined with activity factors to build a bottom-up inventory.

Component - Multiple components (e.g., valves, flanges, and threaded connections) comprise equipment (e.g., tanks, separators) and a site may have multiple pieces of equipment or equipment groups. In LDAR-Sim, a component is the smallest scale of oil and gas infrastructure that can be modeled.

Detection – The determination by a method or device that methane levels are above ambient background concentration. In some cases, this may be an indication of a leak or an emission.

Distribution - The segment of the natural gas value chain comprised of pipelines and metering and regulating equipment, used to deliver natural gas to end-use consumers.

Downstream - The final stage in the oil and gas value chain. Activities include distribution, retail marketing, product development, and consumption by the end user.

Emission Factor - Describes typical methane emissions per unit of activity of a component or part of the gas system (e.g., valve, pipeline section) or from an event and can have units like [kg/km], [kg/event], [kg/time], or [kg/equipment]. Emission factors are typically expressed in mass rate units [kg/hr], [kg/km/year], [kg/equipment/hr][i]. Emission factors can be generic or company specific.

Emissions Inventory – Generally refers to a database that lists the amount of air pollutants discharged into the atmosphere during a year, by source, and can include categories such as combustion, venting, flaring, and fugitives.

Flaring - An intentional, controlled burning of natural gas. Gas is ignited at the top of a flare stack, creating a characteristic flame.

Follow-up survey - An inspection to confirm or deny potential leaks detected through a screening survey. Typically, screening technology will identify a potential leak at the site or equipment-scale. Follow-up surveys diagnose leaks at the component scale, typically with handheld detection methods.

Fugitive Emissions - The unintentional release of hydrocarbons to the atmosphere. These emissions can occur due to leaks or third-party damages.

Fugitive Emissions Measurement Plan (FEMP) – In this report, "FEMP" refers to the Fugitive Emissions Measurement Plan that will be developed by Enbridge Gas.

Note: The Alberta Energy Regulator uses the acronym "FEMP" to refer to a "Fugitive Emissions Management Program" In the U.S. and elsewhere, the term 'LDAR Program' is often used.

Greenhouse Gas (GHG) - A gas that traps heat in the atmosphere, such as carbon dioxide, methane, nitrous oxide, and fluorinated gases.

Handheld Instrument - A small, portable methane detection instrument that is often used to detect and diagnose leaks at the component scale. Examples include optical gas imaging (OGI) cameras and handheld organic vapor analyzers (OVAs).

LDAR - Leak detection and repair (LDAR) are the work practice and execution of identifying leaking equipment and conducting repairs. A component subject to LDAR requirements must be monitored at specified, regular intervals to determine if it is leaking. Often, regulatory requirements specify a repair timeline, which may be related to leak size and severity.

Leak - The unintentional release of hydrocarbons to the atmosphere. A component of fugitive emissions.

Measurement - Quantification of emissions mass or volume rates from data collected directly from the environment at a specific place and time. Measurements can be used to inform bottom-up or top-down inventories.

Measurement-Informed Inventory (MII) – An emissions inventory that incorporates company-specific measurements and that does not rely exclusively on generic assumptions. Various regulatory and non-regulatory guidance exist for the development of MIIs. These can differ in their requirements. For example, OGMP 2.0 Level 4 is a MII in which company-specific measurements, engineering estimates, and/or simulations are used at the source level for material sources. Veritas Pathways 1 and 2 provide methodologies to develop MIIs that rely on site level measurements extrapolated across space and time. Most MIIs do not require exclusive use of measurements but encourage operators to minimize use of generic inputs.

Methane - A colorless, odorless gas that occurs abundantly in nature and as a product of certain human activities. Its chemical formula is CH_4.

Midstream - The segment in the oil and gas value chain following that falls between upstream and downstream. Activities include transmission and storage.

Minimum Detection Limit - The smallest atmospheric concentration or emission rate that a technology is capable of discerning above background.

Probability of detection is the likelihood that a measurement method will successfully detect the presence of a target species such as methane gas in the atmosphere. For example, a technology with detection sensitivity of 10 kg/hr with 90% PoD means that, for given environmental and operational parameters, the technology solution will statistically detect at least 9 out of 10 leaks that are 10 kg/hr. The POD may vary with environmental conditions.

Natural Gas: Natural gas is a naturally occurring and flammable hydrocarbon gas used for fuel. Its primary component is methane (CH_4), but it can also contain ethane, propane, butane, and pentanes. Often, impurities including oxygen, hydrogen sulfide (H_2S), nitrogen, water, and carbon dioxide are also present.

Optical Gas Imaging (OGI) - A common leak detection technology that uses thermal infrared cameras to visualize methane and various other organic gases. Common OGI cameras create images of a narrow range of the mid-IR spectrum (3.2– 3.4 µm wavelength) which methane and other light hydrocarbons actively absorb.

Parametric Data - operational data and characteristics utilized to inform inventories including production rates, equipment specifications, performance characteristics, gas composition, and process parameters.

Quantification - Determining an emission rate, such as mass per time or volume per time. This can be done directly through measurement of the emissions, or indirectly through estimations, calculations, and modeling.

Quantitative Optical Gas Imaging (QOGI) - Combines optical gas imaging (OGI) camera technology with cross-section pixel absorption algorithms to quantify emissions. The brightness of each pixel seen through the OGI camera is proportional to the amount of infrared radiation incident on the camera along the corresponding line of sight through the plume. The brightness is converted to a concentration and combined with estimated velocities to obtain mass fluxes.

Screening Survey - LDAR screening methods are used to rapidly flag high-emitting sites to direct close-range follow-up source diagnosis and root cause analysis. An example of a common screening method is an aerial monitoring campaign.

Transmission - Natural gas transmission systems move natural gas from upstream gathering, processing, or storage facilities to distribution systems, large-volume customers or other storage/processing facilities.

Unaccounted for Gases (UFG) - The difference between gas receipts and gas deliveries, where gas receipts are volumes that enter a pipeline system and gas deliveries are volumes that exit the pipeline system. In the case of Enbridge Gas's regulated distribution assets: receipts include (but are not limited to) volumes of gas received into the distribution system from various interconnects, including upstream pipelines, underground storage, and local supplies/production; deliveries include (but are not limited to) volumes of gas delivered from integrated storage, transmission, and distribution systems to various interconnects, including downstream pipelines, underground storage, and to end-use customers.

Upstream - The first segment in the oil and gas value chain, consisting of exploration and production processes. Activities include drilling, production, and processing.

Vented Emissions - The controlled release of unburned gases into the atmosphere, such as natural gas or other hydrocarbon vapors.

3. Introduction

In June 2023, a commitment was made by Enbridge Gas Inc. (EGI) to investigate and determine an appropriate way to accurately measure fugitive emissions, as part of a partial settlement proposal in EGI's 2024 Rebasing application (EB-2022-0200). The report will include an analysis of EGI's current emissions inventory and give recommendations on how to improve the accuracy of reported fugitive emissions.

3.1. Partial Settlement Proposal

On June 28, 2023, in EB-2022-0200, EGI filed a partial settlement proposal with the Ontario Energy Board (OEB). In this proposal, EGI agreed to investigate a way to accurately quantify fugitive emissions:

> "In relation to fugitive emissions, which are a component of UFG, Enbridge Gas has agreed to investigate and determine an appropriate way to accurately measure fugitive emissions, including consideration of top-down measurements (i.e., by aircraft, satellite, and/or towers), with the goals of:
>
> (a) confirming the volume of fugitive emissions,
>
> (b) determining if recent UFG increases could be due to fugitive emissions, and
>
> (c) attempting to locate specific fugitive sources that can be mitigated. This would include all kinds of assets (transmission, rural & urban distribution, and storage).
>
> Enbridge Gas will file a robust investigation plan for consideration and determination in the 2024 deferral and variance account proceeding, which filing shall include justification of the planned approach, including, without limitation, whether it will include aerial (i.e., top-down) investigation. "

3.2. Objectives and Approach

The objective of this report is to assess EGI's current fugitive inventory and make recommendations for appropriate strategies and technology deployment options to increase the accuracy of reported fugitive emission volumes. EGI contracted Highwood Emissions Management (Highwood) to prepare this report to support EGI's submission to the OEB.

This report provides background on Greenhouse Gas (GHG) emissions and EGI's business segments. This report also provides an overview of regulatory frameworks, emissions quantification and estimation methodologies, and uncertainty. An overview of technology options and operating parameters is provided to give context to the analysis and recommendations. Highwood's review included:

- A review of EGI's year-over-year total emissions, identifying any notable increases or decreases,
- A materiality assessment to look at which sources have the highest contribution to emissions, to provide focus on the most impactful emitters,
- A review of current calculation methodologies and measurement and detection practices considering current regulatory frameworks,
- A review of technology deployment scenarios to determine optimum deployment strategies available across each EGI business segment and
- Recommendations on technology deployment strategies to increase the accuracy of fugitive emissions.

4. Background

This section defines GHG emissions and provides an overview of contributing gases. It includes an explanation of reporting units and an introduction to the Global Warming Potential (GWP) of methane, noting the significance of how adjusting the GWP number impacts overall reported emissions.

This section also gives an overview of EGI's transmission, storage, and distribution segments, noting the distinct components of each segment and the operational size and magnitude of key operational infrastructures. Specific sources of GHG emissions in EGI's operating areas and their significance relative to other sources of emissions will also be discussed.

4.1. Greenhouse Gas Emissions

GHGs are gases that trap heat in the atmosphere and include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and fluorinated gases (F-gases). GHGs can be classified as natural, which are found in nature, or anthropogenic, which are man-made.

Natural GHGs are emitted through natural processes such as volcanic eruptions, wildfires, decomposition of organic matter, and biological processes in plants and animals.

Anthropogenic emissions are emitted through the combustion of fossil fuels, industrial processes, deforestation, agriculture, and waste management. According to the Intergovernmental Panel on Climate Change (IPCC)[ii], anthropogenic sources are estimated to contribute around 50-60% of total global GHG emissions. Anthropogenic emissions can be intentional (i.e., operational releases such as venting) or unintentional (i.e., fugitive emissions).

The Joint Research Center estimates that CO_2 and CH_4 account for approximately 71% and 21%, respectively, of 2022[iii] global anthropogenic GHGs (Figure 1).

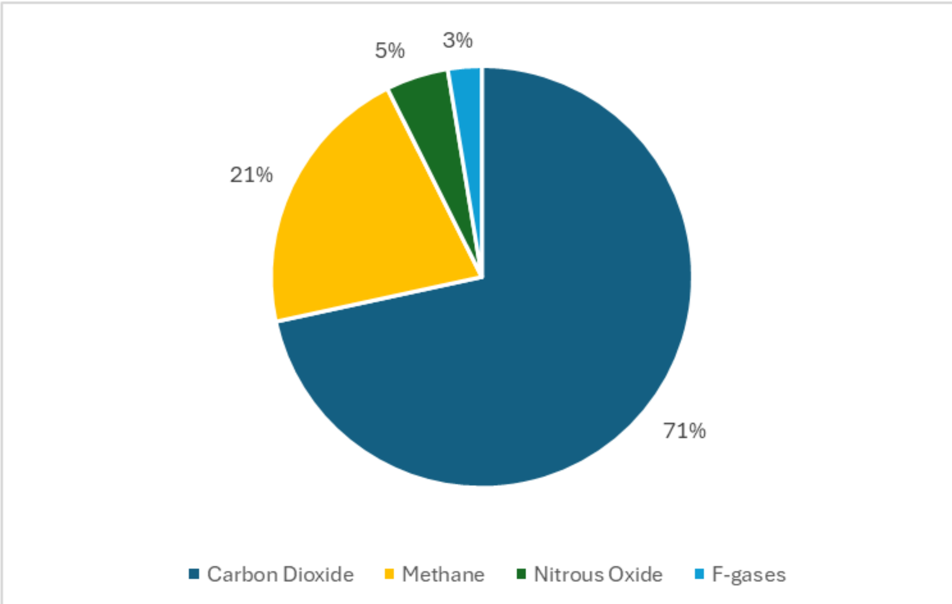


Figure 1: Anthropogenic greenhouse gas emissions breakdown

CO_2 is produced by the combustion of fossil fuels. CO_2 can also be produced by solid waste, biological materials, and because of certain industrial chemical reactions (e.g., cement production). CH_4, the main component of natural gas, is produced during fossil fuel extraction (coal, natural gas, and oil) and distribution, agricultural practices, land use, and by the decay of organic landfill waste. Any leakage along the value chain or release constitutes a direct emission of CH_4 into the atmosphere and is often referred to as a fugitive emission.

Global Warming Potential (GWP) was developed to allow comparisons of the impacts of different gases on global warming. Specifically, GWP reflects other greenhouse gas's ability to trap heat in the atmosphere compared to CO_2. The larger the GWP, the more significant the impact is on climate change. CH_4 has a GWP of 27-30 over 100 years and 81-83 over 20 years[iv], subject to revisions to the Intergovernmental Panel of Climate Change Assessment Reports. This means the impact of methane emissions can be 27-83 times greater than CO_2, depending on the chosen time horizon.

GHG emissions can be expressed in volume or mass, most commonly in tonnes of a specific gas. When multiplied by the GWP, the result allows for a comparison between each of the gases and is expressed in tonnes of CO_2 equivalent, or tCO_2e (Table 1). For the purposes of this report, all emissions are expressed in tCO_2e.

Table 1. The effect of the GWP when comparing CO_2 to CH_4 in CO_2e for AR5 100-year time horizon

	CO_2	CH_4
Mass (tonnes)	1	1
GWP	1	28
Mass (tCO_2e)	1	28
% Contribution based on tCO_2e	3%	97%

Fugitive emissions represent the unintentional release of GHGs, including CH_4, into the atmosphere. For the purposes of this report, fugitive emissions are defined as leaks from the natural gas system or gas losses due to third-party damages.

In natural gas systems, unaccounted-for gas reflects the imbalance that exists at any given time between the measured gas coming into the system and the measured gas exiting the system.

Fugitive emissions make up just one of several potential contributors to unaccounted-for gas and refer specifically to the unintended releases of gases from equipment leaks or emissions from third party damages.

4.2. EGI Business Segment Overview

EGI is Canada's largest natural gas storage, transmission, and distribution company[v]. EGI serves approximately 3.9 million customers in Ontario and Quebec, distributes about 2.3 billion cubic feet (Bcf) per day of natural gas, and has an effective peak demand capacity of 7.6 billion cubic feet (Bcf) of natural gas. EGI operational segments can be categorized by: Storage and Transmission Operations (STO) and Distribution Operations (DO).

EGI's STO network consists of transmission systems and gas storage facilities. The storage and transmission system consists of 4700 kilometres (km) of pipelines, 22 compressor stations, as well as other supporting infrastructure, including receipt stations, valve stations, farm taps, and batteries (Table 2).

Table 2. EGI system parameters for transmission and distribution

Storage and Transmission		
Net Storage Working Capacity	291.6	Bcf (billions of cubic feet)
Transport Capacity	11,239,121	GJ
Compressor Stations	22	count
Wellheads	399	count
Transmission Pipeline	4,707	km
Distribution		
Service Pipeline	68,389	km
Main Pipeline	74,547	km
Customer Meter Sets	3,940,632	count
Gate Stations	465	count

EGI's storage facility at Dawn is the largest facility of its kind in Canada, with a working capacity of over 284 Bcf in 34 facilities utilizing depleted gas fields. The storage system consists of compressor stations, storage metering sites (receipt/sales meter stations), storage wells, and associated gathering lines.

EGI's DO segment provides natural gas to residential, commercial and industrial customers. The operational infrastructure consists of over 105,000 km of pipelines, distribution stations, and 3.9M customer meter sets (Table 2).

Much of EGI's natural gas distribution network is located within populated urban areas, including the greater Toronto area (GTA) and Ottawa. The network also services southwestern Ontario, expanding to the North (Figure 2).

Figure 2: Map of EGI's service areas in Southern Ontario

5. Methane Emissions Reporting Methods

5.1. Introduction

In Canada, CH_4 reporting requirements for storage, transmission, and distribution are governed by various regulatory frameworks and reporting requirements established by federal and provincial authorities.

In this section, we provide an overview of the regulatory frameworks and industry-specific practices applicable to EGI and the quantification and reporting methodologies within those frameworks. We also describe a broad range of approaches, including bottom-up and top-down methods and introduce the concept of measurement-informed inventories (MII). We also discuss sources of uncertainty, the main types of uncertainty, and mitigation strategies.

5.2. Regulatory Frameworks

In this section, we provide an overview of regulatory frameworks and reporting methodologies for GHG emissions in the natural gas transmission, storage, and distribution sectors in Canada.

5.2.1. Federal Regulations

The key frameworks that regulate GHG emissions and reporting are Canada's federal Greenhouse Gas Reporting Program (GHGRP), and the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector).

GHGRP

Canada's Greenhouse Gas Reporting Program (GHGRP) is administered by Environment and Climate Change Canada (ECCC). The program requires companies with emissions above a certain threshold to report them annually to ECCC. GHGRP provides guidelines and methodologies for reporting greenhouse gas emissions, including CH_4. Canada's Greenhouse Gas Quantification Requirements (GGQR) provides technical guidance for those required to report information to ECCC under the GHGRP. The GGQR includes an overview of quantification methods and provides generic emission factors for use when facility-specific factors are not available. EGI's natural gas storage, transmission, and distribution system is subject to reporting requirements under the GHGRP if emissions exceed 10,000 tonnes of CO_2e per year.

Federal Methane Regulations (Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)

The Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) introduced emissions thresholds (facility and equipment level standards) to reduce fugitive and venting emissions of hydrocarbons, including methane, from applicable facilities. Proposed amendments to this regulation, introduced in early 2024, build upon the existing Regulations to further reduce methane emissions through more frequent leak surveys, shorter repair timelines and more stringent venting and flaring requirements.

5.2.2. Provincial Regulations (Ontario)

Provinces in Canada have unique regulatory frameworks and reporting requirements related to GHG emissions. Ontario facilities which exceed the 10,000 tCO2e emissions threshold must report emissions annually under Ontario Regulation 390/18. Facilities must follow the standard quantification methods as set out in the Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions (the Ontario Guideline), which references emission factors and methodologies published in the Canadian Energy Partnership for Environmental Innovation (CEPEI) Methodology Manual. Ontario emitters are also required to register and report applicable emissions under Ontario's Emissions Performance Standards (EPS) program, under Regulation 241/19. Under the EPS program facilities engaging in natural gas transmission and storage require verification of applicable emissions by an accredited verification body.

5.2.3. Industry Best Practices and Guidelines

Industry associations and organizations in Canada, such as the Canadian Energy Partnership for Environmental Innovation (CEPEI), develop best practices and guidelines for CH_4 calculation and reporting.

CEPEI publishes an annual Air Emissions Methodology Manual to assist companies in quantifying atmospheric emissions from fugitive, venting, flared and combustion sources at Canadian natural gas transmission, storage, and distribution facilities. The manual facilitates a complete accounting of atmospheric emissions, including CO_2, CH_4, and N_2O. The emission factors for fugitive equipment leaks and venting provided in the CEPEI manual are primarily based on measurement studies sponsored by the Canadian and/or US natural gas industry. This manual is included as a Technical Reference Document in Ontario's Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions.

5.3. Emissions Quantification Methodologies

There are several recognized methodologies for calculating fugitive emissions. These range from using published generic emission factors to developing company-specific emission factors and completing site-level measurement campaigns for top-down reconciliation. All methods incorporate measurement data, parametric data, and activity data (operations data such as km of pipeline and equipment counts) in different ways.

An emission factor is a value that relates the typical emissions per unit of activity (such as a component or event) occurring within a gas system. In most cases, emission factors are averages of all available data of acceptable quality and are generally assumed to be representative of long-term averages for all facilities in the source category.

A "bottom-up" inventory of emissions involves compiling an inventory of equipment and components and estimating the associated emissions for those components. Bottom-up inventories can be developed using generic emission factors, company-specific emission factors, or direct measurements.

"Top-down" measurements aggregate multiple potential sources into a single estimate and may be site level (consisting of all equipment groups on site), or regional (consisting of all sites in a measurement area. Top-down estimates can be developed without knowledge of the source-level inventory. There is significant value in comparing and reconciling the two estimates. Understanding the differences can provide significant insights into the accuracy of the emissions inventory and can result in an improved emissions inventory. Both bottom-up and top-down approaches may be used for building emissions inventories (Table 3).

Table 3: Overview of potential emissions estimation techniques for building inventories

Bottom-Up Approach	**Generic Emission Factors:** Generic emission factors are average emission rates for a given component, generally derived based on industry measurement campaigns and used with activity factors. Generic EFs assume typical steady-state leak rates and typical frequency of intermittent leak rates across a range of equipment, maintenance activities, and equipment malfunctions. These factors provide a straightforward way to estimate fugitive emissions without site-specific measurements. While generic emission factors represent the leak rate per component type considering the entire population of components (i.e. "population average factor"), leaker emission factors represent the leak rate per component considering leaking components only (i.e. "leaker factor"). Generally, the more representative an emission factor is of the actual operating conditions it is being applied to, the more accurate it is.
	Company-Specific Emission Factors: Company-specific emission factors are developed based on direct measurement of a representative sample of company assets. These factors reflect the emissions associated with the company's unique operational characteristics and components.
	Direct Measurement: Leak flow rate can be directly measured using technologies such as hi-flow samplers by performing a survey of all assets of a given type. With direct measurement, activity factors are not required.
Top-Down	**Top-Down Measurement**: Top-down measurements are typically done at a site or regional scale. Activity factors are not required or used with top-down measurement.

Top-down measurements can be used to complement and verify bottom-up inventories. Reconciliation is a process whereby top-down measurements are combined with a bottom-up inventory to develop a more accurate emissions estimate. A reconciliation can be used to help identify discrepancies and refine emission estimates. In some cases, where discrepancies between the bottom-up inventory and the site-level measurements are identified, site-level measurements may be added to the bottom-up inventory if they cannot be explained. For example, a site-level measurement may reveal a previously unknown emission source, in which case, the operator may choose to add the measured volume to their inventory to account for that source. In other instances, there may be alignment between the sources in the bottom-up inventory and the site-level measurement.

The selection of an appropriate emissions estimation methodology should consider:

- The objective of the emissions inventory
- Data availability
- The contribution of a given emission source to the overall inventory (materiality)
- The cost and practicality of the emission estimation method

Combining multiple methodologies or using a tiered approach can enhance the accuracy and reliability of CH_4 emission estimates.

The advantages and disadvantages of each methodology are presented in Table 4. Advantages and disadvantages of different emissions estimation techniques for building inventories, with consideration given to:

- Level of effort
- Cost
- Uncertainty
- Resource implications (requirements for each methodology noting, however, options exist to outsource to third-party providers)

The specific cost data of each methodology depend on individual contracts between operators, technology providers, site-specific parameters, frequency, work practices, asset density, and other factors. Therefore, specific cost data is not included in the table below.

Table 4. Advantages and disadvantages of different emissions estimation techniques for building inventories

Methodology	
Advantages	Disadvantages
Generic Emission Factors	
• Provides a rapid estimation of emissions without the need for site-specific emissions measurements. • Sometimes derived from measurements from a larger sample population than a single operator might measure, providing a more representative statistical average. • Least resource and cost intensive method – does not require annual surveys.	• May not accurately reflect emissions arising from a specific company's current operating practices. • Generic factors may not capture uncertainty due to technology, practices, or regional differences unique to a specific operator.
Company-Specific Emission Factors	
• Can more accurately reflect the company's emissions, unique characteristics, variations and operating conditions compared to Generic EFs. • Can be used to validate previous emissions reduction initiatives and actions. • Can help identify trends and opportunities to reduce emissions based on the company's unique asset profile and characteristics.	• Developing and maintaining company-specific emission factors requires more resourcing than using generic EFs since company-specific measurements are required. • Requires effective site stratification to develop representative EFs. • Insufficient statistical sampling strategies or sample sizes could impact accuracy or contribute to uncertainty.

• Less cost and resource intensive than full system measurement. Does not require system-wide measurement – EFs are developed by measuring a representative sample of assets.	• Increased costs over generic EFs, as a sampling and measurement survey plan must be performed.
Direct Measurement	
• Generally considered to provide high accuracy CH_4 concentrations • Allows for more accurate determination of frequency and size of leaks, as well as changes in CH_4 levels. • Standardized calibration and measurement protocols help maintain consistency and comparability of data across asset ranges.	• Can be expensive to purchase, operate and maintain measurement equipment, or hire third-party service providers. • Direct measurement methods may have limitations in sampling certain environments or sources of CH_4, such as remote locations, confined spaces, or areas with limited access to the source (road versus foot access). • The highest resource requirements for the bottom-up methods. Can be outsourced to a 3rd party.
Top-Down Measurement	
• emissions can be measured over large geographic areas in relatively short timeframes. • Can provide insights on unexpected emissions, e.g., significant but rare leaks that have not been identified in a bottom-up approach. • Provides validation of bottom-up estimates. • Allows for more accurate determination of frequency and size of leaks, as well as changes in CH_4 levels.	• Top-down technologies generally have higher minimum detection limits (MDLs) and lack the spatial resolution to capture smaller leaks. • technologies only provide a 'snapshot' in time that must be extrapolated to the reporting period using models (e.g., OGI, gas chromatography, stack testing) • Challenging to identify the sources of measured emissions (e.g. anthropogenic CH_4 vs. company leaks) • It can be expensive to purchase, operate, and maintain measurement equipment or outsource.

5.4. Measurement Informed Inventories

A Measurement-Informed Inventory (MII) is an emissions inventory that leverages company-specific data and that does not rely exclusively on generic assumptions. Various regulatory and non-regulatory criteria exist. For example, OGMP 2.0 Level 4 specifies reporting requirements that would produce an MII inventory in which company-specific measurements, engineering estimates, and/or simulations are used at the source level for material sources. Veritas Pathways 1 and 2 provide approaches for obtaining measurements that can be used to develop MIIs. Most MIIs do not require the exclusive use of measurements but encourage operators to minimize the use of generic inputs. The goal of an MII is to improve confidence and defensibility of CH_4 emission estimates and prioritize emissions mitigation efforts. MIIs can be valuable for effectively allocating resources to emissions mitigation projects, supporting companies in achieving reduction targets and demonstrating progress with confidence.

Bottom-up inventories have commonly been based on generic emission factors. In its most basic form, a MII can be calculated in the same way as a generic bottom-up inventory, but with company-specific data such as company-specific emission factors or direct methane measurements used in place of generic assumptions. More rigorous MIIs can leverage multiscale measurements, such as aerial top-down surveys followed up with source level ground-based measurements to validate or improve bottom-up inventories via reconciliation. More rigorous MIIs also use a higher proportion of measurements relative to generic assumptions and adequately constrain uncertainty in those estimates.

While current regulatory requirements in Canada do not require reconciliation of different emissions estimates, several voluntary initiatives do. Initiatives including GTI Veritas, MiQ, and OGMP 2.0 consider integration of top-down and bottom-up measurements to be more robust than inventories which are built using only one methodology, since a multiscale measurement campaign allows one scale of measurement to validate the other.

5.5. Site Stratification and Sampling Guidance

The goal of a site stratification exercise is to determine reasonable site categorizations that can be used as the basis for a sampling strategy, and extrapolation of site-specific emission factors across unmeasured sites. Site stratification should be an iterative improvement process.

Once groupings and sub-groupings are determined, a representative sample size should be chosen that balances population representativeness with feasibility and resource availability. OGMP2.0[vi] provides an example of guidance on balancing materiality with population sizes (Figure 3). Blue represents a low materiality, and red represents a high contribution to materiality.

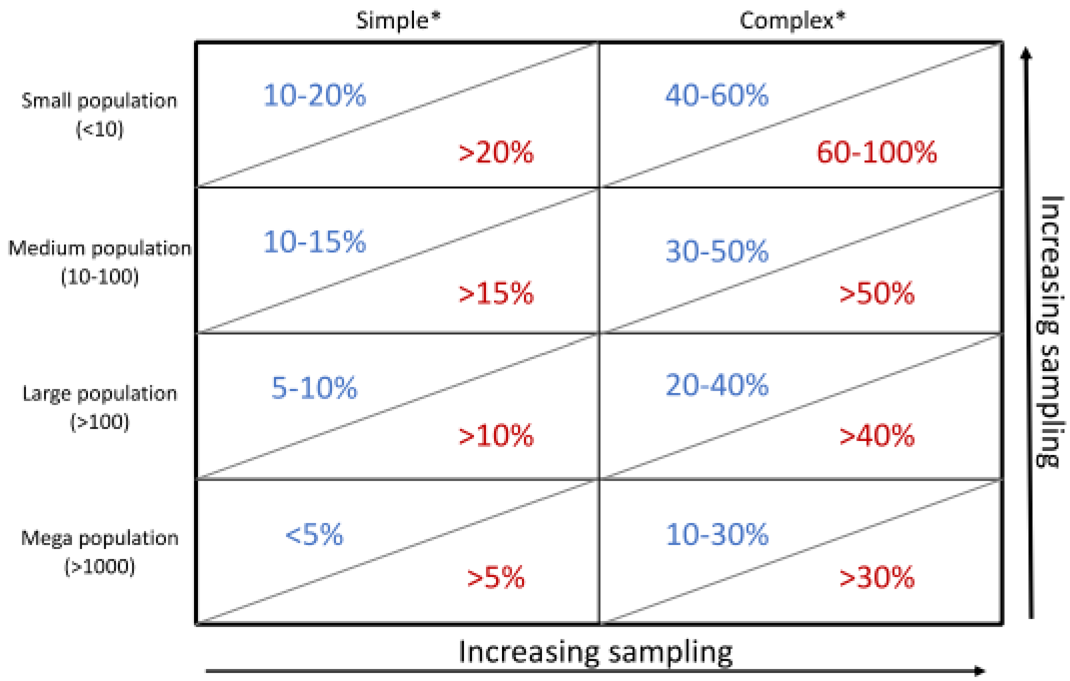


Figure 3: OGMP2.0 site sampling matrix

OGMP2.0 guidance notes that pipe segments, meter runs and pressure regulating stations are generally classified as simple sites/facilities in that they would be expected to have low variability in emissions. OGMP2.0 also notes that directionally, as population increases, the percentage of sites requiring measurement lowers. As population sizes increase into the mega-population size, sampling feasibility can become challenging, however, OGMP is only one guidance reference point. Other examples of statistical methods to determine sample size exist, such as those in the recent study published by Newton et al..[vii]

Once a sampling plan is determined based on materiality and available resources, a measurement technology can be scheduled for deployment. Results can be aggregated and assessed across each subcategory sample population and extrapolated to inform company specific emission factors.

Developing company-specific emission factors should be an iterative and evolving process. As emissions measurements are performed and data is gathered, trends and anomalies should be identified, and mitigation resources can be strategically deployed. Operators can reclassify as needed and adjust subsequent survey plans based on results and impact on inventory. For example, if there are high levels of consistency across a given source, operators can consider focusing on a smaller sample size the following year or pivoting resources to another high-materiality source category.

Increasing or adjusting programs to refine company-specific emission factors can increase the accuracy of reported emissions and add validity to the overall quantification process, as well as the results of mitigation efforts.

5.6. Company Specific Emission Factors

Generic emission factors are generally representative of like assets but do not represent the specific characteristics of a company's unique operating parameters, such as maintenance, replacement procedures or preventive policies.

To displace generic emission factors, company specific sampling programs can be utilized to develop company-specific emission factors. The sampling guidance noted in Section 5.3.2 from OGMP2.0 can be used as guidance for sampling a test area to help inform sample set determinations. Existing asset/source classifications can be used, as well as initial groupings of assets alongside features that may provide distinct groupings. Groupings and sub-grouping can be based on populations of sites/facilities (production batteries, pipeline segments, compressor stations, meter set, etc.) or by a population of sources (equipment type, operating status, process).

The Veritas Measurement and Reconciliation Version 2.0[viii] guidance notes that "in the distribution segment, most emissions sources are amenable to measurements for purposes of estimating annual inventories." The protocol provides guidance on categorizing assets and then stratifying sources and groups of assets to inform a sampling strategy. Step 8 in the protocol, Reconcile Inventories and Estimate Measurement Informed Inventory, gives comprehensive guidance on extrapolating and using measurement results to inform non-surveyed areas. For sample size guidance, Veritas references the OGMP 2.0 guidance, as noted in Section 5.3.2.

5.7. Uncertainty

Uncertainty estimates are an important element of a complete inventory of greenhouse gas emissions. Uncertainty associated with methane emissions refers to the level of confidence in reported CH_4 emissions and characterizes the dispersion of values that could reasonably be attributed to the measurement.

The three main sources of uncertainty are:

- Technology performance
- Sampling strategy
- Extrapolation (temporal and spatial)

Within the three main sources of uncertainty, the following are some of the specific contributors:

- Technology
- Detection capabilities (probability of detection)
- Emission rate quantification accuracy
- Spatial and temporal resolution
- The use of atmospheric transfer models for the conversion from concentration to emission rate
- Emission source localization and attribution
- Non-representative sampling
- Lack of accurate activity data
- Environmental conditions
- Presence of unaccounted for sources
- Presence of intermittent, potentially high-emitting sources

This section will aim to discuss these main sources of uncertainty and their associated core concepts, as well as how to manage them.

The key goal of assessing uncertainty is to be aware of how it can impact confidence in measurement-informed inventories. While it is possible to reduce some sources of uncertainty, many sources cannot be mitigated, and others can be extremely cost-prohibitive. For example, performing more frequent measurements can decrease uncertainty associated with temporal variations and extrapolations, but there is a trade-off between reduced uncertainty and cost.

While the knowledge on accurately quantifying methane emissions uncertainty is continually evolving, a best practice has yet to be established. However, identifying and understanding the factors that influence measurement uncertainty aids in proactively implementing strategies to reduce uncertainty.

5.7.1. Technology Performance Uncertainty

Technology uncertainty for CH_4 detection and quantification considers errors associated with the method or instrument and its intended use. Making an informed decision about the most suitable technology is crucial for obtaining accurate and reliable CH_4 data and minimizing uncertainty.

Table 5 provides a summary of the main drivers of uncertainty in CH_4 measurement technologies along with potential considerations to mitigate each source.

Table 5. Overview of sources of uncertainty from CH_4 emissions measurement technologies

Uncertainty Source	
Uncertainty	Consideration
Emission rate random error and systematic bias	
The emission rate reported by measurement technology can be a large source of uncertainty. While some technologies provide an emission rate via direct measurement of methane flow rate (Hi-Flow samplers) some use concentration measurements in conjunction with atmospheric transfer models. Atmospheric transfer models rely on multiple data streams and algorithms which, while commonly accepted, could introduce systematic bias.	Quantification error and bias can be established through controlled release testing. Known emission rates are blinded from the tested technology which then must report quantified emission rates. This can establish an understanding of the relationship between quantification error and emission rate. Methane quantification error of measurement technologies is becoming increasingly published.
Probability of Detection	
Probability of detection is the probability a methane measurement technology can detect an emission based on various factors like emission rate, wind speed and direction, distance of measurement technology to emission source, etc. While all these variables are important, probability of detection is most often associated with emission rate: given standard conditions, what emission rate will be detected 90% of the time. Probability of detection has a bearing on uncertainty in that it defines the emissions which are too small to be consistently detected by the methane measurement technology.	The probability of detection of well-known methane measurement technology classes (aerial, handheld solutions, satellites, etc.) has become increasingly public and accessible over the last 2-3 years. Conducting controlled release testing is not necessary, instead, controlled release testing (see section 6.3) of the technology in question, or, a similar technology, should be consulted to form an understanding of the emission sizes which could be missed due to the technology's probability of detection.
Spatial Resolution	
Different measurement technologies will "see" emissions differently depending on their spatial resolution. Spatial resolution is typically described as either site-level, equipment-level, or component-level. For example, a technology which has site-level resolution (a satellite) will "see" all emissions present at a site as one single emission, whereas a technology with a	An understanding of the spatial resolution of the technology can be established through testing, or conversation with the technology vendor. Incorporating measurements of differing spatial resolution in a measurement campaign can help reduce overall uncertainty.

component-level resolution (handheld solutions) would "see" the individual emissions which make up the single site-level emission "seen" by the satellite. While neither measurement is inherently wrong, they can differ. Component-level emissions can often be better attributed and localized.	
Environmental Conditions	
The performance of all methane measurement technologies can be impacted by environmental conditions. The impact of environmental conditions varies based on the technology and its relationship to the given technology. For example, aerial flyovers can struggle to provide accurate measurements if there is thick cloud cover or snow on the ground (in the case of LiDAR surveys). Another example is that continuous monitoring solutions require air flow to move the methane plume across the sensor for accurate readings.	An awareness of the technologies operational windows is important. Often, these operational windows are already well established by the technology vendor companies so deferring to them on work practice is recommended.

5.7.2. Technology Performance Uncertainty Mitigation Strategies

Operators should carefully consider the specific requirements of the application and the characteristics of the monitoring environment when selecting CH_4 measurement and detection technologies. Validation against established methods and calibration are key practices to reduce uncertainties associated with technology selection. Strategies to reduce uncertainty include:

- **Technology Selection Based on Comprehensive Evaluation and Testing:** Methane measurement technology testing results have increasingly become publicly available as the methane detection industry moves towards adoption of greater transparency. For example, testing often establishes minimum detection limits and probability of detection (PoD). Leveraging these existing results to select equipment with appropriate capabilities and reproducible performance can help reduce performance uncertainty.[ix]
- **Calibration:** Calibrate sensors regularly using traceable standards.
- **Use of Technologies with Appropriate Spatial Resolution:** Where possible, deploy technologies with varying spatial resolution concurrently to cross-check and validate measurements, enhancing the reliability of the data.[x]

- **Data Post-Processing and Corrections:** Implement post-processing algorithms and corrections to compensate for known biases and uncertainties associated with the selected technology.[xi]
- **Regular Maintenance:** Ensure regular maintenance of the selected technology to preserve its accuracy over time.

5.7.3. Sampling Strategy Uncertainty

Sampling strategy uncertainty for CH_4 measurement occurs as a result of the sampling process as well as the assumptions made when applying measurement duration to leak duration. Table 6 provides an overview of key aspects of uncertainty related to sampling strategy and ways to mitigate them.

Table 6. Overview of sources of uncertainty relating to sampling strategies

Uncertainty Source	
Uncertainty	Consideration
Representative Sampling	
The choice of sample groups for measurement may introduce uncertainty if the groupings do not adequately represent the population distribution. Infrequent sampling can also introduce uncertainty due to variations in CH_4 emissions with time, leading to incomplete or inaccurate data. The Veritas Source-Level Measurement and Reconciliation Protocol notes that increasing the frequency of measurements aids in estimating the typical duration and frequency of emissions sources, ultimately diminishing the uncertainty in annual emissions estimates.[xii]	Consider operational categories that represent natural groupings of assets (e.g., asset type, industrial vs. residential districts) and similar emissions characteristics (e.g., pipeline vintage or material). Randomly select sample groups from each category to ensure an adequate population representation. It is also important to determine the appropriate frequency for emissions measurements. Sources that contribute more to the emissions inventory (high materiality) or are believed to be more intermittent in nature, may receive more frequent surveys. Methods may be altered in subsequent years to coincide with changes in materiality assessments or may be updated once the expected emissions distribution and its source breakdown is better understood. Consider continuous monitoring for real-time data where applicable or practical (for midstream and downstream operations, continuous aboveground monitoring is unlikely to be practical on buried pipelines or geographically dispersed small assets but may

	provide valuable information on leaks from larger aboveground facilities that are part of those systems, such as compressor stations).
Measurement Duration	
Measurement duration refers to the total time a potential emission source is measured and considered a single data point when constructing a measurement informed inventory. For example, some aerial methods perform back-to-back flyovers (often over 1 or 2 days) to determine which emissions detected during the first flyover are intermittent in nature. These back-to-back flyovers are considered a single measurement, and their nature mitigates uncertainty. Another example is continuous monitoring solutions who collect measurements on a minute-to-minute or even sometimes second-to-second timescale.	While ensuring longer measurement duration will reduce uncertainty, it can be difficult in practice to assure this across an entire measurement campaign. It is recommended to deploy technology with longer measurement duration (i.e., continuous monitoring) on high materiality sources (those that contribute a large amount to an emissions inventory).
Estimated Emissions Durations	
Many measurement campaigns obtain “snapshot in time” measurements of emissions. A crucial consideration is the assumptions around how long these “snapshot” emission measurements last. For example, if a measurement campaign based on aerial flyovers flags an emission during a screening but not during the previous screening, do we assume the duration existed the whole time between screenings? Half the time between screenings? Note, some regulations do have methodologies in place for emissions duration calculations.	This uncertainty cannot be mitigated with “snapshot in time” measurements (it will always exist). It is advisable to simply be aware of how emissions duration estimates are calculated and if these calculations tend to lead to over or under-estimations.

5.7.4. Sampling Strategy Uncertainty Mitigation Strategies

It's advisable to tailor the sampling strategy to the specific goals of the measurement program. Mitigating uncertainty can be achieved through increased sample size and survey frequency, but program cost and diminishing returns must be considered. Some strategies to mitigate uncertainty associated with sampling strategy include:

- **Increased Sampling:** Increase sampling to improve accuracy and precision, reduce sampling bias, and provide more representative data.
- **Site Stratification:** Conduct a detailed site stratification to identify emission sources and variability and identify representative sampling locations.[xiii]
- **Continuous Monitoring:** Implement continuous or semi-continuous monitoring systems where applicable or practical to capture short-term events and provide a more comprehensive dataset.[xiv] For midstream and downstream operations, continuous aboveground monitoring is unlikely to be practical on buried pipelines or geographically dispersed small assets but may be valuable for aboveground facilities such as compressor stations.

5.7.5. Extrapolation Uncertainty (temporal and spatial)

Spatial and temporal extrapolation uncertainty in CH_4 detection and quantification arises from the challenges of extending localized measurements to broader geographic areas and longer time periods.

Table 7 provides an overview of key aspects of extrapolation uncertainty and potential mitigation strategies.

Table 7. Overview of sources of uncertainty relating to extrapolation of CH_4 emissions measurement data when developing inventories

Uncertainty Source	
Uncertainty	Considerations
Spatial Extrapolation	
Extrapolating measurements from a representative sample to a larger population may introduce uncertainties due to spatial heterogeneity.	Conduct systematic spatial sampling across representative locations to capture variability. Employ spatial modeling techniques such as kriging or geostatistics to interpolate measurements. Use remote sensing data to enhance spatial coverage and resolution.
Temporal Extrapolation	
Extrapolating measurements performed over short timeframes to the entire emissions reporting period (one year) may introduce uncertainty due to temporal variations, trends, and seasonality.	Leverage probabilistic modelling to validate temporal extrapolation based on the ergodic hypothesis. As a simplified definition, the ergodic hypothesis states that over time, a system will explore all its possible “states” (in this case, emissions behavior), with the time

	spent in each state reflecting its probability of occurrence. Consider increasing the frequency of measurements to better account for temporal variability and trends. Consider deploying continuous monitoring systems for detailed temporal assessments.

5.7.6. Extrapolation Uncertainty (temporal and spatial) Mitigation Strategies

It is important to acknowledge the complexities of spatial and temporal extrapolation and to adopt a multi-faceted approach that combines various data sources, models, and methodologies. Regular validation against ground-truth data is crucial for assessing the reliability and accuracy of extrapolation methods. Mitigation strategies include:

- **Integrated Monitoring Systems:** Integrate data from multiple "scales" of measurement (bottom-up measurements, and top-down measurements), to improve the spatial representation of CH_4 concentrations.[xv]
- **Satellite-Based Observations:** Where applicable, operators can utilize satellite observations to minimize the need for spatial extrapolation, providing wide coverage and identifying spatial patterns.[xvi]
- **Machine Learning Models:** Apply machine learning models trained on comprehensive datasets to improve the accuracy of spatial and temporal extrapolation.[xvii]
- **Inverse Modeling Techniques:** Employ inverse modeling techniques that optimize emission estimates based on observed concentrations, providing insights into spatial and temporal patterns.[xviii]
- **Data Assimilation Methods**: Use data assimilation methods that integrate measurement data with model simulations to improve the representation of spatial and temporal variations over time as more data is acquired.[xix]

6. Methane Detection and Measurement Technologies

6.1. Introduction

Natural gas transmission, storage, and distribution face unique challenges in CH_4 detection due to a large number of geographically dispersed assets, complex distribution pipeline networks, urban operating areas, and small-sized leaks that can be challenging to detect with existing technologies.

When considering the performance of an emissions measurement technology, it is important to consider both the technology itself and the methodologies used. Technologies refer to the hardware, including deployment platforms and sensors, while methods refer to the combination of these technologies with analytics and deployment practices.[xx] In particular, understanding these methods and how they might work in collaboration within an overall program is critical when evaluating performance.

A broad range of commercial CH_4 detection or detection and quantification technologies exist which can be utilized by operators to detect, locate, and quantify emissions. Technology selection requires careful consideration of accuracy, efficiency, safety, and resourcing. It is important to understand if and how a technology has been tested to verify its performance and specifications for effective use and regulatory compliance.

Effective emissions management is not limited to technology selection; Considerable innovation has occurred around deployment practices: thinking about how, when, where, and whether to deploy different types of technologies, alone and in combination with complementary solutions. The use of diverse sources of data, including operational, parametric and measurement, as well as understanding which sources are best measured or best calculated can inform a more accurate emissions inventory.

In this section, we will provide an overview of available technologies and discuss technology selection considerations, sensing principles, deployment platforms, and controlled release testing. Technology options will be identified that may be suitable for deployment on storage, transmission, and distribution assets.

6.2. Overview of Deployment Platforms and Sensing Principles

Classifying detection and measurement technologies helps to make sense of the 200+ commercially available solutions, yet there are many possible ways to do so, and there is flexibility for a broad range of approaches. This summary is meant to review the capabilities of a broad range of different solutions and does not target any individual solution provider. It is meant to provide an overall picture of the solutions available.

Historically, the legacy techniques for pipeline leak detections have been:

- Auditory, Visual, Olfactory (AVO) – the use of human senses to detect leaks, which can be done from the ground or as an aircraft passenger (visual).
- Handheld – handheld leak detectors, Optical Gas Imaging (OGI) or laser detection.
- Continuous Monitoring – above or below ground mass balance detection, internal or external to the pipeline.

Over the past decade there has been considerable innovation in the detection, localization, and quantification of CH_4. Innovation has accelerated in many areas, including deployment platforms, sensors, testing procedures, work practices, and analytics. A large and growing number of advanced methods now exist, including a range of point, active, and passive sensors deployed on handheld instruments, aircraft, drones, vehicles, satellites, and stationary systems.

Technologies are classified according to deployment mode and sensing principles. CH_4 sensing instruments can be deployed on a variety of platforms, offering different advantages and disadvantages. CH_4 sensing technologies can be mobile or stationary.

Deployment modes can be generally classified into the following categories: satellites, aircraft, unmanned aerial vehicles, mobile ground labs, continuous monitoring, and handheld. Table 8 summarizes these deployment modes and their advantages and disadvantages.

Specific cost data is dependent on, individual contracts between operators, technology providers, site specific parameters, frequency, work practices, asset density, and other factors, therefore specific cost data is not included in the table below.

Table 8. Overview of commercially available CH_4 emissions detection technology deployment modes

Measurement Technology Deployment Modes	
Advantages	**Disadvantages**
 **Satellites** Remote sensing instruments on satellites are used to detect and measure concentrations of CH_4 in the Earth's atmosphere.	
• Global coverage for monitoring emissions on a large scale. • Identification of emissions from various sources. • Large sources identified by satellite can be used for reconciliation with ground-based data.	• Lower spatial resolution compared to ground-based methods. • Limited ability to detect small leaks. • Generally, the highest cost to deploy, data may be available to purchase from new satellite technology providers. • Weather conditions such as wind and cloud coverage can impact data collection.
 **Aircraft** Typically, small fixed-wing aircraft or helicopters. These systems are in widespread use in numerous countries, especially for upstream and midstream operations.	
• Rapid coverage of large areas. • Ability to target specific sources or regions. • Higher spatial resolution compared to satellite-based methods. • Flexibility in flight patterns and altitudes.	• Higher operational costs compared to some ground-based technologies. • Weather conditions may affect flight feasibility. • Limited continuous monitoring capabilities compared to satellite-based systems.
 **Unmanned Aerial Vehicles (UAVs)** Fixed-wing and rotary-propelled UAVs are emerging for detecting CH_4 emissions at short and medium ranges.	
• Quick coverage of expansive areas. • Access to remote and challenging terrains. • Reduced human risk in certain inspections where terrain or other barriers prevent direct access.	• Often cannot operate beyond visual line of sight (BVLOS) - the UAV pilot must be able to see the UAV. • Subject to air space and regulatory restriction, particularly in urban areas or close to airports. • Weather conditions may impact effectiveness. • May require skilled operators. • travel time can be comparable to handheld solutions as operators must travel to monitored area via truck. • Costs vary depending on the aerial extent of coverage.
 **Mobile Ground Labs (MGLs)** Pickup trucks, vans, or cars equipped with a variety of sensors for detecting CH_4 and measuring local atmospheric conditions.	

• Typically, MGLs are highly sensitive compared to aerial methods (can detect smaller emissions). • Flexibility for periodic inspections. • Rapid response to changing conditions. • Ability to cover large and remote areas. • Provide an allowance for work practices which see follow-up surveys immediately performed if onboard analytics are available and MGL operators are trained in handheld surveys.	• Weather, as well as road conditions, can affect performance. • Remote access monitoring areas may be inaccessible due to road access or height and field of view. • Expected significantly increased resource requirements for ground follow-up surveys to locate and verify leak presence and deploy repairs. • Dependence on personnel availability. • Less spatial coverage than aerial methods unless multiple passes of monitored area are conducted.
Continuous Monitoring These systems are stationary. Continuous systems are uniquely positioned to resolve temporal variability in emissions. Can be internal or external (i.e. Pipelines)	
• Near-immediate detection of leaks depending on wind speed and direction • Continuous monitoring provides real-time data. • Integration with alarm systems for quick response.	• Limited to specific locations, may not cover entire facilities. • Requires regular maintenance and calibration. • Above ground operations affected by weather and environmental conditions. • Below ground deployment requires installation at time of pipeline installation.
Handheld Portable systems that are held by an inspector. These technologies are mandated by regulations and leak survey guidelines in certain jurisdictions and include combustible gas detectors, optical gas imaging (OGI) technology, and other types of technology (e.g., handheld laser CH_4 detectors).	
• Quick identification of leaks by visualizing infrared emissions. • Can be very sensitive in the hands of experienced operators. • Pinpointing source locations. • Compliance with regulatory requirements. • Direct measurement of emissions, as opposed to using plume dispersion modelling to arrive at emissions.	• Weather conditions and distance limitations. • Depending on the complexity of the area to be monitored, can have a low spatial coverage (operators may not have access to sufficiently survey all equipment). • Can be time and resource consuming to do walking surveys with handheld technology for geographically extensive assets. • Can be an affordable option to purchase, however, deployment costs are dependent on the manpower and resources required and the extent of coverage.

To add perspective, images of the data products provided by each of the six deployment methods described above are shown below (Figure 4).

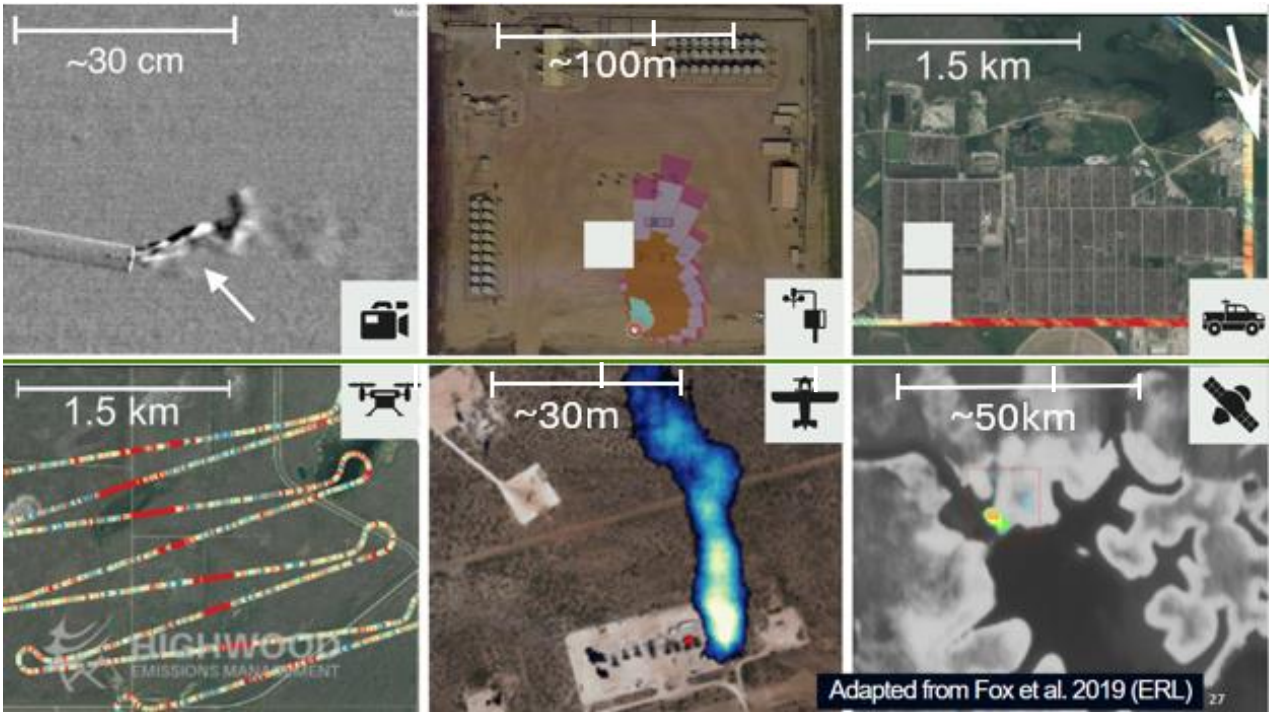


Figure 4. Visual representation of deployment platforms

Satellites (bottom right) can cover regional to global scales but may be limited in spatial resolution to pinpoint localized sources or points of emissions. Aircrafts and drones (bottom middle and bottom left) are not able to cover the same large areas as satellites but can more accurately target specific regions or facilities. MGL (top right) coverage is dependent on road access but can be nimble and adapt to changing conditions. In addition, while MGLs may be able to cover similar areas as aircraft and drones, they may not be as time efficient. Continuous monitoring (top middle) is location specific and will require multiple sensors depending on the size of the facility but allow for faster detection and response to leaks. Handheld (top left) is effective for identifying emissions from specific sources and components but is limited by walking speeds.

Beyond deployment platforms, there are also different sensor types that are mounted onto different deployment platforms. Sensing principles can be classified into three general categories: active remote imaging, passive remote imaging, and point sensing. The technologies, advantages, and disadvantages are described in Table 9.

Table 9. Overview of the sensing principles of commercially available CH_4 emissions detection and measurement technology

<table>
<tr><th colspan="2">Sensing Modes</th></tr>
<tr><th>Advantages</th><th>Disadvantages</th></tr>
<tr><td colspan="2">Active Imaging (Remote sensing)
Active imaging systems generate source(s) of light that traverse CH_4 plumes, reflects off a remote surface, and returns to a detector. Changes in the reflected light are used to infer CH_4 concentrations along the path. A common example is Light Detection and Ranging (LiDAR)[xxi].</td></tr>
<tr><td>• Direct interaction with the CH_4 plume is not required.
• More sensitive than passive imaging.
• Strong source attribution performance has been demonstrated</td><td>• Targets individual sites instead of sweeping coverage of the entire landscape (slower than passive imaging).
• Follow up is required to localize and confirm emission sources.</td></tr>
<tr><td colspan="2">Passive Imaging (Remote sensing)
Passive imaging systems use reflected sunlight to measure CH_4 concentration in the atmosphere. They are used in all types of platforms, ranging from OGI cameras to satellite imagery.</td></tr>
<tr><td>• Technologies which use passive imaging cover large areas quickly.
• Focus on large emitters.
• Site access is not required.
• Flexibility in flight patterns and altitudes.</td><td>• Follow up is required to localize and confirm emission sources.
• Use is weather dependent and relies on the presence of sunlight.
• Less sensitive – optimally suited for identifying large emitters quickly.</td></tr>
<tr><td colspan="2">Point Sensing
Point sensing involves directly measuring CH_4 mixing ratios (the proportion of CH_4 molecules in a mixture of gases) in the atmosphere, which requires the sensor to be positioned in a plume to discern anomalies above the background. Point sensors range from simple solid-state metal oxide detectors to complex cavity ringdown spectrometers (CRDS) and gas chromatographs. Point sensors can be deployed on any platform that passes through CH_4 plumes or has CH_4 plumes that pass over the sensor. Hi-Flow sensors and Mobile Ground Labs are examples of point sensors.</td></tr>
<tr><td>• Most sensitive- can detect CH_4 on a ppm or ppb scale.
• Can be deployed on a variety of mobile and stationary platforms.</td><td>• Direct contact with the CH_4 plume is required.
• Multiple passes through the plume are needed for quantification.
• Slower than imaging technologies.</td></tr>
</table>

The deployment platforms and sensing principles outlined above can be combined in several ways. For example, there are commercial aircraft-based technologies which operate using passive imagery, active imagery, and point sensing. Each of these technologies perform differently to one another and may be better suited for different applications.

6.3. Controlled Release Testing

Controlled release testing is the process of testing the performance of a CH_4 detection technology against known release rates. Controlled release testing is used to validate claims about technology performance, develop probability of detection curves, determine minimum detection limits, and understand uncertainty/error bounds on individual measurements.

In controlled release tests, participants deploy technologies in a controlled release environment, where there are dedicated release points, each capable of being turned on and off remotely, and with adjustable release rates from each release point. Release points and rates are generally blind to testing participants. Participants attempt to discern the presence of releases, the location of releases, and release rates. After testing, participants submit their results, which are compared against the actual releases, and performance metrics are developed.

The Methane Emissions Technology Evaluation Center (METEC) is the world's leading testing facility for CH_4 sensing technologies. It is located at Colorado State University in Fort Collins, Colorado. METEC was designed specifically as an academic research and testing facility for testing leak detection and quantification methods in an upstream oil and gas context. The facility includes aboveground oil and gas infrastructure, and buried pipelines and right-of-ways, to allow for testing of technologies for a wide array of natural gas applications. See Section 6.5 for technology specific results of controlled release testing.

In the absence of controlled release testing results, performance claims from a technology provider may be challenging to verify. Technology performance and fit-for-purpose are critical considerations when developing sampling plans and making technology selections. Controlled release testing results may enable a company to decide whether a particular technology is suitable for use on their assets, i.e. whether the instruments are sufficiently sensitive to capture the expected emissions from their sites, and if it will provide useful and actionable information.

6.4. Technology Selection Considerations

Selecting CH_4 detection technology for downstream operations requires careful consideration for efficiency, safety, and effectiveness. When considering safety, regulatory compliance and the safety of all stakeholders should be considered. The efficiency of the technology can include several factors such as cost and scalability over the life cycle of the assets. When assessing your assets, the effectiveness of technology to capture an accurate representative of your emissions profile can vary with respect to leak size, aerial extent, and frequency of measurements.

Table 10 outlines 14 considerations, grouped by color to indicate the following categories:

Table 10. Overview of technology selection considerations

Performance	Fit for Purpose

Consideration	Overview
Source and Facility Type:	Consider the suitability to the specific sources you are trying to detect or measure CH_4 emissions from (Asset, Facility, and Source)
Need for Follow-up Investigation	Consider the requirements for ground follow-up surveys to locate and verify leak presence and deploy repairs
Sensitivity and Detection Range:	Consider the technology's sensitivity to detect varying concentrations of CH_4 and leaks sizes.
Spatial Coverage:	Consider the technology's capability to cover large areas, specific zones, or critical points.
Temporal Coverage:	Consider the frequency and duration over which measurements or observations of CH_4 concentrations will be made and data will be collected.
Accuracy and Precision:	Consider whether the technology has undergone controlled release testing by an independent party to validate performance specifications, determine minimum detection limits, and understand uncertainty.
Durability in Variable Environments:	Consider how the selected technology can withstand the varying environmental and operational conditions common to the geographic areas it will be deployed in.
Response Time:	Understand the response time of the technology to provide leak reports to the operator, particularly in the context of safety and mitigating leak hazards quickly.
Safety Features:	Review safety features, such as remote monitoring capabilities to reduce human exposure to potential hazards.
Regulatory Compliance:	Ensure that the selected technology complies with industry-specific regulations and standards governing CH_4 emissions.
Mobility and Flexibility:	Consider whether the technology offers mobility for on-the-go inspections (is the technology portable), especially in large facilities or remote field locations.
Data Logging and Reporting:	Consider the data logging, storage, and reporting capabilities of the technology to understand what outputs will be obtained and how they can be utilized.
Training and Ease of Use:	If the technology is used by company employees, consider the training requirements for operating and maintaining the technology.
Lifecycle Costs:	Consider the overall life-cycle costs associated with the technology, including equipment purchase, installation,

	maintenance, and potential future upgrades. Consideration should also be given to resourcing requirements for ground follow-up to locate and repair leaks.
Scalability:	Consider whether the technology is scalable to accommodate changes in facility size, infrastructure expansions, or modifications.

6.5. Technology for Storage, Transmission, and Distribution

Methane detection technology can be deployed on various platforms to monitor storage, distribution, and transmission pipelines. The choice of deployment platform depends on factors such as the scale of the pipeline network, accessibility, and monitoring requirements.

Combining multiple methods can provide a comprehensive approach to managing and mitigating CH_4 emissions. Advances in technology continue to improve the accuracy, efficiency, and accessibility of CH_4 detection tools, and the methodologies to effectively incorporate the data captured. It was recommended in several expert interviews conducted by Highwood Emissions Management that combining different technology types will result in more leak detection events than any one technology alone[xxii].

Appendix 11.1 details the technology and characteristics suitable for storage, transmission, and distribution. Not all technologies are applicable for all assets within each segment.

Due to the unique characteristics of transmission and distribution, certain technologies have limitations based on current controlled release testing detection limits or are still in the early stages of development and have not been implemented outside of a test environment.

In general, distribution systems have smaller and more leak events than transmission, requiring technologies with lower minimum detection limits. Distribution also has below ground equipment with added complications of urban infrastructure and variability in surface permeability.

Most methane emissions from transmission systems come from compressor stations, which have unique complexities. For example, uncombusted methane (i.e., “slip”) is emitted in compressor exhaust that may introduce noise and obfuscate the ability of screening technologies to discern leaks.

7. 2022 EGI Fugitive Emissions Inventory Analysis

7.1. Introduction

This section provides an overview of EGI's current approaches to quantifying and reporting fugitive emissions.

First, there is a discussion of EGI's 2022 fugitive emissions inventory including:

- Total fugitive emissions and year-over-year trends.
- Segment source category materiality assessment, including identification of components contributing most to total emissions.
- Commentary on higher emitting sites with respect to station size and contribution.

Second, EGI's current calculation methods are described followed by the leak detection and repair practices, broken out by storage and transmission (STO) and distribution (DO).

7.2. Overview of STO and DO Reported Emissions

The fugitive emissions inventory is shown in tCO_2e, or tonnes of CO_2 equivalent and includes CO_2 and CH_4 emissions. This tCO_2e value for CH_4 is calculated by multiplying the tonnes of CH_4 emissions by the Global Warming Potential (GWP) of CH_4.

As noted in Section 4.1, GWP quantifies the warming impact of a particular greenhouse gas in terms of its ability to absorb and retain heat in the atmosphere compared to CO_2. EGI uses a GWP of 28 for CH4 based on the federal and provincial reporting programs' requirements (EGI changed from a 25 in 2021 to 28 in 2022 due to a regulatory requirement). This change only impacts the proportionate CH_4 contribution to total CO_2e fugitive emissions when converting from tonnes of CH_4 to tCO_2e (Table 11).

Table 11. Sample calculation to show the GWP change impact when converting tonnes of CH_4 to tonnes of CO_2e

GWP	25	28
CH_4 (t)	100	100
CH_4 (tCO_2e)	2,500	2,800

The total fugitive emissions for EGI from 2020-2022 are broken out by segment (Figure 5). Table 12 provides additional information, including the fugitive CH_4 volumes in standard cubic meters (scm), the relative contributions of each segment, and the aggregated year-over-year emissions.

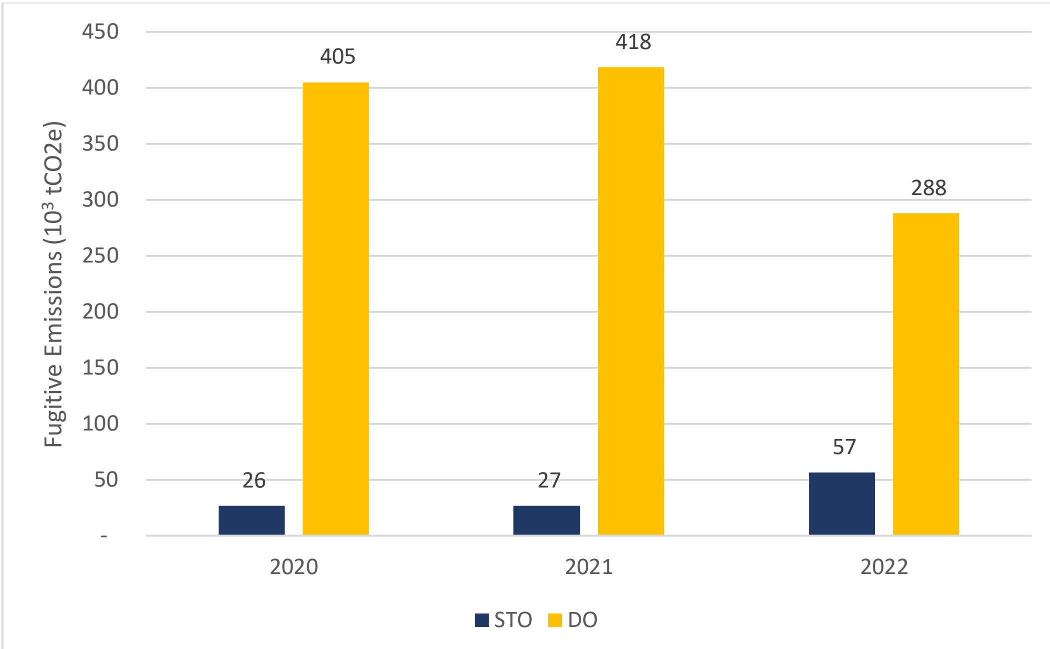


Figure 5. EGI year-over-year fugitive CH_4 emissions from 2020-2022

Year-over-year, the total volume of fugitive emissions decreased by 23% between 2021 and 2022, from 445,000 tCO_2e to 344,000 tCO_2e.

From 2021 to 2022, the STO contribution increased from 6% to 16%, while DO contribution decreased from 94% to 84% of total fugitive emissions (Table 12). The increase in STO is a result of higher fugitive detection as a result of LDAR surveys. The decrease in DO emissions can be partially attributed to the identification and elimination of a double counting error from the DO equipment inventory, resulting in a net overall reduction in reported fugitive emissions.

Between 2021 and 2022, there was a 76% increase in reported STO fugitive emissions volumes (scm) attributed to an increase in the occurrence and volumes of leaks (detected through leak surveys). The increase of the fugitive emission mass (tCO_2e) is proportionately higher (113%) due to a regulatory required increase in the CH_4 GWP, from 25 to 28, between 2021 and 2022. Since most STO fugitive emissions are obtained through direct measurements (3x/year), annual fluctuations in reported emissions reflecting the reporting year's specific operating conditions are expected. As measurement of emissions replaces the use of generic emission factors, the accuracy of reported emissions should increase and total emissions, over time, can be expected to decrease because of continuous, targeted repairs.

There was a net decrease in reported DO fugitive emission volumes (scm) of 40% between 2021 and 2022. Due to the regulatory required increase GWP noted above, the overall decrease in corresponding fugitive emission mass in tonnes of CO_2 equivalent (tCO_2e) was only 31%. Within DO, there was an increase in fugitives attributed to third party damage events between 2021 and 2022. However, due to an alignment of customer meter counts in 2022, a double counting error was identified within the Legacy EGI count of commercial customer meter sets. This error was resolved, resulting in a reduction of emissions for customer meter sets from approximately 231,000 tCO_2e to approximately 129,0000 tCO_2e as a result of the decreased activity count.

Table 12. Contributions of STO and DO to the reported fugitive emissions inventory in 2020, 2021, and 2022

Total Emissions by Segment	2020	2021	2022
STO			
Volume of fugitive CH_4 [10^3 scm]	1,653	1,653	2,913
Fugitive emissions [$10^3 tCO_2e$]	26	27	57
Contribution of STO to total tCO_2e fugitives [%]	6%	6%	16%
DO			
Volume of fugitive CH_4 [10^3 scm]	25,612	26,351	15,933
Fugitive emissions [10^3 tCO_2e]	405	418	288
Contribution of DO to total tCO_2e fugitives [%]	94%	94%	84%
Totals			
DO + STO [10^3 scm]	27,265	28,004	18,846
DO + STO [10^3 tCO_2e]	432	445	344

7.3. Emissions from Transmission and Storage

This section provides a detailed breakdown of fugitive emissions by source category for EGI's STO segment, including:

- Compressor station equipment leaks
- Storage wells
- Other station equipment leaks (receipt/sales meter station, valve stations, and transmission farm taps)
- Oil batteries
- Pipeline leaks (protected and unprotected steel)
- Storage gathering pipelines

Table 13 presents STO fugitive emissions in tonnes of CO_2 equivalent, by source.

Table 13. 2022 STO fugitive emissions by source

STO Source Category	2022 Fugitive Emissions [tCO_2e]	Contribution (%)
Compressor Station Equipment Leaks	35,308	62%
Storage Wells	8,677	15%
Other Station Equipment Leaks	8,240	15%
Receipt-sales Meter Station	*6,182*	*11%*
Valve Station	*2,047*	*4%*
Transmission Farm Tap	*11*	*0.02%*
Oil Batteries	4,328	8%
Pipeline Leaks	53	0.09%
Protected Steel	*51*	*0.09%*
Unprotected Steel	*2*	*0.003%*
Storage Gathering Pipelines	15	0.03%
Total	56,621	100%

The top 3 source categories account for more than 90% of STO fugitive emissions. These are compressor station equipment leaks (62%), storage wells (15%) and other station equipment leaks (15%).

A site-level breakdown of compressor station equipment leaks in 2022 (Figure 6) shows that Dawn Compressor Station is the highest leaking compressor station (10,393 tCO_2e), equivalent to the emissions of the next three largest sites combined. Dawn Compressor Station is one of 24 stations but accounts for 30% of overall emissions, thus exhibiting the ‘heavy tail’ commonly observed in CH_4 emissions distributions.

The comparatively higher emissions at the Dawn Compressor Station can be explained by the fact that it is one of the largest integrated natural gas storage facilities in North America with eight compressors. Comparatively Parkway, the second largest contributor, has only two compressors.

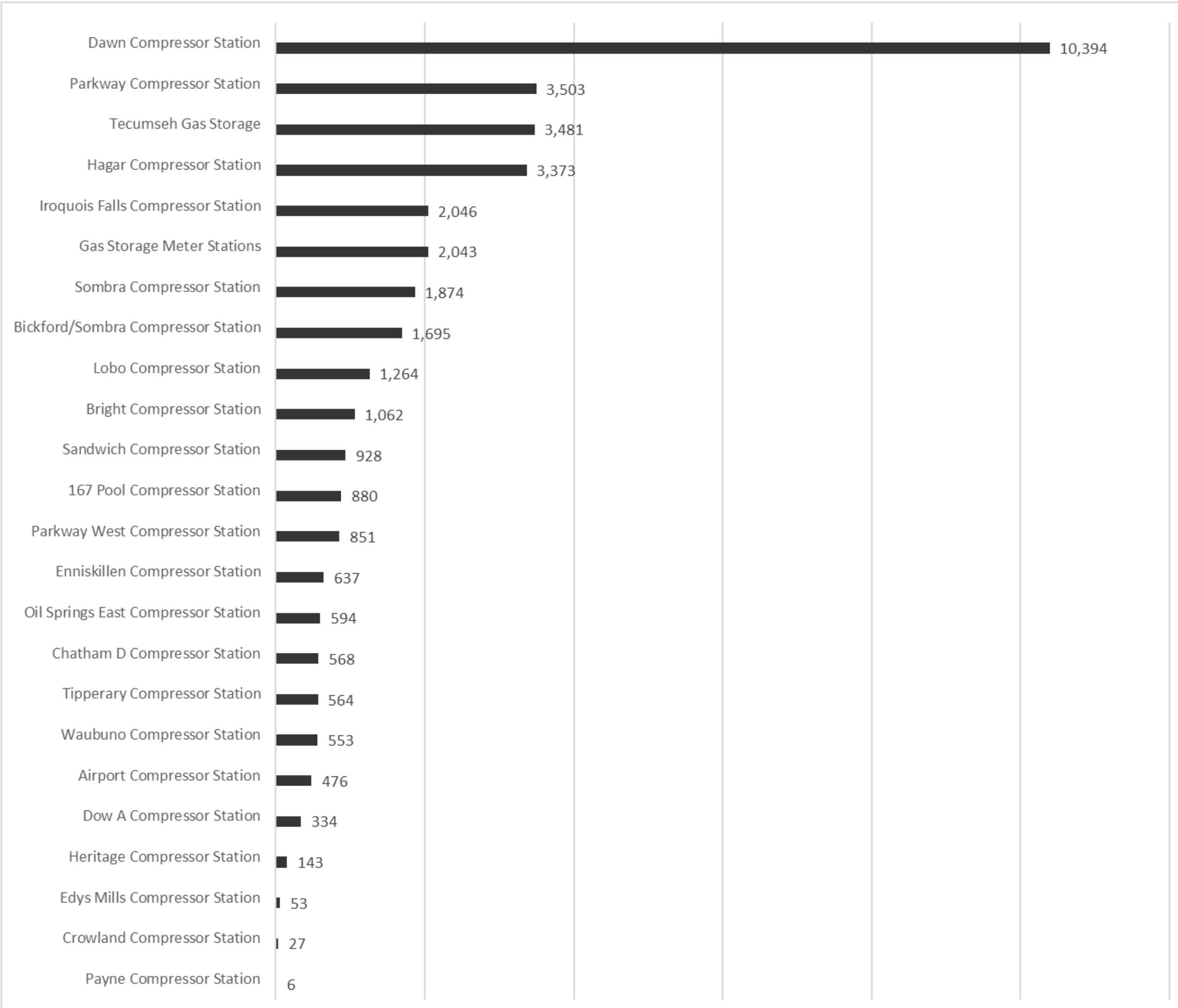


Figure 6. STO equipment leak emissions breakdown per location (tCO_2e)

A breakdown of leak counts by component type at compressor stations reveals that more than half of all leaks occur at connectors and an additional third at valves (Figure 7). Only a small number of leaks occur on other component types.

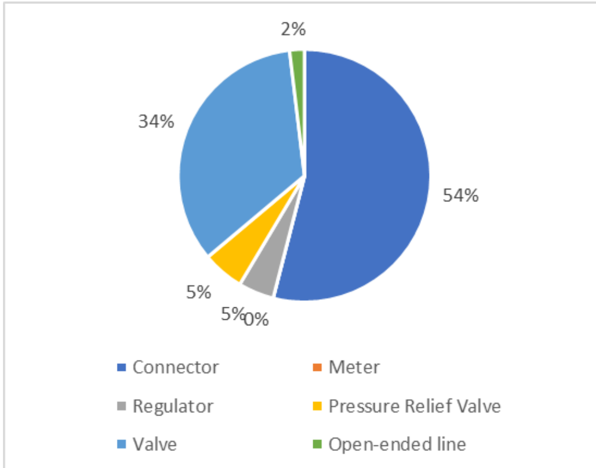


Figure 7. Number of leaks per component for STO compressor leaks

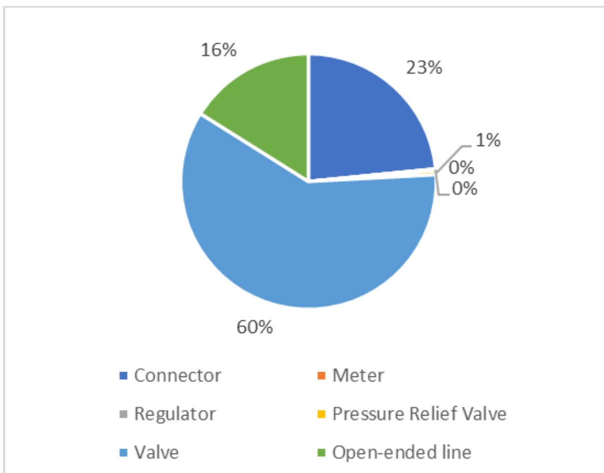


Figure 8. Volume of leaks per component for STO compressor leaks

Based on total volumes (Figure 8), the leaks from valves and open-ended lines, while less frequent, are larger on average than the more frequent leaks from connectors. Connectors, which contributed 54% of the total number of leaks, only contributed 23% of the total volume of leaks. Valves, which represent 34% of total number of leaks, contributed 60% of the total leak volumes. Pressure Relief Valves and Regulators, which contributed a combined 10% of the number of leaks, contributed a negligible amount to the total volume. Open-ended lines, which contributed only 2% of the total number of leaks, contributed 16% of the volume.

7.4. Emissions from Distribution

This section provides a detailed breakdown of fugitive emissions by source category for EGI's DO segment, including:

- Customer meter sets (industrial/commercial, residential)
- Leaking buried pipe – service (plastic, protected steel, unprotected steel)
- Distribution stations (gate, district)
- Damage events (services, mains)
- Farm taps
- Leaking buried pipe – mains (plastic, protected steel, unprotected steel)

Table 14 below shows the 2022 Distribution fugitive emissions by source.

Table 14. 2022 DO fugitive emissions by source

DO Source Category	2022 Fugitive Emissions [tCO_2e]	Contribution (%)
Customer Meter Sets	128,906	45%
Industrial/Commercial	*69,422*	*24%*
Residential	*59,484*	*21%*
Leaking Buried Pipe – Services	52,270	18%
Plastic	*12,384*	*4%*
Protected steel	*5,704*	*2%*
Unprotected steel	*34,182*	*12%*
Station Leaks	42,539	15%
Gate	*24,906*	*9%*
District	*17,633*	*6%*
Damage Events	26,349	9%
Services	*15,704*	*5%*
Mains	*10,644*	*4%*
Farm Taps	25,598	9%
Leaking Buried Pipe – Mains	12,015	4%
Plastic	*750*	*0.26%*
Protected steel	*11,157*	*4%*
Unprotected steel	*108*	*0.04%*
Total	287,677	100%

The top three sources account for 78% of total fugitive emissions. These are customer meter sets (45%), leaking service pipelines (18%) and station leaks (15%). Within customer meter sets, each of the two sub-categories represent a larger contribution than any other single category. Leaking buried unprotected steel pipe is also a notable contributor as the third largest single sub-category.

Table 15 shows the breakdown of the contribution of commercial and residential customer meter sets to fugitive emissions. Residential meter sets, which represent 96% of the asset population by meter count, are responsible for 46% of meter set fugitive emissions. This is driven by the activity count of over 3.6 million residential meters, and the comparatively lower generic emission factor. This is a significant contributor to DO emissions and while the activity counts are relatively constant, the generic emission factor being used may or may not accurately reflect the total emissions from this source resulting in a high uncertainty in the reported emissions in this category. Without company-specific emission factors based on measurement data to increase the accuracy of emissions, this will continue to be a source category with high uncertainty.

Table 15. 2022 DO breakdown of customer meter sets by emissions and activity factor

Customer Meter Sets	Emissions (tCO_2e)	Emission % Contribution	Meter Count	% of Activity Count	tCO_2e/ Leak
Commercial/Industrial	69,422	54%	167,924	4%	0.41
Residential	59,484	46%	3,678,571	96%	0.02

The second largest source category is services pipelines at 18%, with unprotected steel contributing 12% alone. As with the customer meter sets, the emissions are calculated by multiplying an activity factor (total equivalent leak ratio) and a generic emission factor. Without company-specific emission factors based on measurement data to increase the accuracy of emissions, this will also continue to be a consistently large source category (will always be a materially large source based on activity, but more accurate emission factors could increase or decrease materiality) with high uncertainty. Developing company specific emission factors will increase the accuracy of emissions and be more reflective of EGI's emissions.

7.5. Calculation Methods

This section provides an overview of the methodologies used by EGI for calculating fugitive emissions from STO and DO assets.

7.5.1. STO Calculations

Table 16 below shows the inventory calculation methods associated with each fugitive source category for STO

Table 16. STO fugitive source categories and associated fugitive emissions inventory calculation methods

STO Fugitive Source Category	Percent Contribution	2022 Calculation Method
Compressor station equipment leaks	**62%**	**Measurement**
Storage wells	**15%**	**Generic EF**
Other station equipment leaks	**15%**	
Receipt-sales meter station	*11%*	Measurement
Valve station	*4%*	Generic EF
Transmission farm tap	*0.02%*	Generic EF
Oil batteries	**8%**	**Generic EF**
Pipeline leaks	**0.1%**	
Protected steel	*0.1%*	Generic EF
Unprotected steel	*0%*	Generic EF
Storage gathering pipelines	**0.1%**	**Generic EF**

EGI's STO fugitive emissions inventory is calculated using a combination of measurement and generic emission factors. Additional inputs into the calculations include annual equipment operating hours (used to extrapolate emission rates to the total emissions estimate for the year) and gas composition values (which represent the ratio of CH_4 within the total natural gas). Activity factors such as component and equipment counts are maintained and updated annually to ensure the calculation basis is current, as these counts impact the emissions calculations.

73 % of EGI's STO fugitive inventory is calculated via direct measurement, where leak detection and measurement surveys are performed, and the results are used to inform the final fugitive inventory.

The remaining 27% of STO's fugitive inventory is calculated using generic emission factors (obtained from industry standard guidance and publications, as per the Ontario Guideline), applied to all components within each population of sources (the activity factor). Calculating fugitive emissions using this methodology does not require that leak surveys are conducted to determine the number of emitting components; rather, the same emission factor is applied to all components, regardless of if they are leaking or not.

Compressor Station Equipment Leaks

Fugitive emissions from compressor stations are calculated using direct measurement of leak rates obtained during regulatory LDAR surveys. The total leak volume for a given year is aggregated by taking the hourly leak rates from leak surveys and approximating the duration using the methodology provided in the Ontario GHG Guideline[xxiii].

Storage Wells Leaks

Storage well leaks are calculated utilizing a generic emission factor for storage wells (expressed in tCH_4/well/year), multiplied by the number of wells (the activity factor).

Other station equipment leaks

- *Receipt-sales meter stations*

Fugitive emissions from receipt-sales meter stations are calculated in the same manner as compressor stations: utilizing direct measurement of leak rates from regulatory LDAR surveys. The total leak volume for a given year is aggregated by taking the hourly leak rates from leak surveys and approximating the duration using the methodology provided in the Ontario GHG Guideline.

- *Valve stations*

Valve station fugitive emissions are calculated by multiplying a generic emission factor (m^3 natural gas/year/station) by the total number of stations (the activity factor).

- *Transmission farm taps*

Transmission farm tap fugitive emissions are calculated by multiplying a generic emission factor (m^3 natural gas/year/station) by the total number of farm taps (the activity factor).

Pipeline Leaks

Pipeline leaks in the transmission segment are reported by pipeline material: protected steel, and unprotected steel. Pipeline fugitive emissions are calculated using a company specific total equivalent leak (TEL) ratio (calculated using company specific leak statistics) multiplied by a generic emission leak rate (m^3 natural gas/leak/year).

Storage Gathering Pipeline Leaks

Leaks from gathering lines are calculated utilizing a generic emission factor (tCH4/km pipeline/year) multiplied by length of gathering lines (the activity factor).

DO Calculations

Table 17 below shows the inventory calculation methods associated with fugitive source categories for DO.

Table 17. DO fugitive source categories and associated fugitive emissions inventory calculation methods

DO Fugitive Source Category	Percent Contribution	2022 Calculation Method
Customer meter sets	**45%**	
Industrial/Commercial	*24%*	Generic EF
Residential	*21%*	Generic EF
Leaking buried pipe – services	**18%**	
Plastic	*4%*	Generic EF
Protected steel	*2%*	Generic EF
Unprotected steel	*12%*	Generic EF
Above grade meter-regulating stations	**15%**	
Gate	*9%*	Generic EF
District	*6%*	Generic EF
Damage events	**9%**	
Services	*5%*	Generic EF
Mains	*4%*	Generic EF
Farm taps	**9%**	**Generic EF**
Leaking buried pipe – mains	**4%**	
Plastic	*0.3%*	Generic EF
Protected steel	*4%*	Generic EF
Unprotected steel	*0.04%*	Generic EF
Below grade meter-regulating stations	0.01%	**Generic EF**

For all of EGI's DO assets, fugitive emissions are calculated using the generic emission factor method (see Table 8, Section 6.3). Emissions are calculated by multiplying activity factors (asset and component counts) with generic emission factors (obtained from industry standard guidance and publications, as per the Ontario Guideline).[5,6] This multiplication yields an emissions volume, reported in m^3 natural gas/year. To convert this to CH_4 mass, the emissions volume is multiplied by the default CH_4 density (0.678 kg/m^3), and annual hours of operation (8760 hours, unless otherwise specified), as per Ontario GHG Guideline.

Customer Meter Sets

For commercial and residential meter sets, emissions are calculated by multiplying the number of meter sets (the activity factor) by the associated emission factor. The meter set emission factor is derived by multiplying generic component counts and generic component emission factors.

Leaking Buried Pipe- Services

For leaking buried service pipelines (including plastic, protected steel, unprotected steel, and copper pipelines) emissions are calculated from the number of leaks based on the company specific total equivalent leaks ratio (the activity factor) multiplied by a generic emission factor expressed in units of m^3 natural gas/leak/year.

Above grade meter-regulating stations

For above grade meter-regulating stations, including gate stations, district regulator stations, and receipt/sales meter stations, emissions are calculated utilizing the number of stations (the activity factor), multiplied by a station emission factor. The station emission factor is obtained by multiplying the generic component counts by the generic emission factors for those components, expressed in units of m^3 natural gas/year/station.

Damage events

For damage events, including both mains and service lines, emissions are calculated utilizing the number of events per year (the activity factor) multiplied by a generic emission factor, in units of m^3 natural gas/event.

Farm taps

For farm taps, emissions are calculated by multiplying the number of stations (the activity factor) by a station emission factor. The station emission factor is the sum of the generic component counts multiplied by the generic emission factors, expressed in units of m^3 natural gas/year/station.

Leaking buried pipe – mains

For leaking buried main pipelines (including plastic, protected steel, and unprotected steel) emissions are calculated utilizing the number of leaks based on the company specific total equivalent leaks ratio (the activity factor) multiplied by a generic emission factor expressed in units of m^3 natural gas/leak/year.

Below grade meter-regulating stations

For below grade meter-regulating stations including those with inlet pressures of >300psig, 100-300psig, and <100psig, the emissions are calculated utilizing the number of stations (the activity factor), multiplied by a generic emission factor expressed in units of m^3 natural gas/hour/station.

7.6. Uncertainty in EGI's Inventory – Clearstone Study

In 2021, Clearstone Engineering Ltd. Conducted an analysis of the potential uncertainties associated with the EGI's 2020 reported fugitive emissions inventories. The uncertainties associated with fugitive emissions are presented in Table 18. As the methodology by which EGI's fugitive inventory is calculated has not significantly changed since the Clearstone study was conducted, the uncertainties reported in Table 18 are likely representative of the current inventory.

Table 18. Summary of the calculated uncertainties for the 2020 GHG inventory, as assessed by Clearstone Engineering in 2021

Segment	Fugitive Uncertainty
Transmission	8.2%
Storage	3.1%
Distribution	117.6%

Sources of uncertainty which were considered within these calculations included uncertainties from individual metered gas volumes, leak rates measured as part of leak detection and repair programs, activity values and time counts, gas composition, and uncertainty assigned to the emission factors used in the inventory calculations. The study noted that individual emissions values quantified as part of leak detection and repair studied were assigned an uncertainty of ±15%.

Note that EGI's distribution fugitive emissions are calculated using generic emission factors and activity counts (Table 6). All activity counts were assumed to have an associated uncertainty of 5% by Clearstone, and the number of individual components is significantly higher in DO than in STO, contributing to a higher associated uncertainty because the uncertainty implied in the generic emission factor is applied to a large population. Leak Survey Practices

7.7. Leak Survey Practices

7.7.1. Background

Due to differing risk factors, operating conditions, and operational controls (such as construction and maintenance specifications, and presence of pressure monitoring systems), leak survey requirements differ significantly among different segments of the natural gas supply chain.

Gas utilities (i.e. distribution companies) must conduct regular surveys of their entire network to ensure public safety as part of regulatory compliance. Studies have shown that leaks on distribution systems are highly dependent on the age and material of pipes, and that the leaks that do occur in these systems tend to be relatively small[xxiv]. Detection and localization of these small leaks, for eventual repair, is also a significant challenge, due the size and complexity of distribution networks, and their location in urban areas, often buried under pavement.

Midstream operations, especially large, high-pressure, and high-volume transmission systems, transport large volumes of natural gas, and present a more significant risk to people and environment in the case of an incident and are therefore closely and continuously monitored for potential incidents and process upsets. They are also built to a higher spec than smaller, lower pressure pipeline, as per CSA Z662 standard[xxv].

Detecting and repairing leaks significantly reduces emissions from gas transmission, storage, and distribution systems.

In this section, an overview of EGI's leak survey practices across transmission, storage, and distribution assets is provided, including the technologies used and the coverage and frequency of deployment. EGI conducts regular leak surveys on all assets to ensure safety, asset integrity, and regulatory compliance.[13] In some cases, information gathered as part of the leak survey program is used to estimate emissions for EGI's reported inventory. For each of the segments, a discussion of how results from leak detection campaigns are integrated into inventory calculations is provided.

Leak survey technologies are used to detect the presence of leaks. Technologies also exist that are capable of both detection and quantification, which provide a measurement of the flow rate of the detected leak. Detection-only technologies, which have been the industry standard for leak surveys, may directly measure the concentration of CH_4 gas in the air or indirectly infer the presence of a leak through pressure changes, process upsets or audio, visual, olfactory (AVO) methods.

7.7.2. Transmission Leak Survey Practices

EGI's transmission system consists of buried transmission pipelines and associated aboveground infrastructure, including compressor stations and pigging stations.

Overview of current LDAR Practices

Transmission pipelines, due to their high operating pressures, large size, and high carrying capacity, are monitored closely and consistently for potential leaks, using a variety of techniques and methods. Current leak survey practices on EGI transmission pipelines detect the presence of leaks. Leak survey practices on transmission compressor stations and meter/receipt stations use detection and quantification technologies to additionally measure leak flow rates.

LDAR Overview

Below outlines the different technologies used in EGI's transmission system.

- *Visual inspection of pipeline right of ways*

Visual right of way inspections are conducted as part of regulatory requirements. Weekly, a small aircraft (airplane or helicopter) passes over the pipeline right of way as trained personnel check for any visual signs of leaks or disturbances on the pipeline or immediate surrounding area. Indications of potential leaks include dead vegetation, areas of melted snow, or visible encroachment or disturbance. Visual inspections do not involve the use of any detection or quantification technologies.

- *Foot patrol with handheld gas monitor*

In addition to the visual inspections on right of ways, EGI's transmission pipeline system is surveyed by foot, by trained personnel carrying handheld gas monitors, which are capable of sensing CH_4 concentrations in the air immediately above the buried transmission pipeline. EGI's handheld gas monitors detect CH_4 concentrations but do not quantify leak flow rates.

- *Ground-based follow ups of visual inspections*

If the visual inspections result in the identification of potential leaks, a ground-based follow up is performed, using a handheld method (gas monitor or OGI camera). The purpose of the follow up is to pinpoint the source of the leak for repair and emission mitigation.

- *Satellite imagery for visual signs of impact*

EGI annually reviews satellite and aerial imagery[xxvi] for any visual changes to the areas within their transmission system. Potential signs of leaks include dead vegetation (which often appear as large circles of dead vegetation, contrasted against otherwise healthy vegetation), melted snow (often appearing as circles of melted snow), and visual encroachment.

- *Smart pigging*

Smart pigs are sent through the pipeline, which carry sensors which can measure any physical changes or deformities in the internal structures of the pipeline. Smart pigs may be able to identify weak areas or areas which are more prone to failure, which allow repairs to happen in advance of a failure. EGI utilizes smart pigging within their transmission system.

- *SCADA system monitoring*

All pipelines within EGI's transmission network are monitored continuously by a Supervisory Control and Data Acquisition (SCADA) system, which can identify potential signs of a leak, including pressure changes and vapor concentration changes[xxvii]. Both crude oil and natural gas transmission pipelines are monitored 24/7/365 by SCADA.

- *Mass balance calculations*

Mass balance calculations are performed multiple times per day, which calculate the volume of natural gas flowing through the pipelines, at different locations within the pipeline system, to verify that the volumes are not changing. Losses of flow rates from one point within the pipeline to another would indicate the presence of a potential leak. These digital monitoring controls can localize potential leak sources to between two points along the pipeline and can be used to inform and direct more detailed follow up methods, which would be similar to the ground-based follow ups of visual detections, as discussed above.

- *OGI and hi-flow sampler (for compressor and meter/receipt stations only)*

Compressor stations are surveyed for leaks as part of EGI's obligations under the Ontario GHG Reporting Program and the federal methane regulations, using an optical gas imagine camera (OGI). Additionally, EGI quantifies the flow rate of each leak detected using a hi-flow sampler.

Coverage and Frequency Overview

EGI's full transmission system is surveyed using flyovers on a weekly basis and ground-based methods on an annual basis. Compressor stations, and meter/receipt stations are surveyed three times per year using ground-based OGI, and quantification of leak rates is performed using hi-flow sampling. This coverage and frequency are in line with the regulatory requirements.

Impacts of LDAR on Reported Inventory

Transmission pipeline fugitive emissions are calculated using the generic emission factor method as per the 2022 CEPEI manual based on Total Equivalent Leaks (TEL). Results from leak surveys are not included in emissions calculations since flow rates are not being measured.

Fugitive emissions from compressor stations and meter/receipt stations are calculated using the measured emissions from the regulatory LDAR surveys. The total leak volume for a given reporting year is aggregated by taking the hourly leak rates from the surveys and approximating the duration using the methodology provided in the Ontario GHG Guidelines[xxviii].

7.7.4. Storage Leak Survey Practices

EGI's storage system consists of storage wells, compression systems, and other aboveground infrastructure to support injecting and withdrawing natural gas from storage.

Overview of current LDAR Practices

Leak survey is performed at all storage facilities, including the LNG facility.

Current leak survey practices on EGI storage assets, including compressor stations and other aboveground infrastructure, use detection and quantification technologies. Detection is performed using optical gas imaging, and quantification of detected leaks is performed using hi-flow samplers.

LDAR Overview

Below outlines the different technologies used in EGI's storage system.

- *OGI and hi-flow sampler*

Compressor stations and meter/receipt stations are surveyed for leaks as per regulatory requirements, using OGI is for detection of leaks. Additionally, EGI performs hi-flow sampling to quantify leak rate.

Coverage and Frequency Overview

Leak surveys are performed at all storage facilities three times per year, consistent with regulatory requirements. Hi-flow quantifications are performed on all the OGI-detected leaks.

Impacts of LDAR on Reported Inventory

Like transmission leak survey practices, fugitive emissions from compressor stations and meter/receipt stations are calculated using the measured emissions from the regulatory LDAR surveys. The total leak volume for a given reporting year is aggregated by taking the hourly leak rates from leak surveys and approximating the duration using the methodology provided in the Ontario GHG Guidelines[xxix].

7.7.5. Distribution Leak Survey Practices

EGI's distribution system consists of gas distribution pipelines (mains and service lines), customer meter sets, above grade meter-regulating stations, and farm taps.

Overview of current LDAR Practices

Gas distribution pipelines operate under low pressure and flow rates and are the smallest in diameter of pipeline types. They are also the most prevalent type of gas pipeline with thousands of kms of distribution mains and service lines under EGI's operation. Current leak survey practices for EGI's distribution network involve detecting, classifying, and repairing leaks to ensure customer safety. The current practice does not include measurement of leak flow rate.

LDAR Overview

The following technologies are used to perform leak surveys of EGI's distribution system.

- *Handheld ppm gas detector (sniffer)*

Handheld ppm gas detectors are used to conduct walking surveys of distribution systems.

- *Vehicle-mounted gas detector*

Vehicle-mounted gas detectors are used to conduct surveys in rural areas. In addition, a vehicle-mounted advanced mobile leak detection (AMLD) system, capable of detecting and quantifying leaks, was piloted in 2023.

Coverage and Frequency Overview

Annual leak surveys are performed on a portion of distribution assets, covering about one-fifth of the system yearly. Surveys are conducted on foot and by vehicle, using gas detectors, which detect CH_4 concentration (ppm) in the air.

Leak surveys of pipelines and meter set assemblies are conducted every 1, 4, or 8 years depending on the characteristics of the individual pipe that serves the customer meter (as per CSA Z662). Also, as per the Electricity and Gas Inspection Act, statistical sampling and verification of gas meters occur to monitor compliance with the Electricity and Gas Inspection Act (i.e., confirm measurement accuracy). Any time a gas meter is part of this statistical sampling program, or if the sample group fails and the full group of gas meters needs to be exchanged, a leak check and operational inspection are performed on the meter set assembly by a licensed gas fitter. EGI field reps also look for leaks when they do meter set exchanges for all assets above ground, upstream and downstream of the regulator and meter.

Any customer calls for the smell of gas, fire, fumes, TSSA investigation, etc., triggers a complete leak check and inspection of the meter set assembly by licensed gas fitters. Leaks are assigned a risk level relative to their size.

Impacts of LDAR on Reported Inventory

DO emissions are calculated using generic EFs. Since DO LDAR practices do not include measuring leak flow rates, this information cannot be used to calculate emission factors. However, activity information obtained during LDAR surveys, including leak counts and repairs, is used to calculate the total equivalent leak ratio (activity factor). Currently, this activity factor is used to calculate emissions for buried distribution pipelines, including both services and mains.

8. Technology Deployment Scenario Analysis

8.1. Introduction

The purpose of the scenario analysis is to evaluate different options for measuring fugitive emissions from EGI's transmission & storage, and distribution segments. EGI is seeking to develop a robust fugitive emissions measurement plan (FEMP) to decrease uncertainty in reported fugitive emissions. Technology performance, as well as other considerations such as cost, feasibility of implementation, impacts on emissions uncertainty, and survey and travel time, must be evaluated to understand the most suitable option to meet EGI's goals. A holistic evaluation of possible options is intended to aid EGI with developing a FEMP and identifying associated risks and opportunities.

To complete this holistic evaluation of different potential programs, a qualitative and quantitative analysis was undertaken. Highwood conducted a quantitative analysis to estimate the time and associated cost to complete surveys, potential emissions mitigation, number of detected leaks, and measurement uncertainty of each scenario. For the qualitative analysis, industry research and analyses were used to evaluate the primary sources of uncertainty impacting quantitative results, opportunities and risks, and which scenarios offered the best performance, considering the combination of all metrics evaluated.

The objectives of this scenario analysis are to provide an overview of different possible measurement options and evaluate which may be the most suitable for EGI to reach their goals of more accurately quantifying fugitive emissions and reducing uncertainty, in line with OEB commitments. In addition, EGI aims to maximize potential emissions mitigation opportunities.

8.2. Background Information

For the scenario analysis, EGI's DO and STO segments were considered separately, and the latter was evaluated qualitatively. Highwood focused its quantitative analysis on the DO segment due to its larger contribution to overall fugitive emissions and the higher uncertainties associated with the current emission calculation methods. The DO segment encompasses all the infrastructure that is associated with downstream gas distribution, including buried main and service pipelines, meter-regulating stations, farm taps, and customer meter sets. The STO segment consists of transmission systems and gas storage facilities, which include transmission pipelines, compressor stations, and other infrastructure such as receipt stations, valve stations and farm taps.

The decision to exclude the STO segment from the quantitative analysis was driven by several factors. First, the uncertainty of the EGI emissions inventory for the STO segment is significantly lower than the DO segment, as demonstrated by the Clearstone analysis (section 7.6). Second, as reviewed in section 7.2, the reported volumes of fugitive emissions for the company are primarily attributed to the DO segment. Third, existing leak survey practices on the STO segment already include the detection and quantification of fugitive emissions three times per year (section 7.7.3) for compressor stations and receipt-sales meter stations, with even more frequent surveys expected as a result of upcoming amendments to the Canadian methane regulations. Given these considerations, efforts were focused on the DO segment. However, the STO segment still underwent a qualitative scenario analysis and is discussed in the recommendation section (Section 9).

8.3. Methodology

8.3.1. Quantitative Analysis

FEMP Scenario Construction Methodology

FEMP scenarios for DO segment were developed through collaboration with EGI and were selected based on a high-level technology overview which assessed potential technologies of interest for deployment. This overview also considered technologies in use for other North American gas utilities, as well as those technologies specifically identified in the EB-2022-0200 – 2024 Rebasing, partial settlement agreement.

A note on terminology: A FEMP scenario considers measurement of leak flow rate which is not required under an LDAR program. For the quantitative analysis we are required to assume that all scenarios incorporate formal measurement of all detections, thus we refer to all scenarios as FEMP scenarios.

When developing screening and survey (see glossary) frequency and coverage parameters for the scenarios, EGI’s stated goal of accurately measuring fugitive emissions (i.e., reducing uncertainty in the fugitive emissions inventory) was given the highest priority, and as such, all FEMP scenarios which were selected are believed to have lower uncertainty compared to the currently deployed LDAR program for DO as it contains no measurement (current practices described in section 7). This lowered uncertainty stems from these options using measurements of EGI’s emissions (as opposed to generic EFs), increased frequency of deployment, and increased coverage – all characteristics known to decrease emissions uncertainty.

Satellites, aircraft (helicopters), vehicles and handheld technologies were evaluated to assess the potential performance of each, considering uncertainty, technical feasibility of deployment, etc. Some scenarios use a combination of different methane detection and quantification technologies. These scenarios aim to assess if there are tangible benefits to deploying multiple technologies, such as improved detection capabilities, speed and coverage advantages, or survey efficiencies.

A full overview of the key inputs and assumptions associated with each of the explored FEMP scenarios described below is available in the attached appendix. Components of the FEMP scenarios which were considered include:

- Detection threshold of the methane detection/quantification technology.
- Frequency of surveys/screenings.
- Time to complete a survey/screening.

The following FEMP scenarios were explored in the quantitative and qualitative scenario analysis:

Handheld Every 7 Years FEMP Scenario

A FEMP Scenario that considers handheld surveys of all infrastructure every 7 years. While EGI currently conducts leak surveys without measuring leak flow rates, the quantitative analysis necessitates that we assume each detected emission is measured, hence the FEMP Scenario terminology.

The current LDAR program is based on historic practices of surveying approximately 1/7th of the infrastructure each year using handheld portable gas monitors on foot (in rural areas, operators drive with gas monitors). Detected leaks are evaluated and assigned a relative risk level (safety), which is how repairs are triggered. Due to the model's limitations, we modelled a scenario which sees the entire infrastructure surveyed every 7 years. This modelling is based on the historic LDAR Program, with EGI now surveying approximately 1/5th of the infrastructure each year (larger area surveyed per year).

Handheld Every 3 Years FEMP Scenario

This scenario is identical to the “Handheld Every 7 Years” Scenario, only here the program sees a survey of the entire system every 3 years (again, to represent a real-world scenario which sees 1/3rd of the infrastructure surveyed each year).

Annual Full System Coverage FEMP Scenarios

A series of scenarios were explored in which the full system receives annual surveys with satellite, aerial, vehicle, or handheld technology deployment. Each technology is considered separately within these scenarios (scenarios do not consider technologies working in combination).

Twice per Year Full System Coverage FEMP Scenarios

This FEMP scenario considers a semi-annual (twice per year) deployment of vehicle-mounted technology. All assumptions and simulation inputs are consistent with the annual full system coverage scenario.

Technology Combination FEMP Scenarios

A series of FEMP scenarios with a combination of methane detection and quantification technologies was explored. These technology FEMP scenarios are:

- **Multi Tech FEMP Scenario 1:** Aerial 1x/year + Vehicle 1x/year + Handheld 1x/year
- **Multi Tech FEMP Scenario 2:** Aerial 1x/year + Vehicle 1x/year + Handheld every 3 years
- **Multi Tech FEMP Scenario 3:** Aerial 1x/year + Vehicle 1x/year
- **Multi Tech FEMP Scenario 4:** Vehicle 2x/year + handheld every 7 years
- **Multi Tech FEMP Scenario 5:** Vehicle 1x/year + handheld every 7 years

The same considerations are in effect for the technology combination scenarios as described above, but now they are considered as working together. The primary purpose for the five combination FEMP scenarios is to compare the mitigation potential and number of detected leaks between the scenarios and understand how the inclusion (and frequency) of the handheld deployment affects the performance of the FEMP.

Survey Time, Personnel and Survey Cost

An initial analysis outside LDAR-Sim was completed to estimate the total time required to complete surveys.

Survey Time and Personnel

Survey time and personnel requirements were calculated based on pipeline length, method speed and deployment windows. See the following assumptions:

- Method speed:
    - **Vehicle:** 35 km/hr (280 km/day) considering average urban speed and method performance.
    - **Handheld:** 0.75 km/hr (6 km/day), informed by EGI.
    - **Aerial:** 110 km/h (880 km/day), based on average Bridger Photonics speed when deploying across the distribution sector. Aircraft would be a helicopter flying as low as local regulations allow.
- Length surveyed:
    - **Vehicle**: The entire length of pipelines. The vehicle method must intersect the plume. So, they need to perform the surveys following the pipeline in a straight line. Each survey considered 6 passes.

   - **Handheld:** The entire length of pipelines, based on the same logic as the vehicle method. Each survey only includes 1 pass.
   - **Aerial:** Only mains length. Bridger "sees" a grid, so an assumption is made that they can "see" service lines in the grid.
- Deployment window
   - All surveys had to be completed between April and October, which corresponds to approximately 120 working days per year.
   - Each personnel was considered to work 8 hours per day.

Survey cost
Cost for methane measurement technology deployment is extremely difficult to predict. Cost will generally depend on the business model of the solution provider and indirect costs associated with deployment, such as increased data management requirements, field personnel, and the need for specialized software. The most common business models include:

- ***Upfront/capital costs***

  More common for handheld systems, continuous monitoring or any solution where the operator must purchase equipment (rather than contracting to a solution provider).

- ***Recurring costs***

   - *Cost per time*: Most common approach for service providers because labour can be the most expensive component of a survey (especially for ground-based methods that have to travel/drive between locations). Daily rates lead to cost sensitivity due to variable asset densities and facility size. Cost per hour or day is more common for handheld methods.

   - *Ongoing subscription costs:* Ongoing subscription costs commonly supplement systems with upfront capital costs and cover software subscriptions and analytics.

- ***Cost per program (fixed fee)***

  Sometimes, service providers give a total estimate on a project basis. How the total estimate is calculated may not be evident, but it could depend on facility density, remoteness, environment, etc. Most of the time, fixed costs are provided per survey and vary with the scope (number of facilities or length of the pipelines) and deployment frequency. Usually, cost per survey decreases when covering more assets and at higher deployment frequencies (such as semi-annual screenings / quarterly screenings, etc).

Cost information is not publicly available for most methane measurement companies and products. In Table 19 below, Highwood provides a high-level initial cost assessment for the technologies evaluated in the different scenarios.

Table 19. Cost Estimates

Technology	Upfront Cost per Unit [5] (USD)	Annual Recurring Cost per Personnel (USD)	Annual Cost per Program - Fixed fee (USD)
Handheld Device (FID and Hiflow samplers)[1]	$15,000 ($3,000 per year)	$50,000	-
Vehicle (based on Picarro costs)[2]	$1,200,000 ($240,000 per year)	$110,000	-
Aerial (based on Bridger Photonics)[3]	-	-	$ 12,000,000
Satellite (based on GHGSat) [4]	-	-	$10,000,000

[1] Source: Measurement of Methane Emissions: Abandoned Wells & Mines.

[2] Estimated based on Picarro quote for EGI. Hybrid cost approach, which includes upfront capital for hardware, ongoing subscription costs for the associated software and cost per unit time to cover the technician time performing the survey. Different pricing options are available for this technology.

[3] Estimated based on a signed project of Bridger with SoCal Gas. Considering that EGI DO infrastructure encompasses a larger area, costs will potentially be higher. Estimate for one survey at the entire DO infrastructure.

[4] Estimated based on Satelytics cost of ~$120K for 4 analyses in 100-200 km^2 area.

[5] Cost per hardware unit (one handheld device or one truck system). To determine the total upfront cost, the cost per unit was multiplied by the number of personnel needed (which varied depending on the technology and deployment frequency). To project the annual cost, the total upfront cost was evenly spread across a five-year period. Overall annual upfront cost is detailed in the results (section 8.4.1).

LDAR-Sim Analysis

LDAR-Sim was used in the quantitative analysis of the explored FEMP scenarios. LDAR-Sim is an open-source, agent-based numerical model developed at the University of Calgary used to predict the emissions reduction effectiveness of different FEMPs and work practice configurations. LDAR-Sim works by building a "virtual world" of oil and gas infrastructure and emissions sources that are informed by empirical measurement data and historical environmental data. Different FEMP scenarios are then applied to the virtual world to predict emissions reductions and compare performance amongst the programs.

LDAR-Sim uses a geospatial approach to simulating LDAR, accounting for actual facility locations and local environmental conditions anywhere in the world. In this case, historical Canadian weather data was used. All relevant LDAR-Sim information can be found on the LDAR-Sim GitHub page and a detailed description of LDAR-Sim can be found in Fox et al. 2019[xxx].

Figure 9 presents a graphical overview of the LDAR-Sim virtual world, the programs which are applied to this virtual world and some of the parameters which inform both. Note that the figure encompasses all possible LDAR-Sim inputs, but not all were used in this investigation such as vented/routine emissions, and the price of carbon. LDAR-Sim is intentionally designed such that non-relative input parameters can be ignored and will have no impact on results.

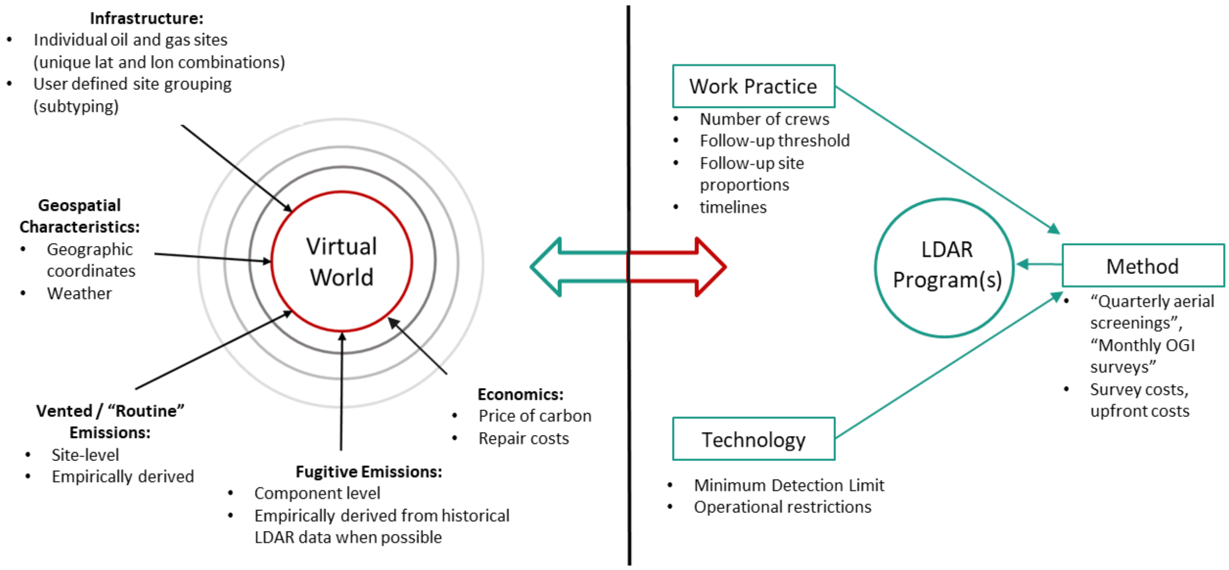


Figure 9. LDAR-Sim virtual world and program interaction. All bullet points are informed by the LDAR-Sim user, using empirically derived data specific to the region and infrastructure being simulated whenever possible.

Figure 10 is an overview of the LDAR-Sim processes from setting up the simulation through to the processes that happen while the simulation is running.

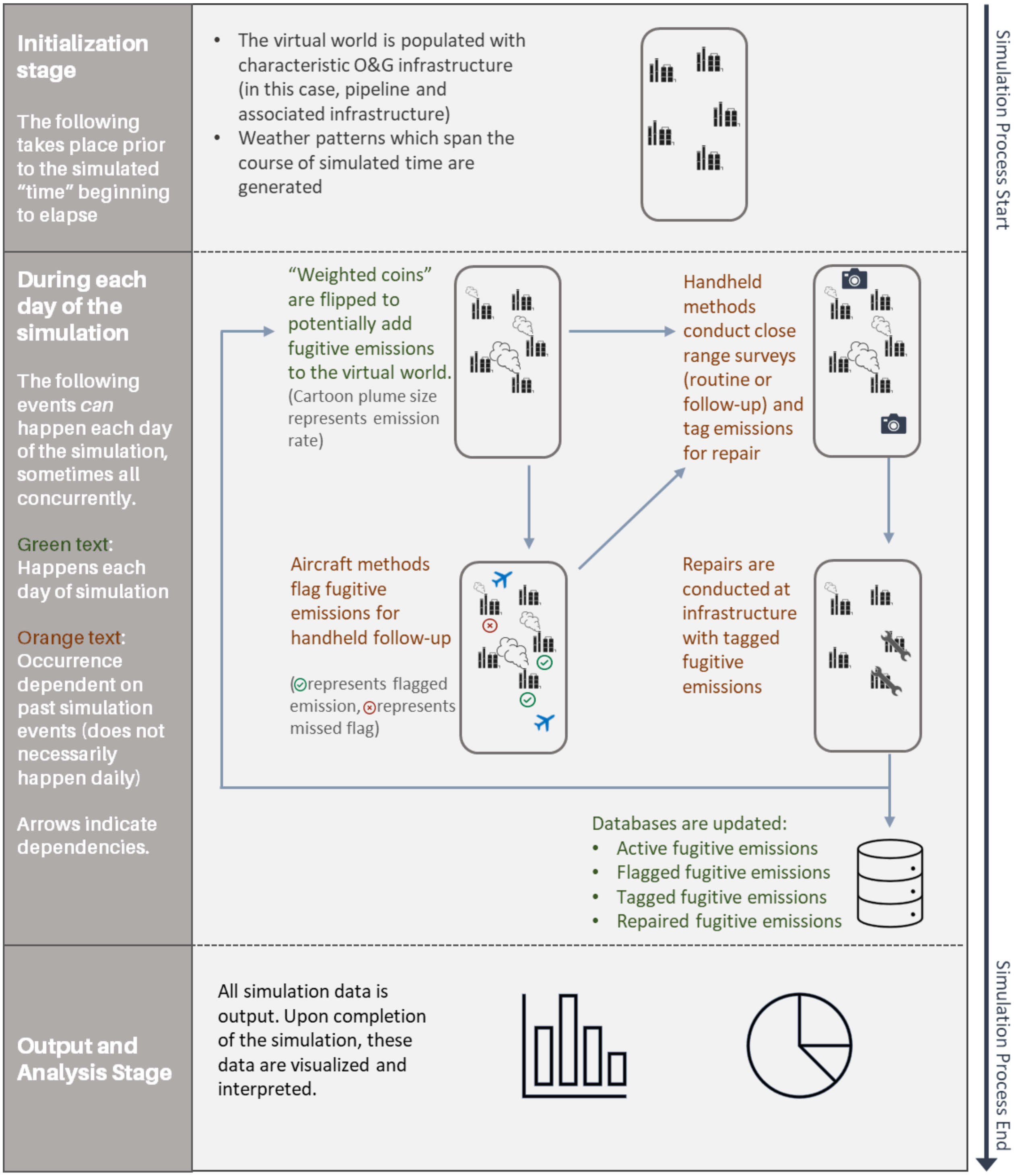


Figure 10. The LDAR-Sim process. Before the "simulated time" begins the virtual world is constructed. Once "virtual time" begins, the simulated emissions are randomly generated and crews travel between facilities detecting these emissions, eventually leading to their repair.

Key LDAR-Sim input assumptions

LDAR-Sim has over 100 parameters which allow for the fine-tuning of the sites in the virtual world (the size and frequency of emissions they generate) and the performance / behaviour of the technologies and methods (minimum detection limit, travel speed, survey speed, operational weather envelopes, etc.). A full breakdown of LDAR-Sim operation and parameterization can be provided upon request; however, this section will describe the most relevant parameters to be aware of when interpreting simulations results.

- **Minimum Detection Threshold:** The smallest methane emission rate a particular technology can detect. Minimum detection threshold in LDAR-Sim can be expressed as either a probability of detection (PoD) curve, or a single threshold cut-off value when probability of detection data is lacking. The following minimum detection thresholds (and their source) were applied to the modeled methane detection / quantification technologies:
  - Satellite: A detection threshold cut-off of 100 kg /hr CH_4 was applied. In modelling, any emission larger than 100 kg /hr CH_4 is detected by the satellite. This cut off is sourced from the whitepaper by McKeever and Jervis[xxxi]. Note, this whitepaper provides a PoD curve for GHGSat with a 50% PoD at 100 kg /hr CH_4, as such, modelling the satellite detection threshold a cut-off value of 100 kg /hr CH_4 (essentially 100% PoD at 100 kg /hr CH_4) is an optimistic interpretation of satellite performance.
  - Aerial: The aerial method was assumed to have 90% PoD for rates ≥0.5 kg CH_4. This PoD is sourced from the Bridger Photonics website stated 90% PoD for the distribution sector[xxxii], with further details available in Thorpe et al.[xxxiii].
  - Vehicle and Handheld: The PoD of the vehicle and handheld technology is based on a PoD curve from Tian et al.[xxxiv] with coefficients representing leak rate, survey speed, survey distance (sensor to source), Monin-Obukhov length, wind speed, and air temperature. This PoD curve was applied to both vehicle and handheld modeled PoD considering that both would use similar sensor (in the study a high-precision gas analyzer GasScouter™ G4301, Picarro, Inc. with 0.1 ppb measurement precision at a 1 Hz measurement interval was used), but differ in survey speed and distance, which can be accounted for via changing the coefficient values of the PoD Curve. Figure 11 shows the Tian et al. PoD curve and the following tables show how the coefficients were parameterized for the modeled handheld and mobile methods.

$$DP = \frac{1}{1 + e^{-\left(5.0221 + 0.139q - 0.1498c - 0.057s - \frac{12.7024}{L} - -0.4115U - 0.0807T\right)}} \quad (5)$$

Parameter	Regression coefficient (μ ± 1 σ)	p value (μ ± 1 σ)
Intercept (b_o)	5.0221 ± 0.0117	6.14761E-39 $\pm$ 3.65743E-39
Leak rate (b_1)	0.139 ± 0.0005	4.7734E-16 $\pm$4.34151E-16
Survey speed (b_2)	-0.1498 ± 0.0002	1.0119E-102 $\pm$ 9.1455E-103
Survey distance (b_3)	-0.057 ± 0.0002	1.26593E-13 $\pm$ 1.3302E-13
Monin-Obukhov length (b_4)	-12.7024 ± 0.0976	1.0586E-04 $\pm$ 4.99716E-05
Wind speed (b_5)	-0.4115 ± 0.0021	1.5131E-07 $\pm$ 5.2156E-08
Air temperature (b_6)	-0.0807 ± 0.0006	4.279E-06 $\pm$ 2.45119E-06

Figure 11. Handheld and Vehicle Detection Probability (DP, referred to as Probability of Detection (PoD) elsewhere in this report)

Table 20. Handheld and Vehicle Parameters

Method	Leak Rate, wind speed, air temperature	Travel Speed	Estimated Distance from the Source	Monin-Obukhov Length[1]
Handheld (walking)	Simulation dependent	0.8 km/hr (0.47 mph)	5 m	3
Vehicle (driving)	Simulation dependent	35 km/hr (22 mph)	5 m	3

[1] The Monin-Obukhov length characterizes the balance between buoyancy forces and shear forces within the atmospheric boundary layer. Positive values indicate stable atmospheric stratification (i.e., buoyancy dominates over shear) while negative values indicate unstable stratification (i.e., shear dominates over buoyancy).

- **Infrastructure Subtypes:** Subtyping is the process in which LDAR-Sim sites are grouped according to shared characteristics. In this investigation, the following subtypes were used, each assumed to have unique emissions behavior which therefore behaved differently from a modeled emissions standpoint. Distribution stations were not subtyped into legacy service areas because data to characterize how those assets differ in terms of emissions profiles was not available.

- Legacy Union Gas (LUG) Main Pipelines
- Legacy Union Gas (LUG) Service Pipelines
- Legacy Enbridge Gas (LEG) Main Pipelines
- Legacy Enbridge Gas (LEG) Service Pipelines
- Distribution Stations (gate station, district station or farm taps)
- Industrial/Commercial Meter Sets

- **Infrastructure Modeled**: The most granular piece of infrastructure in LDAR-Sim is a "site", which depending on the infrastructure could represent a specific length of pipeline or a unique station as described below:
  - 1 site = 10 km of pipeline (service and main).
  - 1 site = 1 distribution Station (gate station, district station or farm taps).
  - 1 site = 1 customer meter Set (either residential, industrial, or commercial).

Modeling every single asset was impractical due to constraints in computing capacity. Therefore, we applied a scaling factor to represent a subset of the infrastructure. This approach doesn't compromise the accuracy or reliability of the final results because the subtype distribution within the subset mirrors that of the entire infrastructure. Due to the increased number of customer meter sets we had to model this part of infrastructure separately. Considering the infrastructure size we chose scaling factors of 1/100 and 1/10,000 for pipelines + distribution stations and customer meter sets, respectively. This decision was based on computational constraints, the requirement for representativeness, and the desired level of details. The raw subtype counts as well as the modeled counts with the applied scaling factor are provided in Table 21.

Table 21: Summary of the subtype counts and scaling factors.

LDAR-Sim Infrastructure: Pipelines + Distribution Stations	Raw Distance or Counts Provided by EGI	Modeled Infrastructure (scaling factor = 1/100)
Pipeline Main LUG	40,031 km	400 km
Pipeline Main LEG	34,516 km	350 km
Pipeline Service LUG	31,231 km	310 km
Pipeline Service LEG	38,886 km	390 km
Distribution Stations [1]	19,453 stations	195 stations
LDAR-Sim Infrastructure: Meter Sets	**Raw Counts Provided by EGI**	**Modeled Infrastructure (scaling factor = 1/10,000)**
Residential Meter Sets	3,874,241 stations	387 stations
Industrial/Commercial Meter Sets	66,391 stations	7 stations

[1] Includes gate stations, district stations and farm taps.

Leak Production Rate: The probability a leak will arise at a given site on a given day. EGI data was used to inform the LEG and LUG pipeline subtypes while two key publicly available sources; a peer-reviewed journal article from Lamb et al.[xxxv] and a preprint journal article from Coleman et al.[xxxvi] were used to inform the distribution stations, and customer meter set subtypes. In addition, an **EGI** estimate was used to confirm the distribution stations subtype leak production rate sourced from Lamb et al. The leak production rates for each subtype are provided in Table 22.

Table 22. Summary of the subtype leak production rates

Subtype	Average Annual Leaks per 10km of Pipeline or Station	Leak Production Rate
LUG Main	0.15	0.0004
LUG Service	3.72	0.0102
LEG Main	0.19	0.0005
LEG Service	4.89	0.0134
Distribution Station	3.03	0.0083
Residential Meter Sets	0.19	0.0005
Industrial/Commercial Meter Sets	1.40	0.0038

Leak Rate Source: Informs the size (emission rate) of randomly generated leaks in simulation. Quantified emission rates from Lamb et al.[xxxvii] and Coleman et al.[xxxviii] were used to inform simulated leak rates for all subtypes except industrial/commercial meter sets, in which EGI quantification data was used. Hi-Flow samplers were used to quantify emission rates in Lamb et al.[xxxix] and Coleman et al. [xl], with the addition of a high precision analyzer when rates were too small. The leak rate sources for each subtype are provided in Table 23

Table 23. Summary of the subtype leak rate source for each subtype

Subtype	Leak Rate Source Reference Data	Data Points	Average Leak Rate (g CH_4/hr)	Maximum Leak Rate (g CH_4/hr)	Minimum Leak Rate (g CH_4/hr)
LUG Main	Lamb et al. (Main)	160	47.03	2102	0.07
LUG Service	Lamb et al. (Service)	93	12.53	199	0.10
LEG Main	Lamb et al. (Main)	160	47.03	2102	0.07
LEG Service	Lamb et al. (Service)	93	12.53	199	0.10
Distribution Stations	Lamb et al. (M&R)	691	26.58	2769	0.02
Residential Meter Sets	Coleman et al.	7	0.09	0.40	0.00039
Industrial / Commercial Meter Sets	Enbridge	48	0.53	2.53	0.00043

High-Level Measurement Uncertainty Modelling Investigation

Included in this LDAR-Sim analysis is a high-level investigation into the measurement uncertainty of the explored FEMP Scenarios. The goal of this analysis was to investigate how a few key sources of uncertainty (represented as LDAR-Sim input parameters) can impact measurement uncertainty.

This investigation is **not** a robust investigation into measurement uncertainty of the explored scenarios. It is assumption-heavy with regards to important considerations like emissions behavior of the virtual world, and detection thresholds of the methane detection and quantification technology. In addition, it does not consider quantification error. Quantification error is a measure of how accurately methane detection and quantification technologies can quantify emission rates from their raw data products. Quantification error is poorly understood (minimal controlled testing has been conducted), so for this investigation we assume all technology "perfectly" quantifies emission rates. Finally, this investigation assumes all modeled technologies are capable of emission rate quantification. As discussed earlier in this Section (8.3), the "Every 7 year Scenario" is a hypothetical FEMP scenario that assumes all detected leaks are quantified via Hi-Flow sampler. To conduct a robust measurement uncertainty analysis, many high-quality data are required, outside the scope of what many oil and gas operators typically have access to, however, this is changing as more operators are considering measurement informed inventories.

While the assumptions of this investigation must be kept front of mind, it does provide some preliminary insights into how 3 key sources of uncertainty can affect measurement uncertainty:

- Detection threshold of the technology.
- Survey/screening frequency of the technology.
- Necessary assumptions around emissions durations.

The detection threshold and screening/survey frequency of the explored FEMP scenarios are described above and in Section **Error! Reference source not found.**. In a measurement campaign b ased on routine measurements, all measurements are a "snapshot in time," and as such, emissions duration must be assumed. Here, we adopt the conservative assumption that when an emission is detected and measured, it has existed since the previous survey/screening when no emission was found. Future work can explore different emissions duration assumption methodologies. The impacts of the 3 key modeled sources of uncertainty will be discussed in more detail in Sections 0 and 8.5.

8.3.2. Qualitative Analysis

The following were key considerations undertaken in the qualitative analysis. The qualitative analysis is discussed in more detail in Section 8.5.

Scenario Evaluation Methods

To determine the optimal deployment program from the scenario analyses, Highwood considered which of the scenarios offered the best combination of performance (number of leaks detected), survey time (costs and resources of deploying the surveys) and cost.

The scenarios which had the strongest performance in terms of leaks detected vs time requirements were progressed to the next level of the analysis, which was a more detailed discussion and evaluation of the scenario uncertainty and its ability to improve the accuracy of the emissions inventory estimate. Note that an assessment of the uncertainty impacts of all scenarios is available in the scenario analysis spreadsheet included in the appendix. The discussion in this report is limited to the scenarios with better performance.

Evaluation of uncertainty

When evaluating the potential uncertainty and accuracy impacts of each of the FEMP scenarios, an assessment of the primary sources of uncertainty associated with each program was completed. To narrow the analysis and focus on sources of uncertainty for comparison, Highwood reviewed sources of uncertainty associated with the measurements of each FEMP scenario, as well as the spatial extrapolation uncertainty and the temporal extrapolation uncertainty.

Additionally, the detection and quantification capabilities of the technologies are discussed for each scenario. Some of the technologies included within the scenarios, such as handheld devices, are only capable of methane detection, while others have detection and quantification capabilities (keep in mind that in the *quantitative* analysis, we assume all scenarios incorporate measurement, sometimes using a hypothetical Hi-Flow sampler in the handheld based scenarios). The detection-only programs that are discussed in this qualitative analysis are highly sensitive but do not provide any information about emission rates, so they offer limited opportunities for developing emission factors or understanding leak sizes and distributions. Technology options which can perform quantification but have a higher detection threshold, such as aerial screenings via Bridger Photonics, may not capture as many leaks compared to a more sensitive technology like the vehicle-based surveys, but these can be used to measure higher emitting sources for more targeted mitigation of large leaks.

Detection and quantification capabilities are a key consideration, as they contribute to how the results from leak detection programs can be applied to inventory calculations and will affect the accuracy of those calculations.

Opportunity and Risk Assessment

For each of the scenarios, risks and opportunities were identified and discussed. For each, a relative risk or opportunity was assigned (low, medium, high), with an explanation of the level provided.

Development of Company-Specific Emission Factors

Highwood also qualitatively evaluated the possibility of sampling a “representative” part of the population for the development of company-specific emission factors. In this case, measurements would be performed on the representative sample.

Conducting representative measurements would allow for a smaller number of measurements to be performed, which would reduce the resource requirements, compared to conducting full scale quantification programs. The ultimate purpose of developing company-specific measurement-derived emission factors is to improve the accuracy of the fugitive emissions inventory for the distribution segment.

8.4. Quantitative Analysis Results

8.4.1. Survey Time, Personnel and Cost

Survey Time and Personnel

Figure 12. Survey time of the explored single technology FEMP scenarios. Bar height represents the total number of days required per year across all crews for each method assuming 8 hours per day shifts.
is a bar chart visualizing the total survey time for the single FEMP scenarios.

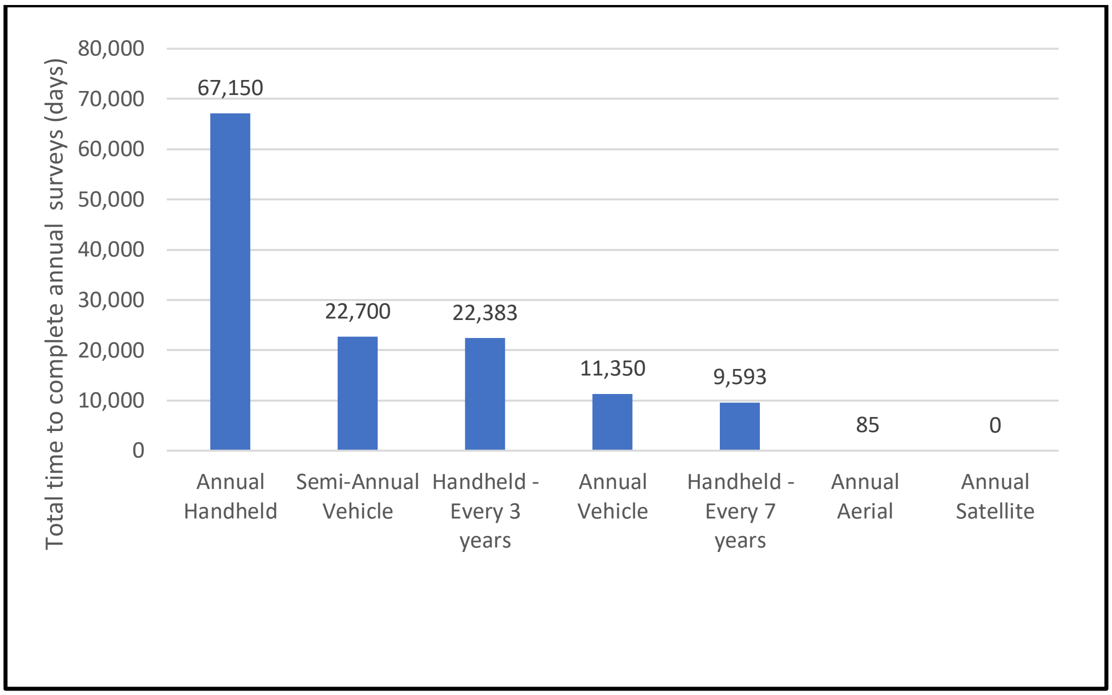


Figure 12. Survey time of the explored single technology FEMP scenarios. Bar height represents the total number of days required per year across all crews for each method assuming 8 hours per day shifts.

The number of crews (personnel) required to complete the surveys for each scenario was also evaluated. This analysis considered the method deployment window (April – October, which was considered to be 120 working days) and 8-hour work shifts. For this analysis, we considered 1 crew = 1 employee.

The following is a summary of the required crews for each FEMP scenario to ensure all surveys are completed:

- Annual Handheld: 560 personnel
- Semi-Annual Vehicle: 189 vehicles

- Handheld - Every 3 years: 187 personnel
- Annual Vehicle: 95 vehicles
- Handheld - Every 7 years: 80 personnel
- Annual Aerial: 1 aircraft (surveys completed in less than 120 days)
- Annual Satellite: 0 crews (this method does not require personnel to survey the site)

This does not include support staff to assist with leak surveys and investigations (such as planning, classification, etc.), repairs, and personnel needed for data analysis.

Cost

Based on the assumptions described in section 8.3.1, the cost of deployment was estimated. For handheld and vehicle-based methods, the number of required personnel was used to estimate the required hardware and dedicated employees. Table 24 and Figure 13 summarize the results.

Table 24. Estimation of annual cost of deployment.

Method	Total Annual Upfront Cost [5] (USD)	Total Annual Recurring Cost (USD)	Annual Cost per Program - Fixed fee (USD)	Total
Annual Handheld	$ 1.7 MM	$ 28.0 MM	-	$ 29.7 MM
Semi-Annual Vehicle	$ 45.4 MM	$ 20.8 MM	-	$ 66.2 MM
Handheld - Every 3 years	$ 0.6 MM	$ 9.3 MM	-	$ 9.9 MM
Annual Vehicle	$ 22.7 MM	$ 10.4 MM	-	$ 33.1 MM
Handheld - Every 7 years	$ 0.2 MM	$ 4.0 MM	-	$ 4.2 MM
Annual Aerial	-	-	$12.0 MM	$ 12.0 MM
Annual Satellite	-	-	$10.0 MM	$ 10.0 MM

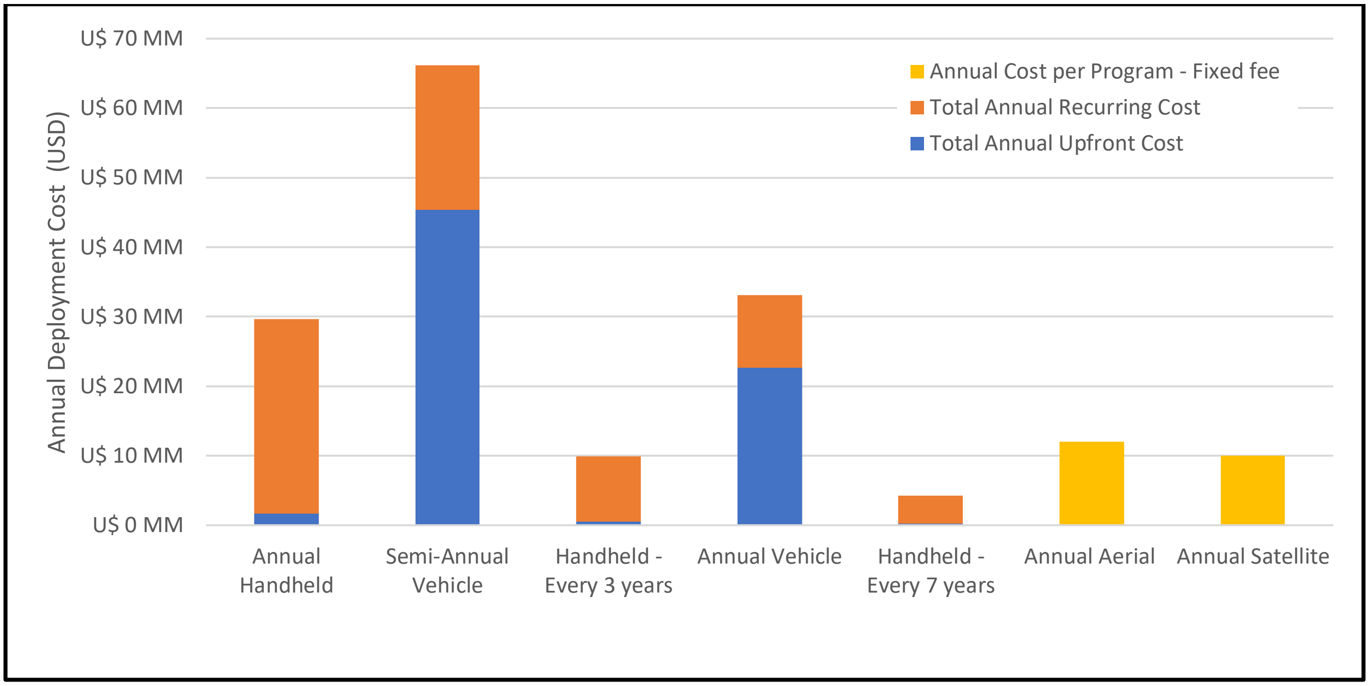


Figure 13. High-level cost analysis for different methods evaluated. The annual component of upfront cost considers overall upfront cost distributed in 5 year-period.

Main limitations for the above analysis:

- Both aerial and satellite methods are new technologies for distribution surveys. The cost to deploy an aerial method (based on Bridger Photonics) was estimated based on a pilot project with SoCal gas, which has a DO segment concentrated in a smaller area.
- The above analysis does not consider the increase in resources that will be required for ground follow-up to locate/repair leaks. This increase is expected to be higher for all non-walking technologies compared with handheld due to poor location accuracy of vehicle/aerial options. Each technology type will have different follow-up, data management, and repair costs associated with it.
- Programs with upfront capital costs (vehicle and handhelds) have this value amortized, but this is not the case for other costs. Therefore, the number of surveys and duration of the program matter. For example, if you compare a ground-based vehicle system (with upfront costs) to an aircraft-based survey for a one-year period, it will look worse than if you compare costs over a five-year period.
- Another complexity with cost is whether the solution providers have leveraged economies of scale. For example, some aerial and satellite companies will survey entire regions at once, not just targeting the assets of a single operator. They can therefore offer lower per-site costs

because these are offset by other companies "subscribing" to the same service. These and other factors make it very difficult to acquire and estimate costs.
- Costs are always evolving as the methane monitoring innovation landscape is new and evolving, and competitive pressures and the presence of venture capital for some companies may temporarily bias costs.

Ultimately, it is critical to acquire and compare quotes from different vendors for specific programs determined to be of interest to an operator. The above complexities also underline the critical importance of conducting pilots, which often reveal hidden and unanticipated costs.

8.4.2. Emissions Mitigation and Leak Counts Modelling Results

The bar charts of Figures 14 to 17 are the results of LDAR-Sim emissions modelling. The bar length in the "Percent of Leaks Detected" visualizations represents the proportion of all randomly generated leaks in simulation detected by each of the explored FEMP Scenarios. The expected mitigation if all leaks detected were repaired in 30 days was also evaluated and included in the appendix for reference.

Across all scenarios, both the Annual Vehicle and Annual Handheld methods demonstrated a comparable number of detected leaks. This happens because both methods use highly sensitive sensors, enabling the detection of even minor sources under favourable deployment conditions. Typically, trucks overlook some minor sources due to their increased distance from the emission point and higher speed, which impacts their likelihood of detecting such leaks. Consequently, if only a single pass were considered for both methods deployed in the same environmental conditions, handheld devices would detect more leaks. Nevertheless, truck work practices modelled here involve six passes, significantly mitigating the discrepancy between the two methods. While each pass by a truck may have a lower chance of detecting a leak, visiting the same spot multiple times compensates for this, resulting in a similar overall detection rate between the two methods.

Pipelines (LUG and LEG) and Distribution Stations

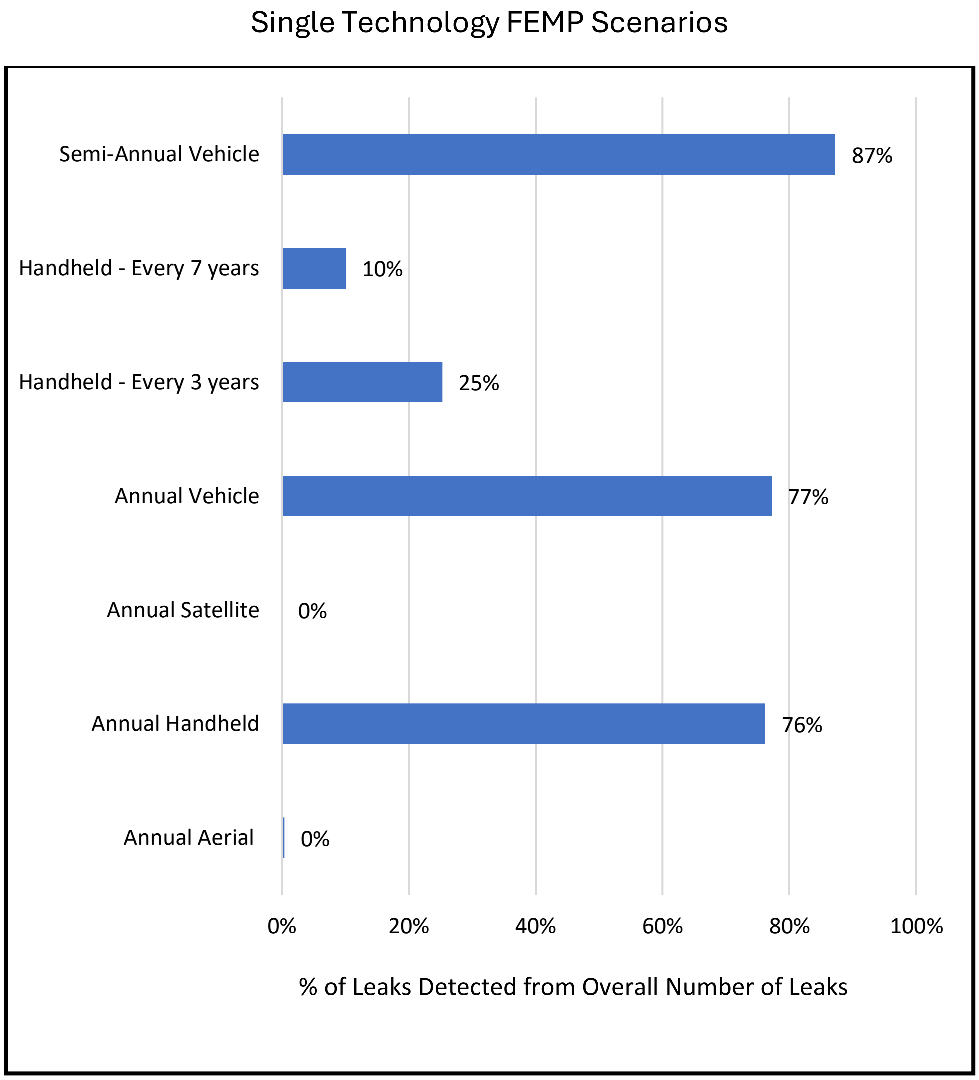


Figure 14. Percent of all randomly generated leaks (based on the subtypes and their associated leak production rates) detected by the explored single technology FEMPs in an LDAR-Sim "virtual world" populated by pipelines and Distribution Stations

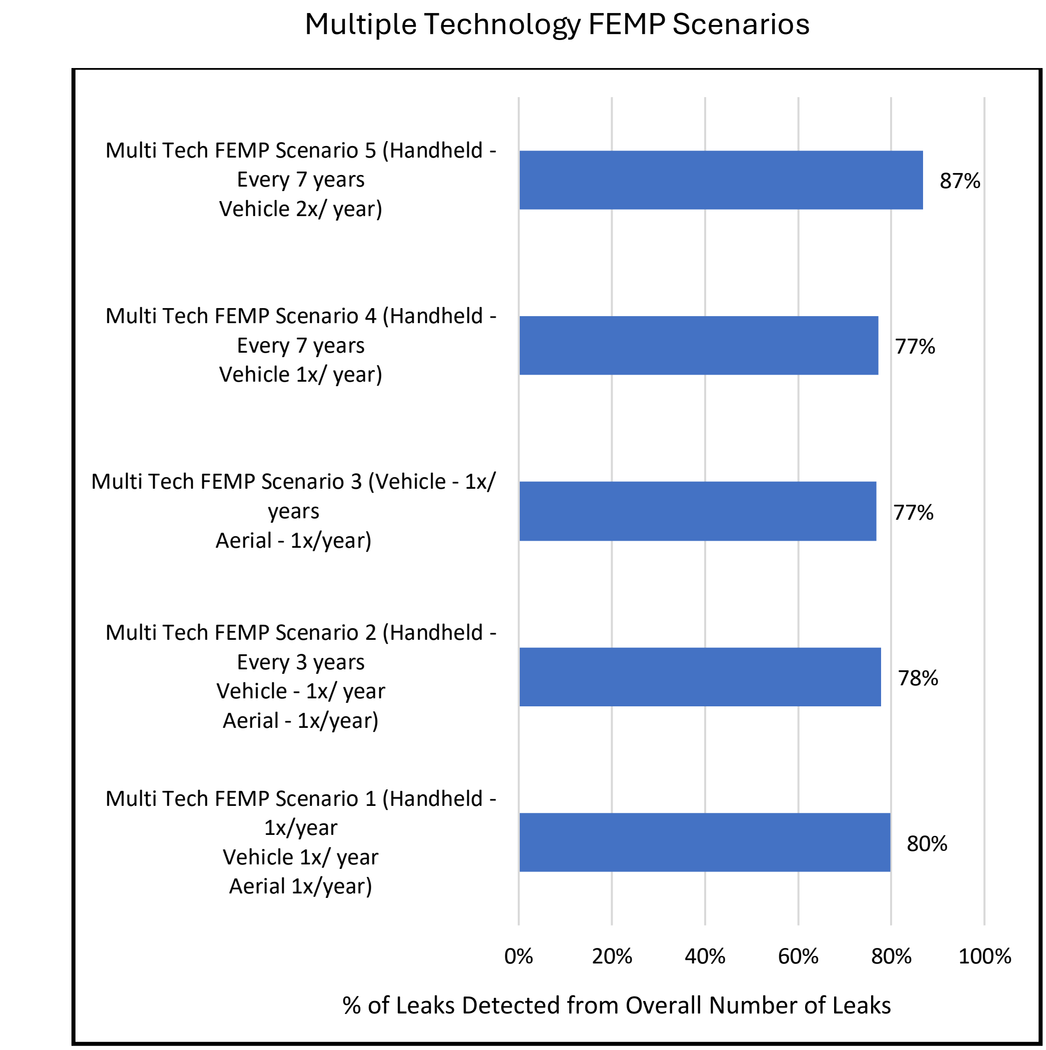


Figure 15. Percent of all randomly generated leaks (based on the subtypes and their associated leak production rates) detected by the explored multiple technology FEMPs in an LDAR-Sim "virtual world" populated by pipelines and Distribution Stations

Residential, Industrial, and Commercial Meter Sets

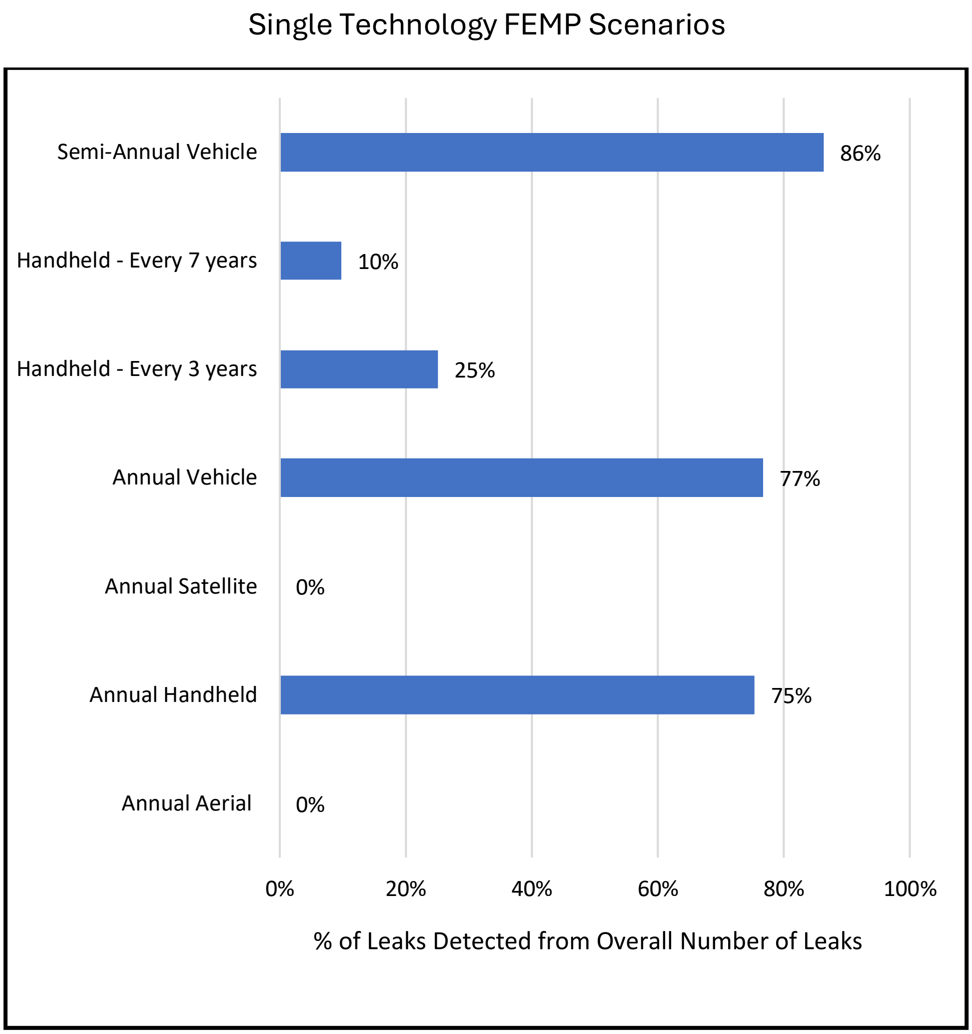


Figure 16. Percent of all randomly generated leaks (based on the subtypes and their associated leak production rates) detected by the explored single technology FEMPs in an LDAR-Sim "virtual world" populated by residential, industrial, and commercial meter sets.

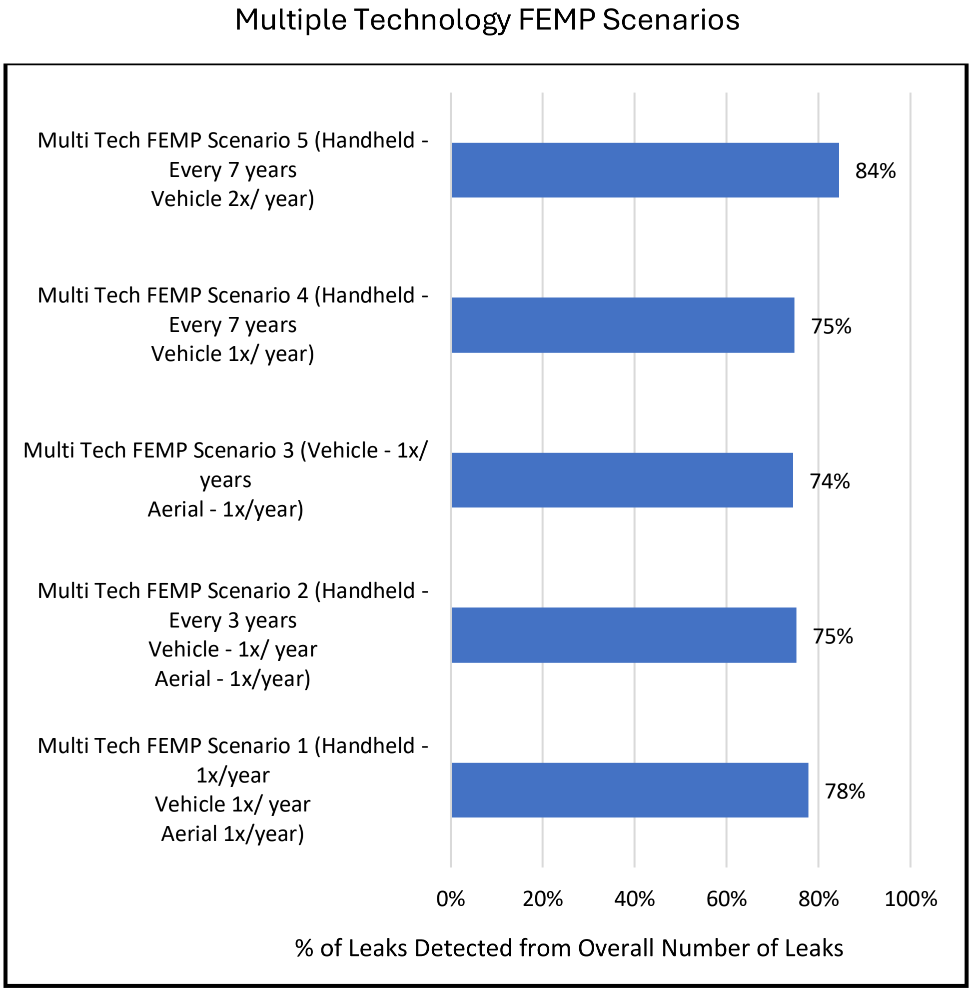


Figure 17. Percent of all randomly generated leaks (based on the subtypes and their associated leak production rates) detected by the explored multiple technology FEMPs in an LDAR-Sim "virtual world" populated by residential, industrial, and commercial meter sets.

8.4.3. Measurement Uncertainty Modelling Investigation Results

The bar charts of Figures 18 to 21 are the results of the high-level measurement uncertainty investigation. The following is a summary of how to interpret the bar distances of these visualizations.

The blue bar represents the average "true" yearly emissions under each FEMP scenario. LDAR-Sim is "omniscient" in that it "knows" how long each emission in simulation lasts. For example, if an emission arose on day 100, was detected via a survey or screening on day 200 and repaired on day 205, LDAR-Sim "knows" the emission lasted for 105 days. LDAR-Sim multiplies each emissions emission rate by this "known" / "true" duration to calculate the total "true" emissions used to construct the blue bar. These calculations are then averaged across all years of simulated time. The blue bar varies between different programs because LDAR-Sim assumes that once a leak is detected by screening technologies, it will be repaired within 30 days. For comparison purposes, a bar representing emissions in the absence of an LDAR program (labeled "None") was also included. Since repairs due to LDAR programs are not happening in this scenario, the "None" bar can be interpreted as the maximum "true" emissions under the assumptions used in the modelling conducted for this report.

The orange bar represents the average “estimated” yearly emissions under each explored FEMP scenario. A real-world FEMP which incorporates measurement and lacks continuous monitoring (as these modeled FEMPs do) must make assumptions around emission duration. For example, if an emission arose on day 100, was detected via a survey or screening on day 200 and repaired on day 205, the FEMP campaign does not “know” that the emission arose on day 100, only that it was first detected on day 200. As such, an assumption must be made regarding its duration. Here, the assumption is the conservative one that assumes the emission has existed since the previous survey/screening, where no emission was detected. In the above example, if the previous survey/screening where no emission was detected was day 50, the FEMP must assume the emission lasted for 155 days. Using these assumption estimates, the same logic as the blue “true” bar is then used to calculate average yearly “estimated” emissions. Because of this assumption, FEMPs with long time deltas between surveys/screenings are forced to likely overestimate emissions duration.

As well as emissions duration assumptions, the reader must also consider the impact of “seeing” more leaks on uncertainty. One input parameter which impacts this is the detection threshold of the modeled technologies. A technology with a lower detection threshold (handheld analyzer) can “see” more emissions than one with a larger detection threshold (aerial screenings via Bridger Photonics). The other input parameter which impacts this is survey frequency; the more frequently a technology surveys/screens for emissions, the more emissions it can “see”.

The interplay between what emissions are “seen” and emissions duration estimation is perhaps best shown in Figure 18 when comparing the estimated emissions in the “Handheld - Every 7 years” and the “Handheld - Every 3 years” scenarios. The Handheld - Every 3 years scenario estimates more emissions despite it applying a shorter duration assumption onto each emission it “sees”. With our emissions duration assumptions in mind, the Handheld - Every 7 years could potentially assume a duration of greater than 3 years, whereas the maximum assumed duration under the Handheld - Every 3 years program is 3 years. The likely cause is that the Handheld - Every 3 years program is “seeing” more emissions, specifically, more *large* emissions due to the increased survey frequency and therefore is estimating more overall emissions. This assumes an inflection point in the impact of emissions duration vs. “seen” emissions (at a certain point, surveying more frequently while decreasing the emissions duration assumption will “see” enough emissions to lead to larger estimates). Assessing uncertainty is difficult as all factors must be considered in tandem.

Pipelines (LUG and LEG) and Distribution Stations

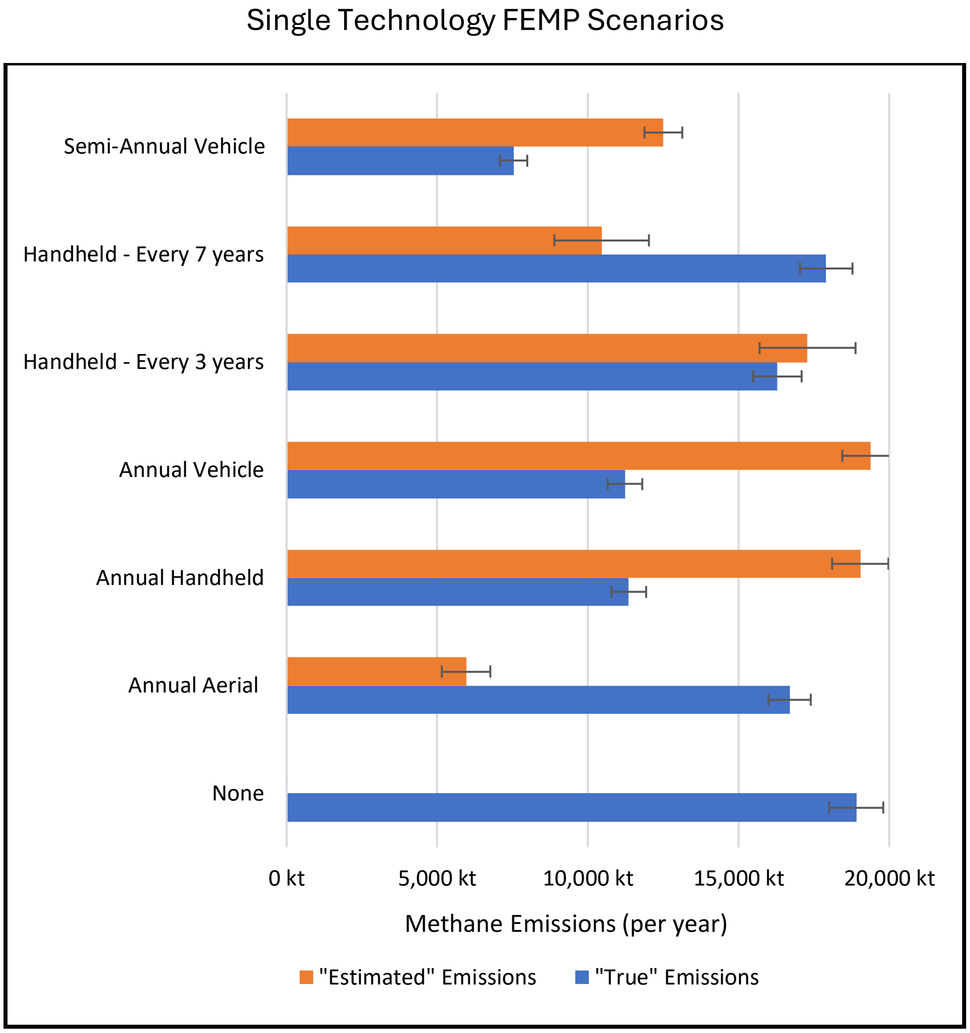


Figure 18. The "estimated" and "true" emissions of explored single technology FEMPs in an LDAR-Sim “virtual world” populated by pipelines and distribution stations. The “emissions” are calculated by multiplying the emission rate of a leak by its duration and summing all volumes. This is done for each year of simulated time, and the average values are shown. “true” emissions (blue bars) represent the emissions where the leak duration is “known” by LDAR-Sim and incorporated into the emissions calculation. The “estimated” emissions (orange bars) represent emissions where the leak duration must be estimated. Both “true” and “estimated” emissions consider the detection capabilities of the FEMP’s technology.

Multiple Technology FEMP Scenarios

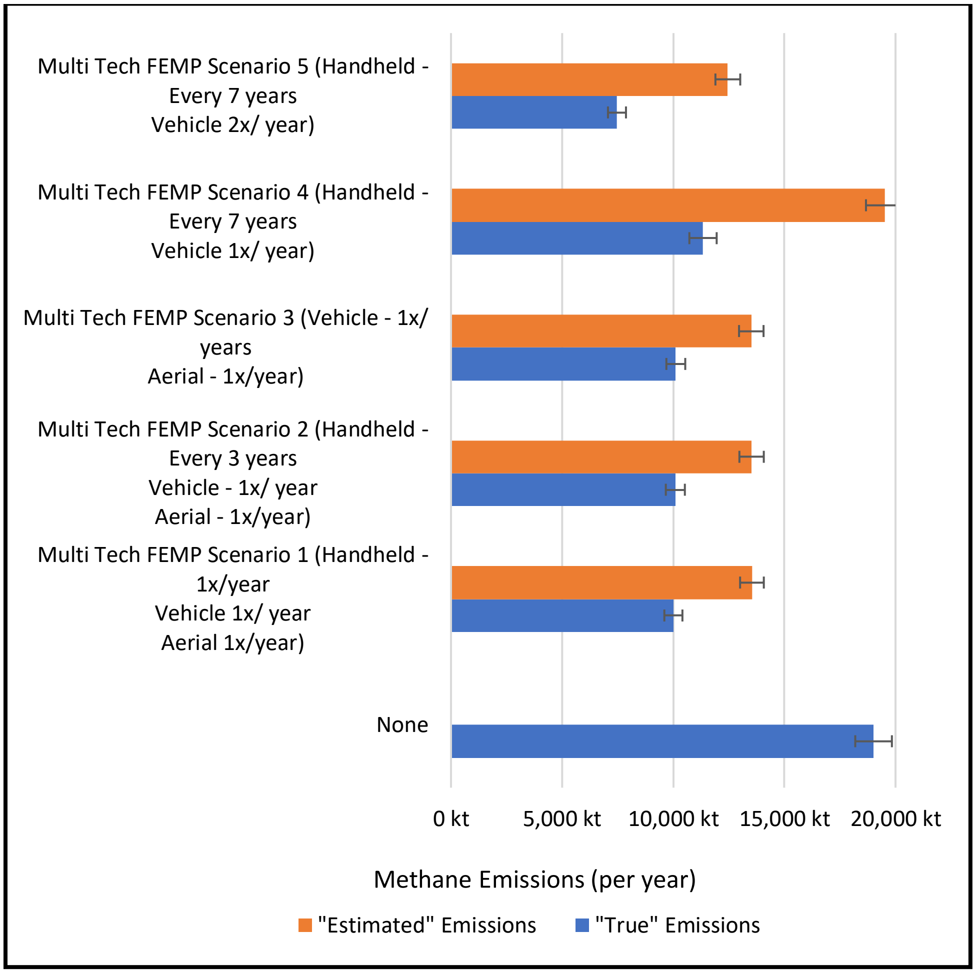


Figure 19. The "estimated" and "true" emissions of explored multiple technology FEMPs in an LDAR-Sim “virtual world” populated by pipelines and distribution stations. The “emissions” are calculated by multiplying the emission rate of a leak by its duration and summing all volumes. This is done for each year of simulated time, and the average values are shown. The “true” emissions (blue bars) represent the emissions where the leak duration is “known” by LDAR-Sim and incorporated into the emissions calculation. The “estimated” emissions (orange bars) represent emissions where the leak duration must be estimated. Both “true” and “estimated” emissions consider the detection capabilities of the FEMP’s technologies.

Residential, Industrial, and Commercial Meter Sets

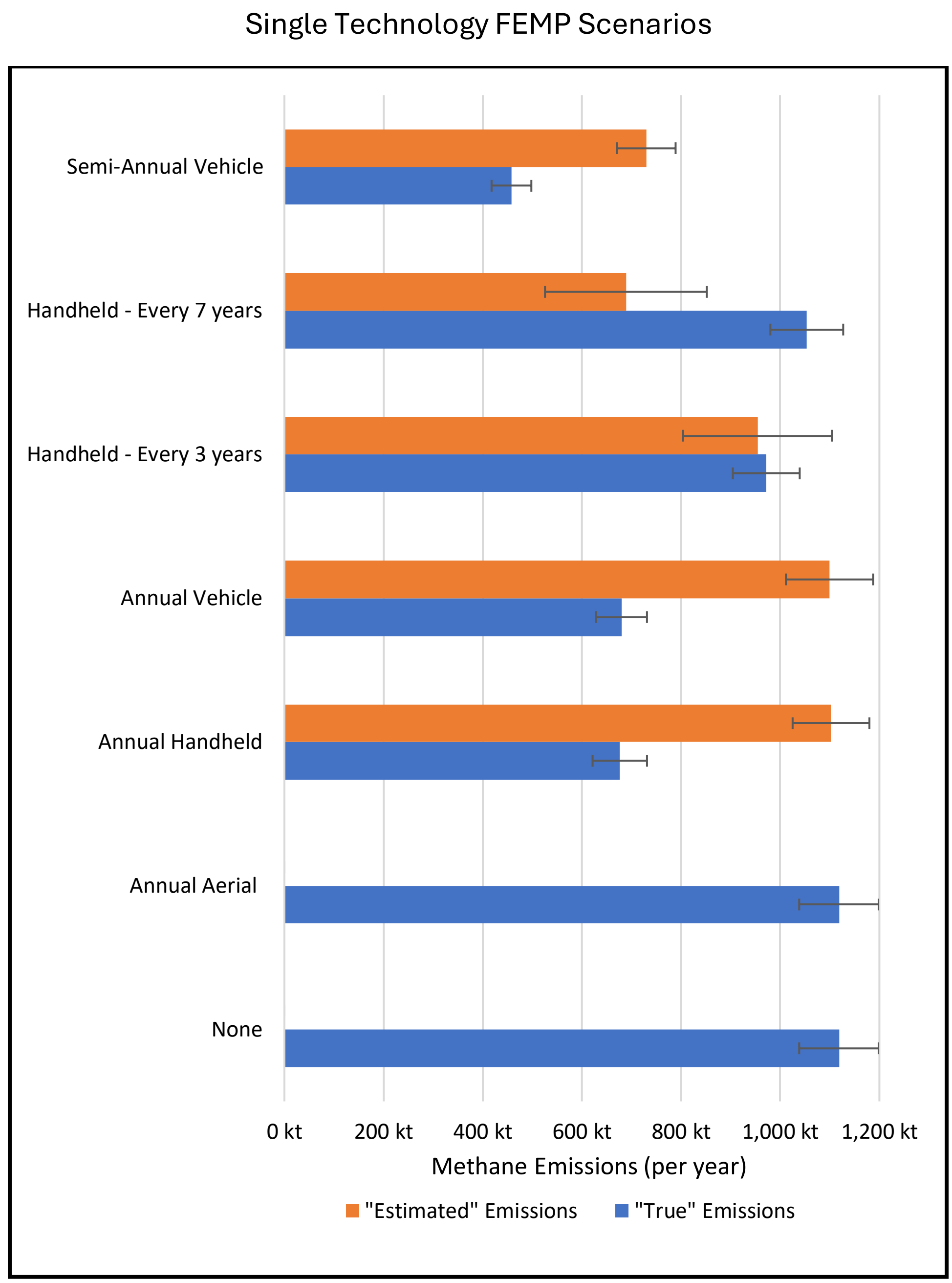


Figure 20. The "estimated" and "true" emissions of explored single technology FEMPs in an LDAR-Sim "virtual world" populated by residential, industrial, and commercial meter sets. "Emissions" are calculated by multiplying the emission rate of a leak by its duration and summing all volumes. This is done for each year of simulated time, and the average values are shown. The "true" emissions (blue bars) represent the emissions where the leak duration is "known" by LDAR-Sim and incorporated into the emissions calculation. "estimated" Emissions (orange bars) represent emissions where the leak duration must be estimated. Both "true" and "estimated" emissions consider the detection capabilities of the FEMP's technology.

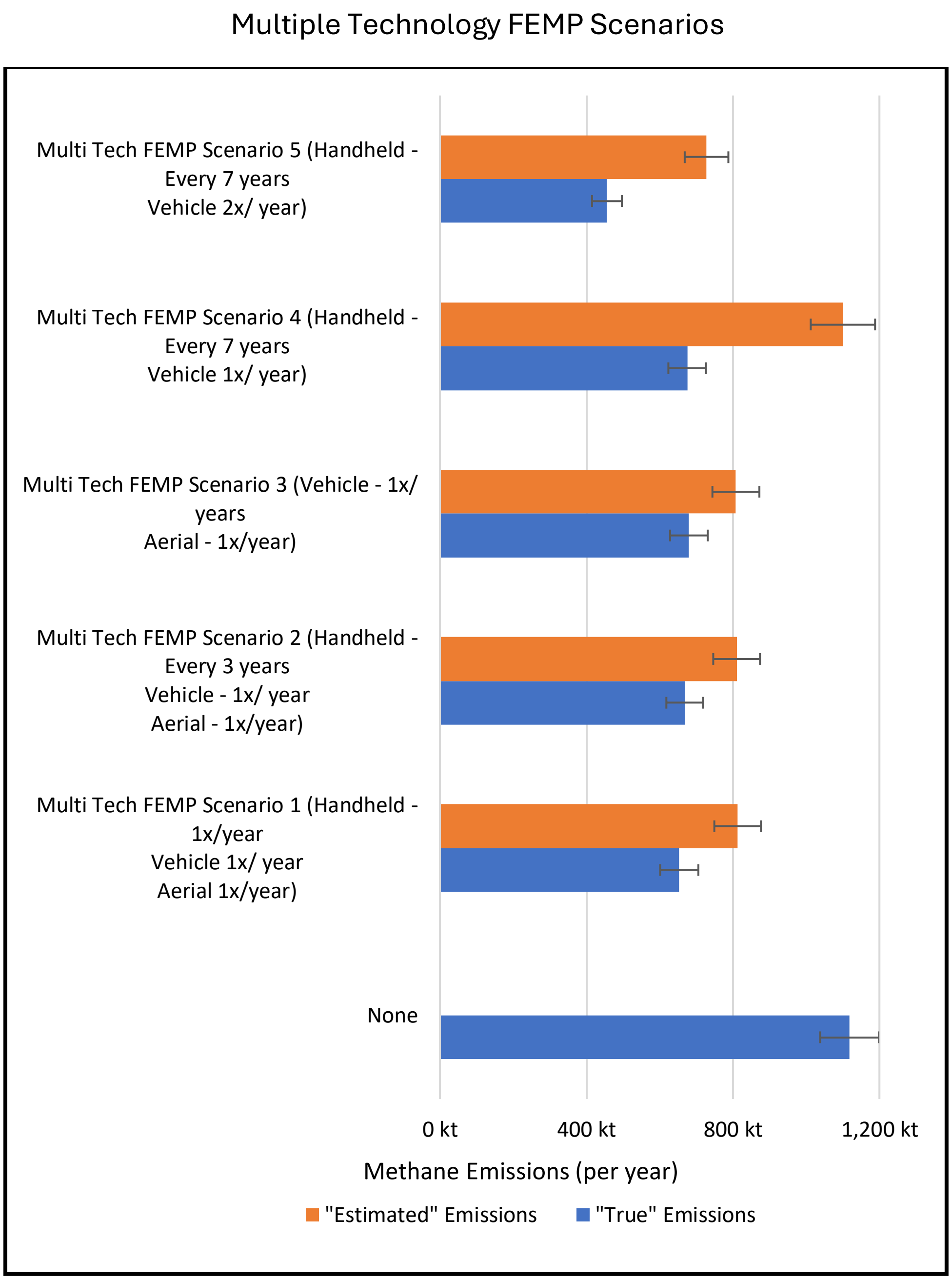


Figure 21. The "estimated" and "true" emissions of explored multiple technology FEMPs in an LDAR-Sim “virtual world” populated by residential, industrial, and commercial meter sets. The “emissions” are calculated by multiplying the emission rate of a leak by its duration and summing all volumes. This is done for each year of simulated time, and the average values are shown. The “true” emissions (blue bars) represent the emissions where the leak duration is “known” by LDAR-Sim and incorporated into the emissions calculation. “estimated” emissions (orange bars) represent emissions where the leak duration must be estimated. Both “true” and “estimated” emissions consider the detection capabilities of the FEMP’s technologies.

8.5. Qualitative Analysis – DO Segment

8.5.1. Summary of the results – Distribution (DO)

Each FEMP scenario was modeled and assessed to evaluate the potential of using measurement to reduce the uncertainty in the fugitive emissions inventory.

It is important to note that the results of the simulation modeling are only as strong as the input data. When modelling the FEMP scenarios on EGI's distribution system, Highwood used a combination of EGI company data and literature values to characterize the leak frequency (leak production rate) and leak size (leak rate source). These results should be considered with the caveat that there is a potential that EGI's leaks are not well characterized by the literature values which were used as inputs into the simulations.

Of the methods evaluated, aerial and satellite were found to be unsuitable for deployment on EGI's DO system due to the dominance of small leaks typical of distribution systems.

Satellites did not detect any emissions in the simulations. Satellites do not have sufficiently sensitive sensors to compensate for the large distance from the sensor to the source, and the leaks present within a typical distribution network are not large enough to be detected by satellite. Highwood evaluated claims by satellite monitoring providers that they were sufficiently sensitive to be effective for use on distribution systems but was unable to validate those claims from any published data.

Aerial-based programs, specifically LiDAR-based helicopter-mounted systems, were also not found to be effective for deployment on EGI's DO system due to the technology sensitivity being too high compared to the size of most leaks present within a typical distribution system. While aerial programs are in use by gas utilities in North America, Highwood's assessment is that the objective of those programs is to detect large sources, prioritize repairs and reduce overall emissions. While effective from a mitigation point of view, currently available aerial-based methods still miss most sources (sources with emission rates below the technology detection limit) and, for that reason, are not recommended to be used as a measurement tool to improve the accuracy of fugitive emissions inventories.

Vehicle-based and handheld programs demonstrated the best-simulated performance of the technologies evaluated. Handheld programs performed very similarly to vehicle-based programs in terms of estimated cost, mitigation potential and number of leaks detected. While the time to complete a walking survey was estimated to be 6 times more than vehicle programs, directly impacting service cost, the upfront cost of acquiring vehicle-mounted systems to survey the entire infrastructure made the cost between the two options competitive. Both handheld and vehicle-based surveys were simulated to be effective in detecting leaks, with a similar likelihood of finding emissions. Handhelds are more sensitive because they take measurements close to the source of emissions, but the protocol includes only one pass, while the vehicle-based protocol involves six passes over the same location, increasing the likelihood of detecting the source. According to the uncertainty analysis described in section 8.4, both methods are expected to have comparable performance in terms of detecting leaks when deployed at the same frequency. However, it's essential to note that the quantification error was not considered in the analysis. The two methods have different quantification methodologies that can impact the accuracy of the final estimate. Hi-flow samplers are used for direct measurement of emissions, while vehicle-based systems use plume dispersion modeling to estimate emissions. Although hi-flow samplers are expected to have better accuracy, we cannot confirm this due to the lack of controlled release studies focusing on the quantification error associated with these technologies.

8.5.2. FEMP Scenario Outcomes and Trends

The use of methane measurement technologies, and more frequent deployment of these technologies will reduce uncertainty in the calculated fugitive emissions inventory. Completing surveys on a more frequent basis will provide “stops” to the temporal extrapolation of leak duration assumptions, thus reducing the uncertainty of how long the leak has been occurring for.

EGI’s currently deployed LDAR program (handheld walking survey using detection only gas analyzer) is expected to be more effective at detecting emissions than aerial methods but is not able to measure any leak rate.

Within this scenario analysis, the detection of a greater number of leaks is advantageous due to the emissions inventory calculation's dependency on the multiplication of the activity factor by the emission factor. A higher percentage of the "average number of leaks detected per year" signifies a FEMP scenario that approaches the detection of all existing leaks within the system, thereby enhancing the accuracy of the activity factors. It should be noted that having a better understanding of the number of leaks that occur does not necessarily improve knowledge of how large those leaks are and the associated emissions. Therefore, handheld surveys should be complemented with Hi-flow sampler measurement for a complete understanding of emissions if walking surveys are chosen.

Trade-offs exist between increasing survey frequency (thus increasing the time required to complete those surveys and the associated costs and resourcing) and improvements in the mitigation and accuracy of a measurement-informed inventory. Across all scenarios evaluated, the number of detected leaks increases as survey frequency increases. Completing any survey program more than annually increases accuracy, but the associated time and cost increases are higher than the performance benefits and are likely not worthwhile.

8.5.3. FEMP Scenario Uncertainty

For an overview of the uncertainties and impacts on the inventory accuracy of all assessed scenarios, consult the scenario analysis spreadsheet included in the appendix.

Detection Uncertainty

The performance of vehicle-mounted sensing technology and handheld devices at detecting leaks has been independently validated through controlled release testing on gas distribution systems globally. For both the vehicle and handheld systems, most vendors deploy very sensitive sensors, but there is still a potential that very small leaks below the detection threshold exist in the system. Picarro trucks, for example, use CRDS methane sensors, which is the same technology modeling was based on. Work practice (number of passes, proximity of the source, speed…) also has a significant impact on the technology performance, but as modelling shows, under appropriate work practices, major sources are consistently detected by both methods. Therefore, the uncertainty in the non-detection from handheld and vehicle measurements is much lower than the uncertainty in the non-detection from the less sensitive technologies which were evaluated (aerial and satellite).

Detection and Quantification Capabilities

Both handheld and vehicle-based FEMP scenarios are capable of detection and quantification of methane emissions. However, additional time and resources are associated with the quantification of emissions.

For vehicles, multiple passes are required to quantify the emissions. Onboard anemometers measure wind speed and direction, which are used for plume dispersion modeling and source localization. The modeled scenarios all considered the recommended six-pass protocol, so there is quantification capability in these modeled scenarios. However, for the purpose of developing company-specific emission factors, the level of granularity in the source localization may be insufficient from vehicle-based detections. For example, a vehicle-based system can detect an emission and quantify its rate, but it may not be able to determine the exact leaking source, posing a potential challenge for developing company-specific emission factors.

For handheld systems, detection and quantification can happen concurrently. Typically, the actual leak rate is quantified directly with a Hi-flow sampler, instead of inferred from dispersion modeling. Direct measurement is expected to have a lower uncertainty as there is less incoming required data streams like with plume modelling, but there is a lack of controlled release studies assessing the quantification accuracy of both.

For all technologies capable of quantification, quantification error needs to be considered. Quantification error is only recently starting to be investigated in more detail in the research space.

All underground infrastructure (such as gas mains and service lines) poses an additional challenge since the emitting source is buried under roadways and through yards, and methane gas permeation through the different surface materials is required before being measured in the air. Source localization may not always be possible without costly excavations, so the emission factors may be developed by less granular source categories (e.g. “pipeline- main” instead of “pipeline- main: threaded connection”). In addition, surface permeability may reduce the gas concentration available to be detected by any leak detection technology.

Spatial Extrapolation Uncertainty

All scenarios evaluated assumed complete coverage of the DO system would be achieved (as close to 100% coverage as is reasonably possible). For this reason, Highwood’s assessment did not identify significant differences between special extrapolation uncertainty in the scenarios.

If there were certain sites or areas being omitted from the survey planning, then spatial extrapolation uncertainty would increase, as EGI would be required to determine if those sites/areas were “like” the areas which were measured and if those same measurements leak counts, and other assumptions could be applied to the un-surveyed sites. This is important to keep in mind when developing company-specific emission factors, as the larger the spatial extrapolation uncertainty is, the greater the overall uncertainty as emissions factors are extrapolated out to the rest of the non-sampled infrastructure.

Temporal Extrapolation Uncertainty

Extrapolation of the detected and quantified emissions to the full reporting period requires that assumptions about the duration of emissions be made. The emission factors that are currently in use to calculate EGI’s DO fugitive emissions inventory are annualized, so there are no considerations required to estimate emissions duration.

However, when deploying technology and using the quantifications to develop a measurement-informed fugitive emissions inventory, estimating the total duration of the leak is a key consideration. Two approaches are common in regulations: assume that the leak has been emitting continuously since the last time a survey was performed or assume that the leak has been emitting for half the time since the last survey (assumes intermittent emissions). In this investigation, the former assumption was used. Leak detection survey frequency is a major driver in the calculation of total fugitive emissions using either assumption. As such, scenarios which survey more frequently are associated with reduced temporal extrapolation uncertainty.

When comparing the Annual Vehicle scenario and Multi Tech FEMP Scenario 4, there is a slightly reduced temporal extrapolation uncertainty associated with Multi Tech FEMP Scenario 4, due to the addition of the handheld survey program. As such, Multi Tech FEMP Scenario 4 is preferred in terms of impacts on uncertainty in the emissions inventory.

8.5.4. Risks and Opportunities of Deployment of the Modeled FEMP Scenarios

For an overview of the identified risks and opportunities of all assessed distribution scenarios, consult the scenario analysis spreadsheet included in the appendix. This discussion focuses on the key risks and opportunities associated with the preferred scenarios: Annual Vehicle and Multi Tech FEMP Scenario 4.

Risk 1: Vehicle technology limitations

Two limitations to consider with the vehicle-based FEMP Scenario are the reliance on favourable meteorological conditions and the frequent inability to be proximal to emission sources. Vehicle technologies rely on atmospheric modelling, which incorporates multiple data streams (methane concentration, wind speed, wind direction, temperature, etc.) Customer meter sets, which make up the single biggest population group of emitting sources, are not easily accessible by vehicle, nor are distribution stations. Vehicles are well suited to use for linear features (pipelines), but access limitations may prevent robust surveys on other sources. As such, vehicles may “miss” small plumes if sufficient dispersion has occurred between the source and the vehicle sensor or if there are obstructions preventing the plume from reaching the vehicle. In addition, during the vehicle screening, the wind must be blowing toward the sensor from the source. This combination of the requirement for favourable meteorological conditions along with the risk of dispersed emissions by the time they reach the vehicle poses a risk.

The opportunity to mitigate this risk is to deploy handheld technologies in tandem since those accessibility challenges do not apply to the same extent. For this reason, Multi Tech FEMP Scenario 4 is preferred over the Annual Vehicle Scenario for improving the accuracy of the emissions inventory.

Risk 2: Safety requirements

The primary driver for EGI's current handheld leak survey program is safety. At this time, it is not clear if there are any safety implications associated with the implementation of other technologies (such as vehicles). Future work can include performing comparative studies to better understand the performance of vehicles compared with handheld options and determine whether total replacement for LDAR programs would be advisable.

The opportunity to mitigate this risk is to continue deploying handheld surveys at the current frequency while also deploying a vehicle-based survey. While the absolute performance of the Annual Vehicle scenario is equal to the Multi Tech FEMP Scenario 4, and the total survey time is 45% less, EGI may be required to continue performing handheld surveys.

In the absence of handheld survey safety requirements, it is not recommended that EGI eliminate handheld surveys, due to the factors discussed with Risk 1 above.

Risk 3: LDAR-Sim inputs may not be representative of the leaks present within EGI's DO system

As previously mentioned, the LDAR-Sim results must be caveated that the outputs are reflective of the inputs. Due to the lack of directly measured leak rates from EGI's distribution system, Highwood used literature values as inputs into the simulations. While those literature values were obtained through large-scale measurement campaigns on North American gas utility systems, and the results of the studies were either peer-reviewed or in pre-print review, there is a possibility that the LDAR-Sim results are not representative of EGI's actual leak profile.

The opportunity to mitigate this risk is to perform a robust detection and measurement campaign and compare the results to the literature values to determine similarity. By implementing any of the proposed scenarios, EGI should be able to mitigate this risk.

8.6. Qualitative Analysis – STO Segment

The STO segment represents 16% of EGI's total fugitive inventory. Of this portion, 73% of STO's fugitive emissions already incorporate measurement into the inventory.

The current leak detection and measurement campaign conducted by the operator has proven to be sufficiently effective, providing comprehensive data on emissions and leakages. The existing methodologies and technologies employed have demonstrated reliability and accuracy in identifying and quantifying leaks across the operational infrastructure. Continuous monitoring and periodic surveys have ensured timely detection and response to any anomalies, maintaining regulatory compliance and environmental stewardship.

Given the success and robustness of the current campaign, additional surveys or technologies may not be necessary at this time, as they could potentially introduce complexity without significant added value in terms of improving leak detection or measurement precision given the existing coverage and materiality. It is advisable for the operator to continue leveraging the established methodologies and technologies while remaining vigilant for any advancements that could further enhance their leak detection and measurement capabilities in the future.

9. Recommendations and Implementation Plan for EGI

Improving the accuracy of fugitive emissions reporting will require a combination of technological, procedural, and operational enhancements. With DO representing 84% of EGI's total fugitive emissions, these recommendations prioritize DO, noting that 73% of STO's fugitive emissions are calculated using direct measurement. Highwood has provided the following recommendations for EGI:

- **Recommendation 1**: Develop company-specific emission factors based on source-level measurements for DO.
- **Recommendation 2**: Pilot mobile ground detection strategy for DO.
- **Recommendation 3:** Leverage data from Recommendations 1 and 2 to develop a measurement-informed inventory for DO.
- **Recommendation 4**: Monitor advances in aerial and satellite performance.

9.1. Recommendation 1: Develop company-specific emission factors based on source-level measurements for DO

EGI should implement a measurement program to develop company specific emission factors for DO. Within the STO segment, EGI already uses measurement to inform the inventory of compressor station and receipt-sales meter station leaks, which collectively represent 73% of fugitive emissions from the STO segment.

EGI's DO assets constitute 84% of the 2022 fugitive emission inventory. Within DO, all emission sources are currently quantified using generic emission factors. The DO segment has high activity counts (asset and component counts) that are relatively consistent over time and unlikely to change relative to emissions. Without company-specific emission factors based on measurement data to increase the accuracy of emissions, this will also continue to be a consistently large source category based on activity, but more accurate emission factors could increase or decrease materiality. Generic emission factors may not represent the specific characteristics of a company's unique operating parameters, including maintenance and repair practices or preventive policies.

It is recommended that EGI should begin developing company-specific emission factors (Section 5.3.2), using existing standards and frameworks, such as OGMP2.0, as guidance to help inform the sampling strategy. These company-specific emission factors could be incorporated with Recommendation 2's pilot program to create a MII.

Developing company-specific emission factors will require defining a statistically relevant sample population (i.e., a representative group of emissions sources within the company that contributes to emissions).

9.1.1. Identify & Categorize Emission Sources:

EGI can use the existing asset/source classifications as initial groupings of assets alongside features that may provide distinct groupings. Groupings and sub-grouping can be based on populations of sites/facilities (distribution stations, customer meter sets, etc), or a population of sources (equipment type, operating status, process).

9.1.2. Prioritize Sources:

EGI should prioritize the emission sources based on their materiality or regulatory importance. For DO, customer meter sets and service lines should be prioritized based on their materiality, collectively contributing 63% of DO's total fugitive emissions.

9.1.3. Select Representative Samples:

From each prioritized category, EGI should select representative samples that reflect the range of emissions within that category. These samples should reflect typical operating conditions, equipment types, and emission control measures where applicable. EGI can use industry guidance such as OGMP 2.0 as outlined in Section 5.3.2. When developing a sampling strategy, EGI should consider seasonal variations in emissions, production level fluctuations, or other factors that may affect emissions rates.

9.1.4. Emissions Measurement:

Emissions flow rates should be measured for the selected representative sample, using suitable technology.

9.1.5. Calculate & Apply Emission Factors:

EGI can extrapolate from the measurements to calculate emission factors for each population. Step 8 in the GTI Veritas Measurement and Reconciliation Version 2.0 protocol, Reconcile Inventories and Estimate Measurement Informed Inventory, gives comprehensive guidance on extrapolating measurement results to non-surveyed areas.

EGI can then incorporate the emission factors into EGI's inventory, reporting frameworks, and decision-making processes. Company-specific emission factors, when updated regularly, can be used to track emissions performance, set reduction targets, and prioritize mitigation measures. OGMP recommends that factors should be reviewed annually to confirm they are still representative but does not mandate a specific update frequency for the underlying emission factor data. Repeat programs may demonstrate consistency or highlight where further investigation is required.

9.1.6. Documentation:

The documentation of sampling strategy, data collection methods, calculations, and resulting emission factors is essential for the credible and transparent use of company-specific emission factors. This documentation will also provide continuity for future measurement campaigns and inventory management.

9.1.7. Validate and Refine:

As a reasonableness check, compare the calculated emission factors with industry benchmarks, or third-party verification. Refine the factors as needed based on additional measurement data collected.

9.2. Recommendation 2: Pilot Mobile Ground Detection Strategy for DO

More accurately quantifying fugitive emissions can be achieved by increasing detection and incorporating measurement to develop a measurement informed inventory. Increased detection can help determine more accurate leak occurrences and measurement can help determine leak sizes. Both will contribute to a more accurate quantification of fugitive emissions.

EGI should consider piloting mobile ground detection for improved emissions quantification, as detailed in Scenario 4 in Section 8.4. In Scenario 4 EGI would continue with their current compliance handheld survey program on the distribution system and would introduce annual vehicle surveys. Our modeling suggests that EGI will be able to achieve up to a 77% annual detection rate. This is an increase of 67% over the every 7 year scenario leak detection rate (from 10% to 77%), and an increase of 52% over the every 3 year scenario (from 25% to 77%) with a potential increase of 35% on potential annual mitigation (from 5% every 7 years to 40% for the annual vehicle scenario). Importantly, this would introduce measurement of EGI's DO fugitive emissions, compared with the current distribution leak survey methods that do not include leak flow rate measurements.

Scenarios 1-3, which included aerial and satellite detection, are not recommended. According to available controlled release test data (Section 6.5) and Highwood modeling, neither technology is likely to be sensitive enough to detect expected leaks for EGI.

To pursue an expanded mobile ground detection strategy and to verify the assumptions modeled, EGI should develop and execute a pilot and scale up plan with defined goals and stage gates.

9.2.1. Goal Setting and Objectives:

Define clear and achievable goals for the pilot program and determine a pilot size and scope. Utilize accepted statistical methods to determine a statistical sample size. Specific goals can include:

- Comparing different measurement technologies
    - Accuracy
    - Detection threshold
    - Level of investigation required
- Identifying potential areas of focus for further measurements
- Increasing the accuracy of leak counts and leak sizes
- Developing a measurement-informed emissions baseline for future comparisons
- Creating an evaluation process to determine scale-up feasibility based on results.

9.2.2. Designing the Pilot Program:

Develop a detailed plan outlining the scope, timeline, budget, and resources required for the pilot program. Determine investigation thresholds that will require follow-up. Select a suitable sample for the pilot program, prioritize high materiality areas and geographic groupings, accessibility, and cooperation from stakeholders. Obtain vendor quotes and determine the specific handheld and mobile ground lab technology and methodologies to be used for fugitive detection and measurement. Decide on costing model – e.g., using 3rd party vendors or purchasing technologies for in-house deployment. Train personnel involved in data collection, analysis, and interpretation to ensure accurate and reliable results, as required.

9.2.3. Implementation:

Execute the pilot program according to the established plan. This includes deploying technology and collecting data. Monitor progress closely and address any challenges or issues that arise during the implementation phase.

9.2.4. Data Analysis:

Analyze the data collected during the pilot program, identify trends, and evaluate the effectiveness of detection and measurement methods. Compare the results with those determined using the current emissions quantification methodology. Assess the impact of the measurement program and its potential for scaling up. Investigate discrepancies and document findings.

9.2.5. Evaluation and Issue Identification:

Detail the findings, lessons learned, challenges, and recommendations from the pilot program. Seek feedback and input for improving the program and address any concerns or suggestions.

9.2.6. Scaling Up and Integration:

Based on the outcomes of the pilot program, consider scaling up fugitive detection and measurement efforts or piloting alternative technologies. Integrate the lessons learned and best practices into broader environmental monitoring and mitigation strategies. Continuously monitor and update the program to incorporate new technologies, regulations, technology, and methodology advancements.

9.3. Recommendation 3: Leverage Data from Recommendations 1 and 2 to Develop a Measurement Informed Emissions Inventory

EGI should utilize the data collected in Recommendations 1 and 2 to start developing a MII for DO. Highwood determined that 73% of EGI's STO emissions are currently measured directly. Leveraging the additional data collected will allow EGI to assess the impact on the inventory, prioritizing high materiality sources, or sources with higher levels of uncertainty.

A MII improves confidence and defensibility of CH4 emission estimates and can help to prioritize emissions mitigation efforts. Several voluntary initiatives provide frameworks for developing a MII, including GTI Veritas, MiQ, and OGMP 2.0.

While the current regulatory reporting framework in Canada does not yet require reconciliation of different estimates, inventories integrating advanced measurement data are more robust than inventories which are built using only one methodology.

9.4. Recommendation 4: Monitor Advances in Aerial and Satellite Performance

EGI is advised against adopting aerial and satellite technology at this time, as it lacks the sensitivity required to detect most leaks expected from EGI's distribution assets. Therefore, these technologies, as they stand, are unlikely to enhance the accuracy of fugitive emissions monitoring on distribution assets.

Instead, EGI is encouraged to stay abreast of advancements and controlled release testing data related to aerial and satellite technology. This involves evaluating new data and options to determine their relevance to distribution monitoring. Additionally, EGI could consider piloting Bridger Photonics' next-generation sensor at low altitudes (e.g., using helicopters), given the positive feedback and ongoing collaboration reported by SoCal Gas with Bridger Photonics.

Below, we expand on aerial and satellite monitoring, discussing their detection limitations, along with an emerging model under early testing phases specifically designed for detecting emissions from buried pipelines. It's crucial to note that technology is continually evolving, and decisions should be based on the most up-to-date information available.

9.4.1. Aerial Monitoring

While aerial detection has become a common practice in the upstream industry, use in distribution systems remains novel and widespread adoption has not yet occurred. Under Highwood simulation aerial monitoring, based on Bridger Photonics' established parameters (90% detection) for aerial methods, is generally unable to detect leaks below 0.5kg/hr. Aerial monitoring is more suited to identification of larger emitters than those typical of distributions systems.

Bridger Photonics has published a case study where they have been performing controlled double-blind release testing with SoCalGas, the largest gas utility distributor in the United States[xli]. SoCalGas signed a multi-year contract with Bridger in 2021 to continue to survey distribution assets, to detect and reduce emissions. A second-generation Gas Mapping LiDAR sensor was set to be released, capable of detecting 0.2kg/h but to our knowledge this limit has not yet been verified through controlled release testing.

9.4.2. Satellite-Based Monitoring

Like aerial, satellites have not seen widespread adoption for distribution and are more commonly used in upstream operations to detect larger emission sources. GHGSat under controlled release testing has a detection threshold of 117 kg/h[xlii], although in practice, has detected sources as low as 42 kg/h. A study released in 2023 conducted single-blind controlled methane release testing from up to five satellites[xliii]. The results showed a detection range of 1,400 – 7,200 kg/h, with GHGSat able to detect at 200kg/h. The study notes the suitability of this technology for deployment in high emitting regions. Current satellites are unable to detect emissions characteristic of a distribution system, which are mostly below 1 kg/h.

9.4.3. Emerging Technology – Sensor Network

A study published in January 2024[xliv] focused on the challenges of detecting methane, specifically from buried pipelines. The study noted that the "current approaches of detection may not be suitable to effectively monitor underground gas leaks under transient conditions due to cost, data accessibility, deployment approach, and varied environmental conditions".

Field testing conducted at METEC used Estimating the Surface Concentration Above Pipeline Emission (ESCAPE) model to compare the methane detected above the surface with the belowground near surface concentrations. The testing found that the belowground near surface concentrations were 20% to 486% higher than the surface concentrations within a 4m monitoring radius under various controlled test conditions. The testing conducted had release rates of 37 – 121 g/h and utilized low-cost methane sensors calibrated against Picarro G4302. The study, performed on PVC pipe 0.91m below ground, noted that the optimum number of sensors is 4 aboveground sensors within a 4m radius of the leak area. This is an early model, which does not discuss the feasibility and practicality of implementing 4 sensors every 4m in a distribution system. The study concluded that this was a tool to assess risk and potentially prevent leakage but did not provide estimates of scope and cost of deployment outside of the test environment.

10. Conclusions

In conclusion, this report provides a comprehensive overview of EGI's current greenhouse gas fugitive emissions inventory and calculation methods. This report also provides recommendations for improving the accuracy of EGI's fugitive emissions inventory. By examining various methodologies and technologies, the report underscores the critical importance of accuracy, efficiency, and compliance in emissions reporting.

The recommendations outlined by Highwood provide a strategic roadmap for EGI to enhance the accuracy and reliability of its fugitive emissions reporting. These recommendations direct EGI to focus on DO emissions since they represent the majority of EGI's total fugitive emissions and are not currently measured, unlike STO emissions. By focusing on DO and leveraging existing measurement practices within the STO segment, EGI can make substantial progress in emissions quantification.

The first recommendation suggests the development of company-specific emission factors based on source-level measurements for DO, prioritizing the most material sources. This approach, in conjunction with prioritizing emission sources, selecting representative samples, and applying rigorous measurement methodologies, can lead to more accurate emission factors tailored to EGI's unique operational parameters. The documentation, validation, and refinement processes outlined provide transparency and credibility in the use of these emission factors, crucial for informed decision-making and regulatory compliance.

The second recommendation suggests piloting a mobile ground detection (vehicle) strategy for DO, aiming to obtain flow rate measurements to work towards developing a measurement-informed emissions inventory. By comparing different measurement technologies, identifying focus areas, and setting clear objectives, EGI can inform its next steps based on outcomes of the pilot program. This approach highlights the importance of gathering field data and meets the need for practical and sensitive detection methods aligned with EGI's operational realities. In contrast, Highwood identified limitations with aerial and satellite technologies and does not recommend their deployment on EGI's systems.

Furthermore, Recommendation 3 proposes the creation of a MII for DO, leveraging findings from the company-specific emission factors and pilot program. This MII, guided by industry frameworks, would enhance confidence and defensibility in EGI's CH^4 emission estimates, enabling EGI to prioritize mitigation efforts and adapt to evolving regulatory requirements.

Lastly, while cautioning against current aerial and satellite technologies, Recommendation 4 advises EGI to monitor advancements in this field. Bridger Photonics' next-generation sensor underscores the potential for future innovation in fugitive emissions monitoring.

In essence, these recommendations form a holistic approach to fugitive emissions management, combining technological innovation, procedural rigor, and operational insights. By implementing these strategies, EGI can improve the accuracy of its fugitive emissions and achieve a more accurate, transparent, and proactive stance in addressing fugitive emissions, aligning with sustainability goals and regulatory expectations.

11. Appendix

11.1. Technology Table Summary

Transmission and Storage - Aircraft

Company Name	Technology Name	Technology Description	Equipment Sensitivity (MDL)	Quantification Performance	Survey Speed and Coverage	Environmental Limitations	Other Considerations	Controlled Release Testing	Source Attribution Capability
Bridger Photonics	Gas Mapping LiDAR	Active remote sensing using light detection and ranging (LiDAR)	3kg/hour or 0.5 kg/hour	Does detection and quantification	Seconds-minutes per site		Highest commercial uptake of any of the aircraft-based options,	METEC (multiple Adhoc testings performed), also have been subject to many single-blind testings, results of which have been published in the literature.	Equipment Level
FlyScan	CHARM	Active remote sensing using differential absorpotion LiDAR (DIAL)	Not listed	Detection and quantification	Seconds-minutes per site		Built and marketed specifically for use on pipelines	2023 testing was performed at METEC, noted that only detection was tested, there was no localization or quantification testing performed	Equipment Level
LaSen	Alpis Helicopter System	Active remote sensing using light detection and ranging (LiDAR)	10 kg/hour	Detection and quantification	Seconds-minutes per site		Higher claimed MDL may be too high for effective detection of EGI's assets	N/A	Equipment Level
Boreal Laser	GasFinder3-AB	Point sensing using tunable diode laser absorption spectroscopy (TDLAS)	0.66 ppm	Detection	185km/hour helicopter travel speed	Must fly through the methane plume in order to detect emissions	Boreal Laser is just a manufacturer, there are service providing vendors worldwide	N/A	Equipment Level
Vanguard Pipeline	Falcon-XL Aerial Methane Detector	Point sensing using tunable diode laser absorption spectroscopy (TDLAS)	unlisted- ppm sensor	Detection (but markets as real time ppm detection during visual flyovers)	Seconds-minutes per site	Must fly through the methane plume in order to detect emissions	ppm detection plus	N/A	Equipment Level

Transmission and Storage - Drones /UAV

Company Name	Technology Name	Technology Description	Equipment Sensitivity (MDL)	Quantification Performance	Survey Speed and Coverage	Environmental Limitations	Other Considerations	Controlled Release Testing	Source Attribution Capability
SeekOps	SeekIR	Point sensing (unknown sensor type)	1 scf/hour	Detection and quantification (quantification is performed in post-processing using dispersion modeling algorithms)	Whole sites, 1-5 sites/day	UAV systems are manned by trained operators, so constrained within a regular workday, and cannot fly in rain. All point sensing drones require wind to ensure more accurate plume dispersion modeling calculations. Drones are subject to Transport Canada regulations and may require special authorization within certain zones. Many companies require specific permission from operations before conducting drone surveys, in order to fly closer to equipment. Obtaining this permission in advance, and flying closer, improves source delineation and increases actionability of results. Anecdotally, results from drone surveys are significantly impacted by forest fire smoke present in the air, and should not be operated during times of significant	Many vendors use SeekOps drone system and can be hired as a third party service, not necessarily reliant on hiring SeekOps directly	METEC (Adhoc testing performed multiple times), EDF Mobile Monitoring Challenge (2018)	Equipment Level
ABB	HoverGuard	Point sensing using TDLAS sensor	0.05 kg/hour	Detection and quantification	Whole sites, 1-5 sites/day		ABB have not published or updated materials about the Hoverguard product/service since around 2020/2021. Performance claims may be outdated.	EDF Mobile monitoring Challenge (2018) ** only detection was tested, no localization or quantification was tested	Equipment Level
ChampionX Scientific Aviation	Drone System	Point sensing (unknown sensor type)	unlisted	Detection and quantification	Whole sites, 1-5 sites/day		Hired through a service	Advancing Development of Emissions Detection (ADED) 2023	Equipment Level
Baker Hughes	Lumen Sky	Hybrid sensor (assumed combination of point and active)	unlisted	Detection and quantification	Whole sites, 1-5 sites/day		No updates or other news articles have been published by Baker Hughes about this technology since 2021, so performance claims are likely to be outdated and no longer accurate.	ADED Continuous Monitoring Protocol (2020)	Equipment Level

Transmission and Storage - Satellites

Company Name	Technology Name	Technology Description	Equipment Sensitivity (MDL)	Quantification Performance	Survey Speed and Coverage	Environmental Limitations	Other Considerations	Controlled Release Testing	Source Attribution Capability
GHGSat	DATA.SAT	Passive Imagery Satellite, uses interferometer sensing technology to look for methane absorption spectra within visible light, to identify	Unlisted, but in single-blind testing, GHGSat was able to detect 0.2 tonnes CH4/hour	Detection and quantification	near-instantaneous	reliance on reflected sunlight	200 kg/hour detection limit is likely to be unsuitable for use on EGI's assets. Each satellite within the GHGSat constellation revisits a location every 14 days	Participation in single blind testing, results have been published in peer-reviewed literature.	Facility / Region Level
Satelytics	Satelytics	Passive Imagery Satellite, uses interferometer sensing technology to look for methane absorption spectra within visible light, to identify methane emissions	35kg/hour?	Uses satellite data to perform detection and quantification, does not collect this data themselves	near-instantaneous	reliance on reflected sunlight	Satelytics uses the Maxar satellite, and they have algorithms which are used to create a data product. They are in an agreement with Maxar to purchase their data products to be used for analytics. Satelytics markets themselves more heavily for encroachment monitoring, and liquids leaks from pipelines (crude and produced water)	METEC testing has been performed, but Satelytics has not participated in any of these studies. Satelytics has published internal white papers, but results from METEC have not been peer-reviewed.	Facility / Region Level
Kayrros	Methane Watch	Passive Imagery Satellite, uses interferometer sensing technology to look for methane absorption spectra within visible light, to identify	Lowest detection by Kayrros (using the Maxar Worldview-3 satellite) was 100 kg/hour	Uses satellite data to perform detection and quantification, does not collect this data themselves	near-instantaneous	reliance on reflected sunlight	Kayrros uses the Maxar WorldView-3 satellite, and performs data analytics in a similar way to Satelytics	Kayrros has participated in single-blind peer reviewed testing (results are still in pre-print but have been reviewed).	Facility / Region Level
Maxar	WorldView-3	Passive Imagery Satellite, uses interferometer sensing technology to look for methane absorption spectra within visible light, to identify	Smallest detected leak by Maxar in the peer-reviewed literature was 30kg/hour, but majority of emissions detected are over 100 kg/hour	Detection and quantification	near-instantaneous	reliance on reflected sunlight	Many other companies are using the Maxar satellites for their own data analytics purposes, and results from the same plume (processed by different analytics companies) has been found to be quite wide ranging	Maxar has participated in single-blind peer reviewed testing (results are still in pre-print but have been reviewed).	Facility / Region Level
TROPOMI		TROPOMI technology, located on the Sentinel-5 satellite, passive imagery satellite	Very high	Detection	near-instantaneous	reliance on reflected sunlight	Detection limit from TROPOMI is too high to be useful to EGI. Publicly available, free to use and access data. Could be used as a free resource to check for extremely large super-emitters.		Facility / Region Level

Transmission and Storage - Continuous Monitoring Systems (for use only at compressor stations, storage sites, or other discrete point source within STO)

Company Name	Technology Name	Technology Description	Equipment Sensitivity (MDL)	Quantification Performance	Survey Speed and Coverage	Environmental Limitations	Other Considerations	Controlled Release Testing	Source Attribution Capability
Qube	Axon	Point sensor, stationary mounted on site		Detection, quantification and localization is performed in post-processing	continuous monitoring of whole sites	Stationary point sensors are reliant on wind; since methane gas must pass through the sensor in order to be detected, wind direction has a significant impact on whether or not emissions events are detected. Because of this, most continuous point sensors are installed at multiple locations within a single site, to increase detection probability			Equipment Level
Project Canary	Sanary-S, Canary-X	Point sensor, stationary mounted on site		Detection, quantification and localization is performed in post-processing					Equipment Level
Scientific Aviation	SOOFIE	Point sensor, stationary mounted on site	10kg/hour	Detection, quantification and localization is performed in post-processing					Equipment Level
LongPath	Frequency Comb Laser	Laser-based system with reflectors					Much more expensive per unit compared to other continous monitoring solutions, however each individual sensor system can cover a much larger area. More suitable for deployment in areas with a higher density of sites, to reduce the cost per site.		Equipment Level
Kuva	Kuva Gas Cloud Imagine	OGI camera, stationary mounted on site	Unpublished, assumed roughly equal to OGI sensitivity, potential to be worse due to increased distance away from emitting equipment.	Quantification algorithms			OGI camera has to "see" emissions, so careful consideration should be made to placement on site, to maximize the likeliness of detection		Equipment Level

Company Name	Technology Name	Technology Description	Equipment Sensitivity (MDL)	Quantification Performance	Survey Speed and Coverage	Environmental Limitations	Other Considerations	Controlled Release Testing	Source Attribution Capability
Picarro	Surveyor	Point sensor using Cavity Ring-Down Spectroscopy	0-20 ppm	Detection and quantification (post-processing)	As fast as the car that the system is mounted on can accurately measure while respecting local speed restrictions.	Areas must be accessible by vehicle	Picarro has seen the highest uptake in use from leading gas utility companies, as per publications from those companies. Picarro markets themselves specifically for effective use on natural gas mains and service lines within distribution networks.	Picarro sensors have been used in many leading peer-reviewed studies on methane emissions in various parts of the natural gas supply chain, especially in *A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems* (Weller et al. 2020)	Region Level
Boreal Laser	GasFinder3-VB	Point sensor using TDLAS	0.6 ppm	Detection			The data produced from the GasFinder3-VB (Vehicle Based) is simply a 1-D Data Plot that charts concentration over time. Post-processing can create a 2-D map showing where	No records of METEC testing can be found, nor are there any peer-reviewed publications with performance results from the technology.	Region Level
Heath Consultants	Discover AMLD	Point sensor	Company publication states ppb range, not verified	Detection and quantification (post-processing)				No records of METEC testing can be found, nor are there any peer-reviewed publications with performance results from the technology.	Region Level
ABB	MobileGuard	Point sensor using TDLAS	0.05 kg/hour	Detection and quantification (post-processing)				No specific vehicle-based controlled release testing has been performed at METEC, but the drone-mounted system uses the same sensor, and the drone was tested in 2018 as part of the EDF Mobile Monitoring Challenge.	Region Level

Distribution - Drones

Company Name	Technology Name	Technology Description	Equipment Sensitivity (MDL)	Quantification Performance	Survey Speed and Coverage	Environmental Limitations	Other Considerations	Controlled Release Testing	Source Attribution Capability
SeekOps	SeekIR	Point sensing (unknown sensor type)	1 scf/hour	Detection and quantification (quantification is performed in post-processing using dispersion modeling algorithms)	Whole sites, 1-5 sites/day	UAV systems are manned by trained operators, so constrained within a regular workday, and cannot fly in rain. All point sensing drones require wind to ensure more accurate plume dispersion modeling calculations. Drones are subject to Transport Canada regulations and may require special authorization within certain zones. Many companies require specific permission from operations before conducting drone surveys, in order to fly closer to equipment. Obtaining this permission in advance, and flying closer, improves source delineation and increases actionability of	Many vendors use SeekOps drone system and can be hired as a third party service, not necessarily reliant on hiring SeekOps directly	METEC (Adhoc testing performed multiple times), EDF Mobile Monitoring Challenge (2018)	Component Level
ABB	HoverGuard	Point sensing using TDLAS sensor	0.05 kg/hour	Detection and quantification	Whole sites, 1-5 sites/day		ABB have not published or updated materials about the Hoverguard product/service since around 2020/2021.	EDF Mobile monitoring Challenge (2018) ** only detection was tested, no localization or quantification was tested	Component Level
Baker Hughes	Lumen Sky	Hybrid sensor (assumed combination of point and active)	unlisted	Detection and quantification	Whole sites, 1-5 sites/day		No updates or other news articles have been published by Baker Hughes about this technology since 2021, so performance claims are likely to be outdated and no longer accurate.	ADED Continuous Monitoring Protocol (2020)	Component Level

Distribution - Aerial

Company Name	Technology Name	Technology Description	Equipment Sensitivity (MDL)	Quantification Performance	Survey Speed and Coverage	Environmental Limitations	Other Considerations	Controlled Release Testing	Source Attribution Capability
Bridger Photonics	Gas Mapping LiDAR (helicopter)	Same LiDAR technology as is used by Bridger, but mounted on a helicopter, specifically for use on distribution systems (for flying in cities	3kg/hour or 0.5 kg/hour	Does detection and quantification	Seconds-minutes per site	N/A - active sensor does not require any interaction with sunlight to detect methane emissions. Deployment platform (helicopter) is likely to be more limited in its operation than the Gas Mapping LiDAR sensor.	Successful deployments on gas utilities in high-population density areas	METEC (multiple Adhoc testings performed), also have been subject to many single-blind testings, results of which have been published in the literature.	Region Level

Distribution - Handheld

Company Name	Technology Name	Technology Description	Equipment Sensitivity (MDL)	Quantification Performance	Survey Speed and Coverage	Environmental Limitations	Other Considerations	Controlled Release Testing	Source Attribution Capability
Various	OGI	Optical gas imaging camera			Each individual component must be searched for emissions	Heavy precipitation can impact the viewability of the OGI feed. Adverse weathe conditions which hamper the ability for a "boots on the ground" survey should also be considered.	Many service providers of OGI surveys do provide a quantification estimate, this is typically based on visual estimates of the leak size.	Yes	Component Level
	QOGI	Optical gas imaging camera, plus quantification software (often an accompanying			Slower than OGI, since there is a waiting period for live quantifications		Well established and understood technology.	Yes	Component Level
	Hi-flow sampler	The Hi-flow sampler measures both the flow rate of the sampling stream and the methane concentration within that stream, the device calculates methane emission rates in cubic feet per minute (CFM) or litres per minute (LPM). Used exclusively for quantification after an emission has been identified.	Sensitivity not commonly considered for quantification-only devices, however, the Hetek device can quantify leaks with flow rates as low as 4.95 gph	Quantification	Two minutes for a measurement as per https://energy.colostate.edu/wp-content/uploads/sites/28/2022/08/FACF_High_Flow_Final_Report_ada.pdf	Can be affected by extreme temperatures and high humidity levels, wind flow, and air disturbances.	Well established and understood technology.	Yes, but likely unblinded as detection performance is not a concern for Hi-Flow samplers.	Component Level
	Handheld gas monitors	All handheld gas analyzers which meet EPA Method-21 requirements.	Varies by make and model. 1-10 ppm.	Detection	Similar to, but more labor intensive than OGI, as the operator must be in direct proximity to all components requiring survey, whereas they can be observed from a distance with OGI.		Well established and understood technology.	Yes	Component Level

11.2. Scenario Analysis

Program Name	Methods-Frequency	Description	Key Assumptions	Survey Time (per year)	Emissions (kt of CH4 / year)	Potential Annual Mitigation (kt of CH4 / year)	Average number of leaks detected per year (%)	Suitability for Use on EGI
Handheld - Every 7 years	Handheld - Every 7 years	Program uses handheld technology to detect emissions (every 7 years). Detected leaks are evaluated and assigned a relative risk level based on measured concentration. Detection probability increases with source rate.	Average survey speed of 0.75km/hr. Detection probability increases with source rate (minimum 95%). Performance based on high-precision gas analyzer (GasScouter™ G4301, Picarro, Inc.). Similar peformance expected for sensors with 1ppm sensitivity and 1–10 Hz response time. Deployment window: ~ 120 days from April to October.	9,593 days (~80 crews)	Pipelines and M&R: 17,412kt Customer Metersets: 1,022kt Overall:18,435kt	Pipelines and M&R: 922kt (5%) Customer Metersets: 51kt (5%) Overall:973kt (5%)	Pipelines and M&R: 10k (10%) Customer Metersets: 96k (10%) Overall:107k (10%)	This is the incumbent method that is currently being used by EGI on DO system. The scenario is technically feasible for deployment but there are significant performance limitations. To meet EGI's objective of reducing the uncertainty in the reported fugitives inventory, this program is not well suited.
Annual Handheld	Handheld - 1x/year	Program uses handheld technology to detect emissions. Detected leaks are evaluated and assigned a relative risk level based on measured concentration. Detection probability increases with source rate.	Same as above, but more frequent deployment.	67,150 days (~560 crews)	Pipelines and M&R: 11,167kt Customer Metersets: 664kt Overall:11,831kt	Pipelines and M&R: 7,167kt (39%) Customer Metersets: 410kt (38%) Overall:7,577kt (39%)	Pipelines and M&R: 79k (76%) Customer Metersets: 739k (75%) Overall:818k (75%)	This program and scenario is roughly equivalent to the annual vehicle program (below), and the technology and method is well established for use on distribution systems. This program is resource intensive and the total annual survey time required to complete one full walking survey of the system is very high, especially when considering that the mitigation potential and the number of detected leaks from the program is equivalent to the vehicle surveys.

Program Name	Methods-Frequency	Description	Key Assumptions	Survey Time (per year)	Emissions (kt of CH4 / year)	Potential Annual Mitigation (kt of CH4 / year)	Average number of leaks detected per year (%)	Suitability for Use on EGI
Annual Vehicle	Vehicle - 1x/year	Program uses a vehicle-based technology to detect and quantify emissions. Detection probability increases with source rate. Protocol includes 6 passes.	Average survey speed of 35km/hr. Detection probability increases with source rate (minimum 40%). Peformance based on high-precision gas analyzer with 1ppm sensitivity and 1–10 Hz response time. Deployment window: ~ 120 days from April to October.	11,350 days (~95 crews)	Pipelines and M&R: 11,063kt Customer Metersets: 661kt Overall:11,724kt	Pipelines and M&R: 7,272kt (40%) Customer Metersets: 412kt (38%) Overall:7,684kt (40%)	Pipelines and M&R: 80k (77%) Customer Metersets: 752k (77%) Overall:832k (77%)	Yes, this program is suitable. The detection threshold of the technology is sufficiently low to detect small emissions present within distribution systems, the technology performance is approximately equivalent to walking surveys, and the survey time is 1/6th of the walking survey. The vehicle surveys include six passes of each location, whereas the walking surveys only pass each location once.
Semi-Annual Vehicle	Vehicle 2x/ year	Program uses a vehicle-based technology to detect and quantify emissions 2x per year. Detection probability increases with source rate. Protocol includes 6 passes.	Same as above, but more frequent deployment	22,750 days (~190 crews)	Pipelines and M&R: 8,009kt Customer Metersets: 491kt Overall:8,500kt	Pipelines and M&R: 10,325kt (56%) Customer Metersets: 583kt (54%) Overall:10,908kt (56%)	Pipelines and M&R: 91k (87%) Customer Metersets: 846k (86%) Overall:937k (86%)	Yes, this program is suitable. However, EGI should consider if the significant increase in resources required to complete 2 full system surveys (using the 6-pass protocol) per year are justified given that the program only performs 9% better. Potential that the increases in performance are marginal compared to the increase in resources (and associated costs).

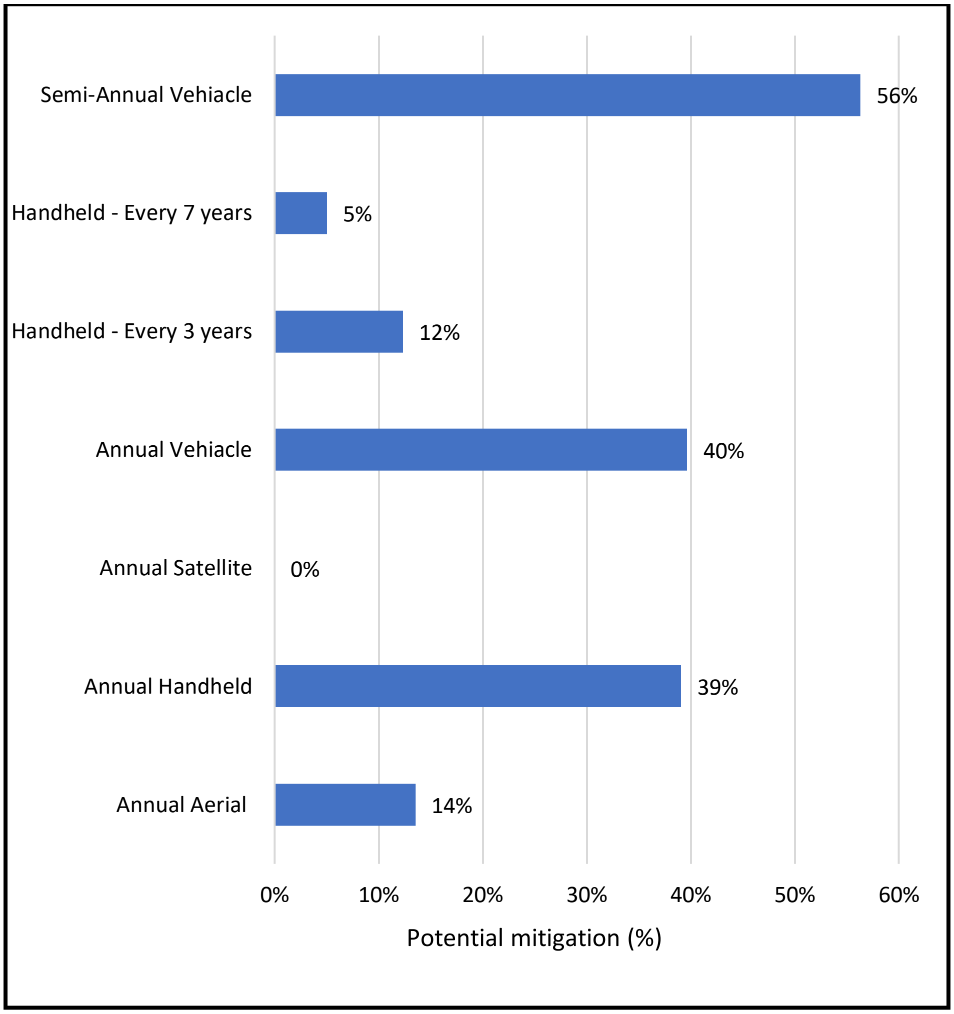
Program Name	Methods-Frequency	Description	Key Assumptions	Survey Time (per year)	Emissions (kt of CH4 / year)	Potential Annual Mitigation (kt of CH4 / year)	Average number of leaks detected per year (%)	Suitability for Use on EGI
Annual Aerial	Aerial - 1x/year	Program uses a aircraft-based technology to detect and quantify emissions. Detection is limited to sources above 0.5kg/hour.	Average survey speed of 110km/hr. Constant detection probability of 90% of rates above 0.5kg/hr (does not detect any source below). Performance based on Bridger Photonics sensitivity considering deployment at distribution sector. Deployment: August-October	85 days (~1 crew)	Pipelines and M&R: 15,854kt Customer Metersets: 1,074kt Overall:16,928kt	Pipelines and M&R: 2,480kt (14%) Customer Metersets: 0kt (0%) Overall:2,480kt (13%)	Pipelines and M&R: 460(0.44%) Customer Metersets: 0k (0%) Overall:460 (0.04%)	No, this method is not recommended for full adoption on EGI's DO systems. While the technology will detect some of the emissions from the distribution, it is not sufficiently sensitive to capture enough of the smaller emitters to reduce the uncertainty in the emissions estimate. Instead, this method could be deployed for identification of super-emitting sources (or other large emitters) to allow for rapid repair and mitigation. However, Highwood's desktop research indicates that leaks which are sufficiently large to be detected through aerial methods are likely to be reported by customers, due to mercaptan scented additive in the gas.
Annual Satellite	Satellite	Program uses a satellite to detect and quantify emissions. Detection is limited to sources above 100kg/hour.Method surveys the same location on a ~2 week periodicity.	Constant detection probability of 100% of rates above 100kg/hr (does not detect any source below). Performance based on GHGSat sensitivity. ~ 120 days from April to October.	n/a	Pipelines and M&R: 18,334kt Customer Metersets: 1,074kt Overall:19,408kt	Pipelines and M&R: 0kt (0%) Customer Metersets: 0kt (0%) Overall:0kt (0%)	Pipelines and M&R: 0k (0%) Customer Metersets: 0k (0%) Overall:0k (0%)	No, satellites have not been proven to be sufficiently sensitive to detect any of the emissions which are characterized and described in the literature on distribution systems.

Program Name	Methods-Frequency	Description	Key Assumptions	Survey Time (per year)	Emissions (kt of CH4 / year)	Potential Annual Mitigation (kt of CH4 / year)	Average number of leaks detected per year (%)	Suitability for Use on EGI
Scenario 1	Handheld - 1x/year Vehicle 1x/ year Aerial 1x/year	Program considers a combination of handheld, vehicle and aerial-based technologies.	Same assumptions as single technology options.	Handheld - 67,150 days (~180 crews) vehicle -11,350 days (~95 crews) Aerial - 85 days (~1 crew)	Pipelines and M&R: 9,769kt Customer Metersets: 600kt Overall:10,369kt	Pipelines and M&R: 7,704kt (44%) Customer Metersets: 417kt (41%) Overall:8,122kt (44%)	Pipelines and M&R: 83k (80%) Customer Metersets: 762k (78%) Overall:845k (78%)	this program is technically feasible, however this is not a suitable program. The addition of the aircraft does not improve the performance of the program to detect emissions, and it will not improve accuracy of emissions invenotry estimates.
Scenario 2	Handheld - Every 3 years Vehicle - 1x/ year Aerial - 1x/year	Program considers a combination of handheld (every 3 years), vehicle and aerial-based technologies.	Same assumptions as single technology options.	Handheld - 22,383 days (~180 crews) vehicle -11,350 days (~95 crews) Aerial - 85 days (~1 crew)	Pipelines and M&R: 9,815kt Customer Metersets: 613kt Overall:10,428kt	Pipelines and M&R: 7,659kt (44%) Customer Metersets: 404kt (40%) Overall:8,063kt (44%)	Pipelines and M&R: 81k (78%) Customer Metersets: 736k (75%) Overall:817k (75%)	this program is technically feasible, however this is not a suitable program. The addition of the aircraft does not improve the performance of the program to detect emissions, and it will not improve accuracy of emissions invenotry estimates. Comparison of this scenario to scenario 1 indicates that reducing the handheld deployment frequency does not significantly reduce the performance of this program, and the performance of this program is marginally stronger than the vehicle-only deployment.

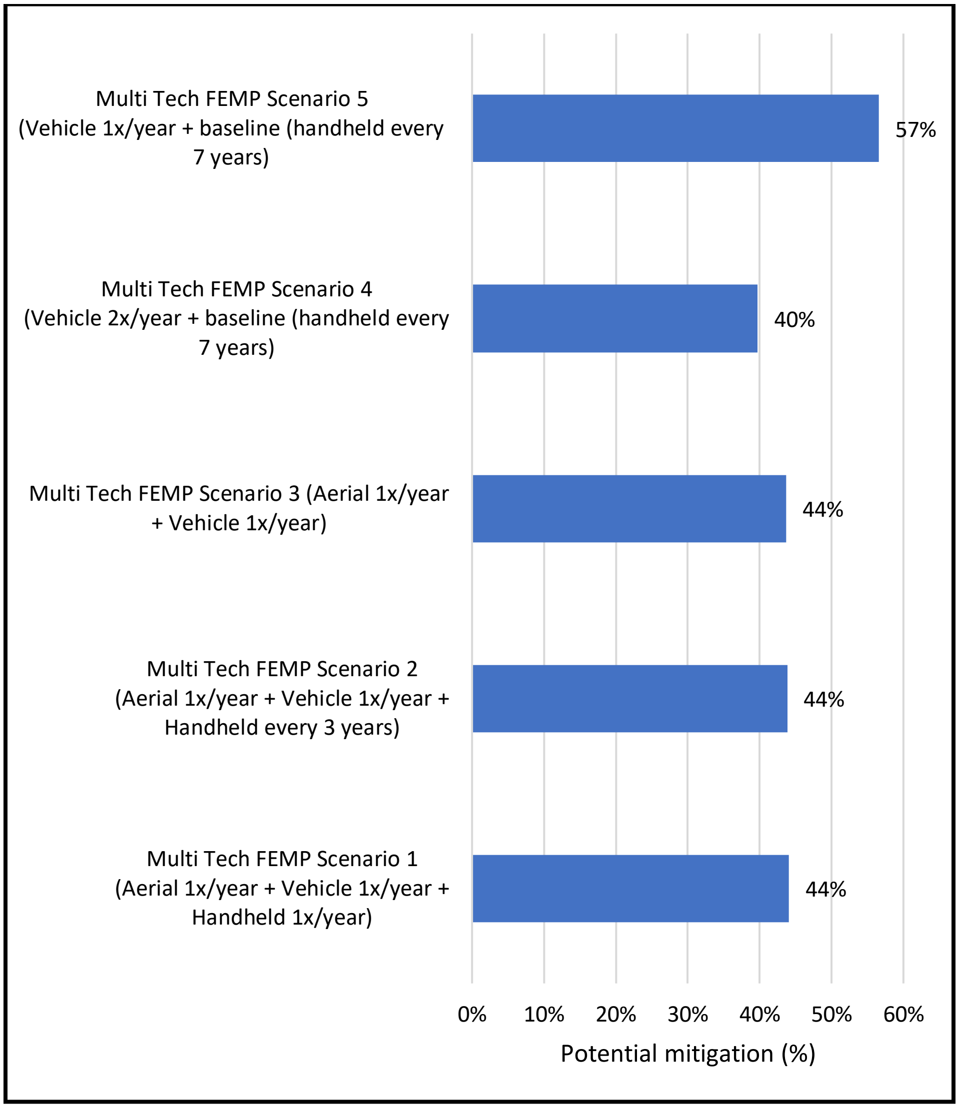
Program Name	Methods-Frequency	Description	Key Assumptions	Survey Time (per year)	Emissions (kt of CH4 / year)	Potential Annual Mitigation (kt of CH4 / year)	Average number of leaks detected per year (%)	Suitability for Use on EGI
Scenario 3	Vehicle - 1x/ years Aerial - 1x/year	Program considers a combination of vehicle and aerial-based technologies.	Same assumptions as single technology options.	vehicle -11,350 days (~95 crews) Aerial - 85 days (~1 crew)	Pipelines and M&R: 9,842kt Customer Metersets: 620kt Overall:10,462kt	Pipelines and M&R: 7,631kt (44%) Customer Metersets: 397kt (39%) Overall:8,028kt (43%)	Pipelines and M&R: 80k (77%) Customer Metersets: 729k (74%) Overall:810k (75%)	Similar to scenarios 1 and 2, the performance of the program is dominated by the performance of the vehicle. Again, this scenario is not suitable because the addition of the aircraft does not add any performance benefits, while significantly increasing the cost and resources required to complete the program.
Scenario 4	Handheld - Every 7 years Vehicle 1x/ year	Program considers a combination of handheld (every 7 years) and vehicle-based technologies.	Same assumptions as single technology options.	Handheld - 9,593 days (~80 crews) vehicle -11,350 days (~95 crews)	Pipelines and M&R: 10,529kt Customer Metersets: 618kt Overall:11,147kt	Pipelines and M&R: 6,944kt (40%) Customer Metersets: 400kt (39%) Overall:7,344kt (40%)	Pipelines and M&R: 80k (77%) Customer Metersets: 733k (75%) Overall:813k (75%)	**Yes, this is the recommended scenario.**
Scenario 5	Handheld - Every 7 years Vehicle 2x/ year	Program considers a combination of handheld (every 7 years) and vehicle-based (2x per year) technologies.	Same assumptions as single technology options.	Handheld - 9,593 days (~80 crews) vehicle -22,750 days (~190 crews)	Pipelines and M&R: 7,584kt Customer Metersets: 438kt Overall:8,022kt	Pipelines and M&R: 9,890kt (57%) Customer Metersets: 579kt (57%) Overall:10,469kt (57%)	Pipelines and M&R: 91k (87%) Customer Metersets: 827k (84%) Overall:918k (85%)	This scenario is suitable but Highwood's assessment is that the improvements of this program against the single vehicle deployment are not sufficient to justify the additional resources and cost associated with doubling the vehicle deployment.

11.3. Mitigation Plot

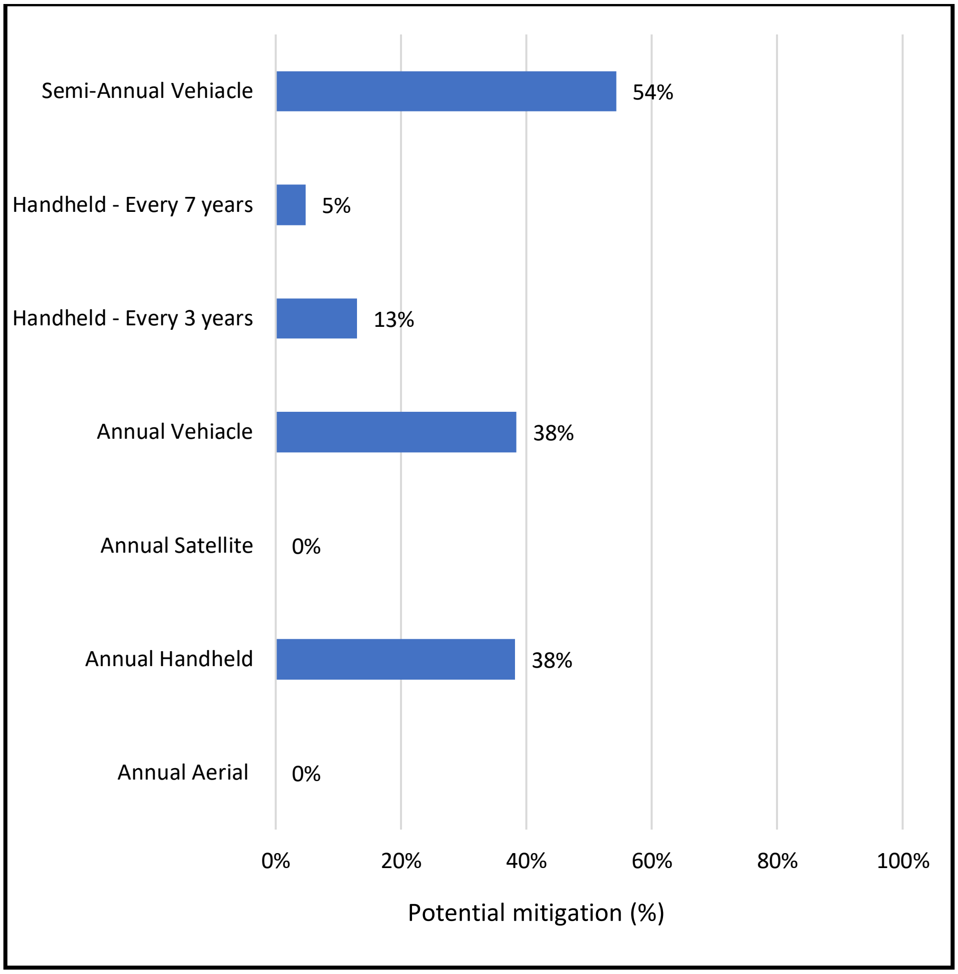
These are the results of complementary analysis to quantitative results in section 8.4, assuming all leaks detected were repaired in 30 days. The bar length of the "Potential Mitigation (%)" visualizations represent the proportion of simulated emission volume each FEMP Scenario mitigates compared to a hypothetical FEMP devoid of any formal LDAR.



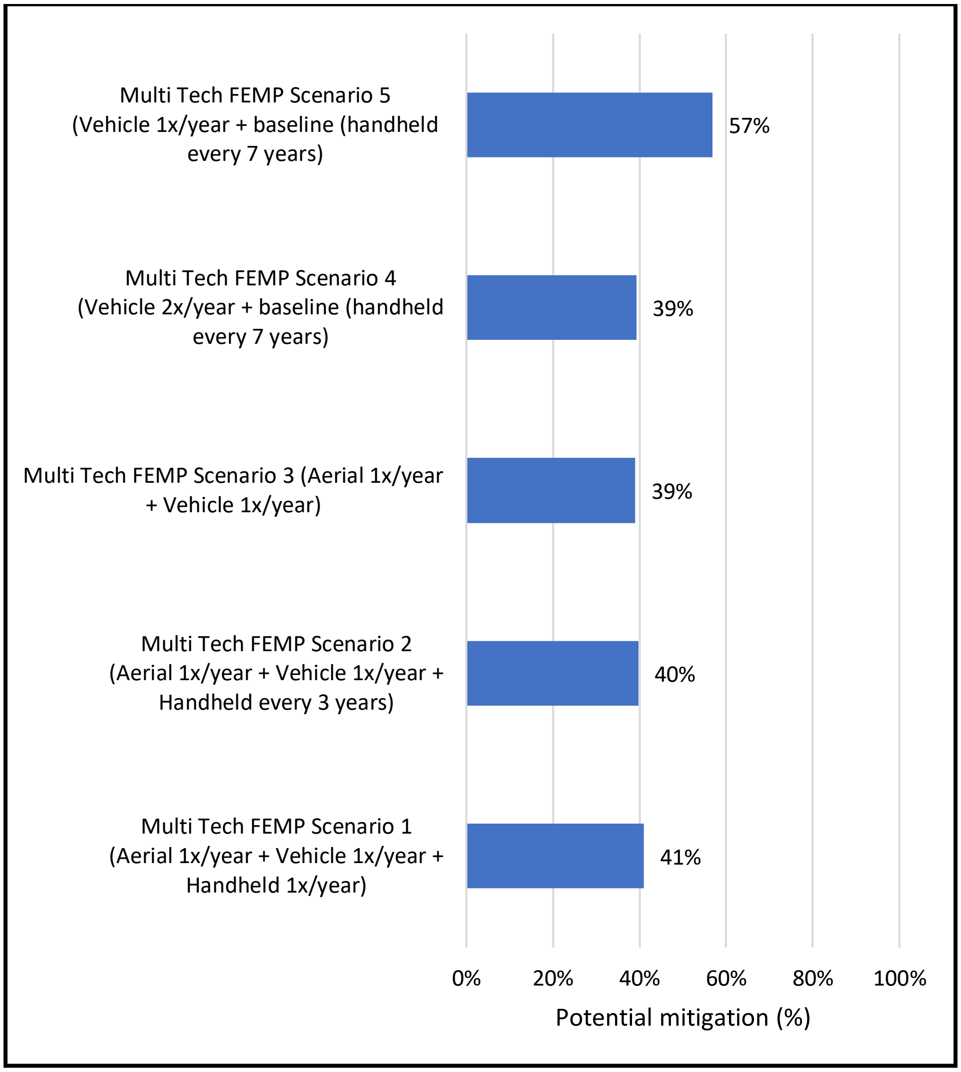
Emissions mitigation (expressed as a % of the total emissions in a hypothetical FEMP scenario devoid of any formal LDAR) by the explored single technology FEMPs in an LDAR-Sim "virtual world" populated by pipelines and Distribution Stations.



Emissions mitigation (expressed as a % of the total emissions in a hypothetical FEMP scenario devoid of any formal LDAR) by the explored single technology FEMPs in an LDAR-Sim “virtual world” populated by pipelines and Distribution Stations.



Emissions mitigation (expressed as a % of the total emissions in a hypothetical FEMP scenario devoid of any formal LDAR) by the explored single technology FEMPs in an LDAR-Sim "virtual world" populated by residential, industrial, and commercial meter sets.



Emissions mitigation (expressed as a % of the total emissions in a hypothetical FEMP scenario devoid of any formal LDAR) by the explored multiple technology FEMPs in an LDAR-Sim "virtual world" populated by residential, industrial, and commercial meter sets.

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ENBRIDGE GAS INC.

Accounting Entries for Fugitive Emissions Measurement Administration Deferral Account (FEMADA) Account No. 179-342

The purpose of the account is to record the incremental costs associated with the Fugitive Emissions Investigation Plan. The revenue requirement will include incremental operating costs as well as costs associated with any required capital investment, including return on rate base, depreciation expense, and associated income taxes. Incremental costs are related to the implementation of measurement technologies, configuration of IT systems, incremental staffing, consulting support and other miscellaneous costs, including training, conferences, and memberships associated with methane measurement technologies and methodologies. This account is for amounts incurred on or after January 1, 2025.

Simple interest is to be calculated on the opening monthly balance of this account using the OEB-approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the OEB in a future rate application.

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act, 1998.

Debit		Account No.179-342 Fugitive Emissions Measurement Administration Deferral Account
Credit	-	Account No. 728 General Expense

To record, as a debit/(credit) in the account, costs related to the technology pilot, configuration of IT systems, incremental staffing, consulting support and other miscellaneous costs, including training, conferences, and memberships associated with methane measurement technologies and methodologies.

Debit		Account No.179-342 Fugitive Emissions Measurement Administration Deferral Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit/(credit) in the account, interest expense on the opening monthly balance.

Breakdown of the 2023 Storage and Transportation Deferral Account (2023 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, 2023 to December 31, 2023	Annual Cost (3)	Balance in the 2023 S&TDA (4)
		(GJ)	($/GJ)	($Millions)	(GJ)	($/GJ)	($Millions)	($Millions)
1	Union Gas Dawn to Lisgar	67,929	2.865	2.3	67,929	3.190	2.6	
2	Union Gas Dawn to Parkway	2,792,173	3.402	114.0	2,792,173	3.760	126.0	
3	Union Gas Dawn to Parkway - M12X	200,000	4.239	10.2	200,000	4.648	11.2	
4	Union Gas F24 T	85,000	0.069	0.1	85,000	0.077	0.1	
5	Union Transmission Costs			126.6			139.8	(13.2)
6	Dawn T Service Costs			(11.2)			(16.9)	5.7
7	Federal Carbon Costs			-			1.6	(1.6)
8	Union & Third Party Market Based Storage			20.1			23.8	(3.7)
9	2021 Deferral Disposition - UG (1)			-			5.9	(5.9)
10	Total			135.5			154.2	(18.7)

Notes
(1) Transporation deferral adjustments related to 2021 S&TDA increased actual costs by $5.9M
M12 Transport $5.9M, M16 Transport $0.1M, Federal Carbon ($0.1M)
(2) Col. 1 * Col. 2 * 12
(3) Col. 4 * Col. 5 * 12
(4) Col. 3 - Col. 6

Breakdown of Transactional Services Revenue By Type of Transaction - EGD Rate Zone

Line No.	Particulars	Col. 1 2019 Transactional Services Revenue ($000's)	Col. 2 2020 Transactional Services Revenue ($000's)	Col. 3 2021 Transactional Services Revenue ($000's)	Col. 4 2022 Transactional Services Revenue ($000's)	Col. 5 2023 Transactional Services Revenue ($000's)
1	Storage Optimization	60.7	0.0	0.0	0.0	0.0
2	Transportation Optimization	13,084.5	17,643.4	17,509.0	47,904.8	59,520.9
3	Transactional Services Revenue	13,145.2	17,643.4	17,509.0	47,904.8	59,520.9
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	11,830.7	15,879.1	15,758.1	43,114.3	53,568.8
6	TSDA sub-total	169.3	(3,879.1)	(3,758.1)	(31,114.3)	(41,568.8)
7	ETT Revenue - Rider H	35.1	5.8	146.1	120.3	169.3
8	TSDA Total	134.3	(3,884.9)	(3,904.1)	(31,234.7)	(41,738.1)

Breakdown of The 2023 Unaccounted-For Gas Variance Account (2023 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	282	282	282	187	187	187	172	172	172	187	187	187	
3	Budget UAF Dollar	4,809,129	5,350,826	4,601,949	2,191,296	1,237,370	628,008	430,523	415,945	424,794	724,752	1,546,672	2,453,024	24,814,287
4	Budget UAF based on actual throughput (10^3m^3) (1)	16,659	15,114	14,587	9,266	5,241	3,744	3,670	3,502	3,593	6,683	11,237	14,194	107,488
5	UAF Annual Variance (10^3m^3) (2) (3)	(4,379)	(3,973)	(3,834)	(2,436)	(1,378)	(984)	(965)	(921)	(944)	(1,757)	(2,954)	(3,731)	(28,255)
6	Total Actual UAF (10^3m^3) (4)	12,280	11,141	10,752	6,830	3,863	2,760	2,705	2,581	2,648	4,926	8,283	10,463	79,232
7	PGVA Rate	282	282	282	187	187	187	172	172	172	187	187	187	
8	Actual UAF Cost ($) (5)	3,467,113	3,145,553	3,035,817	1,276,689	722,119	515,931	466,489	445,147	456,698	919,178	1,545,552	1,952,221	17,948,507
9	UAFVA Volume Variance (6)	(4,753)	(7,811)	(5,547)	(4,893)	(2,756)	(600)	209	169	185	1,042	(6)	(2,684)	(27,445)
10	UAFVA Cost Variance ($) (7)	(1,342,016)	(2,205,273)	(1,566,132)	(914,607)	(515,252)	(112,077)	35,965	29,203	31,904	194,426	(1,120)	(500,803)	(6,865,780)
11	Line Pack Gas (LPG) Allocation													160,131
12	2023 Damage Adjustment													(217,040)
13	Total 2023 UAFVA (8)													(6,922,689)

Notes
(1) UAF volumes based on budget throughput percentage multiplied by actual throughput volumes
(2) Line 5 = Line 6 - Line 4

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
(3) UAF annual variance allocation based on actual throughput profile	15%	14%	14%	9%	5%	3%	3%	3%	3%	6%	10%	13%	
	(4,379)	(3,973)	(3,834)	(2,436)	(1,378)	(984)	(965)	(921)	(944)	(1,757)	(2,954)	(3,731)	(28,255)

(4) Line 4 + Line 5
(5) Line 6 * Line 7
(6) Line 6 - Line 1
(7) Line 8 - Line 3
(8) Line 10 + Line 11 + Line 12

2023 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	2,360	2,308	(51.7)	2,135,521	(110.4)	(4.2)	(4.2)	0.0	(110.4)	0.0794	(8.8)
6	28,390	27,696	(693.8)	171,753	(119.2)	(10.4)	(10.4)	0.0	(119.2)	0.0465	(5.5)
Total											(14.3)

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

September 21, 2022

Dear Recipient,

Subject: Storage at Dawn, injections commencing April 1, 2023

Enbridge Gas Inc. operating as Enbridge Gas Distribution (Enbridge Gas) requires firm natural gas storage services with injections commencing April 1, 2023.

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 five (5) years commencing April 1, 2023. 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	4.5 PJ's
4 – year	4.5 PJ's
5 - year	4.5 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.

Credit*:* Prior to deal execution, service providers must have sufficient open credit with EGI. The current high commodity price environment has had a significant impact on the credit position of potential counterparties and the available credit required to provide non-physical storage products. Providing EGI with 1 PJ of "synthetic storage" could require up to $12,000,000 CAD in available credit. Counterparties are welcome to contact EGI Credit to discuss their credit position.

The deadline to submit your proposal(s) is **11 a.m. Mountain Time (MT) on Oct. 11, 2022,** 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 Time (MT) on September 27, 2022. All queries and responses will be provided to all parties on Sept. 29, 2022.*

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.

2022 Storage RFP - Issued on 9/22/2022; Responses on 10/11/2022 - All responses summary

=RFP Manager recommendations

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 debit from ratepayers of $0.042 million plus interest as of December 31, 2023, of $0.037 million, for a total of $0.079 million. The $0.042 million balance is the difference between the actual UDC incurred by the Union rate zones and the amount of UDC collected in rates, partially offset by a credit to ratepayers related to a refund of Panhandle Pipeline tolls that were applicable to UDC costs between 2020 and 2023.

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 2023 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 2023 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 (a)	Union North West (b)	Union South (c)	Total (d)
1	Capacity Released (TJ)	6,448	4,351	23,348	34,147
2	UDC Costs Incurred ($000s)	2,416	2,105	5,857	10,378
3	Released UDC Capacity ($000s)	(32)	(1,277)	(48)	(1,357)

5. Enbridge Gas collected $6.738 million in rates for UDC for the Union rate zones during 2023 and recorded an associated interest debit of $0.037 million (see Table 2). Actual UDC costs in 2023 were $10.378 million offset by $1.357 million in released capacity value, resulting in a net cost of $9.021 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.

6. As discussed in Enbridge Gas's April QRAM[4], Enbridge Gas received a refund from Panhandle Pipelines regarding over-recovery of costs of service of which $2.24

[3] EB-2021-0149, Settlement Proposal, Exhibit N1, Tab 1, Schedule 1, October 4, 2021, p. 15.
[4] EB-2024-0093, Exhibit D, Tab 1, Schedule 1, para 8.

million, including interest, pertained to UDC between 2020 and 2023. This amount has been credited to the appropriate rate zones that bore the cost of the Panhandle tolls as outlined in Line 6 of Table 2.

7. The variance between the amounts collected in rates and the actual UDC costs, including the interest debit of $0.037 million, and the Panhandle Pipelines refund of $2.24 million, results in a net debit from ratepayers in the UDC Variance Account of $0.079 million.

8. The balance applicable to sales service and bundled DP customers in Union North West is a credit of $1.608 million and in Union North East, a credit of $0.746 million. There is a debit of $2.433 million applicable to sales service customers in Union South.

9. 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 ($000s)	Union North East	Union North West	Union South	Total
		(a)	(b)	(c)	(d)
1	UDC Collected in Rates	(1,369)	(5,370)	-	(6,738)
2	UDC Costs Incurred (Table 3)	993	4,870	3,158	9,021
3	Variance (line 1 + line 2)	(376)	(500)	3,158	2,283
4	Interest	(6)	(8)	52	37
5	(Credit)/Debit to Operations Area	(382)	(508)	3,210	2,320
6	Panhandle Pipelines Refund Impact, including interest	(364)	(1,100)	(778)	(2,241)
7	Total (Credit)/Debit to Operations Area	(746)	(1,608)	2,433	79

The following is a description of each item in Table 2:

1.1 UDC Collected in Rates

10. The 2023 OEB-approved rates include $7.174 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 TransCanada Pipeline final tolls effective January 1, 2023. On an actual basis in 2023, Enbridge Gas recovered $6.738 million in Union North West and Union North East and $0.0 million in Union South.

1.2 UDC Costs Incurred

11. The actual unutilized capacity in 2023 was 34.1 PJ. The level of unutilized capacity experienced in 2023 was largely due to planned unutilized capacity (and resulting UDC) and lower customer use.

12. The costs reflected in the UDC Variance Account are the total demand charges for unutilized pipeline capacity totaling $10.378 million, partially offset by $1.357 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 ($000s)	Union North East	Union North West	Union South	Total
		(a)	(b)	(c)	(d)
1	UDC Costs Incurred	1,142	5,602	3,633	10,378
2	Released Capacity Revenue	(149)	(732)	(475)	(1,357)
3	Net UDC Costs (Credit)/Debit	993	4,870	3,158	9,021

1.3 Panhandle Pipelines Refund Impact, net of interest

13. As outlined above, Enbridge Gas received a refund from Panhandle Pipelines regarding over-recovery of costs of service of which $2.2 million, including interest, pertained to UDC between 2020 and 2023. This amount has been credited to the appropriate rate zones in alignment with the historic allocation of UDC costs for each year.

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 2023 balance in this deferral account is a debit from ratepayers of $8.087 million plus interest of $0.444 million for a total debit from ratepayers of $8.531 million.

2. In setting rates for 2023, 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 2023 rates.[1] On an actual basis, consistent with the method approved in its EB-2011-0210 Decision and Rate Order, Union credited $15.280 million in rates to ratepayers during 2023, $1.854 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 $7.991 million in net revenues from upstream transportation optimization during 2023 in the Union Rate Zones. In accordance with the OEB-approved sharing methodology, 90% of this net revenue, or $7.193 million, is to be credited to customers. As stated above, $15.280 million has already been credited through rates; therefore, the deferral balance is a debit from ratepayers of $8.087 million ($15.280 million less $7.193 million).

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

[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.

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. 2023 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 $1.637 million, plus interest of $0.090 million for a total debit from ratepayers of $1.727 million.

2. As shown in Table 3, the balance is calculated by comparing $2.914 million (ratepayer 90% share of the actual 2023 Short-Term Storage and Other Balancing Services net revenue of $3.237 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.

Table 3
Deferral Summary: Short-term Storage and Other Storage Services

Line No.	Particulars ($000's)	Actual 2023
1	Net Revenue	3,237
2	Ratepayer Portion (90%)	2,914
3	Approved in Rates	4,551
4	Deferral Balance Payable to/(Collectable from) Ratepayers	(1,637)

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

3. Actual 2023 revenues from C1 Off-Peak Storage, Gas Loans and all other Balancing services of $1.950 million were $0.550 million lower than the 2013 OEB-approved forecast of $2.500 million.

4. The C1 Short-Term Firm Peak Storage revenues of $2.634 million were $5.249 million lower than the 2013 Board-approved forecast of $7.883 million. Actual Union rate zone utility storage requirements for 2023 were 9.4 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 1.9 PJ in 2023). 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 2023 were 1.6 PJ higher than the requirement in 2022, resulting in a decrease in the C1 Short-Term Peak Storage available for sale (from 3.5 PJ in 2022 to 1.9 PJ in 2023). This is a result of an increase 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 2023 was $1.41/GJ

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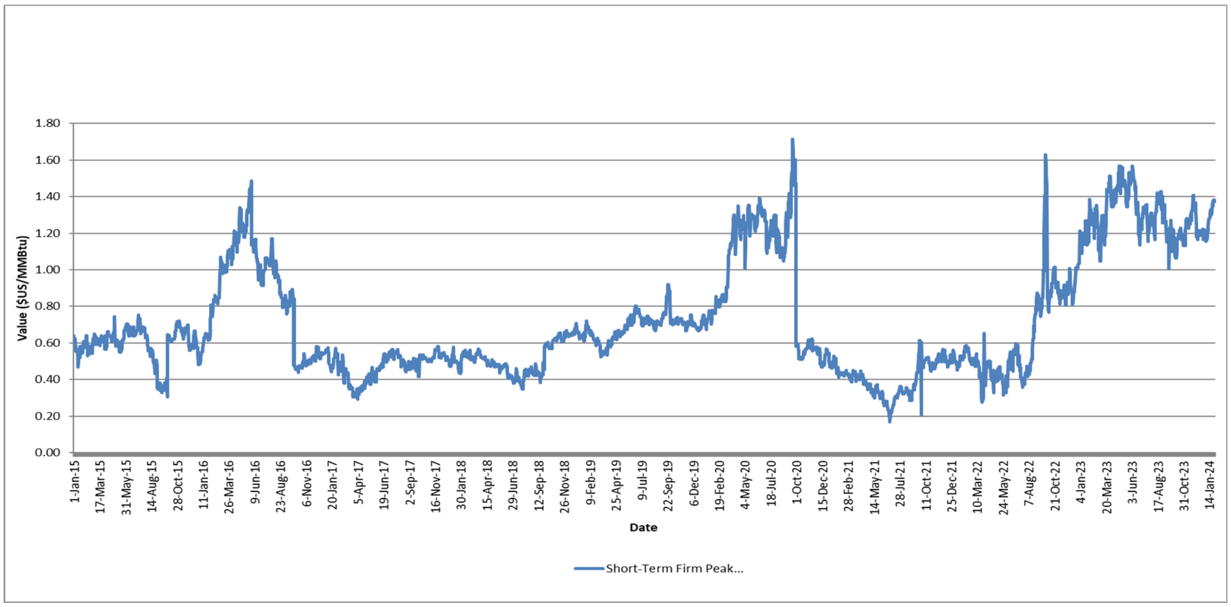
[2] EB-2016-0245, OEB Decision and Rate Order, Schedule 1, Settlement Proposal, p. 7.
[3] EB-2021-0149, OEB Decision on Settlement Proposal, Schedule 1, Settlement Proposal, p.16.

($2.6 million/1.9 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 2015-2024



1. Non-Utility Storage Balances for 2023

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 2023 (for Union storage).

8. During the 2023 injection season, the non-utility storage balance peaked on November 18, 2023 at 96.312% full with a balance of 124.6 PJ compared to available space of 129.4 PJ. On October 31, 2023, the date to which the Company manages its storage balance, the non-utility balance was 95.967% of available space. The balance stayed below the total non-utility available space of 100% for the rest of 2023.

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 2023 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 2023 Enbridge Gas sold a total of 3.2 PJ of short-term peak storage (Union).[5] Of this total, 1.9 PJ was excess utility space, calculated by deducting 98.1 PJ of in-franchise utility requirement (as per the Gas Supply Plan) from the total 100 PJ of in-franchise utility storage. Therefore, the excess short term peak sales of 1.4 PJ was sold as non-utility space. Total revenue from the sale of C1 Short-Term Peak Storage (Utility) in 2023 was $2.6 million. Details of the above sales are reflected in Exhibit E, Tab 1, Schedule 4.

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[4] EB-2011-0210, OEB Decision and Order, October 24, 2012, pp. 116-117.
[5] Total short-term peak storage sales of 3.2 PJ was derived from the sum of 1.36 PJ of non-utility short term peak storage and 1.86 PJ of utility short term peak storage.

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 2023, the balance in the NAC deferral account is a credit to ratepayers of $3.651 million plus interest of $0.201 million for a total credit to ratepayers of $3.852 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 2023 target NAC used to calculate base rates for each rate class was approved by the OEB in Enbridge Gas's 2023 Rates[4] proceeding. The 2021 actual NAC, weather normalized using the 2023 weather normal, was used to determine the 2023 target NAC for each rate class to calculate base rates. Setting the 2023 target NAC based on the 2021 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 inclusion of the DSM saved volumes within the actual reported consumption.

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[1] EB-2015-0010.
[2] EB-2013-0202.
[3] EB-2014-0271.
[4] EB-2022-0133.

5. The 2023 forecast usage used to calculate Y factor unit rates for each rate class was approved by the OEB in Enbridge Gas's 2023 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 2023 actual NAC for each rate class is weather normalized using the 2023 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 2023 target NAC and 2023 actual NAC by rate class for base rates.

Table 1
2023 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	2023 Target NAC	2,731	149,709	2,631	148,143
2	2023 Actual NAC	2,709	140,937	2,680	149,349
3	Variance (Target - Actual NAC)	22	8,772	(50)	(1,206)

8. Table 2 provides the 2023 target NAC and 2023 actual NAC by rate class for Y factor rates.

Table 2
2023 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	2023 Target NAC	2,763	163,047	2,572	156,375
2	2023 Actual NAC	2,709	140,937	2,680	149,349
3	Variance (Target - Actual NAC)	54	22,109	(108)	7,026

[5] EB-2022-0133.

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 2023 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
2023 NAC Deferral Account

Line No.	Particulars ($000s)	Rate 01	Rate 10	Rate M1	Rate M2	Total
		(a)	(b)	(c)	(d)	(e)
1	Delivery Revenue Balances	783	1,590	(3,869)	251	(1,246)
2	Storage Revenue Balances	340	703	(474)	(77)	492
3	Storage Cost Balances	(420)	(186)	(1,065)	(1,226)	(2,897)
4	Interest	39	116	(298)	(58)	(201)
5	Total NAC Deferral Balance	741	2,222	(5,706)	(1,110)	(3,852)

3. Deferral Account Impacts

11. For Rate M1, the 2023 actual NAC is higher than the target NAC used to derive base rates by 50 m^3/customer (Table 1, line 3, column (c)) and higher than the target NAC used to derive Y factor rates by 108 m^3/customer (Table 2, line 3, column (c)). As shown in Table 3, this results in a delivery and storage revenue credit to ratepayers of $4.343 million ($3.869 million and $0.474 million respectively). In addition, the NAC volume variance decreases the Rate M1 storage requirement by 1.590 PJ. Accordingly, Enbridge Gas must refund an amount of $1.065 million

(Table 3, line 3, column (c)) to Rate M1 customers to recognize the decreased Rate M1 storage requirements.

12. For Rate M2, the 2023 actual NAC is higher than the target NAC used to derive base rates by 1,206 m^3/customer (Table 1, line 3, column (d)) and lower than the target NAC used to derive Y factor rates by 7,026 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 $0.174 million ($0.251 million debit and $0.077 million credit respectively). In addition, the NAC volume variance decreases the Rate M2 storage requirement by 1.830 PJ. Accordingly, Enbridge Gas must refund $1.226 million (Table 3, line 3, column (d)) to Rate M2 customers to recognize the decreased Rate M2 storage requirements.

13. For Rate 01, the 2023 actual NAC is lower than the target NAC used to derive base rates by 22 m^3/customer (Table 1, line 3, column (a)) and lower than the target NAC used to derive Y factor rates by 54 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 $1.123 million ($0.783 million and $0.340 million respectively). In addition, the NAC volume variance decreases the Rate 01 storage requirement by 0.510 PJ. Accordingly, Enbridge Gas must refund an amount of $0.420 million (Table 3, line 3, column (a)) to Rate 01 customers to recognize the decreased Rate 01 storage requirements.

14. For Rate 10, the 2023 actual NAC is lower than the target used to derive base rates NAC by 8,772 m^3/customer (Table 1, line 3, column (b)) and lower than the target NAC used to derive Y factor rates by 22,109 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 $2.292 million ($1.590 million and $0.703 million respectively). In addition, the NAC volume variance decreases the Rate 10 storage requirement by 0.230 PJ. Accordingly, Enbridge Gas must refund an amount of $0.186 million

(Table 3, line 3, column (b)) from Rate 10 customers to recognize the decreased Rate 10 storage requirements.

4. Storage Costs

15. The storage costs recognize that variances between the 2023 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, "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."[6]

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 2023/2024 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 2023/2024 Gas Supply Plan volumes represent the April 1, 2023 to March 31, 2024 period, which are used to determine the storage requirements for general service rate classes effective November 1, 2023. 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, 2023. 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, 2023.

[6] EB-2014-0145, OEB Decision and Order, pg. 9.

18. For Rate M1, the NAC volume variance between the 2023/2024 Gas Supply Plan and the 2013 OEB-approved volumes was a decrease of 8.352 PJ. The majority of the NAC volume variance decrease occurred in the winter months, which decreased the Rate M1 storage requirement by 1.590 PJ. This resulted in decreased storage costs of $1.065 million (Table 3, line 3, column (c)).

19. For Rate M2, the NAC volume variance between the 2023/2024 Gas Supply Plan and the 2013 OEB-approved volumes was an increase of 2.839 PJ. The majority of the NAC volume variance increase occurred in the summer months, which decreased the Rate M2 storage requirement by 1.830 PJ and resulted in decreased storage costs of $1.226 million (Table 3, line 3, column (d)).

20. For Rate 01, the NAC volume variance between the 2023/2024 Gas Supply Plan and the 2013 OEB-approved volumes was a decrease of 0.538 PJ. The majority of the NAC volume variance decrease occurred in the winter months, which decreased the Rate 01 storage requirement by 0.510 PJ and decreased storage costs by $0.420 million (Table 3, line 3, column (a)).

21. For Rate 10, the NAC volume variance between the 2023/2024 Gas Supply Plan and the 2013 OEB-approved volumes was a decrease of 1.272 PJ. The majority of the NAC volume variance decrease occurred in the winter months, which decreased the Rate 10 storage requirement by 0.230 PJ and resulted in decreased storage costs of $0.186 million (Table 3, line 3, column (b)).

22. Overall, the NAC volume variance between the 2023/2024 Gas Supply Plan and the 2013 OEB-approved volumes resulted in a decrease in general service storage requirements of 4.160 PJ. Accordingly, Enbridge Gas has included a storage cost credit of $2.897 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)

	PJ		PJ
Rate M1	(1.590)	Rate 01	(0.510)
Rate M2	(1.830)	Rate 10	(0.230)
Total South	(3.420)	Total North	(0.740)

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

24. The 4.160 PJ reduction in general service storage requirements due to NAC volume variances forms part of the 1.863 PJ of excess utility space available for sale for winter 2023/2024. The revenue from the sale of the 1.863 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 $3.372 million, plus interest to December 31, 2023 of a $0.185 million, for a total debit of $3.557 million. The balance includes the residual amounts not disposed of from the following deferral dispositions: 2021 Earnings Sharing and Deferrals (EB-2022-0110) cleared effective January 2023, and 2021 Federal Carbon Pricing Program (EB-2022-0194) cleared effective April 2023. The total forecast disposition balance of these combined was a debit of $42.083 million, total recoveries were a credit of $38.711 million, resulting in a net residual debit balance of $3.372 million. A summary is provided in Table 1.

Table 1
Deferral Summary: Deferral Clearing Variance Account

Line No.	Proceeding	Amount ($ millions)
1	2021 Earnings Sharing and Deferrals (EB-2022-0110)	41.679
2	2021 Federal Carbon Pricing Program (EB-2022-0194)	0.404
3	Subtotal – Approved for Disposition in 2023	42.083
4	Amounts disposed of in 2023 through one-time billing adjustments	(38.711)
5	Residual balance to Deferral Clearing Variance Account	3.372

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 2023 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. 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." This treatment continued through to the 2021 deferral and variance account disposition proceeding. However, as part of the 2022 deferral and variance account disposition proceeding, clearance of the 2022 balance (and prior balances) was on a final basis. This reflected that within the EB-2022-0200 (Enbridge Gas's 2024 Rebasing Application) approved Settlement Proposal, the actual capital spending and rate base amounts through 2022 (including the Parkway West project) were agreed to and approved. As a result, Enbridge Gas is seeking approval for the disposition of the Parkway West Project Costs Deferral Account (179-136) in this proceeding on a final basis.

3. The balance in this deferral account is a credit to Union rate zones ratepayers of $0.696 million plus interest of $0.049 million for a total credit balance of $0.745 million. The balance of $0.696 million represents the difference between the revenue requirement of $20.307 million included in 2023 rates (EB-2022-0133) and the calculation of the actual revenue requirement for 2023 of $19.611 million as shown in Table 1.

Table 1
2023 Parkway West Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	Col. 1 2023 Board-approved (a)	Col. 2 2023 Actuals (b)	Col. 3 Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	-	-	-
2	Cumulative Capital Expenditures	233,147	232,432	(715)
3	Average Investment	188,678	187,433	(1,245)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses	2,295	1,884	(411)
5	Depreciation Expense (1)	5,532	5,505	(27)
6	Property Taxes	602	407	(196)
7	Total Operating Expenses	8,430	7,796	(634)
8	Required Return (2)	10,678	10,608	(70)
9	Total Operating Expense and Return	19,108	18,404	(704)
	Income Taxes:			
10	Income Taxes - Equity Return (3)	2,187	2,172	(15)
11	Income Taxes - Utility Timing Differences (4)	(988)	(965)	23
12	Total Income Taxes	1,199	1,207	8
13	Total Revenue Requirement	20,307	19,611	(696)

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 2023 required return calculation is as follows:
$187.433 million * 64% * 3.82% = $4.582 million plus
$187.433 million * 36% * 8.93% = $6.026 million for a total of $10.608 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 $1.245 million from OEB-approved is primarily due to the cumulative capital expenditures being $0.715 million lower than OEB-approved capital expenditures.

2. Operating Expenses

5. Operating and maintenance expenses were $0.411 million below the costs included in the 2023 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 2023 OEB-approved rates but not incurred in actual O&M expense. The Company elected 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.

6. Property taxes were $0.196 million lower than costs included in 2023 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 $0.003 million plus interest of $0.0003 million for a total credit balance of $0.003 million. The balance of $0.003 million represents the difference between the revenue requirement of $15.506 million included in 2023 rates (EB-2022-0133) and the calculation of the actual revenue requirement for 2023 of $15.503 million as shown in Table 1.

Table 1
2023 Brantford-Kirkwall Pipeline/Parkway D Project Rate Base and Revenue

Line No.	Particulars ($000's)	Col. 1 2023 Board-approved (a)	Col. 2 2023 Actuals (b)	Col. 3 Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	-	-	-
2	Cumulative Capital Expenditures	197,404	197,378	(26)
3	Average Investment	157,718	157,694	(24)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses	-	-	-
5	Depreciation Expense (1)	4,995	4,995	(0)
6	Property Taxes	995	994	(1)
7	Total Operating Expenses	5,990	5,989	(1)
8	Required Return (2)	8,926	8,925	(1)
9	Total Operating Expense and Return	14,916	14,914	(2)
	Income Taxes:			
10	Income Taxes - Equity Return (3)	1,828	1,828	-
11	Income Taxes - Utility Timing Differences (4)	(1,239)	(1,239)	-
12	Total Income Taxes	589	589	-
13	Total Revenue Requirement	15,506	15,503	(3)

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:
$157.694 million * 64% * 3.82% = $3.855 million plus
$157.694 million * 36% * 8.93% = $5.070 million for a total of $8.925 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.

2023 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 2023 balances recorded in the UFGVDA.

2. In the Union Rate Zones, 2023 OEB-approved rates included $11.6 million in UFG costs (based on forecasted throughput volumes). Based on 2023 actual throughput volumes, Enbridge Gas recovered $16.4 million in UFG costs through rates. In comparison, Enbridge Gas's actual 2023 UFG costs were $20.3 million. The variance between 2023 UFG costs recovered through rates and actual 2023 UFG costs is $3.9 million, which is below the $5.0 million dead band established by the OEB for the UFGVDA. As a result, there is no 2023 balance in the UFGVDA (see Table 1 for detailed calculations).

[1] Deferral Account No. 179-135.

Table 1
2023 Utility UFG Variances from OEB-Approved

Line No.	Particulars	Variance ($Millions)
1	UFG Cost Included in Rates (1) (3)	11.6
2	Net Recovery Variance	4.8
3	Total UFG Collected in 2023 Rates (line 1 + line 2) (2) (3)	16.4
4	Total Utility UFG Actual Cost (2)(4)	20.3
5	Total Utility UFG Variance (line 3 - line 4)	(3.9)
6	$5M UFG Symmetrical Dead-band	5.0
7	UFG Volume Deferral	-

Notes:
(1) Board Approved throughput is 32,010 106m3
(2) Actual throughput is 45,242 106m3
(3) Board Approved UFG % is 0.219%
(4) Actual UFG % is 0.271%

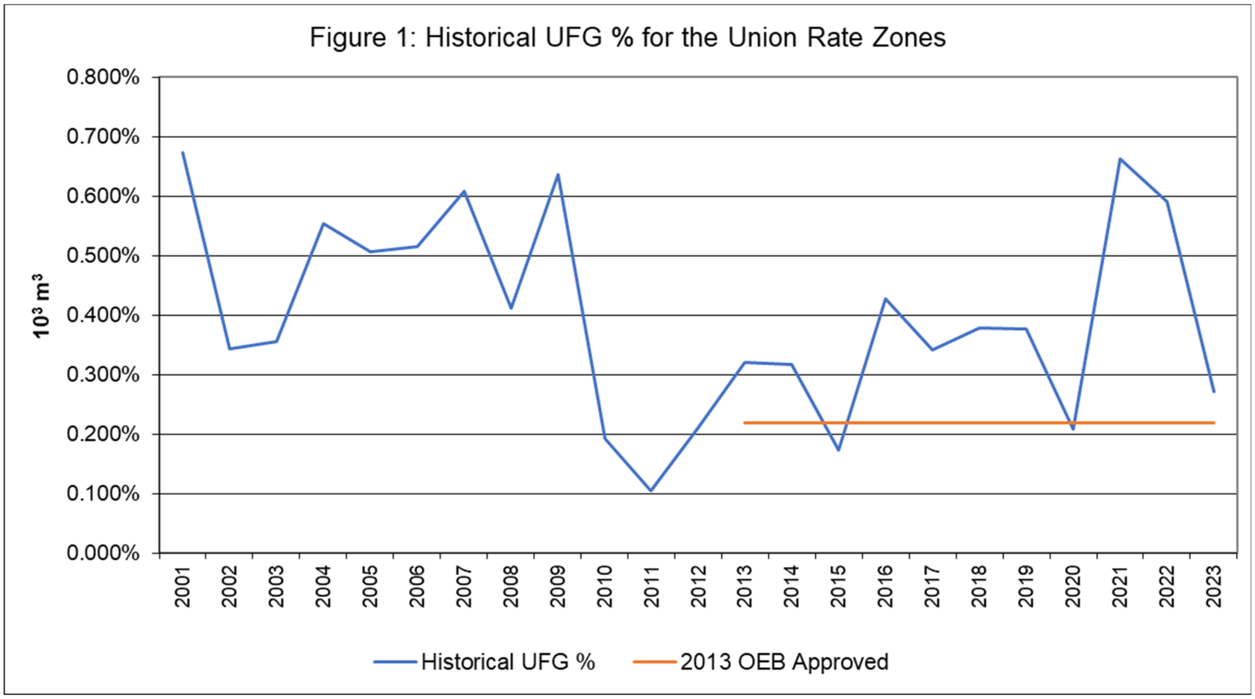
3. Table 2 provides historical total UFG volumes (utility and non-utility) and UFG volumes as a percentage of total throughput (UFG%) for the Union Rate Zones from 2001 to 2023.

Table 2
Historical Total UFG Volumes for the Union Rate Zones (1)

Line No.	Calendar Year	UFG Volumes (10^3 m^3)	UFG %
1	2001	184,102	0.673%
2	2002	109,542	0.344%
3	2003	108,819	0.356%
4	2004	176,650	0.554%
5	2005	169,540	0.507%
6	2006	154,015	0.516%
7	2007	203,713	0.609%
8	2008	143,880	0.411%
9	2009	201,845	0.637%
10	2010	67,283	0.192%
11	2011	35,668	0.105%
12	2012	68,690	0.210%
13	2013	113,997	0.320%
14	2014	97,109	0.318%
15	2015	54,408	0.174%
16	2016	131,588	0.427%
17	2017	108,901	0.342%
18	2018	136,447	0.379%
19	2019	137,652	0.376%
20	2020	74,120	0.208%
21	2021	252,582	0.663%
22	2022	250,692	0.592%
23	2023	122,613	0.271%

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

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



5. In the Settlement Proposal for the Company's 2022 Deferral and Variance Account and Earnings Sharing proceeding (EB-2023-0092)[2], Enbridge Gas agreed to address the following items in the current Application:

- Detailed evidence will be filed about the items learned and future plans arising from the ongoing review and investigation of UFG (see Exhibit I.Staff.6), including (without limitation):
    - the work completed by Enbridge Gas during 2023 and 2024 and the resulting observations and learnings,
    - the impact on UFG from "no bill" customers / volumes that are later billed,
    - the role, if any, played by line pack in transmission and other high pressure systems in the incidence and determination of UFG, and
    - the Company's investigation plan for assessing fugitive emissions.[3]

6. Accordingly, to support the relief sought by Enbridge Gas and to satisfy commitments previously made regarding UFG volumes, Enbridge Gas is providing additional detail surrounding recent learnings and observations made regarding UFG, the impact of No-Bills and transmission and high-pressure system Linepack

[2] EB-2023-0092, Decision on Settlement Proposal and Rate Order, February 6, 2024, p.4.
[3] As agreed in the EB-2022-0200 Settlement Proposal, Exhibit O1, Tab 1, Schedule 1, June 28, 2023, pp. 36-37.

on UFG, and the Company’s Fugitive Emissions Measurement Project. The additional detail broadly applies to all rate zones unless otherwise indicated and is set out at Exhibit D, Tab 1.

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 2023, the Company purchased 25,047 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 2023 is $25.12/$10^3m^3$ lower than the OEB-approved reference prices included in rates based on the Union South rate zone gas portfolio cost of $179.35/$10^3m^3$. The result is a $0.63 million balance to be refunded to ratepayers, as shown in Table 1. Table 2 provides the detailed calculation supporting the price variance of $25.12/$10^3m^3$.

Table 1
Calculation of 2023 UFG Price Variance

Line No.	Particulars	UFG Volumes (10^3m^3)
1	Experienced Regulated UFG (1)	110,438
2	UFG Collected through CSF	85,390
3	UFG Volumes – Company Supplied (2)	25,047
		Deferral Calculation
4	UFG Volumes (10^3m^3) – Company Supplied (2)	25,047
5	Price Variance ($/$10^3m^3$) (3)	$(25.12)
6	Variance Account Balance ($ millions)	$(0.63)

Notes
(1) Converted using the following heat values (39.12 Jan-Mar) (39.17 Apr – Dec).
(2) UFG Volumes represent gas supply related to actual UFG volumes on behalf of ratepayers who do not provide UFG in kind as part of CSF.
(3) See Table 2 for the price variance calculation.

Table 2
Calculation of 2023 Union South Price Varaince

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average Price
1	Board Approved Reference Price ($ / 10^3m^3)	$260.27	$260.27	$260.27	$156.99	$156.99	$156.99	$142.15	$142.15	$142.15	$158.01	$158.01	$158.01	$179.35
2	Actual Purchase ($)	$84,284,125	$53,867,441	$43,742,400	$29,850,340	$33,298,860	$32,522,592	$26,349,940	$41,063,934	$40,695,471	$25,203,931	$40,760,374	$43,793,987	
3	Purchase Volumes (10^3m^3)	323,298	282,273	281,039	225,234	261,806	273,778	192,873	315,344	302,906	165,919	250,496	293,222	
4	Average Purchase Cost (Union South) ($ / 10^3m^3) (1)	$260.70	$190.83	$155.65	$132.53	$127.19	$118.79	$136.62	$130.22	$134.35	$151.91	$162.72	$149.35	$154.24
5	Union South Price Variance ($ / 10^3m^3) (2)	$0.44	($69.43)	($104.62)	($24.46)	($29.80)	($38.20)	($5.53)	($11.93)	($7.80)	($6.11)	$4.71	($8.66)	($25.12)

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

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 \$0.268 million plus interest of \$0.010 million for a total debit balance of \$0.278 million. The balance of \$0.268 million represents the difference between the revenue requirement of \$26.537 million included in 2023 rates (EB-2022-0133) and the calculation of the actual revenue requirement for 2023 of \$26.805 million as shown in Table 1.

Table 1

2023 Lobo C Compressor/Hamilton-Milton Pipeline Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	Col. 1 2023 Board-approved (a)	Col. 2 2023 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	290,349	289,578	(771)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses	898	1,378	480
5	Depreciation Expense (1)	8,261	8,214	(47)
6	Property Taxes	1,258	1,123	(135)
7	Total Operating Expenses	10,417	10,715	298
8	Required Return (2)	15,578	15,536	(42)
9	Total Operating Expense and Return	25,995	26,252	257
	Income Taxes:			
10	Income Taxes - Equity Return (3)	3,370	3,356	(14)
11	Income Taxes - Utility Timing Differences (4)	(2,828)	(2,803)	25
12	Total Income Taxes	542	553	11
13	Total Revenue Requirement	26,537	26,805	268

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 2023 required return calculation is as follows:
$289.578 million * 64% * 3.36% = $6.227 million plus
$289.578 million * 36% * 8.93% = $9.309 million for a total of $15,536 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 $0.771 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 $0.480 million higher than the costs included in 2023 OEB-approved rates. The increase is a result of higher general maintenance and repairs to equipment and assets incurred in 2023, not in the original forecast.

5. Property taxes were $0.135 million lower than costs included in 2023 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 2023.

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 2023, there were 5 interruption events called in the Union North rate zone for a total of 23 days and 1 interruption event called in the Union South rate zone for a total of 5 days. Two (2) customers were not compliant with interruptions in 2023, resulting in unauthorized overrun non-compliance charges and a credit to ratepayers of $0.0455 million, plus interest of $0.0043 million for a total credit to ratepayers of $0.0498 million.

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 $0.066 million plus interest of ($0.039) million, for a total debit balance of $0.027 million. The principal balance of $0.027 million includes a debit of $1.437 million which represents the difference between the revenue requirement of $47.480 million included in 2023 rates (EB-2022-0133) and the calculation of the actual revenue requirement for 2023 of $48.917 million as shown in Table 1.

3. The principal balance also includes a $1.371 million credit, which relates to the 2023 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 2023 year is calculated based on the M12 Dawn-Parkway rate of $3.760/GJ approved in the EB-2022-0133 Rate Order, dated November 3, 2022. A schedule supporting the 2023 revenue calculation is provided at Exhibit E, Tab 1, Schedule 6.

Table 1
2023 Dawn H/Lobo D/Bright C Compressor Project Rate Base And Revenue Requirement

Line No.	Particulars ($000's)	Col. 1 2023 Board-approved (a)	Col. 2 2023 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	517,534	517,226	(308)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses	1,832	3,008	1,176
5	Depreciation Expense (1)	17,418	17,437	19
6	Property Taxes	1,089	1,087	(2)
7	Total Operating Expenses	20,340	21,532	1,192
8	Required Return (2)	27,535	27,519	(16)
9	Total Operating Expense and Return	47,875	49,051	1,176
	Income Taxes:			
10	Income Taxes - Equity Return (3)	5,998	5,995	(3)
11	Income Taxes - Utility Timing Differences (4)	(6,392)	(6,130)	262
12	Total Income Taxes	(394)	(135)	259
13	Total Revenue Requirement	47,480	48,917	1,437

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 2023 required return calculation is as
$517.226 million * 64% * 3.29% = $10.891 million plus
$517.226 million * 36% * 8.93% = $16.628 million for a total of $27.519 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 $0.308 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 $1.176 million higher than the costs included in 2023 OEB-approved rates. The increase is a result of higher salaries/wages, higher contractor and general maintenance costs than budgeted due to a Gas Generator repair at Dawn H, and higher utility costs at Bright C and Lobo D. Table 2 shows the breakdown and comparison of actual 2023 operating and maintenance costs versus OEB-approved.

Table 2
2023 Dawn H/Lobo D/Bright C Compressor Operating And Maintenance Expenses

		Col. 1	Col. 2	Col. 3
Line No.	Particulars ($Millions)	2023 Board-approved	2023 Actuals	Difference
		(a)	(b)	(c) = (b - a)
1	Salaries & Wages	906	1,297	391
2	HR Costs	408	581	174
3	Fleet Costs	136	194	59
4	Training, Travel and PE	69	6	(63)
5	Other O&M (Contract Services)	172	709	537
6	Company Used Fuel	75	-	(75)
7	Utility Costs	66	220	154
8	Total Capital Expenditures	1,832	3,008	1,176

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 $0.043 million plus interest of $0.003 million for a total credit balance of $0.046 million. The balance of $0.046 million represents the difference between the revenue requirement of $5.840 million included in 2023 rates (EB-2022-0133) and the calculation of the actual revenue requirement for 2023 of $5.797 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
2023 Burlington Oakville Pipeline Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	Col. 1 2023 Board-approved (a)	Col. 2 2023 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	71,351	71,235	(116)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses	18	-	(18)
5	Depreciation Expense (1)	1,732	1,737	5
6	Property Taxes	140	120	(20)
7	Total Operating Expenses	1,889	1,857	(32)
8	Required Return (2)	3,828	3,822	(6)
9	Total Operating Expense and Return	5,717	5,679	(38)
	Income Taxes:			
10	Income Taxes - Equity Return (3)	828	826	(2)
11	Income Taxes - Utility Timing Differences (4)	(705)	(708)	(3)
12	Total Income Taxes	123	117	(6)
13	Total Revenue Requirement	5,840	5,797	(43)

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 2023 required return calculation is as follows:

$71.235 million * 64% * 3.36% = $1.532 million plus

$71.235 million * 36% * 8.93% = $2.290 million for a total of $3.822 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.

2023 ONTARIO ENERGY BOARD COST ASSESSMENT VARIANCE ACCOUNT UNION RATE ZONES

1. The purpose of the 2023 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 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 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 2023 OEBCAVA is $1.630 million, plus interest of $0.131 million for a total debit balance of $1.761 million. This amount reflects the variance between OEB costs assessed to Enbridge Gas (relevant to Union rate zones) in each quarter of fiscal 2023, utilizing the revised CAM, and Union'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 2023 Union rate zones OEBCAVA, the Company first needed to apportion the actual 2023 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,

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

2019), and continuing since, EGI has been receiving one consolidated quarterly bill for the amalgamated utility. To apportion the quarterly assessments received in 2023 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 2023 assessed costs to the Union rate zones, and the calculation of the amount recorded in the 2023 Union rate zones OEBCAVA.

4. To calculate the amount for recovery through the 2023 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-2020-0134 OEB-approved Settlement Proposal, and methodology subsequently approved through the EB-2021-0149, 2020 Earnings Sharing and Deferral and Variance Account Clearance proceeding, 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 2023 base comparator, the Company escalated the 2022 quarterly comparator of $0.762 million by the sum of the 2023 Price Cap Index (PCI) of 3.60%, and the Union rate zones ICM threshold calculation Growth Factor (g) of 1.39%. The 2023 PCI was approved as part of Enbridge Gas's 2023 Rate Application, EB-2022-0133. The 2023 ICM threshold calculation Growth Factor was not filed as part of the 2023 Rate Application, as no ICM funding was requested, but has been calculated using the same methodology as the 2022 ICM threshold calculation Growth Factor, which was approved as part of Enbridge Gas's 2022 Rate Application, EB-2021-0147/0148. The escalation resulted in a 2023 quarterly comparator of $0.800 million ($0.762 million * (1 + (3.60% + 1.39%))). As noted above, Table 2 shows

the apportionment of Enbridge Gas's actual 2023 assessed costs to the Union rate zones, and the calculation of the amount recorded in the 2023 Union rate zones OEBCAVA utilizing a base comparator of $0.800 million.

5. Within this proceeding, the Company is requesting clearance of the principal and interest balances recorded in the 2023 OEBCAVA, in the amount of $1.630 million and $0.131 million respectively, as shown in Exhibit C, Tab 1, Schedule 1.

Table 1

2018/2019 OEB Cost Assessments

Line No.		EGD	UGL	Total
1	Apr. 1 to Jun. 30, 2018	1,467,963	988,479	2,456,442
2	Jul. 1 to Sep. 30, 2018	1,356,860	913,873	2,270,733
3	Oct. 1 to Dec. 31, 2018	1,356,860	913,873	2,270,733
4	Jan. 1 to Mar. 31, 2019	1,356,860	913,873	2,270,733
5		5,538,543	3,730,098	9,268,641
6	Percentage of Total	59.76%	40.24%	100.00%

Table 2

Calculation of 2023 UGL RZ OEBCAVA

Line No.	Period	EGI Assessment	UGL Rate Zone Share (40.24%)	Average Cost assessment Comparator	Variance to UGL Rate Zone OEBCAVA
1	Jan. 1 to Mar. 31, 2023	2,738,849.00	1,102,112.84	800,283.18	301,829.66
2	Apr. 1 to Jun. 30, 2023	3,141,892.00	1,264,297.34	800,283.18	464,014.16
3	Jul. 1 to Sep. 30, 2023	3,062,860.00	1,232,494.86	800,283.18	432,211.68
4	Oct. 1 to Dec. 31, 2023	3,062,860.00	1,232,494.86	800,283.18	432,211.68
5		12,006,461.00	4,831,399.90	3,201,132.72	1,630,267.18

2023 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 2023 was $2.136 million. On an actual basis, the Company collected $2.057 million demand revenues from the North T-service customers. As a result, the balance in the 2023 North T-service TransCanada Capacity Deferral Account is a collection from ratepayers of $0.079 million plus interest of $0.006 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 $1.884 million plus interest of $0.146 million for a total credit balance of $2.030 million. The balance of $1.884 million represents the difference between the net revenue requirement of $9.576 million included in 2023 rates (EB-2022-0133) and the calculation of the actual net revenue requirement for 2023 of $7.692 million as shown in Table 1.

Table 1
2023 Panhandle Reinforcement Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	Col. 1 2023 Board-approved (a)	Col. 2 2023 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	204,069	200,152	(3,917)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses	17	-	(17)
5	Depreciation Expense (1)	4,944	4,788	(156)
6	Property Taxes	1,885	1,677	(209)
7	Total Operating Expenses	6,846	6,464	(382)
8	Required Return (2)	10,857	10,649	(208)
9	Total Operating Expense and Return	17,703	17,113	(590)
	Income Taxes:			
10	Income Taxes - Equity Return (3)	2,365	2,320	(45)
11	Income Taxes - Utility Timing Differences (4)	(2,598)	(2,599)	(1)
12	Total Income Taxes	(233)	(279)	(46)
13	Total Revenue Requirement	17,470	16,834	(636)
14	Incremental Project Revenue	7,895	9,142	1,247
15	Net Revenue Requirement	9,576	7,692	(1,884)

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 2023 required return calculation is as follows:
$200.152 million * 64% * 3.29% = $4.214 million plus
$200.152 million * 36% * 8.93% = $6.434 million for a total of $10.649 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 $3.917 million from OEB-approved is due to the cumulative capital expenditures being $4.270 million lower than OEB-approved capital expenditures.

2. Operating Expenses

4. Property taxes were $0.209 million lower than costs included in 2023 OEB-approved rates. The decrease is a result of Provincial tax reductions for business education tax rates on commercial, industrial, and pipeline tax in 2023.

3. Required Return

5. The decrease in the required return of $0.208 million is the result of a lower average rate base.

4. Incremental Project Revenue

6. The actual incremental revenue of $9.142 million reflects the impacts of customer growth and expansion by existing customers in the Panhandle market, and is $1.247 million higher than the forecast incremental revenue included in 2023 Rates.

2023 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 2023, 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 $6.7 million, resulting in an annual $40.8 million credit variance. The variance carried forward from 2022 is a $102.0 million credit variance, resulting in a cumulative $142.7 million credit variance through 2023.

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 2023 is an interest

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[1] EB-2015-0040, *Regulatory Treatment of Pension and Other Post-employment Benefits (OPEB) Costs*, September 14, 2017, p.2.

credit to ratepayers of $6.2 million to December 31, 2023[2]. Table 1 sets out the detailed calculation of the forecast accrual versus actual cash payments, and associated interest.

[2] Interest is as of December 31, 2023, as interest on this account is calculated on a cumulative account balance basis.

Table 1

Details Of 2023 Interest Calculated on Forecast Accruals vs Actual Cash Payments in Pension and OPEB Variance Account (No. 179-157)

Line No.	Particulars ($000's)	22-Dec	23-Jan	23-Feb	23-Mar	23-Apr	23-May	23-Jun	23-Jul	23-Aug	23-Sep	23-Oct	23-Nov	23-Dec	Total
1	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
2	Actual cash payments		403	333	1,291	289	270	1,032	231	248	1,072	226	254	1,010	6,660
3	Monthly variance		-3,548	-3,618	-2,660	-3,663	-3,682	-2,919	-3,721	-3,703	-2,879	-3,725	-3,697	-2,941	-40,756
4	Cumulative variance	-101,953	-105,501	-109,119	-111,779	-115,442	-119,123	-122,042	-125,763	-129,466	-132,345	-136,070	-139,767	-142,709	
5	OEB prescribed CWIP rate		5.01%	5.01%	5.01%	5.01%	5.01%	5.01%	5.01%	5.01%	5.01%	5.48%	5.48%	5.48%	
6	Asymmetrical interest		-0.426	-0.440	-0.456	-0.467	-0.482	-0.497	-0.510	-0.525	-0.541	-0.604	-0.621	-0.638	-6.207

INCREMENTAL CAPITAL MODULE DEFERRAL ACCOUNT – UNION RATE ZONES

1. The Incremental Capital Module Deferral Account (ICMDA) records the difference between the actual revenue requirement for approved ICM projects, and the revenues collected through ICM rates approved by the OEB on a project-by-project basis.

2. In the EB-2022-0200 Phase 1 Decision on Settlement Proposal dated August 17, 2023, parties agreed to the clearance of deferral and variance accounts as proposed by Enbridge Gas including ICMDA balances. The balance approved at the time was comprised of actual & forecast amounts. Enbridge Gas is seeking final disposition of the remaining balance in the ICM Deferral Account in this proceeding representative of the variance between the forecast balance approved in the OEB approved Interim Rate Order dated April 11, 2024, and the final actual balances as calculated through December 31, 2023.

3. The balance in this deferral account is a credit to the UGL Rate Zone of $0.384 million plus interest of $0.504 million for a total credit balance of $0.888 million. The balance of $0.384 million represents the difference between the credit balance approved for disposition in the Interim Rate Order, of $26.396 million, and the calculation of the final Union Rate Zone ICMDA credit balance of $26.779 million, as shown in Table 1.

4. The principal variance of $0.384 million for the Union Rate Zone projects is the result of a reduction in the actual revenue requirement of $0.9 million, partially offset by $0.5 million less revenue collected in rates compared to forecast.

5. The interest variance of $0.504 is primarily due to the timing of the clearance of deferral and variance accounts. An anticipated January 1, 2024, clearance date was reflected in the forecast interest balance approved as part of the EB-2022-0200 Interim Rate Order, whereas the approved clearance date was May 1, 2024, resulting in an additional 4 months of interest to be applied to the ICMDA balance of $26.779 million.

Table 1
Summary of Incremental Capital Module Deferral Account
Amounts Requested for Clearance in 2023 ESM Proceeding

Line No.	($000's)	Actual & Forecast Balances Approved for Disposition (EB-2022-0200)[1]			Final Cumulative Balances[2]			Amounts Proposed for Disposition (2023 ESM and Deferral Disposition)[3]		
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Principal	Interest	Total	Principal	Interest	Total	Principal	Interest	Total
	UGL Rate Zone									
1.	Kingsville Transmission Reinforcement Project	(14,100.0)	(1,141.6)	(15,241.6)	(14,301.1)	(1,410.4)	(15,711.5)	(201.1)	(268.8)	(469.9)
2	Windsor Line Replacement Project	(8,100.0)	(655.8)	(8,755.8)	(8,438.6)	(832.2)	(9,270.8)	(338.6)	(176.4)	(515.0)
3	London Lines Replacement Project	(4,195.9)	(339.7)	(4,535.6)	(4,040.0)	(398.4)	(4,438.4)	155.9	(58.7)	97.2
4	Total UGL Rate Zone APCDA	(26,395.9)	(2,137.1)	(28,533.0)	(26,779.7)	(2,641.1)	(29,420.7)	(383.7)	(504.0)	(887.7)

Notes:
(1) EB-2022-0200 Rate Order, Working Papers, Schedule 27, pages 1 & 2; approved in Interim Rate Order dated April 11, 2024.
(2) Reflects 2019 through 2023 actuals.
(3) Represent variances between amounts approved for disposition in the Interim Rate Order and the final cumulative balances based on actuals.

ACCOUNTS WITH A ZERO BALANCE
UNION RATE ZONES

1. The following 2023 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
   - Parkway Obligation Rate Variance Account
   - Unaccounted for Gas Volume Variance Account

Breakdown of Upstream Transportation Optimization Deferral Account - Union Rate Zones

Line No.	Particulars	Col. 1 2013 Board Approved ($000's)	Col. 2 2022 Actual Total ($000's)	Col. 3 2023 Actual Total ($000's)
1	Base Exchange Revenue	(9,118.0)	(8,609.9)	(7,991.8)
2	FT RAM Exchange Revenue	(5,800.0)		
3	Total Exchange Revenue	(14,918.0)	(8,609.9)	(7,991.8)
4	Exchange Revenue Subject to Deferral	(14,918.0)	(8,609.9)	(7,991.8)
5	Ratepayer portion - 90%	(13,426.2)	(7,748.9)	(7,192.6)
6	10% Union Incentive Payment		(861.0)	(799.2)
7	Less: Gas Supply Optimization Margin in Rates	13,426.2	16,648.7	15,279.8
8	2023 Deferral Account Balance receivable from Ratepayers	-	8,899.7	8,087.2

Breakdown Of Short Term Storage Deferral Account (STSDA) - Union Rate Zones

Line No.	Particulars ($000's)	Col .1 Board-Approved 2013	Col. 2 Actual 2022	Col. 3 Actual 2023
	Revenue			
1	C1 Off-Peak Storage	500	138	1,046
2	Supplemental Balancing Services	2,000	1,053	905
3	Gas Loans		(1)	(1)
4	LBA		0	0
5		2,500	1,189	1,950
6	C1 ST Firm Peak Storage	7,883	2,108	2,634
7	Total Revenue (1)	10,383	3,297	4,583
	Costs			
8	O&M (2)	3,810	1,172	627
9	UFG (3)	316	1,521	448
10	Compressor Fuel (4)	1,201	487	271
11	Total Costs	5,327	3,180	1,346
12	Net Revenue (line 7 - 11)	5,056	117	3,237
13	Less Shareholder Portion (10%)	505	12	324
14	Ratepayer Portion	4,551	105	2,914
15	Approved in Rates	4,551	4,551	4,551
16	Deferral balance payable to / (collectable from) ratepayers	(0)	(4,446)	(1,637)

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.
2023 Storage Space & Deliverability

Line No.	Particulars	2023 (1) Storage Space (2) (PJ) (a)		Storage Deliverability (2) (GJ/d) (b)
	Union North Rate Zone			
1	Rate 01	12.0		221,290
2	Rate 10	2.8		63,618
3	Rate 20	2.3		36,813
4	Rate 25	-		-
5	Rate 100	0.1		1,189
6	Total Union North Rate Zone	17.2		322,911
	Union South Rate Zone			
7	Rate M1	40.6		973,899
8	Rate M2	10.7		312,539
9	Rate M4	3.0		171,205
10	Rate M5	0.0		286
11	Rate M7	2.2		66,050
12	Rate M9	0.3		9,286
13	Rate M10	0.0		142
14	Rate T1	1.4		40,244
15	Rate T2	9.9		197,492
16	Rate T3	3.3		69,712
17	Total Union South Rate Zone	71.4		1,840,855
	Ex-Franchise			
18	Excess Utility Storage	1.9	(3)	22,355
19	Rate C1	-		-
20	Rate M12	-		-
21	Rate M13	-		-
22	Rate M16	-		-
23	Total Ex-Franchise	1.9		22,355
24	System Integrity Space	9.5		-
25	Total Union Rate Zone	100.0		2,186,121
	EGD Rate Zone			
26	Rate 1	61.2		1,202,465
27	Rate 6	58.7		958,188
28	Rate 9	-		-
29	Rate 100	-		-
30	Rate 110	2.2		5,052
31	Rate 115	0.5		2,004
32	Rate 125	-		-
33	Rate 135	-		-
34	Rate 145	0.3		-
35	Rate 170	0.8		-
36	Rate 200	2.0		20,259
37	Total EGD Rate Zone	125.8		2,187,969
38	Total Enbridge Gas (line 25 + line 37)	225.8		4,374,090

Notes:
(1) Allocation to rate classes using Board-approved cost allocation methodologies.
(2) Union Rate Zone storage space based on actual W23/24 usage and storage deliverability based on forecast W23/24 requirements. EGD Rate Zone storage space and deliverability based on 2023 Gas Supply plan.
(3) Exhibit E, Tab 1, page 8

Union Gas Limited
Summary of Non-Utility Storage Balances

Line No.	Date	Entitlement (PJ)	Balance (PJ)	% Full (%)	Date	Entitlement (PJ)	Balance (PJ)	% Full (%)
1	1-Oct-23	129.4	118.3	91.5%	1-Nov-23	129.4	124.3	96.1%
2	2-Oct-23	129.4	118.5	91.6%	2-Nov-23	129.4	124.4	96.2%
3	3-Oct-23	129.4	118.8	91.8%	3-Nov-23	129.4	124.6	96.3%
4	4-Oct-23	129.4	119.2	92.1%	4-Nov-23	129.4	124.5	96.2%
5	5-Oct-23	129.4	119.5	92.4%	5-Nov-23	129.4	124.4	96.1%
6	6-Oct-23	129.4	119.8	92.6%	6-Nov-23	129.4	124.4	96.2%
7	7-Oct-23	129.4	120.1	92.9%	7-Nov-23	129.4	124.3	96.1%
8	8-Oct-23	129.4	120.5	93.2%	8-Nov-23	129.4	124.3	96.1%
9	9-Oct-23	129.4	120.9	93.4%	9-Nov-23	129.4	124.4	96.2%
10	10-Oct-23	129.4	121.1	93.6%	10-Nov-23	129.4	124.3	96.1%
11	11-Oct-23	129.4	121.2	93.7%	11-Nov-23	129.4	124.0	95.9%
12	12-Oct-23	129.4	121.5	93.9%	12-Nov-23	129.4	123.6	95.5%
13	13-Oct-23	129.4	121.6	94.0%	13-Nov-23	129.4	123.4	95.4%
14	14-Oct-23	129.4	121.9	94.2%	14-Nov-23	129.4	123.4	95.4%
15	15-Oct-23	129.4	122.1	94.4%	15-Nov-23	129.4	123.6	95.5%
16	16-Oct-23	129.4	122.2	94.5%	16-Nov-23	129.4	124.2	96.0%
17	17-Oct-23	129.4	122.4	94.6%	17-Nov-23	129.4	124.4	96.1%
18	18-Oct-23	129.4	122.8	94.9%	18-Nov-23	129.4	124.6	96.3%
19	19-Oct-23	129.4	123.1	95.1%	19-Nov-23	129.4	124.4	96.1%
20	20-Oct-23	129.4	123.2	95.3%	20-Nov-23	129.4	124.0	95.8%
21	21-Oct-23	129.4	123.7	95.6%	21-Nov-23	129.4	123.9	95.8%
22	22-Oct-23	129.4	124.0	95.8%	22-Nov-23	129.4	123.9	95.7%
23	23-Oct-23	129.4	124.2	96.0%	23-Nov-23	129.4	123.6	95.5%
24	24-Oct-23	129.4	124.5	96.2%	24-Nov-23	129.4	123.0	95.1%
25	25-Oct-23	129.4	124.7	96.4%	25-Nov-23	129.4	122.4	94.6%
26	26-Oct-23	129.4	124.9	96.5%	26-Nov-23	129.4	122.1	94.4%
27	27-Oct-23	129.4	125.2	96.7%	27-Nov-23	129.4	121.2	93.7%
28	28-Oct-23	129.4	125.4	96.9%	28-Nov-23	129.4	119.0	92.0%
29	29-Oct-23	129.4	125.4	96.9%	29-Nov-23	129.4	117.7	91.0%
30	30-Oct-23	129.4	124.9	96.6%	30-Nov-23	129.4	117.0	90.5%
31	31-Oct-23	129.4	124.2	96.0%				

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			4.6
2	Total Short Term Peak Storage Sales		3.2	
3	Storage Space reserved for Utility	100.0		
4	Utility Space Requirement	98.1		
5	Excess Utility Storage Space (line 3 - line 4)	1.9		
6	Total Utility Short Term Peak Storage Sales (line 5)		1.9	
7	Total Non Utility Short Term Peak Storage Sales		1.4	
8	Short Term Peak Storage Net Revenues - Utility (line 6 / line 2 * line 1)			2.6
9	Short Term Peak Storage Net Revenues - Non Utility (line 7 / line 2 * line 1)			1.9

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	Rate 10	Rate M1	Rate M2	Net Account Balance
			(a)	(b)	(c)	(d)	(e)
	Base Rates						
1	2023 Target NAC: m³		2,730.6	149,709.1	2,630.8	148,142.6	
2	2023 Actual NAC: m³		2,709.1	140,937.4	2,680.5	149,348.5	
3	Actual change in NAC: m³ (line 1 - 2)		21.5	8,771.7	(49.7)	(1,206.0)	
	Y Factor Rates						
4	2023 Target NAC: m³		2,763.3	163,046.7	2,572.3	156,374.8	
5	2023 Actual NAC: m³		2,709.1	140,937.4	2,680.5	149,348.5	
6	Actual change in NAC: m³ (line 4 - 5)		54.2	22,109.3	(108.2)	7,026.3	
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)	6,797	17,925	(52,502)	(9,071)	(36,851)
9	2023 Net Annual Average Delivery Rate ($/m3)	(2)	$0.100	$0.066	$0.043	$0.042	
10	2023 Net Annual Average Storage Rate ($/m3)	(3)	$0.050	$0.039	$0.009	$0.009	
11	Delivery Rate Annual Balance Amount ($000)	(4)	$680	$1,178	($2,280)	($382)	($805)
12	Storage Rate Annual Balance Amount ($000)	(4)	$340	$702	($474)	($77)	$491
	Y Factor Rates						
13	Annual Volume Impact (10^3m^3)	(1)	17,258	45,299	(114,669)	46,775	(5,337)
14	2023 Net Annual Average Delivery Rate ($/m3)	(2)	$0.006	$0.009	$0.014	$0.014	
15	2023 Net Annual Average Storage Rate ($/m3)	(3)	$0.000	$0.000	$0.000	$0.000	
16	Delivery Rate Annual Balance Amount ($000)	(4)	$103	$412	($1,588)	$633	($441)
17	Storage Rate Annual Balance Amount ($000)	(4)	$0	$1	$0	$0	$1
	Total Annual Balance Amounts ($000)						
18	Total Delivery Rate Annual Balance Amount (line 11+16)		$783	$1,590	($3,869)	$251	($1,245.5)
19	Total Storage Rate Annual Balance Amount (line 12+17)		$340	$703	($474)	($77)	$491.6
20	Storage Cost Annual Balance Amount ($000)		($420)	($186)	($1,065)	($1,226)	($2,897)
21	Interest ($000)	(5)	$39	$116	($298)	($58)	($201)
22	Total Deferral Account Amounts ($000) (line 18+19+20+21)		$741	$2,222	($5,706)	($1,110)	($3,852.1)

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, 2024.

Calculation of 2023 Transportation Revenues on the Lobo D/Bright C/Dawn H Compressor Project Cost Deferral Account
Union Rate Zones

Line No.	Particulars	Volume (TJ/d) (1)	Actual Revenue ($000's) (2)	Project Surplus Allocation (%)	Revenue Allocation ($000's)
		(a)	(b)	(c)	(d) = (b) x (c)
1	January	30	114	100%	114
2	February	30	114	100%	114
3	March	30	114	100%	114
4	April	30	114	100%	114
5	May	30	114	100%	114
6	June	30	114	100%	114
7	July	30	114	100%	114
8	August	30	114	100%	114
9	September	30	114	100%	114
10	October	30	114	100%	114
11	November	30	114	100%	114
12	December	30	114	100%	114
13	Total		1,371		1,371

Notes
(1) Capacity of 30,393 GJ/d assumed to be sold long term.
(2) Sold at the Dawn to Parkway M12 Rate of $3.760 $/GJ

ALLOCATION AND DISPOSITION OF 2023 DEFERRAL AND VARIANCE ACCOUNT BALANCES

1. The purpose of this evidence is to address the allocation and disposition of 2023 deferral and variance account balances identified at Exhibit C, Tab 1, Schedule 1.

2. Enbridge Gas proposes to dispose of the approved 2023 deferral and variance account balances with the first QRAM application following the OEB's approval, as early as January 1, 2025.

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

1. In accordance with the OEB's EB-2017-0306/EB-2017-0307 Decision and Order (MAADs Decision), the OEB approved new Enbridge 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

2. 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:
   - Earnings Sharing Mechanism Deferral Account (ESMDA),
   - Tax Variance Deferral Account (TVDA),
   - IRP Operating Costs Deferral Account,
   - IRP Capital Costs Deferral Account,
   - Green Button Initiative Deferral Account,
   - Cloud Computing Implementation Costs Deferral Account,
   - Getting Ontario Connected Act Variance Account (GOCA) and,
   - Expansion of Natural Gas Distribution System Variance Account (ENGDSVA),
   - Accounting Policy Changes Deferral Account (APCDA), and
   - Impacts Arising from the COVID-19 Emergency Deferral Account (IACEDA).

3. Enbridge Gas is proposing to dispose of the 2023 balance in the TVDA, IRP Operating Costs Deferral Account, GOCA, and APCDA as part of this application. There is no balance for the ESMDA, IRP Capital Costs Deferral Account, Green Button Initiative Deferral Account, Cloud Computing Implementation Costs Deferral Account, ENGDSVA, and IACEDA as shown at Exhibit C, Tab 1, Schedule 1.

4. The 2023 TVDA balance, including interest, is a credit of $31.198 million. Consistent with the methodology approved by the OEB in previous years, Enbridge Gas has split the credit balance of $31.198 million between the EGD and Union rate zones in

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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. The Green Button Initiative Deferral Account was established in accordance with the EB-2020-0183 Accounting Order. The Cloud Computing Implementation Costs Deferral Account was established in accordance with the 003-2023 Accounting Order. The GOCA was established in accordance with the EB-2023-0143 Decision and Order. The IACEDA was established in accordance with the EB-2020-0133 Report of the OEB.

proportion to the 2018 actual rate base for each rate zone.[2] Splitting the $31.198 million TVDA credit balance in proportion to 2018 actual rate base results in a credit of $16.469 million being allocated to the EGD rate zone and a credit of $14.729 million being allocated to the Union rate zones. The details of the split to rate zones is provided at Exhibit F, Tab 1, Schedule 1.

5. The 2023 IRP Operating Cost Deferral Account balance, including interest, is a debit of $3.328 million. Included in the balance is a $0.301 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 $0.301 million to the Union North rate zone. Consistent with the methodology approved in previous years, Enbridge Gas has split the remaining debit balance of $3.027 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 $3.027 million debit balance in proportion to 2018 actual rate base results in a debit of $1.598 million being allocated to the EGD rate zone and a debit of $1.429 million being allocated to the Union rate zones. The total debit balance to be allocated to the Union rate zones is $1.730 million[6]. The details of the split to rate zones is provided at Exhibit F, Tab 1, Schedule 1.

6. Enbridge Gas proposes to allocate the $0.301 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

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[2] EB-2020-0134 Decision and Order, May 6, 2021, page 16.
[3] $0.279 million of IRP project costs plus $0.022 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] $0.301 million direct assignment for IRP project costs plus $1.429 allocation of remaining balance.

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 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.

7. The 2023 GOCA balance, including interest, is a debit of $33.639 million. As described in Exhibit C, Tab 1, Enbridge Gas proposes to split the balance in the GOCA variance account to rate zones in proportion to the number of locates completed within each rate zone during 2023. Accordingly, splitting the debit balance of $33.639 million in proportion to the 2023 number of locates results in a debit of $20.858 million allocated to the EGD rate zone and a debit of $2.456 million and $10.325 million allocated to the Union North and Union South rate zones, respectively. The calculation of the deferral split to rate zones is provided at Exhibit F, Tab 1, Schedule 1.

8. The GOCA variance account captures the incremental costs of locates resulting from the enactment of Bill 93. Therefore, Enbridge Gas proposes to allocate the balance in each rate zone to rate classes in proportion to the allocation of locate costs included in current approved rates.

9. For the EGD rate zone, Enbridge Gas proposes to allocate the balance in the GOCA variance account related to the EGD rate zone to rate classes in proportion to the allocation of System Operation Distribution Operating Expenses approved by the OEB in EGD's 2018 Cost Allocation Study[8]. For both the Union North and Union South rate zones, Enbridge Gas proposes to allocate the balance in the GOCA variance account related to the Union North and Union South rate zones to rate

[7] EB-2010-0210.
[8] System Operation Distribution Operating Expenses are classified at EB-2017-0086, Exhibit G2, Tab 4, Schedule 3, p. 2, line 2.3 and allocated at EB-2017-0086, Exhibit G2, Tab 5, Schedule 3, lines 4.1-4.4 and line 4.7.

classes in proportion to the allocation of Mains and Services Distribution Operating O&M expenses by rate zone approved by the OEB in Union's 2013 Cost Allocation Study[9].

10. The 2023 APCDA balance, including interest, is a debit of $5.547 million, consisting of a credit of $7.713 million for the EGD rate zone and a debit of $13.260 million for the Union rate zones as provided at Exhibit C, Tab 1, Schedule 2. The proposed cost allocation methodologies are consistent with the methodologies approved by the OEB in the calculation of the APCDA component by rate zone of Rider D as part of Enbridge Gas's Phase 1 rate order in EB-2022-0200. A description of the proposed methodology by rate zone is provided below.

11. Enbridge Gas proposes to allocate the APCDA deferral balance for capitalization vs. expense, interest during construction and overhead capitalization related to the EGD rate zone to EGD rate classes in proportion to the OEB approved rate base in EGD's 2018 cost allocation study. This proposed allocation recognizes the accounting policy changes are primarily related to capital and rate base assets.

12. Enbridge Gas proposes to allocate the APDCA deferral balance for amortized gas supply storage & transportation costs related to the EGD rate zone to EGD rate classes in proportion to the storage deliverability requirements from the OEB approved 2018 cost allocation study for the EGD rate zone. This proposed allocation approach is consistent with the allocation of similar storage costs in the 2018 cost allocation study.

13. Enbridge Gas proposes to allocate the APCDA deferral balance for capitalization vs. expense, interest during construction, depreciation expense and overhead capitalization related to the Union rate zones to Union rate classes in proportion to

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[9] Union North Rate Zone as per EB-2011-0210, Exhibit G3, Tab 5, Schedule 1, pg. 21, Mains & Services line within Distribution Operating O&M expenses. Union South Rate Zone as per EB-2011-0210, Exhibit G3, Tab 5, Schedule 1, pg. 16-17. Mains & Services line within Distribution Operating O&M expenses.

the OEB approved rate base in Union's 2013 cost allocation study. This proposed allocation recognizes the accounting policy changes are primarily related to capital and rate base assets.

14. Enbridge Gas has allocated the split balance of the TVDA, and the remaining 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

15. The 2023 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.

16. The 2023 RNGISVA balance, including interest, is a credit of $0.360 million. In its Decision and Order in EB-2017-0319[10], the OEB determined that RNG injection services is a distribution activity and that it was appropriate to clear the balance in the account to distribution customers and not RNG producers. Accordingly, Enbridge Gas proposes to allocate the balance in the RNGISVA to EGD rate zone rate classes in proportion to 2023 actual throughput volumes.

17. The 2023 Incremental Capital Module deferral account (ICMDA) for the EGD rate zone, including interest, is a credit of $5.141 million. Enbridge Gas proposes to allocate the ICMDA balance for the EGD rate zone to rate classes in proportion to the total design day demands utilizing high pressure mains greater than 4 inches in

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[10] EB-2017-0319, Decision and Order dated October 18, 2018, pp. 21-22.

diameter from the OEB approved 2018 Cost Allocation Study. The proposed cost allocation methodology is consistent with the methodology approved by the OEB in the calculation of the EGD rate zone ICMDA component of Rider D as part of Enbridge Gas's Phase 1 rate order in EB-2022-0200.

18. The remaining 2023 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.

19. 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

20. The 2023 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.

21. The 2023 Incremental Capital Module deferral account ("ICMDA") for the Union rate zone, including interest, is a credit of $0.888 million. As shown in Table 1 of Exhibit E, Tab 1, Page 3, the deferral balance consists of a credit of $0.470 million related to the Kingsville Transmission Reinforcement Project, a credit of $0.515 million related to the Windsor Line Replacement Project, and a debit of $0.097 million related to the London Lines Replacement Project. Enbridge Gas proposes to allocate the ICMDA credit balance related to the Kingsville Transmission Reinforcement Project to Union South in-franchise rate classes in proportion to 2019 Other Transmission design day demands. Enbridge Gas proposes to allocate the ICMDA credit balance related to the Windsor Line Replacement Project to Union South in-franchise rate classes in proportion to 2020 Distribution design day demands. Enbridge Gas proposes to allocate the ICMDA debit balance related to the London Lines Replacement Project

to Union South in-franchise rate classes in proportion to 2021 Union South in-franchise Other Transmission design day demands. The proposed cost allocation methodologies are consistent with the methodologies approved by the OEB in the calculation of Union rate zones ICMDA component of Rider D as part of Enbridge Gas's Phase 1 rate order in EB-2022-0200.

22. The remaining 2023 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.

23. 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

24. Enbridge Gas proposes to dispose of the approved 2023 deferral and variance account balances with the first QRAM application following the OEB's approval, as early as January 1, 2025.

25. Enbridge Gas proposes to dispose of the 2023 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 2025. 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, 2023 to December 31, 2023.

26. 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

27. 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 credit is $5.12.[11]

28. 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 $9.51. For a Rate M1 bundled direct purchase (DP) residential customer, the one-time billing adjustment charge is $1.60.

29. 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 $0.13.

30. 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 $0.47.

31. 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.

[11] In addition to the EGD rate zone 2023 Deferral bill impacts, the allocation of Union rate zone deferrals to Rate M12 results in a bill credit of approximately $0.14 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)	Allocation to Rate Zone	Account Balance Principal	Interest	Total
		(a)	(b)	(c)	(d) = (b+c)
	2023 Tax Variance Deferral Account				
	Allocation -2018 Rate Base (1) (2)				
1	EGD rate zone	6,729	(15.036)	(1.433)	(16.469)
2	Union rate zones	6,018	(13.448)	(1.282)	(14.729)
3	Total Balance (lines 1 + 2) (3)	12,748	(28.483)	(2.715)	(31.198)
	2023 IRP Operating Costs Deferral Account				
4	Total Deferral Account (3)		3.081	0.247	3.328
5	Direct Assignment to Union rate zones (2) (4)		0.278	0.022	0.301
6	Remaining Balance to Be Allocated		2.803	0.225	3.028
	Remaining Balance Allocation- 2018 Rate Base (1) (2)				
7	EGD rate zone	6,729	1.480	0.119	1.598
8	Union rate zones	6,018	1.323	0.106	1.429
9	Total Remaining Balance Allocation	12,748	2.803	0.225	3.028
	Total Balance Allocation				
10	EGD rate zone (line 7)		1.480	0.119	1.598
11	Union rate zones (line 5 + 8)		1.602	0.129	1.730
12	Total Balance (lines 10 + 11)		3.081	0.247	3.328
	2023 Getting Ontario Connected				
	Allocation -2023 Number of Locates (2) (5)				
13	EGD rate zone	605,137	19.782	1.077	20.858
14	Union South rate zone	299,532	9.792	0.533	10.325
15	Union North rate zones	71,250	2.329	0.127	2.456
16	Total Balance (lines 1 + 2) (3)	975,919	31.903	1.736	33.639
	2023 Accounting Policy Changes				
	Allocation -Direct Assigned (2) (6)				
17	EGD rate zone	(7.713)	(8.669)	0.956	(7.713)
18	Union rate zones	13.260	14.180	(0.920)	13.260
19	Total Balance (lines 1 + 2) (3)	5.547	5.511	0.036	5.547

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.
(5) Exhibit C, Tab 1, Schedule 6.
(6) Direct assignment to rate zones consistent with evidence presented at Exhibit C, Tab 1, Table 2.

Enbridge Gas Inc.
EGD Rate Zone
Unit Rate and Type of Service: Clearing in January 2025

		COL.1
		UNIT RATE (¢/m³)
Bundled Services:		
RATE 1	- SYSTEM SALES	(0.2134)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.3502
	- DAWN T-SERVICE	0.3502
	- WESTERN T-SERVICE	(0.2134)
RATE 6	- SYSTEM SALES	(0.2949)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.2686
	- DAWN T-SERVICE	0.2686
	- WESTERN T-SERVICE	(0.2949)
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	(0.5379)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0257
	- DAWN T-SERVICE	0.0257
	- WESTERN T-SERVICE	0.0000
RATE 110	- SYSTEM SALES	(0.5876)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.0241)
	- DAWN T-SERVICE	(0.0241)
	- WESTERN T-SERVICE	(0.5876)
RATE 115	- SYSTEM SALES	(0.5966)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.0330)
	- DAWN T-SERVICE	(0.0330)
	- WESTERN T-SERVICE	0.0000
RATE 135	- SYSTEM SALES	(0.6224)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0000
	- DAWN T-SERVICE	(0.0589)
	- WESTERN T-SERVICE	0.0000
RATE 145	- SYSTEM SALES	(0.6496)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0000
	- DAWN T-SERVICE	(0.0860)
	- WESTERN T-SERVICE	0.0000
RATE 170	- SYSTEM SALES	(0.5881)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.0245)
	- DAWN T-SERVICE	(0.0245)
	- WESTERN T-SERVICE	0.0000
RATE 200	- SYSTEM SALES	(0.5180)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0000
	- DAWN T-SERVICE	0.0455
	- WESTERN T-SERVICE	0.0000
Unbundled Services (Billing based on CD):		
RATE 125	- All	(2.1665)
RATE 300	- All	0.9577
RATE 332	- All	(1.7240)

Enbridge Gas Inc.
EGD Rate Zone
Determination of Balances to be Cleared
From the 2023 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	(41,738.1)	(2,291.5)	(44,029.6)
2.	UNACCOUNTED FOR GAS V/A	(6,922.7)	(266.5)	(7,189.2)
3.	STORAGE AND TRANSPORTATION D/A	18,705.8	1,572.8	20,278.6
4.	DEFERRED REBATE ACCOUNT	2,132.7	187.1	2,319.8
5.	OEB COST ASSESSMENT VARIANCE ACCOUNT	3,732.8	302.1	4,034.9
6.	AVERAGE USE TRUE-UP V/A	14,307.1	785.5	15,092.6
7.	TRANSITION IMPACT OF ACCT CHANGE D/A	-	-	-
8.	INCREMENTAL CAPTIAL MODULE D/A	(4,909.0)	(232.4)	(5,141.4)
9.	DAWN ACCESS COSTS D/A	-	-	-
10.	RNG INJECTION SERVICES V/A	(331.5)	(28.7)	(360.2)
11.	EGD RATE ZONE SUB-TOTAL	(15,022.9)	28.4	(14,994.5)
	EGI ACCOUNTS			
12.	TAX VARIANCE - ACCELERATED CCA - EGD RATE ZONE PORTION	(15,035.8)	(1,433.2)	(16,469.0)
13.	IRP OPERATING COST DEFERRAL ACCOUNT - EGD RATE ZONE PORTION	1,479.5	118.7	1,598.3
14.	GETTING ONTARIO CONNECTED V/A	19,781.8	1,076.6	20,858.4
15.	ACCOUTING POLICY CHANGES D/A	(8,669.0)	956.2	(7,712.8)
16.	EGI SUB-TOTAL	(2,443.4)	718.3	(1,725.1)
17.	TOTAL	(17,466.3)	746.7	(16,719.6)

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 DELIVERY DEMAND TP > 4" ($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)	COL. 11 GOCA ALLOCATION ($000)
	CLASSIFICATION											
1.	TRANSACTIONAL SERVICES D/A	(44,029.6)	(43,851.0)			(60.8)	(117.8)					
2.	UNACCOUNTED FOR GAS V/A	(7,189.2)			(7,189.2)							
3.	STORAGE AND TRANSPORTATION D/A	20,278.6				6,903.4	13,375.2					
4.	DEFERRED REBATE ACCOUNT	2,319.8			2,319.8							
5.	OEB COST ASSESSMENT VARIANCE ACCOUNT	4,034.9								4,034.9		
6.	TAX VARIANCE - ACCELERATED CCA - EGI	(16,469.0)								(16,469.0)		
7.	AVERAGE USE TRUE-UP V/A	15,092.6						15,092.6				
8.	ACCOUNTING POLICY CHANGES D/A	(7,712.8)					(1,997.4)			(5,715.4)		
9.	INCREMENTAL CAPITAL MODULE D/A	(5,141.4)		(5,141.4)	0.0			0.0				
10.	IRP OPERATING COST DEFERRAL ACCOUNT - EGI	1,598.3								1,598.3		
11.	RNG INJECTION SERVICE V/A	(360.2)			(360.2)				0.0			
12.	TRANSITION IMPACT OF ACCT CHANGE D/A	0.0								0.0		
13.	GETTING ONTARIO CONNECTED V/A	20,858.4									0.0	20,858.4
	TOTAL	(16,719.6)	(43,851.0)	(5,141.4)	(5,229.7)	6,842.6	11,260.0	15,092.6	0.0	(16,551.2)	0.0	20,858.4
	ALLOCATION											
1.1	RATE 1	(9,669.7)	(26,047.6)	(2,381.0)	(2,157.8)	3,273.7	6,184.7	9,250.9	0.0	(10,857.4)	0.0	13,064.9
1.2	RATE 6	(4,258.7)	(16,212.2)	(2,090.7)	(2,053.0)	3,132.6	4,879.3	5,841.7	0.0	(4,583.2)	0.0	6,826.6
1.3	RATE 9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.4	RATE 100	(64.2)	(77.0)	0.0	(23.1)	32.6	54.8	0.0	0.0	(51.5)	0.0	0.0
1.5	RATE 110	(1,043.3)	(741.4)	(116.6)	(578.6)	211.4	26.3	0.0	0.0	(198.7)	0.0	354.3
1.6	RATE 115	(118.2)	(0.9)	(72.2)	(163.8)	30.3	10.5	0.0	0.0	(72.9)	0.0	150.9
1.7	RATE 125	(200.6)	0.0	(413.1)	0.0	0.0	0.0	0.0	0.0	(159.5)	0.0	372.0
1.8	RATE 135	(48.7)	(9.3)	(0.2)	(30.8)	0.0	0.0	0.0	0.0	(9.1)	0.0	0.8
1.9	RATE 145	(42.1)	0.8	(4.8)	(23.0)	(13.4)	0.0	0.0	0.0	(16.3)	0.0	14.6
1.10	RATE 170	(68.6)	(8.8)	(4.7)	(112.5)	66.1	0.0	0.0	0.0	(22.9)	0.0	14.2
1.11	RATE 200	(668.8)	(754.6)	(57.4)	(86.9)	109.4	104.4	0.0	0.0	(41.5)	0.0	57.9
1.12	RATE 300	0.1	0.0	(0.7)	0.0	0.0	0.0	0.0	0.0	(1.3)	0.0	2.1
1.13	RATE 332	(536.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(536.9)	0.0	
		(16,719.6)	(43,851.0)	(5,141.4)	(5,229.7)	6,842.6	11,260.0	15,092.6	0.0	(16,551.2)	0.0	20,858.4

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	COL.11
		TOTAL	SALES AND WBT	DELIVERY DEMAND TP > 4"	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DIRECT	NUMBER OF CUSTOMERS	RATE BASE	BUNDLED ANNUAL DELIVERIES	GOCA ALLOCATION
		($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Bundled Services:												
RATE 1	- SYSTEM SALES	(9,846.4)	(26,004.3)	(2,349.0)	(2,128.8)	3,229.7	6,101.6	9,126.6	-	(10,711.5)	-	12,889.3
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	0.0	-	(0.0)	(0.0)	0.0	0.0	0.0	-	(0.0)	-	0.0
	- DAWN T-SERVICE	193.1	-	(28.1)	(25.4)	38.6	72.9	109.1	-	(128.0)	-	154.1
	- WBT	(16.4)	(43.3)	(3.9)	(3.5)	5.4	10.2	15.2	-	(17.8)	-	21.5
RATE 6	- SYSTEM SALES	(8,259.7)	(15,782.3)	(1,315.7)	(1,292.0)	1,971.4	3,070.7	3,676.3	-	(2,884.3)	-	4,296.2
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	103.3	-	(18.1)	(17.8)	27.1	42.2	50.5	-	(39.6)	-	59.0
	- DAWN T-SERVICE	4,122.6	-	(721.1)	(708.1)	1,080.4	1,682.8	2,014.7	-	(1,580.7)	-	2,354.4
	- WBT	(225.0)	(429.9)	(35.8)	(35.2)	53.7	83.6	100.1	-	(78.6)	-	117.0
RATE 9	- SYSTEM SALES	-	-	-	-	-	-	-	-	-	-	-
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	-	-	-	-	-	-	-	-	-	-	-
	- DAWN T-SERVICE	-	-	-	-	-	-	-	-	-	-	-
	- WBT	-	-	-	-	-	-	-	-	-	-	-
RATE 100	- SYSTEM SALES	(73.5)	(77.0)	-	(6.3)	8.9	15.0	-	-	(14.1)	-	-
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	(0.1)	-	-	0.2	(0.2)	(0.4)	-	-	0.3	-	-
	- DAWN T-SERVICE	9.4	-	-	(16.9)	23.9	40.2	-	-	(37.8)	-	-
	- WBT	-	-	-	-	-	-	-	-	-	-	-
RATE 110	- SYSTEM SALES	(706.1)	(677.1)	(11.2)	(55.4)	20.3	2.5	-	-	(19.0)	-	33.9
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	(12.3)	-	(4.8)	(23.6)	8.6	1.1	-	-	(8.1)	-	14.5
	- DAWN T-SERVICE	(257.9)	-	(99.6)	(494.3)	180.6	22.4	-	-	(169.7)	-	302.7
	- WBT	(67.0)	(64.3)	(1.1)	(5.3)	1.9	0.2	-	-	(1.8)	-	3.2
RATE 115	- SYSTEM SALES	(0.9)	(0.9)	(0.0)	(0.1)	0.0	0.0	-	-	(0.0)	-	0.1
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	(35.0)	-	(21.5)	(48.9)	9.0	3.1	-	-	(21.7)	-	45.0
	- DAWN T-SERVICE	(82.2)	-	(50.6)	(114.9)	21.2	7.3	-	-	(51.1)	-	105.8
	- WBT	-	-	-	-	-	-	-	-	-	-	-
RATE 135	- SYSTEM SALES	(10.3)	(9.3)	(0.0)	(0.8)	-	-	-	-	(0.2)	-	0.0
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	-	-	-	-	-	-	-	-	-	-	-
	- DAWN T-SERVICE	(38.4)	-	(0.2)	(30.1)	-	-	-	-	(8.9)	-	0.8
	- WBT	-	-	-	-	-	-	-	-	-	-	-
RATE 145	- SYSTEM SALES	0.9	0.8	0.0	0.1	0.0	-	-	-	0.0	-	(0.0)
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	-	-	-	-	-	-	-	-	-	-	-
	- DAWN T-SERVICE	(43.0)	-	(4.8)	(23.1)	(13.4)	-	-	-	(16.4)	-	14.6
	- WBT	-	-	-	-	-	-	-	-	-	-	-
RATE 170	- SYSTEM SALES	(9.2)	(8.8)	(0.0)	(0.7)	0.4	-	-	-	(0.1)	-	0.1
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	(26.2)	-	(2.0)	(49.3)	29.0	-	-	-	(10.0)	-	6.2
	- DAWN T-SERVICE	(33.2)	-	(2.6)	(62.5)	36.7	-	-	-	(12.7)	-	7.9
	- WBT	-	-	-	-	-	-	-	-	-	-	-
RATE 200	- SYSTEM SALES	(693.6)	(754.6)	(40.8)	(61.8)	77.7	74.2	-	-	(29.5)	-	41.1
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	-	-	-	-	-	-	-	-	-	-	-
	- DAWN T-SERVICE	24.8	-	(16.6)	(25.2)	31.7	30.2	-	-	(12.0)	-	16.7
	- WBT	-	-	-	-	-	-	-	-	-	-	-
Unbundled Services: (Billing based on CD)												
RATE 125		(200.6)	-	(413.1)	-	-	-	-	-	(159.5)	-	372.0
RATE 300		0.1	-	(0.7)	-	-	-	-	-	(1.3)	-	2.1
RATE 332		(536.9)	-	-	-	-	-	-	-	(536.9)	-	-
		(16,719.6)	(43,851.0)	(5,141.4)	(5,229.7)	6,842.6	11,260.0	15,092.6	0.0	(16,551.2)	0.0	20,858.4

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	COL. 11
		TOTAL	SALES AND WBT	DELIVERY DEMAND TP > 4"	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DIRECT	NUMBER OF CUSTOMERS	RATE BASE	BUNDLED ANNUAL DELIVERIES	GOCA ALLOCATION
		(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)
Bundled Services:												
RATE 1	- SYSTEM SALES	(0.2134)	(0.5635)	(0.0509)	(0.0461)	0.0700	0.1322	0.1978	0.0000	(0.2321)	0.0000	0.2793
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVIC	0.3502	0.0000	(0.0509)	(0.0461)	0.0700	0.1322	0.1978	0.0000	(0.2321)	0.0000	0.2793
	- DAWN T-SERVICE	0.3502	0.0000	(0.0509)	(0.0461)	0.0700	0.1322	0.1978	0.0000	(0.2321)	0.0000	0.2793
	- WESTERN T-SERVI	(0.2134)	(0.5635)	(0.0509)	(0.0461)	0.0700	0.1322	0.1978	0.0000	(0.2321)	0.0000	0.2793
RATE 6	- SYSTEM SALES	(0.2949)	(0.5635)	(0.0470)	(0.0461)	0.0704	0.1096	0.1313	0.0000	(0.1030)	0.0000	0.1534
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVIC	0.2686	0.0000	(0.0470)	(0.0461)	0.0704	0.1096	0.1313	0.0000	(0.1030)	0.0000	0.1534
	- DAWN T-SERVICE	0.2686	0.0000	(0.0470)	(0.0461)	0.0704	0.1096	0.1313	0.0000	(0.1030)	0.0000	0.1534
	- WESTERN T-SERVI	(0.2949)	(0.5635)	(0.0470)	(0.0461)	0.0704	0.1096	0.1313	0.0000	(0.1030)	0.0000	0.1534
RATE 9	- SYSTEM SALES	0.0000	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	0.0000
	- ONTARIO T-SERVIC	0.0000	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	0.0000
	- WESTERN T-SERVI	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 100	- SYSTEM SALES	(0.5379)	(0.5635)	0.0000	(0.0461)	0.0652	0.1096	0.0000	0.0000	(0.1030)	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	0.0000
	- ONTARIO T-SERVIC	0.0257	0.0000	0.0000	(0.0461)	0.0652	0.1096	0.0000	0.0000	(0.1030)	0.0000	0.0000
	- DAWN T-SERVICE	0.0257	0.0000	0.0000	(0.0461)	0.0652	0.1096	0.0000	0.0000	(0.1030)	0.0000	0.0000
	- WESTERN T-SERVI	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 110	- SYSTEM SALES	(0.5876)	(0.5635)	(0.0093)	(0.0461)	0.0169	0.0021	0.0000	0.0000	(0.0158)	0.0000	0.0282
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVIC	(0.0241)	0.0000	(0.0093)	(0.0461)	0.0169	0.0021	0.0000	0.0000	(0.0158)	0.0000	0.0282
	- DAWN T-SERVICE	(0.0241)	0.0000	(0.0093)	(0.0461)	0.0169	0.0021	0.0000	0.0000	(0.0158)	0.0000	0.0282
	- WESTERN T-SERVI	(0.5876)	(0.5635)	(0.0093)	(0.0461)	0.0169	0.0021	0.0000	0.0000	(0.0158)	0.0000	0.0282
RATE 115	- SYSTEM SALES	(0.5966)	(0.5635)	(0.0203)	(0.0461)	0.0085	0.0030	0.0000	0.0000	(0.0205)	0.0000	0.0425
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVIC	(0.0330)	0.0000	(0.0203)	(0.0461)	0.0085	0.0030	0.0000	0.0000	(0.0205)	0.0000	0.0425
	- DAWN T-SERVICE	(0.0330)	0.0000	(0.0203)	(0.0461)	0.0085	0.0030	0.0000	0.0000	(0.0205)	0.0000	0.0425
	- WESTERN T-SERVI	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 135	- SYSTEM SALES	(0.6224)	(0.5635)	(0.0004)	(0.0461)	0.0000	0.0000	0.0000	0.0000	(0.0136)	0.0000	0.0013
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVIC	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- DAWN T-SERVICE	(0.0589)	0.0000	(0.0004)	(0.0461)	0.0000	0.0000	0.0000	0.0000	(0.0136)	0.0000	0.0013
	- WESTERN T-SERVI	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 145	- SYSTEM SALES	(0.6496)	(0.5635)	(0.0096)	(0.0461)	(0.0268)	0.0000	0.0000	0.0000	(0.0327)	0.0000	0.0292
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVIC	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- DAWN T-SERVICE	(0.0860)	0.0000	(0.0096)	(0.0461)	(0.0268)	0.0000	0.0000	0.0000	(0.0327)	0.0000	0.0292
	- WESTERN T-SERVI	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 170	- SYSTEM SALES	(0.5881)	(0.5635)	(0.0019)	(0.0461)	0.0271	0.0000	0.0000	0.0000	(0.0094)	0.0000	0.0058
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVIC	(0.0245)	0.0000	(0.0019)	(0.0461)	0.0271	0.0000	0.0000	0.0000	(0.0094)	0.0000	0.0058
	- DAWN T-SERVICE	(0.0245)	0.0000	(0.0019)	(0.0461)	0.0271	0.0000	0.0000	0.0000	(0.0094)	0.0000	0.0058
	- WESTERN T-SERVI	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 200	- SYSTEM SALES	(0.5180)	(0.5635)	(0.0305)	(0.0461)	0.0580	0.0554	0.0000	0.0000	(0.0220)	0.0000	0.0307
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVIC	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- DAWN T-SERVICE	0.0455	0.0000	(0.0305)	(0.0461)	0.0580	0.0554	0.0000	0.0000	(0.0220)	0.0000	0.0307
	- WESTERN T-SERVI	0.0000	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	(2.1665)	0.0000	(4.4612)	0.0000	0.0000	0.0000	0.0000	0.0000	(1.7229)	0.0000	4.0177
	- Customer-specific **											
RATE 300	- All	0.9577	0.0000	(4.4612)	0.0000	0.0000	0.0000	0.0000	0.0000	(8.1385)	0.0000	13.5574
	- Customer-specific **											
RATE 332	- All	(1.7240)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(1.7240)	0.0000	0.0000

Notes:
* Unit Rates derived based on 2023 actual volumes

Enbridge Gas Inc.
EGD Rate Zone
2023 Deferral and Variance Account Clearing
Bill Adjustment in January 2025 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 m^3	SALES (¢/m^3)	ONTARIO TS (¢/m^3)	DAWN TS (¢/m^3)	WESTERN TS (¢/m^3)	SALES CUSTOMERS ($)	ONTARIO TS CUSTOMERS ($)	DAWN TS CUSTOMERS ($)	WESTERN TS CUSTOMERS ($)
1.1	RATE 1 RESIDENTIAL									
1.2	Heating & Water Heating	2,400	(0.2134)	0.3502	0.3502	(0.2134)	(5.12)	8.40	8.40	(5.12)
2.1	RATE 6 COMMERCIAL									
2.2	Heating & Other Uses	22,606	(0.2949)	0.2686	0.2686	(0.2949)	(66.67)	60.72	60.72	(66.67)
2.3	General Use	43,285	(0.2949)	0.2686	0.2686	(0.2949)	(127.66)	116.27	116.27	(127.66)
	CONTRACT SERVICE									
3.1	RATE 100									
3.2	Industrial - small size	339,188	(0.5379)	0.0257	0.0257	0.0000	(1,824.34)	87.10	87.10	-
4.1	RATE 110									
4.2	Industrial - small size, 50% LF	598,568	(0.5876)	(0.0241)	(0.0241)	(0.5876)	(3,517.23)	(144.08)	(144.08)	(3,517.23)
4.3	Industrial - avg. size, 75% LF	9,976,121	(0.5876)	(0.0241)	(0.0241)	(0.5876)	(58,620.35)	(2,401.34)	(2,401.34)	(58,620.35)
5.1	RATE 115									
5.2	Industrial - small size, 80% LF	4,471,609	(0.5966)	(0.0330)	(0.0330)	0.0000	(26,676.30)	(1,477.18)	(1,477.18)	-
6.1	RATE 135									
6.2	Industrial - Seasonal Firm	598,567	(0.6224)	0.0000	(0.0589)	0.0000	(3,725.49)	-	(352.35)	-
7.1	RATE 145									
7.2	Commercial - avg. size	598,568	(0.6496)	0.0000	(0.0860)	0.0000	(3,888.16)	-	(515.02)	-
8.1	RATE 170									
8.2	Industrial - avg. size, 75% LF	9,976,121	(0.5881)	(0.0245)	(0.0245)	0.0000	(58,664.59)	(2,445.58)	(2,445.58)	-

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
2023 Deferral Account Disposition

Line No.	Particulars	Sales/System Gas Unit Rate for Billing Unit Rate (cents/m^3) (a)	Bundled T-Service Unit Rate for Billing Unit Rate (cents/m^3) (b)	T-Service Unit Rate for Billing Unit Rate (cents/m^3) (c)
	Union North West			
1	Rate 01	0.0060	0.0060	0.2907
2	Rate 10	0.6920	0.6920	0.8502
3	Rate 20	0.3875	0.3875	0.0115
4	Rate 25	0.1444	0.1444	0.0061
5	Rate 100	0.0119	0.0119	0.0119
6	Bundled-T Storage Service ($/GJ)	-	-	0.086
	Union North East			
7	Rate 01	0.0214	0.0214	0.2907
8	Rate 10	0.6237	0.6237	0.8502
9	Rate 20	(3.1925)	(3.1925)	0.0115
10	Rate 25	(0.1114)	(0.1114)	0.0061
11	Rate 100	0.0119	0.0119	0.0119
12	Bundled-T Storage Service ($/GJ)	-	-	0.086
13	North T-Service Transportation from Dawn Base Service ($/GJ)	-	-	0.355
	Union South			
14	Rate M1	0.4323	0.0729	-
15	Rate M2	0.3618	0.0024	-
16	Rate M4	0.3472	(0.0122)	-
17	Rate M5	0.5883	0.2289	-
18	Rate M7	0.3583	(0.0011)	-
19	Rate M9	0.3588	(0.0005)	-
20	Rate T1	-	-	(0.0095)
21	Rate T2	-	-	(0.0081)
22	Rate T3	-	-	0.0024

Enbridge Gas Inc.
Union Rate Zones
2023 Deferral Account Balances To Be Cleared
Year Ending December 31, 2023

Line No.	Account Number	Account Name ($000's)	Balance (a)	Interest (b)	Total (c)
1	179-131	Upstream Transportation Optimization	8,087	444	8,531
2	179-107	Spot Gas Variance Account	-	-	-
3	179-108	Unabsorbed Demand Costs Variance Account	42	38	79
4	179-153	Base Service North T-Service TransCanada Capacity	79	6	85
5	179-070	Short-Term Storage and Other Balancing Services	1,638	90	1,727
6	179-133	Normalized Average Consumption	(3,651)	(201)	(3,852)
7	179-132	Deferral Clearing Variance Account	3,372	184	3,557
8	179-151	OEB Cost Assessment Variance Account	1,630	131	1,761
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	(696)	(49)	(745)
13	179-137	Brantford-Kirkwall/Parkway D Project Costs	(3)	(0)	(3)
14	179-142	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	268	10	278
15	179-144	Lobo D/Bright C/Dawn H Compressor Project Costs	66	(39)	27
16	179-149	Burlington-Oakville Project Costs	(43)	(3)	(46)
17	179-156	Panhandle Reinforcement Project Costs	(1,884)	(146)	(2,030)
18	179-162	Sudbury Replacement Project	-	-	-
19	179-138	Parkway Obligation Rate Variance	-	-	-
20	179-143	Unauthorized Overrun Non-Compliance Account	(46)	(4)	(50)
21	179-159	Incremental Capital Module	(384)	(504)	(888)
22	179-157	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Differential V/A	-	(6,208)	(6,208)
23	179-135	Unaccounted for Gas Volume Variance Account	-	-	-
24	179-141	Unaccounted for Gas Price Variance Account	(629)	(132)	(761)
25	Total for Union Rate Zone Specific Accounts (Lines 1 through 24)		7,846	(6,384)	1,462
26	179-382	Earnings Sharing (Union Rate Zones Portion)	-	-	-
27	179-383	Tax Variance - Accelerated CCA (Union Rate Zones Portion)	(13,448)	(1,282)	(14,729)
28	179-385	IRP Operating Costs Deferral Account (Union Rate Zones Portion)	1,602	129	1,730
29	179-386	IRP Capital Costs Deferral Account	-	-	-
30	179-387	Green Button Initiative D/A	-	-	-
31		Cloud Computing Implementation Costs D/A	-	-	-
32	179-324	Getting Ontario Connected V/A	12,121	660	12,780
33	179-380	Expansion of Natural Gas Distribution Systems V/A (Union Rate Zones Portion)	-	-	-
34	179-381	Accounting Policy Changes D/A - Other - EGI	14,180	(920)	13,260
35	179-384	Impacts Arising from the COVID-19 Emergency D/A - EGI	-	-	-
36	Total for EGI Accounts allocated to Union Rate Zones (Lines 26 through 35)		14,455	(1,414)	13,041
37	Total Union Rate Zones Deferral Account Balances (Line 25 + Line 36)		22,301	(7,798)	14,503

Enbridge Gas Inc.
Union Rate Zones
Classification and Allocation of Deferral and Variance Account Balances

Line No.	Particulars ($000's)	Acct No.	Union North					Union South															Total
			Rate 01	Rate 10	Rate 20	Rate 100	Rate 25	M1	M2	M4	M5A	M7	M9	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)
	Gas Supply Related Deferrals:																						
1	Upstream Transportation Optimization	179-131	(661)	(258)	(133)	-	14	7,865	1,445	149	5	54	50	-	-	-	-	-	-	-	-	-	8,531
2	Spot Gas Variance Account	179-107	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(1,889)	(386)	(79)	-	-	2,000	367	38	1	14	13	-	-	-	-	-	-	-	-	-	79
4	Base Service North T-Service TransCanada Capacity Account	179-153	-	-	62	22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85
5	Total Gas Supply Related Deferrals		(2,549)	(644)	(150)	22	14	9,865	1,812	187	6	68	63	-	-	-	-	-	-	-	-	-	8,695
	Storage Related Deferrals:																						
6	Short-Term Storage and Other Balancing Services	179-70	236	67	36	1	-	538	203	91	1	51	9	39	411	44	-	-	-	-	-	-	1,727
	Delivery Related Deferrals:																						
7	Normalized Average Consumption (NAC)	179-133	741	2,222	-	-	-	(5,706)	(1,110)	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,852)
8	Deferral Clearing Variance Account	179-132	619	203	3	3	1	1,942	764	2	0	2	0	1	16	1	-	-	-	-	-	-	3,557
9	OEB Cost Assessment Variance Account	179-151	353	31	26	23	11	890	84	31	35	9	1	23	62	7	166	0	7	4	0	-	1,761
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	(10)	(1)	2	1	126	5	3	4	0	(0)	5	24	(2)	(914)	0	1	4	0	-	(745)
14	Brantford-Kirkwall/Parkway D Project Costs	179-137	(1)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(0)	(0)	-	(3)
15	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	179-142	(7)	4	0	(1)	(1)	(84)	(7)	(3)	(3)	(1)	(0)	(4)	(23)	(0)	409	(0)	(0)	(0)	(0)	-	278
16	Lobo D/Bright C/Dawn H Compressor Project Costs	179-144	(38)	(1)	(2)	(2)	(1)	(94)	(1)	(1)	(4)	0	0	(2)	(1)	2	176	0	(2)	(1)	(0)	-	27
17	Burlington-Oakville Project Costs	179-149	(3)	(0)	(0)	(0)	(0)	(23)	(7)	(2)	(0)	(1)	(0)	(2)	(12)	(2)	6	0	(0)	0	0	-	(46)
18	Panhandle Reinforcement Project Costs	179-156	(42)	(7)	(5)	(4)	(1)	(466)	(149)	(153)	(6)	(34)	(0)	(102)	(741)	(1)	(55)	(0)	(1)	(217)	(47)	-	(2,030)
19	Sudbury Replacement Project	179-162	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Parkway Obligation Rate Variance	179-138	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Unauthorized Overrun Non-Compliance Account	179-143	-	-	-	-	-	(20)	(7)	(4)	(0)	(2)	(0)	(1)	(15)	(2)	-	-	-	-	-	-	(50)
22	Incremental Capital Module	179-159	-	-	-	-	-	(423)	(153)	(74)	(3)	(35)	(3)	(31)	(155)	(12)	-	-	-	-	-	-	(888)
23	Pension & OPEB Forecast Accrual vs Actual Cash Payment Differential V/A	179-157	(1,247)	(114)	(112)	(94)	(45)	(3,054)	(295)	(124)	(142)	(31)	(5)	(85)	(215)	(24)	(588)	(0)	(20)	(13)	(1)	-	(6,208)
24	Unaccounted for Gas Volume Variance Account	179-135	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Unaccounted for Gas Price Variance Account	179-141	(23)	(3)	(0)	-	(1)	(108)	(43)	(21)	(2)	(28)	(4)	(7)	(77)	(5)	(249)	(1)	-	(184)	(4)	(0)	(761)
26	Tax Variance - Accelerated CCA - EGI	179-383	(2,618)	(403)	(286)	(220)	(78)	(5,717)	(866)	(215)	(183)	(75)	(14)	(149)	(660)	(87)	(3,038)	(2)	(85)	(27)	(4)	-	(14,729)
27	IRP Operating Costs Deferral Account - EGI	179-385	366	75	90	97	23	555	84	21	18	7	1	14	64	8	295	0	8	3	0	-	1,730
28	IRP Capital Costs Deferral Account - EGI	179-386	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Green Button Initiative Deferral Account - EGI	179-387	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Getting Ontario Connected - EGI	179-324	2,010	170	127	111	38	8,629	746	187	256	60	-	129	317	-	-	-	-	-	-	-	12,780
31	Expansion of Natural Gas Distribution Systems V/A	179-380	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Accounting Policy Changes D/A - Other - EGI	179-381	2,356	363	257	198	70	5,147	780	194	164	68	13	134	594	78	2,735	2	77	25	3	-	13,260
33	Impacts Arising from the COVID-19 Emergency D/A - EGI	179-384	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Total Delivery-Related Deferrals		2,472	2,529	98	112	16	1,594	(175)	(160)	134	(59)	(10)	(77)	(821)	(38)	(1,058)	(1)	(15)	(407)	(52)	(0)	4,081
35	Total 2023 Storage and Delivery Disposition (Line 6 + Line 34)		2,708	2,595	134	114	16	2,132	28	(69)	135	(9)	(1)	(38)	(410)	6	(1,058)	(1)	(15)	(407)	(52)	(0)	5,808
36	Total 2023 Deferral Account Disposition (Line 5 + Line 35)		159	1,951	(15)	136	30	11,997	1,841	118	141	59	62	(38)	(410)	6	(1,058)	(1)	(15)	(407)	(52)	(0)	14,503
37	Earnings Sharing Deferral Account - EGI	179-382	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Grand Total (Line 36 + Line 37)		159	1,951	(15)	136	30	11,997	1,841	118	141	59	62	(38)	(410)	6	(1,058)	(1)	(15)	(407)	(52)	(0)	14,503

Enbridge Gas Inc.
Union Rate Zones
Allocation of 2023 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	(1,305)	(246)	(57)	-	-	(1,608)
3	Upstream Transportation Optimization	179-131	562	136	63	-	42	804
4	Total Gas Supply Related Deferrals		(744)	(110)	7	-	42	(804)
	Storage Related Deferrals:							
5	Short-Term Storage and Other Balancing Services (1)	179-70	67	17	3	-	-	88
6	Total North West Deferral Account Disposition (Line 4 + Line 5)		(676)	(93)	10	-	42	(717)
	Union North East							
	Gas Supply Related Deferrals:							
7	Spot Gas Variance Account	179-107	-	-	-	-	-	-
8	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(583)	(140)	(22)	-	-	(746)
9	Upstream Transportation Optimization	179-131	(1,223)	(394)	(196)	-	(28)	(1,841)
10	Total Gas Supply Related Deferrals		(1,806)	(534)	(219)	-	(28)	(2,587)
	Storage Related Deferrals:							
11	Short-Term Storage and Other Balancing Services (1)	179-70	168	50	22	-	-	240
12	Total North East Deferral Account Disposition (Line 10 + Line 11)		(1,637)	(484)	(197)	-	(28)	(2,346)
	Total North							
	Gas Supply Related Deferrals:							
13	Spot Gas Variance Account	179-107	-	-	-	-	-	-
14	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(1,889)	(386)	(79)	-	-	(2,354)
15	Upstream Transportation Optimization	179-131	(661)	(258)	(133)	-	14	(1,037)
16	Total North Gas Supply Related Deferrals		(2,549)	(644)	(212)	-	14	(3,391)
	Storage Related Deferrals:							
17	Short-Term Storage and Other Balancing Services (1)	179-70	236	67	25	-	-	328
18	Total North Deferral Account Disposition (Line 16 + Line 17)		(2,313)	(577)	(187)	-	14	(3,063)

Notes:
(1) Excludes allocation to Rate 20/100 bundled storage service.

Enbridge Gas Inc.
Union Rate Zones
Unit Rates for One-Time Adjustment - Delivery
2023 Deferral Account Disposition

Line No.	Particulars	Rate Class	2023 Deferral Balances ($000's)	2023 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2023 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	2,708	-	2,708	931,782	0.2907
2	Large Volume General Service	10	2,595	-	2,595	305,249	0.8502
3	Medium Volume Firm Service	20	123	-	123	1,074,225	0.0115
4	Large Volume High Load Factor	100	112	-	112	942,952	0.0119
5	Large Volume Interruptible	25	16	-	16	255,665	0.0061
	Union South						
6	Small Volume General Service	M1	2,132	-	2,132	2,925,618	0.0729
7	Large Volume General Service	M2	28	-	28	1,150,624	0.0024
8	Firm Com/Ind Contract	M4	(69)	-	(69)	564,595	(0.0122)
9	Interruptible Com/Ind Contract	M5	135	-	135	58,966	0.2289
10	Special Large Volume Contract	M7	(9)	-	(9)	769,537	(0.0011)
11	Large Wholesale	M9	(1)	-	(1)	97,880	(0.0005)
12	Contract Carriage Service	T1	(38)	-	(38)	397,887	(0.0095)
13	Contract Carriage Service	T2	(410)	-	(410)	5,069,101	(0.0081)
14	Contract Carriage- Wholesale	T3	6	-	6	255,245	0.0024

Enbridge Gas Inc.
Union Rate Zones
Unit Rates for One-Time Adjustment - Gas Supply Commodity
2023 Deferral Account Disposition

Line No.	Particulars	Rate Class	2023 Deferral Balances ($000's)	2023 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2023 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	9,865	-	9,865	2,744,946	0.3594
2	Large Volume General Service	M2	1,812	-	1,812	504,297	0.3594
3	Firm Com/Ind Contract	M4	187	-	187	51,991	0.3594
4	Interruptible Com/Ind Contract	M5	6	-	6	1,767	0.3594
5	Special Large Volume Contract	M7	68	-	68	18,856	0.3594
6	Large Wholesale	M9	63	-	63	17,445	0.3594

Enbridg Gas Inc.
Union Rate Zones
Unit Rates for One-Time Adjustment - Gas Supply Transportation and Bundled Storage
2023 Deferral Account Disposition

Line No.	Particulars	Rate Class	2023 Deferral Balances ($000's)	2023 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2023 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	(744)	-	(744)	261,185	10^3m^3	(0.2847)
2	Large Volume General Service	10	(110)	-	(110)	69,381	10^3m^3	(0.1582)
3	Medium Volume Firm Service	20	7	-	7	1,764	$10^3m^3/d$	0.3760
4	Large Volume Interruptible	25	42	-	42	30,655	10^3m^3	0.1384
	Union North East							
5	Small Volume General Service	01	(1,806)	-	(1,806)	670,597	10^3m^3	(0.2693)
6	Large Volume General Service	10	(534)	-	(534)	235,867	10^3m^3	(0.2265)
7	Medium Volume Firm Service	20	(219)	-	(219)	6,820	$10^3m^3/d$	(3.2040)
8	Large Volume Interruptible	25	(28)	-	(28)	23,960	10^3m^3	(0.1175)
	North T-Service Transportation from Dawn							
9	Base Service ($/GJ)	20T/100T	85	-	85	237,864	GJ/d	0.355
	Storage ($/GJ)							
10	Bundled-T Storage Service	20T/100T	12	-	12	141,504	GJ/d	0.086

Enbridge Gas Inc.
Union Rate Zones
Storage and Transportation Service Amounts for Disposition
2023 Deferral Account Disposition

Line No.	Particulars ($000's) (1)	Rate Class	2023 Deferral Balances	2023 Earnings Sharing Mechanism	Deferral Balance for Disposition
			(a)	(b)	(c) = (a + b)
1	Transportation	M12	(1,058)	-	(1,058)
2	Transportation of Locally Produced Gas	M13	(1)	-	(1)
3	Cross Franchise Transportation	C1	(407)	-	(407)
4	Storage and Transportation Services	M16	(52)	-	(52)
5	Transporation Service	M17	(0)		(0)

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	0.0729	2,200	1.60
2	Commodity	0.3594	2,200	7.91
3	Sales Service Impact	0.4323		9.51
4	Direct Purchase Impact			1.60
	Rate 01 - Union North West			
5	Delivery	0.2907	2,200	6.39
6	Commodity	-	2,200	-
7	Transportation	(0.2847)	2,200	(6.26)
8	Sales Service Impact	0.0060		0.13
9	Bundled-T (Direct Purchase) Impact			0.13
	Rate 01 - Union North East			
10	Delivery	0.2907	2,200	6.39
11	Commodity	-	2,200	-
12	Transportation	(0.2693)	2,200	(5.92)
13	Sales Service Impact	0.0214		0.47
14	Bundled-T (Direct Purchase) Impact			0.47
	Large Volume General Service			
	Rate M2 - Union South			
15	Delivery	0.0024	73,000	1.79
16	Commodity	0.3594	73,000	262.36
17	Sales Service Impact	0.3618		264.15
18	Direct Purchase Impact			1.79
	Rate 10 - Union North West			
19	Delivery	0.8502	93,000	790.70
20	Commodity	-	93,000	-
21	Transportation	(0.1582)	93,000	(147.15)
22	Sales Service Impact	0.6920		643.55
23	Bundled-T (Direct Purchase) Impact			643.55
	Rate 10 - Union North East			
24	Delivery	0.8502	93,000	790.70
25	Commodity	-	93,000	-
26	Transportation	(0.2265)	93,000	(210.62)
27	Sales Service Impact	0.6237		580.09
28	Bundled-T (Direct Purchase) Impact			580.09

Enbridge Gas Inc.
Union Rate Zones
Calculation of One-Time Adjustments for Typical Small and Large Customers

Line No.	Particulars	Deferral Unit Rate (cents/m^3)	Billing Units (m^3)	Bill Impact ($) (1)
		(a)	(b)	(c)
	Union North			
	Small Rate 20 - Union North West			
1	Delivery	0.0115	3,000,000	344
2	Transportation	0.3760	14,000	632
3	Sales Service Impact	0.3875		976
4	Bundled-T (Direct Purchase) Impact			976
	Large Rate 20 - Union North West			
5	Delivery	0.0115	15,000,000	1,722
6	Transportation	0.3760	60,000	2,707
7	Sales Service Impact	0.3875		4,429
8	Bundled-T (Direct Purchase) Impact			4,429
	Small Rate 20 - Union North East			
9	Delivery	0.0115	3,000,000	344
10	Transportation	(3.2040)	14,000	(5,383)
11	Sales Service Impact	(3.1925)		(5,038)
12	Bundled-T (Direct Purchase) Impact			(5,038)
	Large Rate 20 - Union North East			
13	Delivery	0.0115	15,000,000	1,722
14	Transportation	(3.2040)	60,000	(23,069)
15	Sales Service Impact	(3.1925)		(21,347)
16	Bundled-T (Direct Purchase) Impact			(21,347)
	Average Rate 25 - Union North West			
17	Delivery	0.0061	2,275,000	138
18	Transportation	0.1384	2,275,000	3,148
19	Sales Service Impact	0.1444		3,286
20	Bundled-T (Direct Purchase) Impact			3,286
	Average Rate 25 - Union North East			
21	Delivery	0.0061	2,275,000	138
22	Transportation	(0.1175)	2,275,000	(2,672)
23	Sales Service Impact	(0.1114)		(2,534)
24	Bundled-T (Direct Purchase) Impact			(2,534)
	Small Rate 100			
25	T-Service (Direct Purchase) Impact	0.0119	27,000,000	3,220
	Large Rate 100			
26	T-Service (Direct Purchase) Impact	0.0119	240,000,000	28,623
	Union South			
	Small Rate M4			
27	Delivery	(0.0122)	875,000	(107)
28	Commodity	0.3594	875,000	3,145
29	Sales Service Impact	0.3472		3,038
30	Direct Purchase Impact			(107)
	Large Rate M4			
31	Delivery	(0.0122)	12,000,000	(1,466)
32	Commodity	0.3594	12,000,000	43,128
33	Sales Service Impact	0.3472		41,662
34	Direct Purchase Impact			(1,466)

Notes:
(1) Transportation bill impacts based on monthly demand (m^3/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/m^3)	Billing Units (m^3)	Bill Impact ($) (1)
		(a)	(b)	(c)
	Union South (continued)			
	Small Rate M5 Interruptible			
1	Delivery	0.2289	825,000	1,888
2	Commodity	0.3594	825,000	2,965
3	Sales Service Impact	0.5883		4,853
4	Direct Purchase Impact			1,888
	Large Rate M5 Interruptible			
5	Delivery	0.2289	6,500,000	14,876
6	Commodity	0.3594	6,500,000	23,361
7	Sales Service Impact	0.5883		38,237
8	Direct Purchase Impact			14,876
	Small Rate M7			
9	Delivery	(0.0011)	36,000,000	(403)
10	Commodity	0.3594	36,000,000	129,383
11	Sales Service Impact	0.3583		128,981
12	Direct Purchase Impact			(403)
	Large Rate M7			
13	Delivery	(0.0011)	52,000,000	(582)
14	Commodity	0.3594	52,000,000	186,887
15	Sales Service Impact	0.3583		186,306
16	Direct Purchase Impact			(582)
	Small Rate M9			
17	Delivery	(0.0005)	6,950,000	(38)
18	Commodity	0.3594	6,950,000	24,978
19	Sales Service Impact	0.3588		24,940
20	Direct Purchase Impact			(38)
	Large Rate M9			
21	Delivery	(0.0005)	20,178,000	(111)
22	Commodity	0.3594	20,178,000	72,519
23	Sales Service Impact	0.3588		72,409
24	Direct Purchase Impact			(111)
	Small Rate T1			
25	Direct Purchase Impact	(0.0095)	7,537,000	(714)
	Average Rate T1			
26	Direct Purchase Impact	(0.0095)	11,565,938	(1,095)
	Large Rate T1			
27	Direct Purchase Impact	(0.0095)	25,624,080	(2,427)
	Small Rate T2			
28	Direct Purchase Impact	(0.0081)	59,256,000	(4,794)
	Average Rate T2			
29	Direct Purchase Impact	(0.0081)	197,789,850	(16,002)
	Large Rate T2			
30	Direct Purchase Impact	(0.0081)	370,089,000	(29,941)
	Large Rate T3			
31	Direct Purchase Impact	0.0024	272,712,000	6,572

Notes:
(1) Transportation bill impacts based on monthly demand (m^3/d).

2023 SCORECARD RESULTS – ENBRIDGE GAS

1. The purpose of the scorecard is to measure and monitor performance of the utility. The scorecard is produced annually and includes measures in four categories: customer focus, operational effectiveness, public policy responsiveness, and financial performance. 2023 is the fifth year that Enbridge Gas is presenting the scorecard. Enbridge Gas is providing five years of scorecard results (2019 – 2023), at G, Tab 1, Schedule 1.

2. In 2023, Enbridge Gas met or exceeded all elements of the scorecard except for two Service Quality Requirements (SQR) measures: Time to Reschedule Missed Appointment (TRMA) and Meter Reading Performance Metrics (MRPM).

3. In Phase 1 of the Rebasing Application, Enbridge Gas requested a partial exemption for three SQR measures: TRMA, Call Answering Service Level (CASL), and MRPM.

4. The TRMA tracks the percentage of customers contacted to reschedule work within two hours of the end of the original appointment time. In Phase 1 of the Rebasing application Enbridge Gas requested that the TRMA metric be more aligned with the Distribution System Code (DSC) which requires electric utilities to reschedule missed appointments within 1 business day of a missed appointment; and additionally, Enbridge Gas requested that the metric be lowered from 100% to 98%. In the Phase 1 rebasing Decision and Order, the OEB did lower the target to 98% however the decision did leave the requirement at 2 hours rather than 1 business day.[1] As outlined in Phase 1 rebasing evidence, Enbridge Gas has taken mitigation actions[2] to improve TRMA results. Enbridge Gas was able to achieve 97.8% for TRMA in 2023.

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[1] EB-2022-0200 Decision and Order, December 21, 2023, p. 135.
[2] EB-2022-0200 Application and Evidence, Exhibit 1, Tab 7, Schedule 1, p. 19 and Attachment 3.

5. In Phase 1 of the Rebasing Application, Enbridge Gas did apply for a partial exemption for the CASL measure to align with the DSC. Enbridge Gas was able to meet this metric in 2022 and 2023 as a result of the mitigation efforts undertaken from the Company's mitigation plan.[3]

6. Meter Reading Performance Measurement (MRPM) measures the percentage of meters with no read for four consecutive months. As set out in the GDAR, the annual standard for MRPM is not to exceed 0.5% on an annual basis. The metric does not consider why Enbridge Gas has not read a meter.

7. In mid-2021, the OEB compliance staff commenced a review of Enbridge Gas' 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 2022 MRPM mitigation plan[4] with the OEB and as part of an Assurance of Voluntary Compliance (AVC)[5], Enbridge Gas committed to aim for 4% for 2022 (3% when accounting for meters that Enbridge Gas cannot access). The action taken from mitigation planning in 2022 and 2023 have included additional hiring of meter readers, reduction in attrition, extended working hours, collaboration with meter reading vendors to conduct regular performance reviews, process improvements, improved meter reading technology, and marketing campaigns. Overall, the mitigation measures taken have resulted in a 74% improvement in MRPM results from 2021 to 2023. Enbridge Gas was able to significantly decrease the number of meters with consecutive estimates and reached an annual MRPM of 4.1% in 2022 and 1.3% in 2023. Despite significantly improving this metric, there are persisting challenges beyond Enbridge Gas' control that limit the ability for meter readers to access and read a certain portion of gas meters, impairing the ability to achieve this target.

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[3] Ibid, and Attachment 2.
[4] EB-2022-0200, Exhibit 1, Tab 7, Schedule 1, pp. 18-21; and Attachment 4.
[5] EB-2022-0188, [EGI-Assurance-of-Voluntary-Compliance-20220912.pdf (oeb.ca)]

8. In Phase 2 of the Rebasing Application, Enbridge Gas has proposed that all meters with access issues caused by or within the control of the customer to address, be excluded from the MRPM calculation[6]. Customer behaviour impacting the number of inaccessible meters includes; locked gates and inside meters that have unresponsive tenants/landlords, customer sensitivity and obstruction.[7] With access issues removed from the MRPM calculation, Enbridge Gas would have achieved 2.5% in 2022 and 0.7% in 2023. With inaccessible meters removed from the total unread meters count, Enbridge Gas anticipates that the 2024 MRPM will be between 0.5% and 0.6%. Enbridge Gas continues to make efforts to meet the 0.5% target however it would be viewed as a stretch target based on the unknown conditions caused by customer behaviour. For more information on Enbridge Gas' request to remove inaccessible meters from the MRPM calculation can be found in the Company's Phase 2 Rebasing Application (EB-2024-0111), Exhibit 1, Tab 7, Schedule 1.

[6] EB-2024-0111, Application and Evidence, Exhibit 1, Tab 7, Schedule 1, pp. 5-6.
[7] EB-2024-0111, Application and Evidence, Exhibit 1, Tab 7, Schedule 1, pp. 10-13, and Attachment 3.

EGI OEB Scorecard 2019 - 2023

#	Performance Measure	Target	Actual 2023 EGI	Actual 2022 EGI	Actual 2021 EGI	Actual 2020 EGI	Actual 2019 EGI
	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%	99.3%	98.1%	96.9%	98.9%	98.1%
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%	96.3%	95.4%	94.5%	98.8%	98.5%
3	**Telephone calls answered on time (call answering service level)** (# of calls answered within 30 seconds / # of calls received)	75.0%	89.5%	75.9%	64.3%	75.2%	79.0%
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%	100.0%	90.0%	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.'		331,489 manual checks completed as per QAP	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
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%	1.4%	7.1%	16.0%	5.4%	2.50%
7	**Time to Reschedule Missed Appointments** (% of rescheduled work within 2 hours of the end of the original appointment time)	98.0%[1]	97.8%	93.8%	97.0%	97.3%	97.0%
	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%	1.3%	4.1%	5.0%	4.4%	0.7%
9	**% of Emergency Calls Responded within One Hour** (# of emergency calls responded within 60 minutes / # of emergency calls)	90.0%	95.3%	94.1%	95.2%	96.7%	96.7%
10	**Compression Reliability** % reliable for transmission compression		100.0%	100.0%	99.7%	99.7%	99.9%
11	**Damages per 1000 locate requests**		2.10	2.31	1.95	2.22	1.97
12	**Total Cost per Customer** ($ / Customer)		745.7	683.2	643.9	658.2	653.6
13	**Total Cost per km of Distribution Pipe** ($ / km of Distribution Pipe)		19,079.6	17,480.7	16,639.6	16,928.5	16,735.4
	PUBLIC POLICY RESPONSIVENESS (Conservation & Demand Management & Connection of Renewable Generation)						
14	**Total Cumulative Cubic Meters of Natural Gas Saved (Net)** (Millions)		NA[2]	N/A[3]	1,707.5[4]	1,632.2	2,075.9
	FINANCIAL PERFORMANCE (Financial Ratios)						
15	**Current Ratio** (Current Assets / Current Liabilities)		0.92	0.84	0.71	0.66	0.75
16	**Debt Ratio** (Total Debt / Total Assets)		0.39	0.42	0.41	0.40	0.40
17	**Debt to Equity Ratio** (Total Debt / Shareholders' Equity)		0.97	1.10	1.06	1.01	0.98
18	**Interest Coverage** (EBIT / Interest Charges)		1.75	2.54	2.55	2.34	2.53
19	**Financial Statement Return on Assets** (Net Income / Total Assets)		1.20%	2.03%	2.07%	1.97%	2.25%
20	**Financial Statement Return on Equity** (Net Income / Shareholders' Equity)		3.00%	5.37%	5.32%	4.96%	5.56%

[1] Time to Reschedule Missed Appointment target was 100% prior to the Phase 1 Decision

[2] 2023 is in draft pending results

[3] 2022 results will be available in 2024

[4] 2021 results are audited and approved in the DSM Clearance Proceeding

INTEGRATED RESOURCE PLANNING (IRP) ANNUAL REPORT

TO BE FILED AT A LATER DATE

ENBRIDGE

Indigenous Working Group Report
May 31,2024

Table of Contents

ENBRIDGE

1. Introduction

As set out in the complete settlement on item 4 of the Settlement Proposal and accepted by the Ontario Energy Board (OEB) in its Decision on Settlement Proposal in Phase 1 of EB-2022-0200 (2024 Rebasing proceeding), Enbridge Gas Inc. (Enbridge Gas) established an Indigenous Working Group (IWG) and has undertaken a number of activities in relation to the IWG[1]. One of the required activities is for Enbridge Gas to work with the members of the IWG to draft an annual report (IWG Report) summarizing the activities of the IWG and initiatives planned or implemented, including minutes of the IWG meetings. This IWG Report is to be filed as part of Enbridge Gas's annual deferral and variance account (DVA) proceeding. This is the first annual IWG Report.

2. IWG Members

The IWG initially consisted of Ginoogaming First Nation (GFN) and the Three Fires Group (TFG), which groups were intervenors in the Rebasing proceeding. The Settlement Proposal allows for any other First Nation community or reserve to join the IWG provided they or their distribution companies are Enbridge Gas customers. Additional communities that have joined the IWG are Mississaugas of Scugog Island First Nation, Chippewas of the Thames First Nation, Six Nations Natural Gas, and Kettle and Stony Point First Nation (together with GFN and TFG, referred to as the Indigenous Parties).

3. IWG Meetings & Minutes

The IWG has met on a number of occasions commencing with the first meeting on September 18, 2023 (virtual) followed by the following dates (in-person and virtual)

1. September 18, 2023 — virtual
2. October 17, 2023 — in-person
3. December 14, 2023 — in-person
4. April 30, 2024 — in-person

Please refer to Appendix A to this Report for copies of the approved minutes of each meeting.

4. Summary of Discussions

The meetings are managed in accordance with a collaborative approach of determining agenda items and taking turns chairing. Enbridge Gas representatives have attended meetings and provided presentations, providing information and agenda requests from IWG members. Overall, the group looks for opportunities to expand on the discussions

[1] EB-2022-0200, Decision on Settlement Proposal, August 17, 2023, Schedule A, pg. 16-20.

ENBRIDGE

to provide more information for the OEB and others. Discussions at meetings have included the priorities identified by the OEB, however, the Indigenous Parties identified a complementary list of priorities, which the IWG has begun addressing. The priorities as identified by the Indigenous Parties are as follows and are included in the minutes from the October 17, 2023 meeting:

- Energy Transition Programs
    - Heat pump pilots
    - Energy efficiency pilots
    - Geothermal heating pilots
- Access to Natural Gas Act
- Economic Partnerships
- Renewable Natural Gas
- Resilience and Adaptation
    - Stranded assets, cleanup costs, other risks arising from potentially declining customer base
    - Ability of First Nations to transition to alternative sources of energy

Two initiatives have emerged from the IWG meetings held thus far. The first initiative has an IWG member with interest in the topic working with Enbridge Gas on fugitive emissions. The second is a pilot on-reserve Home Winterization program. Progress on these initiatives will be provided in subsequent IWG Reports.

5. Summary of Presentations to the Group

Meetings include presentations from IWG members and Enbridge Gas subject matter specialists to facilitate informed discussion of a topic. The IWG has received the following presentations and resources:

- Letter from Resilient LLP, on behalf of TFG and GFN to the IWG, which set out guiding principles of importance for present First Nations Members of the IWG. Presented to the IWG for its first meeting on September 18, 2023.
- Summary Table of Issues, created and circulated by Resilient LLP, which identified the topics that GFN and TFG would like to see discussed at earlier stages of the IWG meetings, and where external experts may be needed. Circulated and discussed for the October 17, 2023, meeting.
- Overview of Enbridge Gas Inc., led by Enbridge Gas, gave a short introduction and overview of the Enbridge Gas system. Presented to the IWG October 17, 2023.
- Energy Transition Planning at Enbridge Gas, led by Enbridge Gas Manager of Carbon & Energy Transition Planning. The presentation discussed the Pathways Studies to determine the best way forward to GHG net zero and a low carbon future. Presented to the IWG October 17, 2023, at the request of Indigenous

Parties. A follow up presentation was given on December 14, 2023, with a focus on the Clean Home Heating Initiative and IWG input for the Pilot Program.

- Demand Side Management Pilots and Programs, led by Enbridge Gas Manager of Energy Conservation Strategy & Policy alongside Senior Advisor of Indigenous Energy Conservation. The presentation discussed both government and Enbridge Gas initiatives for customers and Indigenous Communities such as the Clean Home Heating Initiative, the Greener Homes Grant, and the Enbridge Gas Home Winterization Program. Presented to the IWG October 17, 2023, at the request of TFG.
- Fugitive Emissions Presentation, led by Enbridge Gas Manager of Carbon Strategy, which included an overview of GHG emission sources, reduction and targets, with an introduction to the Federal Methane Regulations, current emissions reductions, and the Fugitive Emissions Measurement Plan. Presented to the IWG December 14, 2023, at the request of TFG. A follow up presentation on the progress of the Enbridge study into the measurement plan was presented to the IWG on April 30, 2024, at the request of Don Richards and Minogi Corp.
- Access to Natural Gas Act, presentation given by Don Richardson of the TFG recommending that the Natural Gas Expansion Program be adapted so that it is heat technology agnostic and competitive to allow First Nation Community access to low-carbon solutions. Suggestions of pooling funds or utilizing rate payer funds for energy transition. Presented to the IWG December 14, 2023.
- Federal Greener Homes Program Update, presented by Enbridge Gas Manager of Residential Energy Conservation, which discussed updates and status of the program, and how the changes will affect Enbridge Gas' offerings and role as a gas service provider. Presented to the IWG April 30, 2024, at the request of Don Richardson and Minogi Corp.
- Supply Chain Management (SCM) – Indigenous Engagement, presented by Richard Brant, Supply Chain Analyst – Indigenous Engagement, on Enbridge Gas procurement policy, reporting and target setting in SCM. Presented to the IWG April 30, 2024, at the request of TFG.
- Indigenous Employment Practices, presented by Enbridge Inc. Senior strategist on Indigenous Collaboration and Enbridge Inc. Indigenous Recruitment Advisor. Presentation provided an update on the employment practices and opportunities at Enbridge corporate and outlined resources available to Indigenous employees across the entire company. Presented to the IWG April 30, 2024, at the request of TFG.

6. IWG Capacity Funding

Under the Settlement Proposal, Enbridge Gas was required to provide capacity funding for the reasonable costs of each of the Indigenous Parties for their preparation for and participation in the IWG meetings, including reasonable technical expert and legal assistance. The estimated budget for capacity funding to the end of 2024 was $640,000, consisting of:

i. $240,000 for legal support;
ii. $150,000 for general consultants; and
iii. $250,000 for expert analysis and support.

To date, Enbridge Gas has received invoices from Woodward & Co, representing GFN and Resilient LLP, representing TFG, in the amount of $43,453.57, of which $42,694.57 has been fully paid by Enbridge Gas.

The IWG is presenting the 2025 estimated budget for review by the OEB as part of the DVA proceeding. The Indigenous Parties propose the following budget for capacity funding for 2025.

7. IWG Capacity Funding for 2025

The Indigenous Parties presented an estimated budget for capacity funding for the calendar year 2025 of $800,000, described as follows:

1. There is a reasonable likelihood that First Nation membership of the IWG will continue to increase, which would mean increased representation and/or coordination costs.
2. There is an expectation that 2025 will likely see an increased need for expert assistance.
3. There is a growing need to reflect the changing composition of representatives attending and supporting the IWG by amending the previous category of “consultants” to include First Nation representatives who are not consultants.
4. Finally, the costs of the IWG over its first several months of operation are likely not representative of the reasonable costs that will be necessary to participate in and support the IWG in the future, since the IWG’s first few months in many ways were a ramp-up period.
    i. $265,000 for legal support;
    ii. $225,000 for consultants and First Nation representatives; and
    iii. $310,000 for experts.

Enbridge Gas will pay the Capacity Funding in accordance with the Settlement Proposal, based on actual reasonable costs incurred and appropriately invoiced by the Indigenous Parties to participate in the IWG.

Enbridge Gas Inc. Indigenous Working Group Minutes - Draft

Minutes of a meeting of the Indigenous Work Group (IWG) held on **September 17,2023**.

PRESENT

Don Richardson	Three Fires Group
Emily Ferguson	Three Fires Group
Nick Daube	Resilient LLP
Kate Kempton	Woodward and Company
Caolan Lemke	Woodward and Company
Jordan George	Kettle and Stony Point First Nation
Catherine Pennington	Enbridge Gas Inc.
Diana Audino	Enbridge Gas Inc.
Lauren Whitwham	Enbridge Gas Inc.

ABSENT WITH REGRETS

Chief Sheri Taylor	Ginoogaming First Nation
Daniel Vollmer	Resilient LLP
Lisa Demarco	Resilient LLP

1. DISCUSSION ITEMS

Logistics:

- Meetings of the IWG should be hybrid (in person but with a virtual option) to ensure inclusion and accessibility. It was recommended that strong audio/visuals be used to greater facilitate virtual participation.
- Suggest the IWG have a rotating or co-facilitator for future meetings.

Attendees:

- Suggest the IWG establish an agenda and priorities and then engage other Communities who might be interested.
- Animbiigoo Zaagi'igan Anishinaabek First Nation has expressed interest in participating. They are mainly off reserve community living with natural gas in Geraldton area.
- Six Nations Natural Gas has also expressed interest in the working group.

- Suggest potential category for those who are seeking natural gas on reserve through Ontario Grant program such as Aroland First Nation.
- Enbridge Gas Inc. currently services 20 First Nation communities directly. There is some distribution to certain areas of Mississaugas of the Credit First Nation and Six Nations of the Grand River as well.
- Need to be mindful of the budget for the IWG.

Focus Areas:

- Reviewed the OEB settlement agreement for focus areas.
- Reviewed the letter provided to Enbridge Gas Inc. from Resilient LLP (Letter). Input into the Letter was provided by other parties to the IWG; the Letter sets out guiding principles of importance for the current First Nation members of the IWG. (For ease of reference, the Letter is attached to these Minutes)
- Discussed spending the October meeting working through the concerns addressed in the Letter and what the IWG wants to achieve, mapping the course out for future meetings.
- Key categories for next meeting and beyond:
    - Energy Transition – birds eye view scenario
    - Pilots and efficiencies
    - RNG Development – Sourcing and how Enbridge Gas Inc. will achieve supply
- Ontario Home Heating Initiative with Ontario government offers pilot projects for municipalities. Would like to explore options for Indigenous Nations to have equipment.
- Recommendation to minimize use of acronyms and explain common terminology to ensure everyone understands and can participate in the discussion.

2. NEXT MEETING

Next meeting will be held on Tuesday October 17 at the Enbridge Gas Inc. office at 500 Consumers Road North York, Ontario M2J 1P8. We will begin at 8:30 and lunch and refreshments will be provided throughout the day.

APPENDIX A – LETTER TO ENBRIDGE GAS FROM RESILIENT LLP CICULATED PRIOR TO IWG MEETING ON SEPTEMBER 14, 2023

resilient LLP

August 23, 2023

Enbridge Gas Inc.
109 Consumers Road West
London, ON N6J 1X7
Attention: Lauren Whitwam

Dear Ms. Whitwam,

Re: Agenda for Initial Meetings of Indigenous Working Group

We write on behalf of Three Fires Group ("**TFG**") and Ginoogaming First Nation ("**GFN**") (collectively, the "**Indigenous Parties**") concerning the initial meetings of the Indigenous Working Group (the "**IWG**"), which the Ontario Energy Board (the "**Board**") approved on August 17 2023 as part of the larger settlement proposal ("**Settlement Agreement**") in the context of Enbridge Gas Inc.'s ("**EGI**") rate application.

The Indigenous Parties are optimistic that the IWG will serve as an effective discussion forum for matters relating to EGI's rates and services, as well as the impact of those rates and services on First Nations. They are similarly eager to see the first meetings of the IWG proceed in September 2023, as anticipated in the Settlement Agreement.

Accordingly, the Indigenous Parties wish to identify a set of initial discussion topics, which they propose should form the primary focus of the IWG's initial meeting(s) in accordance with the range of issues set out in the Settlement Agreement. The Indigenous Parties have identified these topics as priorities on the basis of the significance of their impact to the relevant communities and, in the case of energy transition, with the rationale that certain topics will almost certainly require discussion at many if not all of the IWG's future meetings, such that early agreement relating to how those discussions should develop will be essential to increasing the likelihood of a focused process and constructive outcomes.

The specific topics that the Indigenous Parties identify as priorities and wish to discuss at the initial meetings of the IWG are:

1. **Energy transition programs**.[1] In particular, the Indigenous Parties would like to prioritize the discussion of energy transition programs and the possibility of pilot programs relating to reliability and resilience including, but not limited to, heat pumps, geothermal heating, and energy efficiency.

2. **Opportunities for economic partnership in the context of energy transition.**[2] The Indigenous Parties propose that the potential for partnership relating to renewable natural gas receive early attention in the IWG.

[1] Article 5 of Settlement Agreement's "Focus Areas".
[2] Article 5 of Settlement Agreement's "Focus Areas".

3. **Resilience and adaptation with impact on energy transition for First Nations**.[3] The Settlement Agreement identified such items within this broad category as the risk of stranded assets, clean-up costs, risks arising from a potentially declining customer base, and the ability of First Nations to transition to alternative energy sources. We also view nature-based fire prevention and response to be an integral part of this initiative. The Indigenous Parties recognize the urgent need for preventative actions and there are also larger and more comprehensive issues that may require discussion over the life of the IWG, with input from EGI and outside experts. The Indigenous Parties therefore believe that this general category must receive early attention so that members of the IWG can agree on a path forward that increases the likelihood of focused discussions and constructive outcomes.

4. **The future of the IWG**.[4] The Settlement Agreement identified the objective of establishing a permanent Indigenous roundtable to provide ongoing engagement with Enbridge Gas on rates and energy transition. The Indigenous Parties are optimistic that a successful IWG could serve as a model for constructive discussions elsewhere in the energy sector and beyond. They would like to ensure that the IWG gives regular and consistent thought on how these objectives are best pursued.

5. **Energy transition matters of specific interest to Indigenous Parties.**[5] Two items under this heading that the Indigenous Parties would like to discuss in the early meetings of the IWG are:

    a. the decarbonization of EGI's gas storage operations, including the use of electric compressors instead of gas compressors; and

    b. EGI's current analysis and proposed action plan for addressing fugitive emissions across pipelines, compressor stations, and other point sources.

The Indigenous Parties recognize that the Settlement Agreement assigns responsibility for convening the IWG to EGI. The Indigenous Parties will therefore expect to hear from EGI shortly on this proposed agenda and the meeting logistics, recognizing that the target date of September is only weeks away. In the meantime, the Indigenous Parties are available to discuss the matters raised in this letter at your convenience.

[3] Article 5 of Settlement Agreement's "Focus Areas".
[4] Article 1 of Settlement Agreement's "Focus Areas".
[5] Article 5 of Settlement Agreement's "Focus Areas".

We look forward to hearing from you.

Sincerely,

Lisa (Elisabeth) DeMarco

c. Don Richardson
Emily Ferguson
Kate Kempton
Diana Audino
Catherine Pennington
Tania Persad
Nicholas Daube
Daniel Vollmer

Enbridge Gas Inc. Indigenous Working Group Minutes - Draft

Minutes of a meeting of the Indigenous Work Group (IWG) held on **October 17,2023** at 9:00 a.m. EST at Enbridge Gas Inc., 500 Consumers Road, North York, Ontario M2J 1P8.

PRESENT

Don Richardson (in-person)	Three Fires Group
Emily Ferguson (virtual	Three Fires Group
Nick Daube (in-person)	Resilient LLP, Three Fires Group
John Glover (virtual)	Minodahmun Development LP
Andrew Bubar (virtual)	Tamarack Environmental Associates
Kate Kempton (in-person)	Woodward and Company, Ginoogaming First Nation
Jordan George (virtual)	Kettle and Stony Point First Nation
Tracy Skye (in-person)	Six Nations Natural Gas
Catherine Pennington (in-person)	Enbridge Gas Inc.
Diana Audino (in-person)	Enbridge Gas Inc.
Lauren Whitwham (in-person)	Enbridge Gas Inc.
Sarah Taylor (virtual)	Enbridge Gas Inc.
Sarah Crowell (virtual)	Enbridge Gas Inc.
Brent Bullough (in-person)	Enbridge Gas Inc.
Tania Persad (in-person)	Enbridge Gas Inc.
Henry Ren (in-person)	Enbridge Gas Inc.
Jennifer Murphy (in-person)	Enbridge Gas Inc.
Keith Boulton (in-person)	Enbridge Gas Inc.
Craig Fernandes (in-person)	Enbridge Gas Inc.
Tausha Esquega (in-person)	Enbridge Gas Inc.

ABSENT WITH REGRETS

Chief Sheri Taylor	Ginoogaming First Nation
Daniel Vollmer	Resilient LLP
Lisa Demarco	Resilient LLP
Caolan Lemke	Woodward and Company

1. DISCUSSION ITEMS

Review of Agenda (attached at Appendix A) and Logistics

- Lauren Whitwham presented a Safety Moment on Fall Safety and provided a safety orientation of the meeting location
- IWG confirmed that meetings should continue to be hybrid (in person but with a virtual option) to ensure inclusion and accessibility.

- Decided to rotate facilitator/chair of each IWG meeting. Nick Daube agreed to chair/facilitate the next IWG meeting.
- The meeting minutes from September 18th were discussed, reviewed and approved. Future meeting minutes will include the Action items arising from the meeting.

Overview of discussions and Review of Summary Table of issues circulated by Nick Daube prior to the IWG meeting (attached at Appendix B).

- Ginoogaming First Nation and Three Fires Group advised that they had started to identify the items/topics they would like to see discussed at earlier stages of IWG meetings.
- IWG discussed the order of priority for topics to be discussed at the IWG while recognizing each item is important.
- Consensus that there is an Indigenous perspective within each item.
- Identified areas where experts may be required and what the scope is for those experts.
- Heat pump programs - may need more information from the Crown including Indigenous Services Canada, Ministry of Energy and Natural Resources Canada (NRCan), and Government of Ontario to determine why certain government programs are not available on reserve.
- Recommendation to minimize the amount that Enbridge Gas Inc. is talking at/presenting to the group with a balance between providing necessary information with the input of independent experts.
- Consider providing information to IWG participants for review in advance of IWG meetings so members can be ready to discuss matters.

Discussion Topics for IWG in order of priority for First Nations Participants

1. Heat Pumps
2. Stranded Assets, clean-up costs, and other risks arising from potentially declining customer base.
3. Renewable Natural gas economic partnership
4. Access to Natural Gas Act (not the Natural Gas Expansion Act, which had been inadvertently referenced in the Summary Table of issues circulated by Nick Daube)
5. Energy efficiency pilots and geothermal heating pilots
6. Fugitive emissions – Analysis and action plan for addressing fugitive emissions
7. Nature based fire prevention and response
8. Decarbonization
9. Need for benefits of and costs of energy transition
10. Future of IWG

Areas Requiring third party Experts

1. Stranded assets/Clean-up costs (energy transition)
2. Renewable Natural Gas (RNG) economic partnership
3. Fugitive Emissions
4. Need for, benefits of, and costs of energy transition

- Kate Kempton suggested John Burrows attend an IWG meeting to speak on Indigenous Law from the Anishinaabe perspective.

- Jennifer Murphy advised she could assist the First Nation participants in defining the scope/topics for expert review, if requested by First Nation participants.

Enbridge Gas Inc. Presentations and Discussions related to:

- Overview of Enbridge Gas Inc. – led by Keith Boulton, Director Public Affairs & Ombudsman
- Energy Transition – led by Jennifer Murphy, Manager Carbon & Energy Transition Planning
- Demand Side Management (DSM) pilots and programs – led by Craig Fernandes, Manager Energy Conservation Strategy & Policy and Tausha Esquega, Senior Advisor, Indigenous Energy Conservation
- Discussed DSM programs for Indigenous communities (e.g. Clean Home heating initiative, Greener homes grant, home winterization program)
- Enbridge Gas Inc. advised the Clean Home heating initiative is a limited pilot funded by the provincial (Ontario) government intended to target consumers who had broken air conditioners and to encourage them to install a heat pump, but it is limited by postal code and the consumer receives a rebate of $4,500 if they install a hybrid system.
- Enbridge Gas Inc. advised it is the program administrator/delivery agent for the Greener Homes grant program in Ontario; this is available in certain postal codes where rebates are provided to customers by NRCan. If someone is interested in participating in this program they enter their postal code on Enbridge Gas Inc.'s website to determine eligibility.
- Government initiatives tend to have restrictions (e.g. heat pump grants program is not available to First Nation reserve customers). First Nation participants would like to know why these programs aren't available on reserve and would like to discuss this with government (e.g. Ontario, NRCan, ISC).
- Enbridge Gas Inc. advised it has programs that may be adapted to allow for a streamlined program without upfront costs, starting with a possible pilot program.
- Enbridge Gas Inc. has hired Tausha Esquega to do outreach with Indigenous communities regarding DSM programs.
- Enbridge Gas Inc. advised that the Home Winterization Program is targeted to First Nations and is funded through gas rate payers. First Nations Engineering Services Limited is the delivery agent for on reserve.

Action Items

- Item 1: Indigenous parties to confirm their proposed third party experts for the issues above. Jennifer Murphy to discuss scope with Nick Daube, if requested. Discussion may move forward with only one or two experts proposed for the next meeting.
- Item 2: Enbridge Gas Inc. to confirm details of incentive programs
- Item 3: Enbridge Gas Inc. to discuss with the Natural Gas expansion team limitations on information that can be shared in the IWG discussions without a Non-Disclosure Agreement recognizing public reporting requirements of IWG.
- Item 4: Kate Kempton to follow up with John Burrows to see if he can present to the IWG.

2. NEXT MEETING

Next meeting will be held on Thursday December 14, 2023, at the Enbridge Gas Inc. office at 500 Consumers Road North York, Ontario M2J 1P8. Meeting will begin at 9:00 and lunch and refreshments will be provided throughout the day.

Note for next meeting: Nick Daube will correct the reference to the Gas Expansion Act, as the intent was to discuss the Access to Natural Gas Act. Nick Daube will correct this on the Topic priority table.

APPENDIX A – AGENDA FOR MEETING OF IWG ON OCTOBER 17, 2023

Enbridge Gas Inc. Indigenous Working Group meeting October 17, 2023		**Participants**
9:00-9:15	Safety Moment, Safety Orientation	Lauren Whitwham
9:15-10:30	• Review and approve minutes from meeting on September 18, 2023 • Review objectives of IWG including budget and participants • Review Lisa DeMarco's Letter to EGI dated Aug 23 • Alignment with OEB settlement agreement	All
10:30-10:45	Break	
10:45-12:00	• Alignment with OEB settlement agreement • Future meeting agenda and topic planning session	All
12:00-1:00	Lunch (Overview of EGI)	Keith Boulton, Enbridge Gas Inc.
1:00-2:30	Energy Transition discussion	Jennifer Murphy, Enbridge Gas Inc.
2:30-2:45	Break	
2:45-3:30	DSM (pilots, programs)	Tausha Esquega, Craig Fernandes, Enbridge Gas Inc.
3:30-4:00	Next steps	

APPENDIX B – SUMMARY TABLE OF ISSUES BY NICK DAUBE

CICULATED PRIOR TO IWG MEETING AND UPDATED BY THE IWG ON OCTOBER 17, 2023

Priority Discussion Topics for IWG

Energy Transition Programs

Topic	Suggested EGI Representatives	Third Party Experts	Target for Discussion at Upcoming Meetings	Current Status
Heat pump pilots		No expert likely needed but need Crown (ISC, NRCAN) and Ontario representation	✓ (1)	
Energy efficiency pilots			✓(5)	
Geothermal heating pilots (combined to be Energy eff – emerging technology)			✓ (5)	
Natural Gas Expansion Act			(4) Update on status. Indigenous communities' status.	

Economic Partnership

Topic	Suggested EGI Representatives	Third Party Experts	Target for Discussion at Upcoming Meetings	Current Status
Renewable natural gas		Expert	✓ (3)	

Resilience and Adaptation

Topic	Suggested EGI Representatives	Third Party Experts	Target for Discussion at Upcoming Meetings	Current Status
Stranded assets, clean-up costs, other risks arising from potentially declining customer base	Energy transition expert	Expert Necessary	✓ (2) (Earliest discussions can focus on proposed roadmap, since this is a complicated and long-term discussion topic)	
Need for, benefits of and cost of Energy Transition		Expert	(9)	
Nature-based fire prevention and response			✓ (7)	

Future of the IWG

Topic	Suggested EGI Representatives	Third Party Experts	Target for Discussion at Upcoming Meetings	Current Status
Future of the IWG and its use as a precedent			✓ (Ongoing discussion topic.)	

Energy Transition Matters of Specific Interest to Indigenous Parties

Topic	Suggested EGI Representatives	Third Party Experts	Target for Discussion at Upcoming Meetings	Current Status
Decarbonization of EGI's gas storage operations, including the use of electric compressors instead of gas compressors			(8)	
Analysis and action plan for addressing fugitive emissions across pipelines, compressor stations, and other point sources		Identify leaks in system: GHG SAT First Nations expertise Expert	(6)	
Indigenous procurement on maintenance of Enbridge Gas assets			(10) Ongoing under each category	

Enbridge Gas Inc. Indigenous Working Group Minutes - Draft

Minutes of a meeting of the Indigenous Work Group (IWG) held on **December 14,2023** at 9:00 a.m. EST at Enbridge Gas Inc., 500 Consumers Road, North York, Ontario M2J 1P8.

PRESENT

Don Richardson (virtual)	Three Fires Group
Emily Ferguson (virtual	Three Fires Group
Nick Daube (in-person)	Resilient LLP, Three Fires Group
John Glover (virtual)	Minodahmun Development LP
Kate Kempton (in-person)	Woodward and Company, Ginoogaming First Nation
Jordan George (virtual)	Kettle and Stony Point First Nation
Kodi Deleary	Chippewas of the Thames First Nation
Tracy Skye (in-person)	Six Nations Natural Gas
Diana Audino (in-person)	Enbridge Gas Inc.
Lauren Whitwham (in-person)	Enbridge Gas Inc.
Sarah Taylor (virtual)	Enbridge Gas Inc.
Sarah Crowell (virtual)	Enbridge Gas Inc.
Brent Bullough (in-person)	Enbridge Gas Inc.
Tania Persad (in-person)	Enbridge Gas Inc.
Cara-Lynne Wade (in-person)	Enbridge Gas Inc.
Henry Ren (virtual)	Enbridge Gas Inc.
Jennifer Murphy (virtual)	Enbridge Gas Inc.
Peter Mussio (virtual)	Enbridge Gas Inc.
Islam Elsayed (in-person)	Enbridge Gas Inc.
Craig Fernandes (in-person)	Enbridge Gas Inc.
Tausha Esquega (in-person)	Enbridge Gas Inc.

ABSENT WITH REGRETS

Chief Sheri Taylor	Ginoogaming First Nation
Caolan Lemke	Woodward and Company
Michelle Bomberry	Six Nations Natural Gas
Catherine Pennington	Enbridge Gas Inc.

1. MATTERS FOR DISCUSSION

Review of Agenda (attached at Appendix A) and Logistics.

- Nick Daube of Resilient LLP, representing Three Fires Group, chaired the meeting, consensus to continue to rotate the facilitator/chair of each IWG meeting.

- Lauren Whitwham provided a safety moment on preventative home security and safety while away from home during the holidays.
- IWG welcomed a new representative from the Chippewas of the Thames First Nation as agreed in the OEB Settlement Agreement that any interested Indigenous Party would be included.
- IWG confirmed that the meetings should continue to be hybrid (in person but with a virtual option) to ensure inclusion and accessibility.
- IWG discussed and approved the minutes of the October 17 IWG meeting as drafted.

1. Discussion led by Indigenous parties concerning status of retaining independent experts.
    - Suggested the discussion on experts involve:
        1. Deliverables – What we are asking the experts to put together.
        2. Themes – Consideration of themes that have been raised so far and what we would need comments on in conversation with experts.
        3. Fees – General thinking on fees and how groups go about paying the experts.
    - Deliverables
        - Agreement that the experts shouldn't be re-inventing the wheel, just offering supplemental information.
        - Experts are to offer advice that identifies and begins to think through at a high level what supplemental work should be performed that speaks to risks, opportunities for First Nations and identify the tracks that don't already perform those tasks.
        - Suggested a future presentation to the IWG by an expert (for example, a 90 minute presentation by an Enbridge Gas Inc. representative like Cara-Lynne Wade or a member of Energy Transition Planning group.
        - Not looking for reports from the experts, an informative PowerPoint would be sufficient.
        - Some discussion of the consequences of energy transition and how Enbridge Gas Inc. could help with that.
    - Themes
        - Energy transition is the first topic where an expert would be helpful.
        - Experts would need to provide insight on the challenges of energy transition, specifically those faced by First Nations, including limitations in access to energy sources and energy alternatives.
            - Better understanding of range of possible futures for First Nations participation in energy transition and possible programs that might help in these scenarios.
            - Analysis of areas where expert believes certain reports demonstrate weaknesses, such as fugitive emissions.
        - Would like to retain an expert who is approaching these issues and energy transition from a First Nation's perspective.
        - Expert insight as to where additional effort should be made to the "average" model to account for incessant financial poverty, remoteness, and lack of alternatives that First Nations face.
        - Reiterated by Indigenous parties that economic reconciliation, highlighting the Truth and Reconciliation Call to Action #92, and recognition of jurisdiction of traditional territory should be at the forefront of the discussion. This could include rights-based jurisdiction expertise and Indigenous Knowledge.
    - Experts being considered by Indigenous parties:
        - Pelino Colaiacovo - Morrison Park Advisors (Canada)
        - AJ Golding - London Economics (Canada)
        - Bruce Tsuchida - Brattle Group (US)
    - Fees
        - Indigenous parties confirmed the proposed experts have not yet been retained, and advised that keeping the requests at a high level should keep the costs from hitting the higher limit of the annual expert budget.

    - Ensuring that the requests for work from the experts are purposeful – not asking for full reports, just information that is not from the perspective of Enbridge Gas Inc.
    - Billing should be done by scope of work instead of by hour.
- Regional Pathway Study
    - In reference to the discussion of the Pathway study in the Enbridge Gas Inc. reply in the Rebasing proceeding, Enbridge Gas Inc. noted that the next step in the energy transition is to look at what a regional model, rather than provincial, would look like to properly reflect the actual customers, their usage and the challenges they face.
    - How to accommodate the drawing of regions to effectively include First Nations into the regions.
        - This is to ensure that in transition, customers are not stranded and there is no undo harm done to them including costs, reliability of energy and consumer choice.
    - Expert at the hearing for the Industrial Gas User Association, Dr. Asa S. Hopkins looked at regional modeling and had a high-level idea of what it could include. Enbridge Gas Inc. has undertaken to look through Dr. Hopkins' ideas to determine what scope Enbridge Gas could reasonably complete and in what timeline.
    - This was proposed at the Ontario Energy Board (OEB), and there was discussion as to whether this would be led by the OEB or Enbridge Gas.

2. Fugitive Emissions Presentation
    - Presentation by Peter Mussio, Manager of Carbon Strategy at Enbridge Gas Inc.
    - Topics of presentation were an overview of GHG emission sources, GHG reductions and targets, Fugitive Emissions measurement plan, Federal Methane Regulations, current emissions reductions, and future emission sources.
    - Discussion of Enbridge Gas Inc. study of fugitive emissions of methane gas, and how methane is measured and targets of reduction. Challenges with reductions are finding the technology that can detect the smaller leaks.
    - Emily Ferguson, who has expertise on fugitive emissions, commented on the measurement of methane gas emissions.
        - Proposed by Indigenous Parties to have Emily more involved in the study of fugitive emissions with Enbridge Gas Inc. and the reporting on sources of fugitive emission.
        - Enbridge Gas Inc. advised they are preparing a study and comparison of Enbridge Gas Inc.'s system to other systems and the technology being used. Study targeted to be completed in May 2024. Enbridge Gas to confirm in mid-January whether Emily can participate in the study and use funds from the IWG to assist her participation in the study.
    - Future Action Item would be to review and discuss the report that will be sent to the OEB on fugitive emissions in a meeting of the IWG.

3. Follow up on heat-pump discussion and Presentation
    - Presentation by Energy Transition Team Craig Fernandes and Tausha Esquega with Enbridge Gas Inc. - a return to the Energy Transition presentation from the October 17th IWG meeting.
    - Using the Clean Home Heating Initiative as a contextual example for a possible pilot program for First Nations who are Enbridge Gas customers. The heat pump programs are hybrid systems, so the pilot would need to start in a community that is an existing Enbridge Gas Inc. customer. Due to regulation, funding of the program must flow to gas rate payers.
    - The purpose of the discussion was to seek IWG input for the Pilot on what its goals or objectives should be, how it should be reported, any concerns with marketing heat pumps to First Nation Communities and which communities would be amenable to hosting the pilot.
        - Suggested that community members go door to door to market the program, look for a community that tracks their energy usage, start with a more southern located community so the

heat pumps can be more effective, speak with First Nations Engineering Services to see how their experience has been on retrofitting or implementation in the community.

- Enbridge Gas Inc. will be drafting a plan for a pilot program to start with a winter proofing program in order to save costs and move into a heat pump program. The draft may include a selected community with whom direct engagement has been started for an agreement to host the pilot.

4. Access to Natural Gas Act Discussion and Presentation
   - Presentation from Don Richardson, Three Fires Group, recommending that the Natural Gas Expansion Program be adapted so that it is heat technology agnostic.
   - This would create an environment of competition for access to the funds and could offer First Nations communities easier access to low-carbon solutions.
   - Suggested the future of energy transition include pooling of funds and working with the Electric provider to make rater payer money more applicable to energy transition.
   - Enbridge Gas Inc. representative mentioned it is currently preparing a submission for the next phase of the Access to Natural Gas Act and could consider including the comments from Indigenous parties if provided to Craig Fernandes and Tausha Esquega with Enbridge Gas Inc. by mid-January.

Action Items

- Item 1: Enbridge Gas Inc. to provide map of its distribution system including connections to TC Energy system.
- Item 2: Enbridge Gas Inc. to plan to present and discuss the Report on fugitive emissions that will be submitted to the OEB with the IWG.
- Item 3: Enbridge Gas Inc. to increase information sharing about what is known of the volume, locations, and mitigations of fugitive emissions.
- Item 4: Enbridge Gas Inc. Energy Transition team to determine how they can incorporate the expertise of Emily Ferguson and utilize her input on fugitive emissions in the study.
- Item 5: Enbridge Gas Inc. to draft a scope for the pilot program, conduct direct engagement with selected community for agreement to host and implement planning.
- Item 6: Enbridge Gas Inc. Energy Transition Team to return to the next IWG to discuss the winterization program and DSM.
- Item 7: Indigenous parties that have comments on the Judicial Review that was filed by the Chiefs of Ontario against the federal government about the Fuel Services Act to share their comments with Enbridge Gas Inc. by mid-January 2024 so Enbridge Gas Inc. can consider including them in their submission.

5. NEXT MEETING

Next meeting will be held on Tuesday February 27, 2024, at the Enbridge Gas Inc. office at 500 Consumers Road North York, Ontario M2J 1P8. Meeting will begin at 9:00 and lunch and refreshments will be provided throughout the day.

APPENDIX A – AGENDA FOR MEETING OF IWG ON DECEMBER 14, 2023

Time	Matter	Participants
9:00-9:15	Preliminary matters, safety moment, approval of minutes.	Group
9:15-10:15	Discussion led by Indigenous Parties concerning status of retaining independent experts.	Group EGI – Cara-Lynn Wade and Jennifer Murphy
10:15-11:15	EGI presents on Fugitive Emissions	EGI - Peter Mussio Group
11:15-12:00	Discussion of Access to Natural Gas Act	Don Richardson
12:00-1:00	Lunch	
1:00-1:45	Follow up on heat pumps discussion and progress update	EGI - Craig Fernandes and Tausha Esquega
1:45-2:30	Discussion on potential for similar pilot programs in DSM or geothermal (or other) areas	EGI - Craig Fernandes and Tausha Esquega
2:30-3:00	Debrief and planning	Group

Enbridge Gas Inc. Indigenous Working Group Minutes - Draft

Minutes of a meeting of the Indigenous Work Group (IWG) held on **April 30,2024** at 9:00 a.m. EST at Enbridge Gas Inc., 500 Consumers Road, North York, Ontario M2J 1P8.

PRESENT

Don Richardson (in-person)	Minogi Corp
Emily Ferguson (virtual	Minogi Corp
Todd Jardine (virtual)	Three Fires Group
Reggie George (virtual)	Three Fires Group
Jessica Wakefield (in-person)	Three Fires Group
Nick Daube (in-person)	Resilient LLP, Three Fires Group, Minogi Corp
John Glover (virtual)	Minodahmun Development LP
Kate Kempton (in-person)	Woodward and Company, Ginoogaming First Nation
Jordan George (virtual)	Kettle and Stony Point First Nation
Jennifer Mills (virtual)	Chippewas of the Thames First Nation
Tracy Skye (in-person)	Six Nations Natural Gas
Diana Audino (in-person)	Enbridge Gas Inc.
Lauren Whitwham (in-person)	Enbridge Gas Inc.
Tania Persad (in-person)	Enbridge Gas Inc.
Brent Bullough (in-person)	Enbridge Gas Inc.
Sarah Taylor (in-person)	Enbridge Gas Inc.
Craig Fernandes (in-person)	Enbridge Gas Inc.
Richard Brant (in-person)	Enbridge Gas Inc.
Mark Shilliday (virtual)	Enbridge Gas Inc.
Peter Mussio (virtual)	Enbridge Gas Inc.
Sarah Crowell (virtual)	Enbridge Gas Inc.
Henry Ren (virtual)	Enbridge Gas Inc.
Jody Whitney (virtual)	Enbridge Gas Inc.

1. MATTERS FOR DISCUSSION

Review of Agenda (attached at Appendix A) and Logistics.

- Lauren Whitwham, Enbridge Gas Inc., chaired the meeting, consensus to continue to rotate the facilitator/chair of each IWG meeting.
- Brent Bullough provided a safety moment. Lauren Whitwham proposed that going forward any interested IWG members could share a safety or cultural moment at a future meeting.
- IWG welcomed additional Indigenous representatives from Three Fires Group and confirmed as per the Ontario Energy Board (OEB) Settlement Agreement any interested Indigenous Party could be included in the IWG.
- IWG confirmed that the meetings should continue to be hybrid (in person, but with a virtual option) to ensure inclusion and accessibility.
- IWG discussed and approved the minutes of the December 14, 2023 IWG meeting.

1. Updates related to OEB Rebasing Proceeding
   - Tania Persad provided an overview of the OEB Decision and Order EB-2022-0200, Enbridge Gas Inc. Application for 2024 Rates – Phase 1 (Rebasing Decision) and its implications to the IWG.
     - Details of the Rebasing Decision were discussed and explained to the IWG.
     - Enbridge Gas advised that it has filed a Motion to Review with OEB (Review Motion) and a Notice of Appeal with the Ontario Divisional Court. The Review Motion will be dealt with first but is currently in abeyance until June. The OEB stayed part of the Rebasing Decision dealing with the revenue horizon.
     - Discussions of the Provincial Government's proposed legislation, Bill 165, to set aside the revenue horizon portion of the Rebasing Decision and to require the OEB to set a revenue horizon through a generic proceeding that takes into account the views of impacted parties.
     - Noted Enbridge Gas's plan to file an amended notice of Review Motion, to remove at least the revenue horizon issue.
   - Phase 2 of the rebasing proceeding has commenced with Enbridge Gas's evidence filed at the end of April 2024.
     - The procedural order issued by the OEB and the issues included in the order were discussed.
   - Kate Kempton on behalf of Ginoogaming gave notice to the group that Ginoogaming is thinking of challenging Bill 165 on the basis that it is not tough on climate change and places an undue burden on Indigenous groups who already pay a higher proportion of their income on basic living expenses including natural gas costs.
     - A request was made that Enbridge Gas Inc. consider changing its stance on the legislation and voicing to the government that this legislation is not in the best interest of Indigenous groups.
     - A request was made that a meeting in the future include both the Chief of Ginoogaming and a high level representative of Enbridge Gas to discuss the direction Enbridge Gas is heading with this.
   - Kate Kempton, on behalf of Ginoogaming, spoke at length about Indigenous way of life including a much more holistic and interconnected worldview and relationship to all beings, of caring for all beings and Mother Earth. She spoke on how the Western worldview, which came to dominate North America through colonialism, is atomistic, linear and based on dominance and exploitation of the Earth, which is what has led to the catastrophe of climate change that threatens to be an extinction event. Unless and until those who are responsible and profit from goods that cause climate change accept that the status quo and incremental change will only see us to an extinction, and that fundamental change is necessary now, we will fail. One of those is Enbridge, and we are appealing to Enbridge to learn from and work with First Nations to make this fundamental shift away from gas, starting right now.
   - Frustration by all IWG parties was shared about the recent IESO Expedited Long Term Procurement process, where many clean energy projects were not selected for funding, including the battery storage project between Enbridge Gas and Three Fires Group.

2. Updates on the Enbridge Gas fugitive emissions study.
   - Presentation by Peter Mussio, Manager of Carbon Strategy at Enbridge Gas Inc. as requested by Don Richardson and Minogi Corp.
   - The presentation gave an outline and purpose of the study that has been completed, and a review of the findings and technology that is available.
   - The study was outlined to the group with explanations on the measurements and the technology review that took place. The purpose of the study is to improve the accuracy of methane emissions being detected and recorded, and determining which technology is best suited to measure these emissions on the Enbridge Gas system. The goal is to implement this technology on the system to improve data accuracy to help identify potential options for mitigation going forwards.
   - Reviews of technology are being undertaken to determine potential capabilities to not only detect a source, but to quantify the type of emission. Mobile ground detection is most effective and practical for

the system, and a pilot program using these methods is being created to develop a system specific assessment.
- A final draft of the pilot program and assessment will be circulated to the Enbridge Gas consultant in the next few weeks, and once finalized, will make a part of the deferral account in June.
- A request was made to promptly involve Emily Ferguson of Minogi Corp in the process, so she can be involved in the next steps as much as possible. IWG members would like this to be a collaborative and ongoing commenting process.
    - o Enbridge Gas will get in touch with Emily and facilitate a way to keep her more involved going forward.

3. Presentation update on CGHG/HER+ programs, as requested by Minogi Corp.
    - Presentation by Energy Conservation Team Craig Fernandes of EGI, on the wind down of CGHG/HER+.
    - Program uptake was wildly successful such that the initial budget forecast for 2023-Q1 2027 was exceeded on a forecast basis for the CGHG/HER+ federal program, and the entry was closed in Feb. 2024. There was an amendment to increase the budget in order to include additional participants.
    - A question was posed on whether there is specific funding allocated for Indigenous groups. Enbridge Gas representative reiterated that the home winter proofing program (“HWP”) is better funded and suited directly for Indigenous communities, and those interested in the CGHG/HER+ programs have been directed by Enbridge Gas to pursue the route of HWP.
    - A request was made to get in contact with Tasha Esquega with Enbridge Gas Inc. on the pilot program for the Indigenous specific winter proofing and heat pump program and which communities have been selected and/or consulted with for the pilot.
    - It was confirmed that due to OEB restrictions on the funding allocation of the program, that they were only open to Enbridge Gas customers, and those on other gas systems would not be covered under the program – Six Nations Natural Gas customers would not be eligible.
        - o Request was made for Enbridge Gas to pen an informative email that Six Nations Natural Gas may use to pass on to their community members about why they are not eligible as they are customers of another gas utility – Six Nations Natural Gas.

4. Group discussion of the IWG Settlement Agreement Report for 2024 (IWG Report) and budget estimate for 2025.
    - The IWG discussed the draft IWG Report and members pointed to any changes that they would like to see in the report.
    - A request was made to include additional detail in the IWG Report about the presentations that have been provided during the IWG meetings.
    - The Budget was discussed and an Action item for the Indigenous IWG members to discuss together and propose a new budget for 2025 that will reflect what they believe they will need for representative involvement and legal/consultant advice.

5. Updates on the retention of experts
    - Brattle Group is close to being retained by the Indigenous parties. The main focus of Brattle Group as contemplated by the Indigenous parties will be to review the expert reports from the rebasing application and determine what is important information that may have been missed in those reports that would help mitigate energy-related risks and identify energy-related opportunities of First Nation groups in Ontario. There is also an expectation that other experts will be retained to address other significant issues relevant to the IWG. A potential example of these additional topics is fugitive emissions.

6. IWG Indigenous Parties Coordinator
    - Proposed that the IWG have a participant take on the role of an Indigenous parties coordinator. Jessica Wakefield of Three Fires Group will start to take on that role with tasks such as canvasing the Indigenous

participants about any topics or items they would like to see on the agenda and who should be at the table presenting for those topics.

7. Supply Chain Management (SCM) Indigenous Engagement.
    - Presentation by Richard Brant, Supply Chain Analyst Indigenous Engagement at Enbridge Gas, at the request of Three Fires Group.
    - Topics of the presentation were the Enbridge Indigenous Peoples Policy, the reporting and the target setting in SCM.
    - The Indigenous Peoples Policy is focused on including opportunities for partnership, employment, procurement, and equity participation, with a commitment to increase participation. SCM collects information that is provided by communities of contractors and Indigenous businesses to create a database of those companies. These companies have a leg up for bids against non-Indigenous companies when all parties are competitive.
    - There is an Enbridge enterprise-wide target of $1 billion to be spent over the course of 7 years on Indigenous spend included in the Indigenous Reconciliation Action Plan (IRAP) published in September 2022. All money spent on Indigenous benefits from projects and operations across North America is included in the target.
        - A request was made that Enbridge Gas Inc. share more regional (Ontario-specific data, if available).
    - Kate Kempton on behalf of Ginoogaming indicated there are no penalties for not meeting these targets and that this should change if the targets are going to be taken seriously. Would like a better emphasis on strict wording and equity.
        - Suggestion from Three Fires Group that equity be a commitment with Enbridge playing a role in skill building, to facilitate employment in Projects as well as O&M and post-project restoration.
    - Request from Ginoogaming that the next IWG meeting in July include an in-depth discussion about procurement of Indigenous peoples and equity.

8. Enbridge Employment practices and opportunities presentation.
    - Presentation from Jody Whitney and Mark Shilliday, Enbridge Inc. Senior strategist on Indigenous Collaboration and Enbridge Inc. Indigenous Recruitment Advisor, to provide an update on the employment practices and opportunities as requested by Three Fires Group. Mark Shilliday is the Indigenous recruiting advisor and sources Indigenous talent and then advocates for the Indigenous talent when positions become available within the company. Mark shared many of the categories in which Indigenous peoples have filled roles recently in Enbridge corporate.
    - An overview of the Indigenous wellness program, funds and the Indigenous Employee Resource Group was provided.
    - The numbers and data collected is for Enbridge Corporate, as the jobs in the field with contractors are largely restricted by Unions, especially in Ontario. Enbridge has had discussions with these Unions to seek exemptions where possible and have had some success in Thunder Bay.
    - A request to provide, or compile if not already available, more specific Ontario numbers as well as providing the presentation to the IWG.

Action Items

- Item 1: Enbridge Gas Inc. to incorporate a list with a description of the presentations given to the IWG during meetings in the IWG Report.
- Item 2: Enbridge Gas Inc. to request an update from Tasha Esquega with Enbridge Gas Inc. on the pilot program for the Indigenous specific winter proofing program and which communities have been selected and/or consulted with for the pilot.

- Item 3: Enbridge Gas Inc. Energy Transition team will determine how they can incorporate the expertise of Emily Ferguson and utilize her input on fugitive emissions.
- Item 4: Enbridge Gas Inc. to draft information about the qualifications for the Home Heating Initiative for Six Nations Natural Gas to disseminate to inquiring community members.
- Item 5: Enbridge Gas Inc. to share the presentation materials on the topics of Employment Practices and Opportunities and SCM Indigenous Engagement to IWG members.
- Item 6: Enbridge Gas Inc. to share letter to the OEB on the HER+ replacement program offer with IWG members.
- Item 7: Indigenous Parties to discuss the budget they will require for 2025 to be included in the IWG Report and provide this information to Enbridge Gas.

9. NEXT MEETING

Next meeting will be held on Tuesday, July 30, 2024, 9:00 a.m. at the Enbridge Gas Inc. office at 500 Consumers Road North York, Ontario M2J 1P8. Jessica Wakefield of Three Fires Group will be facilitating the meeting and acting as IWG Coordinator. She will canvass Indigenous IWG members on topics they would like to discuss at the next meeting.

APPENDIX A – AGENDA FOR MEETING OF IWG ON APRIL 30, 2024

Time	Matter	Participants
9:00-9:15 a.m.	Safety moment, introductions, administrative matters, status of action items, approval of minutes	Group
9:15-9:30 a.m.	Enbridge Gas Notice of Appeal and Filing of Review Motion with the OEB regarding Phase 1 rebasing decision	Tania Persad, Associate General Counsel, Enbridge Gas
9:30-10:00 a.m.	OEB Rebasing reporting – IWG report	Group review
10:00-10:30 a.m.	Fugitive Emissions Update – Progress on Enbridge study on available technologies and potential involvement of Emily Ferguson in the study. Consideration of funding support through capacity funding for IWG.	Peter Mussio, Manager, Carbon Strategy, Enbridge Gas
10:30-11:00 a.m.	Federal Greener Homes Program update and how the changes will affect Enbridge's offerings and role as a provider	Craig Fernandes, Manager Residential Energy Conservation, Enbridge Gas
11:00-11:15 a.m.	Break	
11:15-12:00 p.m.	Independent Expert/Speaker schedule: - Energy Transition - Fugitive Emissions (Tie to anticipated May 2024 technology study release) - Economic Reconciliation - Rights-based Jurisdiction - Indigenous Knowledge	Group
12:00-1:00 p.m.	Lunch	
1:00-2:00 p.m.	EGI's Indigenous procurement policy; Reporting and target-setting; Efforts to proactively identify procurement opportunities for Indigenous participants; Capacity building efforts; employment policies and opportunities relating to construction projects	Richard Brant, SCM Indigenous Engagement, Enbridge
2:00-3:00 p.m.	EGI's Indigenous employment practices; general corporate policies and opportunities	Jody Whitney, Sr Strategist Indigenous Collaboration Mark Shilliday, Indigenous Recruitment Advisor, Enbridge
3:00-3:30 p.m.	Next steps, future meetings etc.	Group