ENBRIDGE

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Enbridge Gas Inc.
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VIA EMAIL and RESS

September 3, 2020

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

Re: EB-2020-0134 - Enbridge Gas Inc. ("Enbridge Gas")
2019 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 2019 utility earnings and the disposition and recovery of certain 2019 deferral and variance account balances (the "Application") for all Enbridge Gas rate zones (EGD, Union North and Union South) and for Enbridge Gas.[1]

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

Enbridge Gas proposes to dispose of the approved 2019 deferral and variance account balances with the first QRAM application following the Board's approval, which is assumed to be January 1, 2021.

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.

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

Yours truly,

(Original Digitally Signed)

Anton Kacicnik
Manager, Rates
Regulatory Affairs

cc: David Stevens, Aird and Berlis LLP

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		2019 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
	2	1	Delivery Revenue by Service Type and Rate Class
		2	Total Customers and Revenue by Service Type and Rate Class

EXHIBIT LIST

C- Enbridge Gas Inc 2019 Deferral and Variance Accounts

EXHIBIT LIST

D - EGD Rate Zone Deferral and Variance Accounts

E – Union Rate Zones Deferral and Variance Accounts

EXHIBIT LIST

E – Union Rate Zones Deferral and Variance Accounts

Exhibit	Tab	Schedule	Contents
		6	Calculation of Balances by Rate Class in the NAC Deferral Account
		7	Calculation of Allocation of Short Term Transportation Revenues to the Lobo D / Bright C / Dawn H Compressor Project Cost Deferral Account

F – Rate Allocation

Exhibit	Tab	Schedule	Contents
F	1		Allocation and Disposition of 2019 Combined Deferral Account Balances
		1	Accounting Policy Changes Deferral Account
	2	1	EGD - Unit Rate and Type of Service
		2	EGD - Balances to be cleared
		3	EGD - Classification and Allocation of Deferral Account Balances
		4	EGD - Allocation by Type of Service
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	3	1	Union - Balances to be Cleared
		2	Union - Allocation of Deferral Balances to Rate Classes

EXHIBIT LIST

F – Rate Allocation

G – OEB Scorecard

EXHIBIT LIST

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" 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 (the "Board") approved the amalgamation of the Utilities, as well as a five-year deferred rebasing term during which a price cap ratesetting 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.

3. Enbridge Gas, the Applicant, hereby applies to the Board, pursuant to Section 36 of the *Ontario Energy Board Act*, 1998 (the "Act"), for an Order or Orders approving the

[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".

clearance or disposition of amounts recorded in certain deferral or variance accounts. The annual review and disposition of deferral and variance accounts is consistent with the process applied for each of the Utilities during their previous 2014-2018 Incentive Rate (“IR”) terms.

Earnings Sharing

4. In the MAADs Decision, the Board 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 Board-approved return on equity (“ROE”) would be shared 50/50 between the Utilities and ratepayers.

5. In 2019, Enbridge Gas’s actual utility earnings did not exceed the Board-approved ROE by more than 150 basis points. Accordingly, no ESM amount is proposed to be shared with ratepayers.

EGD Rate Zone

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

7. Enbridge Gas seeks approval to clear the final balances of certain EGD rate zone deferral and variance accounts for 2019 as set out at Exhibit C, Tab 1, Schedule 1.

Union Rate Zones

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

9. Enbridge Gas seeks approval to clear the final balances of certain Union rate zones deferral and variance accounts for 2019 as set out at Exhibit C, Tab 1, Schedule 1.

Enbridge Gas Inc.

10. The Board 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.

11. Enbridge Gas seeks approval to clear part of the final balance of one 2019 Enbridge Gas deferral and variance account related to accounting policy changes required as a result of amalgamation. The balance in this account related to pension expense is not being requested for clearance in 2019.

Relief Requested

12. Enbridge Gas therefore applies to the Board for such final, interim or other orders as may be necessary or appropriate for the clearance or disposition of the 2019 deferral and variance accounts listed in Exhibit C, Tab 1, Schedule 1. The proposed manner of disposition is described at Exhibit F. Enbridge Gas proposes to clear the balances in these accounts in conjunction with the January 1, 2021 QRAM application.

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

14. Enbridge Gas further applies to the Board pursuant to the provisions in the Act and the Board'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.

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

16. 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.

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

The Applicant:

Mr. Anton Kacicnik
Manager, Rates (EGD Rate Zone)
Enbridge Gas Inc.

Address for personal service	Enbridge Gas Inc. 500 Consumers Road Willowdale, Ontario M2J 1P8
	Mailing address: P.O. Box 650 Scarborough, Ontario M1K 5E3
Telephone:	416-495-6087
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Email:	anton.kacicnik@enbridge.com

The Applicant's counsel:

Mr. David Stevens
Aird & Berlis LLP

Address for personal service and mailing address:	Brookfield Place, P.O. Box 754 Suite 1800, 181 Bay Street Toronto, Ontario M5J 2T9

Telephone:	416-863-1500
Fax:	416-863-1515
Email:	dstevens@airdberlis.com

DATED: September 3, 2020, at Toronto, Ontario

ENBRIDGE GAS INC.

[Original digitally signed by]

Anton Kacicnik
Manager, Rates (EGD Rate Zone)

2019 DEFERRAL ACCOUNT DISPOSITION AND EARNINGS SHARING OVERVIEW AND APPROVALS REQUESTED

1. Enbridge Gas Inc. ("Enbridge Gas") is applying to the Ontario Energy Board (the "Board" or "OEB") pursuant to section 36 of the *OEB Act* for approval to dispose and recover certain 2019 deferral and variance account final balances for the Enbridge Gas Distribution ("EGD") and Union Gas ("Union")[1] rate zones and for Enbridge Gas. Enbridge Gas is also presenting the 2019 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: 2019 Utility Results and Earnings Sharing Amount
   Exhibit C: Enbridge Gas Inc. 2019 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

3. Enbridge Gas proposes that the impacts which result from the disposition of 2019 deferral and variance account balances be implemented on January 1, 2021 to align with other rate changes implemented through the Quarterly Rate Adjustment Mechanism ("QRAM").

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

RELIEF REQUESTED

4. Enbridge Gas seeks approval to clear the final balances of certain EGD rate zone and Union rate zones 2019 deferral and variance accounts, as well as one Enbridge Gas Inc. account. The balances are set out at Exhibit C, Tab 1, Schedule 1. Explanations for the balances in each account are set out at Exhibit C (Enbridge Gas account), Exhibit D (EGD Rate Zone) and Exhibit E (Union Rate Zones). The proposed clearance methodology for the accounts being cleared is set out at Exhibit F.

5. In the MAADs Decision (EB-2017-0306/0307), the Board 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 Board-approved return on equity ("ROE") would be shared 50/50 between Enbridge Gas and ratepayers.

6. 2019 is the first year of the deferred rebasing period, and the first year that Enbridge Gas has operated as an amalgamated utility. The Company has prepared its 2019 utility results on a combined basis for the amalgamated utility (see Exhibit B). In 2019, Enbridge Gas's actual utility earnings did not exceed the Board-approved ROE by more than 150 basis points. Accordingly, no ESM amount is proposed to be shared with ratepayers.

DISPOSITION OF DEFERRAL AND VARIANCE ACCOUNTS

7. Consistent with the 2018 Deferral and Variance Account clearance proceeding (EB-2019-0105), Enbridge Gas proposes to dispose of the deferral and variance accounts consistent with the practices of legacy EGD and Union.

   - For the EGD rate zone, Enbridge Gas disposes of deferral balances as a one-time adjustment for both general service and contract rate classes.
   - For the Union rate zones, Enbridge Gas disposes of deferral balances prospectively for general service customers and as a one-time adjustment for in-franchise contract and ex-franchise rate classes.

8. The proposed approach to the one-time adjustments is consistent between the EGD and Union rate zones and will be disposed of as part of the January 2021 bills that customers receive in February 2021.

9. The rationale for the continued use of a one-time adjustment includes:

   - Alignment of the cost incurrence of the deferral account balance with cost recovery by customer. The one-time adjustment avoids material mismatches that could occur between cost incurrence and cost recovery due to customer switching between rate classes and changes in customer's consumption volumes from year to year.
   - Elimination of the forecast variance which results from disposing of deferral account balances prospectively.

10. Enbridge Gas is currently not able to administer one-time adjustments for general service customers in the Union rate zones because of limitations in the system used to bill this group of customers. The continued use of a prospective recovery

disposition methodology from general service customers is appropriate as it generally provides alignment between cost incurrence and cost recovery because of the consistency of consumption patterns throughout the year by customers in these rate classes.

11. As Enbridge Gas is in the process of integrating internal systems and processes between legacy EGD and Union, Enbridge Gas is not able to introduce any further commonality to the disposition approaches at this time. A common approach could be proposed once integrated systems and processes are implemented.

PARKWAY WEST PROJECT COSTS ACCOUNT INTERIM DISPOSITION

12. Enbridge Gas is seeking interim disposition of the 2019 balance in the Parkway West Project Costs Deferral Account (179-136), consistent with the 2016 to 2018 deferral and variance account disposition proceedings. In the 2016 deferral account proceeding, the OEB noted that "all parties agreed that the 2016 balance in the Parkway West Project Costs Account should be disposed of only on an interim basis to allow the OEB to perform a prudence review of the capital overspend prior to final disposition of the balance in the account."[2] Consistent with this direction, Enbridge Gas will seek approval of the final disposition of this account as part of a subsequent proceeding when all the project costs have been incurred and the prudence of the project costs are assessed.

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

2019 ENBRIDGE GAS INC. EARNINGS SHARING AMOUNT AND DETERMINATION PROCESS

1. For the year ended December 31, 2019, 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.

2. The earnings sharing amount was determined in accordance with the following prescribed methodology as identified within the EB-2017-0306/307 Board 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, at pages 42 and 42:

    - 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 Board), then the resultant amount shall be shared equally (i.e., 50/50) between Enbridge Gas and its ratepayers;
    - for the purposes of the ESM, Enbridge Gas shall calculate its earnings using generally accepted accounting principles ("GAAP") consistent with its external

reporting, including the regulatory rules prescribed by the Board from time to time;

- all revenues and costs that would otherwise be included in a cost of service application shall be included in the earnings sharing calculation.

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

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

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

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

Part A)

6. The level of utility income, $859.8 million (Line 4) divided by the level of utility rate base, $13,139.0 million (Line 5) generates a utility return on rate base of 6.544% (Line 6).

7. When compared to the Company's required rate of return for ESM determination, of 6.546% (Line 7), as determined within the capital structure required in support of the determined rate base amount (inclusive of the 150 basis point deadband on ROE before earnings sharing is triggered), there is a resulting deficiency of 0.002% (Line 25) on total rate base.

8. As shown in Lines 9 through 11, the deficiency of 0.002% multiplied by the rate base of $13,139.0 million, produces a net under earnings or deficiency of $0.2 million which from a pre-tax perspective, ($0.2 million divided by the reciprocal, 73.5%, of the corporate tax rate which is 26.5%) shows a $0.3 million total amount of under earnings, and therefore nothing to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

Part B) (Confirming the Calculated Earnings Sharing)

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

10. The $919.7 million (Line 14) of utility income before income tax, less utility taxes of $59.9 million (Line 19), produces the $859.8 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) $859.8 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 $495.4 million, shown at Line 20.

13. The $495.4 million, divided by the deemed common equity level of $4,730.0 million (Line 21, calculated as 36% of the $13,139.0 million rate base) produces a return on equity of 10.475% (Line 23). When comparing the 10.475% achieved return on equity to the threshold ROE percentage of 10.480% (Line 22), which is the Board approved formula return on equity for 2019 of 8.98% plus the 150 basis point deadband before sharing, there is a deficiency in ROE of 0.005% (Line 24).

14. The 0.005% multiplied by the common equity level of $4,730.0 million (Line 21) produces a net under earnings or deficiency of $0.3 million which from a pre-tax perspective ($0.3 million divided by the reciprocal, 73.5%, of the corporate tax rate), shows a $0.4 million total amount of under earnings, and therefore nothing to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

Process Description

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

16. From there, in order to calculate the utility rate base, income, and capital structure results, and supporting evidence exhibits, various adjustments, regroupings or eliminations are required. This is accomplished by following and applying regulatory rules as prescribed by the Board 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 Board 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; and,
    - 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).

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

ONTARIO UTILITY
FOR THE YEAR ENDED DECEMBER 31, 2019

	Col. 1	Col. 2	Col. 3
Line No.	Description	Reference	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)	919.7
3.	Less: Income Taxes	(Ex. B, Tab 1, Sch. 3)	59.9
4.	**Utility Income**		**859.9**
5.	**Utility Rate Base**	(Ex. B, Tab 1, Sch. 4)	**13,139.0**
6.	Indicated Return on Rate Base %	(line 4 / line 5)	6.544%
7.	Less: Required Rate of Return %	(Ex. B, Tab 1, Sch. 5)	6.546%
8.	**(Deficiency) / Sufficiency %**		**-0.002%**
9.	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	(0.3)
10.	Provision for Income Taxes		(0.1)
11.	**Gross Earnings (Deficiency) / Sufficiency**	(line 9 / 73.5%)	**(0.3)**
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)	919.7
15.	Less: Long Term Debt Costs	(Ex. B, Tab 1, Sch. 5)	356.1
16.	Less: Short Term Debt Costs	(Ex. B, Tab 1, Sch. 5)	8.3
17.	Less: Cost of Preferred Capital	(Ex. B, Tab 1, Sch. 5)	0.0
18.	Net Income before Income Taxes		555.3
19.	Less: Income Taxes	(Ex. B, Tab 1, Sch. 3)	59.9
20.	**Net Income Applicable to Common Equity**	(line 18 - line 19)	**495.5**
21.	Common Equity	(Ex. B, Tab 1, Sch. 5)	4,730.0
22.	Approved ROE (including deadband before earning sharing) %	(Board-approved + 150bp)	10.480%
23.	Achieved Rate of Return on Equity %	(line 20 / line 21)	10.475%
24.	**Resulting (Deficiency) / Sufficiency in Return on Equity %**		**-0.005%**
25.	Net Earnings (Deficiency) / Sufficiency	(line 21 x line 24)	(0.3)
26.	Provision for Income Taxes		(0.1)
27.	**Gross Earnings (Deficiency) / Sufficiency**	**(line 25 / 73.5%)**	**(0.3)**
28.	**50% Earnings sharing to ratepayers**	(if line 27 > 1, line 27 x 50%)	-

EGI UTILITY INCOME
2019 ACTUAL

Line No.		Reference	Col. 1 Corporate (a)	Col. 2 Unregulated Storage (b)	Col. 3 Adjustments (c)		Col. 4 Utility Income (d) = (a)-(b)+(c) ($Millions)
1.	Gas sales and distribution	(Ex. B, Tab 2, Sch. 2)	4,660.3	-	(28.8)	(i)	4,631.5
2.	Transportation	(Ex. B, Tab 2, Sch. 3)	142.0	(0.4)	(0.2)	(ii)	142.2
3.	Storage	(Ex. B, Tab 2, Sch. 3)	143.2	137.0	(0.2)	(iii)	6.0
4.	Other operating revenue	(Ex. B, Tab 2, Sch. 4)	71.5	1.2	(20.7)	(iv)	49.6
5.	Other income	(Ex. B, Tab 2, Sch. 4)	26.2	(0.1)	(28.1)	(viii)	(1.8)
6.	Total operating revenue		5,043.2	137.7	(78.0)		4,827.6
7.	Gas costs		2,307.9	25.0	(17.5)	(i)	2,265.3
8.	Operation and maintenance	(Ex. B, Tab 3, Sch. 1)	937.3	19.5	(3.2)	(v)	914.6
9.	Depreciation and amortization expense		637.2	12.9	(22.6)	(vi)	601.7
10.	Fixed financing costs		3.8	-	1.0	(vii)	4.7
11.	Municipal and other taxes		122.9	1.5	-		121.4
12.	Cost of service		4,009.0	58.9	(42.3)		3,907.8
13.	Utility income before income taxes						919.7
14.	Income tax expense	(Ex. B, Tab 1, Sch. 3)					59.9
15.	Utility income						859.9

Notes on Adjustments:

(i)	Reclassification of Union rate zone optimization revenue as a cost of gas reduction	(17.5)
	Elimination of distribution related 2018 accelerated CCA (Bill C97) impacts recorded in 2019, but reflected in 2018 utility results	4.4
	Elimination of EGD rate zone 2018 earnings sharing amounts recorded in 2019 financial results	1.7
	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues	(17.4)
		(28.8)
(ii)	Elimination of transportation related 2018 accelerated CCA (Bill C97) impacts recorded in 2019, but reflected in 2018 utility results	0.4
	Elimination of the Union rate zone shareholder portion of net optimization activity (before tax)	(0.6)
		(0.2)
(iii)	Elimination of the Union rate zone shareholder portion of net short-term storage revenue (before tax)	(0.2)
(iv)	Adjust EGD rate zone OBA costs to reflect EB-2013-0099 approved unit costs agreed to be used for determining net revenue	(2.0)
	Elimination of EGD rate zone Open Bill shareholder incentive	(0.1)
	Elimination of EGD rate zone shareholder portion of transactional service revenues	(1.3)
	Elimination of demand-side management incentive	(16.2)
	Elimination of EGD rate zone net revenue from ABC T-service, considered to be non-utility	(1.1)
		(20.7)
(v)	Elimination of donations	(3.0)
	Elimination of CDM Program shareholder benefit	0.2
	Elimination of non-utility costs and expenses relating to support of the EGD rate zone ABC T-service program	(0.3)
	Eliminate EGD/Union amalgamation transaction costs	(0.1)
		(3.2)
(vi)	Eliminate amortization of PPD (purchase price discrepancy)	(22.5)
	Eliminate depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479)	(0.1)

		(22.6)
(vii)	Interest on security deposits held during the year and included in elimination of corporate interest exp. Expense incurred to reduce bad debt. The average amount of the security deposit held during the year is applied as a reduction to the allowance for working capital in rate base	1.0
(viii)	Elimination of interest income from investments not included in utility rate base	(0.3)
	Elimination of interest income from affiliates	(13.0)
	Elimination of the non-utility gain on the sale of St. Lawrence Gas	(14.8)
		(28.1)

CALCULATION OF EGI UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2019 ACTUAL

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	919.7	919.7	
	Add			
2.	Depreciation and amortization	601.7	601.7	
3.	Accrual based pension and OPEB costs	49.4	49.4	
4.	Other non-deductible items	1.1	1.1	
5.	Total Add Back	652.3	652.3	
6.	Sub-total	1,572.0	1,572.0	
	Deduct			
7.	Capital cost allowance	790.2	790.2	
8.	Items capitalized for regulatory purposes	136.0	136.0	
9.	Amortization of share/debenture issue expense	(0.4)	(0.4)	
10.	Amortization of C.D.E. and C.O.G.P.E	0.0	0.0	
11.	Other	6.5	6.5	
12.	Cash based pension and OPEB costs	49.4	49.4	
13.	Total Deduction	981.6	981.6	
14.	Taxable income	590.4	590.4	
15.	Income tax rates	15.00%	11.50%	
16.	Tax provision excluding interest shield	88.6	67.9	156.5
	Tax shield on interest expense			
17.	Rate base	13,139.0		
18.	Return component of debt	2.77%		
19.	Interest expense	364.4		
20.	Combined tax rate	26.500%		
21.	Income tax credit			(96.6)
22.	Total utility income taxes			59.9

EGI UTILITY RATE BASE
2019 ACTUAL

Line No.		Col. 1 2019 Actual
		($Millions)
	Property, Plant, and Equipment	
1.	Gross property, plant, and equipment	19,765.5
2.	Accumulated depreciation	(7,188.7)
3.	Net property, plant, and equipment	12,576.8
	Allowance for Working Capital	
4.	Materials and supplies	74.9
5.	ABC receivable	(30.2)
6.	Customer security deposits	(91.0)
7.	Prepaid expenses	5.6
8.	Balancing gas	56.2
9.	Gas in storage	522.0
10.	Working cash allowance	24.9
11.	Total Working Capital	562.3
12.	Utility Rate Base	13,139.0

EGI UTILITY PROPERTY, PLANT, AND EQUIPMENT
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2019 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	436.1	(137.4)	298.7
2.	Distribution plant	8,923.5	(2,866.4)	6,057.1
3.	General plant	616.9	(439.1)	177.8
4.	Plant held for future use	1.7	(1.4)	0.3
5.	EGD Rate Zone Total	9,978.2	(3,444.2)	6,533.9
	Union Rate Zones			
6.	Intangible plant	1.7	(1.1)	0.5
7.	Local storage plant	31.9	(15.8)	16.2
8.	Underground storage plant	803.9	(298.2)	505.8
9.	Transmission plant	3,491.7	(1,023.1)	2,468.6
10.	Distribution plant - Southern operations	3,154.2	(1,370.3)	1,783.9
11.	Distribution plant - Northern and Eastern operations	1,940.9	(870.5)	1,070.4
12.	General plant	363.0	(165.6)	197.4
13.	Union Rate Zones Total	9,787.3	(3,744.5)	6,042.8
14.	EGI Total	19,765.5	(7,188.7)	12,576.8

EGI UTILITY GROSS PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2019 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2018	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2019	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2019	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	EGD Rate Zone Underground Storage Plant							
1.	Crowland storage (450/459)	4.2	-	-	4.2	-	4.2	4.2
2.	Land and gas storage rights (450/451)	46.3	-	-	46.3	(1.0)	45.3	45.3
3.	Structures and improvements (452)	31.3	-	(0.2)	31.1	(0.1)	31.0	31.1
4.	Wells (453)	57.5	4.1	(2.4)	59.1	-	59.1	59.2
5.	Well equipment (454)	11.8	0.1	(1.0)	10.9	-	10.9	11.1
6.	Field Lines (455)	102.3	3.8	-	106.1	-	106.1	105.3
7.	Compressor equipment (456)	135.9	0.6	(1.1)	135.4	(0.5)	135.0	135.4
8.	Measuring and regulating equipment (457)	11.2	-	(0.1)	11.2	-	11.2	11.2
9.	Base pressure gas (458)	33.4	-	-	33.4	-	33.4	33.4
10.	Sub-Total	433.8	8.6	(4.7)	437.6	(1.5)	436.1	436.1
	EGD Rate Zone Distribution Plant							
11.	Renewable Natural Gas (461)	-	-	-	-	-	-	-
12.	Land (470)	23.2	20.7	(0.1)	43.8	-	43.8	24.0
13.	Offers to purchase (470)	-	-	-	-	-	-	-
14.	Land rights intangibles (471)	63.8	-	-	63.8	-	63.8	63.8
15.	Structures and improvements (472)	143.7	2.5	(0.2)	146.0	(0.3)	145.7	144.8
16.	Services, house reg & meter install. (473/474)	2,954.9	146.2	(9.9)	3,091.2	-	3,091.2	3,018.7
17.	Mains (475)	4,530.9	214.0	(52.9)	4,692.0	(2.2)	4,689.8	4,601.8
18.	NGV station compressors (476)	3.7	0.7	-	4.5	-	4.5	4.2
19.	Measuring and regulating equip. (477)	608.2	22.8	(1.1)	629.8	(0.5)	629.3	619.5
20.	Meters (478)	429.4	73.7	(5.5)	497.6	-	497.6	446.7
21.	Sub-Total	8,757.8	480.5	(69.7)	9,168.6	(3.1)	9,165.5	8,923.5
	EGD Rate Zone General Plant							
22.	Lease improvements (482)	0.1	-	-	0.1	(0.2)	(0.1)	(0.1)
23.	Office furniture and equipment (483)	20.5	0.5	(0.0)	20.9	-	20.9	20.7
24.	Transportation equipment (484)	51.5	14.2	(2.5)	63.2	(0.1)	63.1	50.8
25.	NGV conversion kits (484)	2.2	0.3	-	2.5	-	2.5	2.3
26.	Heavy work equipment (485)	17.9	0.1	(0.6)	17.3	-	17.3	17.4
27.	Tools and work equipment (486)	50.7	0.2	(0.1)	50.9	-	50.9	50.9
28.	Rental equipment (487)	1.6	0.2	-	1.8	-	1.8	1.7
29.	NGV rental compressors (487)	7.1	0.2	-	7.4	-	7.4	7.3
30.	NGV cylinders (484 and 487)	0.6	-	-	0.6	-	0.6	0.6
31.	Communication structures & equip. (488)	4.1	-	(0.4)	3.7	-	3.7	4.1
32.	Computer equipment (490)	26.4	4.3	(0.7)	30.0	-	30.0	27.9
33.	Software Aquired/Developed (491)	215.2	33.4	(13.6)	235.0	-	235.0	214.1
34.	CIS (491)	127.1	-	-	127.1	-	127.1	127.1
35.	WAMS (489)	92.1	0.2	-	92.2	-	92.2	92.2
36.	Sub-Total	617.0	53.6	(17.9)	652.7	(0.3)	652.5	616.9

	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	9,810.2	542.7	(92.3)	10,260.6	(4.8)	10,255.7	9,978.2
	Union Rate Zones Intangible Plant							
39.	Franchises and consents (401)	1.2	-	-	1.2	-	1.2	1.2
40.	Other intangible plant (402)	0.5	-	-	0.5	-	0.5	0.5
41.	Sub-Total	1.7	-	-	1.7	-	1.7	1.7
	Union Rate Zones Local Storage Plant							
42.	Land (440)	0.0	-	-	0.0	-	0.0	0.0
43.	Structures and improvements (442)	4.7	0.0	-	4.7	-	4.7	4.7
44.	Gas holders - storage (443)	4.6	-	-	4.6	-	4.6	4.6
45.	Gas holders - equipment (443)	20.0	-	-	20.0	-	20.0	20.0
46.	Regulatory Overheads	1.8	1.3	-	3.1	-	3.1	2.6
47.	Sub-Total	31.1	1.3	-	32.4	-	32.4	31.9
	Union Rate Zones Underground Storage Plant							
48.	Land (450)	5.5	0.0	-	5.6	-	5.6	5.6
49.	Land rights (451)	32.0	-	-	32.0	-	32.0	32.0
50.	Structures and improvements (452)	68.9	0.6	(0.7)	68.8	-	68.8	68.6
51.	Wells (453)	46.9	0.4	-	47.3	-	47.3	46.9
52.	Field Lines (455)	46.4	0.5	-	46.9	-	46.9	46.4
53.	Compressor equipment (456)	465.6	4.4	-	470.0	-	470.0	466.6
54.	Measuring and regulating equipment (457)	86.2	1.7	(2.8)	85.1	-	85.1	85.1
55.	Base pressure gas (458)	36.6	-	-	36.6	-	36.6	36.6
56.	Regulatory Overheads	16.2	1.4	-	17.6	-	17.6	16.3
57.	Sub-Total	804.2	9.0	(3.4)	809.7	-	809.7	803.9
	Union Rate Zones Transmission Plant							
58.	Land (460)	73.3	2.1	-	75.4	-	75.4	73.7
59.	Land rights (461)	62.2	3.9	-	66.2	-	66.2	63.0
60.	Structures & improvements (462/463/464)	164.3	1.7	(0.0)	165.9	-	165.9	164.6
61.	Mains (465)	1,784.7	97.7	(1.9)	1,880.5	-	1,880.5	1,800.6
62.	Compressor equipment (466)	939.0	1.9	-	940.9	-	940.9	939.5
63.	Measuring & regulating equipment (467)	272.7	26.5	(0.1)	299.1	-	299.1	276.2
64.	Line Pack Gas	7.4	0.0	-	7.5	-	7.5	7.4
65.	Regulatory Overheads	154.3	22.5	-	176.8	-	176.8	166.7
66.	Sub-Total	3,458.0	156.2	(2.0)	3,612.2	-	3,612.2	3,491.7
	Union Rate Zones Distribution Plant - Southern Operations							
67.	Land (470)	11.3	0.5	-	11.8	-	11.8	11.4
68.	Land rights (471)	7.9	0.3	-	8.2	-	8.2	8.0
69.	Structures and improvements (472)	134.1	2.5	-	136.6	-	136.6	134.1
70.	Services - metallic (473)	124.1	2.2	(0.3)	126.0	-	126.0	124.5
71.	Services - plastic (473)	897.9	29.7	(1.9)	925.7	-	925.7	909.3
72.	Regulators (474)	83.8	7.3	-	91.1	-	91.1	86.6
73.	House regulators & meter installations (474)	71.1	2.5	(0.1)	73.5	-	73.5	71.3
74.	Mains - metallic (475)	522.0	35.7	(0.4)	557.3	-	557.3	527.7
75.	Mains - plastic (475)	645.9	28.7	(0.5)	674.1	-	674.1	651.9
76.	Measuring & regulating equipment (477)	43.7	6.6	-	50.4	-	50.4	44.3
77.	Meters (478)	334.0	29.9	(8.9)	355.0	-	355.0	344.9
78.	Regulator Overheads	226.0	38.6	-	264.6	-	264.6	240.4
79.	Sub-total	3,101.8	184.5	(12.1)	3,274.2	-	3,274.2	3,154.2

	Union Rate Zones Distribution Plant - Northern & Eastern Operations							
80.	Land (470)	4.5	0.2	-	4.6	-	4.6	4.5
81.	Land rights (471)	10.3	0.2	-	10.5	-	10.5	10.4
82.	Structures and improvements (472)	66.9	0.6	-	67.5	-	67.5	66.9
83.	Services - metallic (473)	106.4	2.3	(0.2)	108.5	-	108.5	107.2
84.	Services - plastic (473)	465.8	13.4	(1.0)	478.2	-	478.2	470.0
85.	Regulators (474)	31.9	9.5	-	41.4	-	41.4	35.5
86.	House regulators & meter installations (474)	40.3	0.6	(0.0)	40.9	-	40.9	40.4
87.	Mains - metallic (475)	585.9	40.0	(0.5)	625.4	-	625.4	589.7
88.	Mains - plastic (475)	232.9	5.6	(0.2)	238.3	-	238.3	233.4
89.	Measuring & regulating equipment (477)	139.8	6.8	(0.6)	145.9	-	145.9	139.9
90.	Meters (478)	83.9	7.5	(2.6)	88.8	-	88.8	86.4
91.	Regulator Overheads	153.3	15.5	-	168.7	-	168.7	156.6
92.	Sub-total	1,921.6	102.1	(5.1)	2,018.7	-	2,018.7	1,940.9
	Union Rate Zones General Plant							
93.	Land (480)	0.6	-	-	0.6	-	0.6	0.6
94.	Structures & improvements (482)	69.5	3.5	-	73.0	-	73.0	69.9
95.	Office furniture and equipment (483)	10.1	(0.0)	-	10.1	-	10.1	10.1
96.	Office equipment - computers (483)	87.0	33.8	-	120.8	-	120.8	100.1
97.	Transportation equipment (484)	61.1	8.0	(5.4)	63.7	-	63.7	61.5
98.	Heavy work equipment (485)	15.8	4.3	(0.7)	19.3	-	19.3	16.2
99.	Tools and work equipment (486)	35.6	1.6	-	37.2	-	37.2	36.1
100.	NGV fuel equipment (487)	1.3	0.6	-	2.0	-	2.0	1.9
101.	Communication equipment (488)	13.9	0.2	-	14.1	-	14.1	14.0
102.	Regulatory Overheads	49.0	8.3	-	57.3	-	57.3	52.8
103.	Sub-total	343.9	60.3	(6.1)	398.1	-	398.1	363.0
104.	Union Rate Zones Total	9,662.3	513.5	(28.7)	10,147.0	-	10,147.0	9,787.3
105.	EGI Total	19,472.5	1,056.2	(121.0)	20,407.6	(4.8)	20,402.8	19,765.5

EGI UTILITY PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2019 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2018	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2019	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2019	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	EGD Rate Zone Underground Storage Plant								
1.	Crowland storage (450/459)	(1.3)	(0.1)	-	-	(1.4)	-	(1.4)	(1.3)
2.	Land and gas storage rights (451)	(24.7)	(0.5)	-	-	(25.2)	-	(25.2)	(25.0)
3.	Structures and improvements (452)	(2.8)	(0.6)	0.2	1.5	(1.7)	0.1	(1.6)	(2.1)
4.	Wells (453)	(14.7)	(0.9)	2.4	-	(13.3)	-	(13.3)	(13.3)
5.	Well equipment (454)	(7.4)	(0.6)	1.0	-	(7.0)	-	(7.0)	(6.9)
6.	Field Lines (455)	(29.8)	(1.6)	-	-	(31.3)	-	(31.3)	(30.5)
7.	Compressor equipment (456)	(50.1)	(3.6)	1.1	0.2	(52.4)	0.3	(52.1)	(50.9)
8.	Measuring and regulating equipment (457)	(7.3)	(0.3)	0.1	-	(7.5)	-	(7.5)	(7.4)
9.	Sub-Total	(138.0)	(8.1)	4.7	1.7	(139.7)	0.3	(139.4)	(137.4)
	EGD Rate Zone Distribution Plant								
10.	Renewable Natural Gas (461)	-	-	-	-	-	-	-	-
11.	Land rights intangibles (471)	(4.2)	(0.8)	-	-	(5.0)	-	(5.0)	(4.6)
12.	Structures and improvements (472)	(25.1)	(9.1)	0.2	0.0	(34.0)	0.3	(33.7)	(29.4)
13.	Services, house reg & meter install. (473/47	(1,027.4)	(68.9)	9.9	20.8	(1,065.6)	-	(1,065.6)	(1,049.6)
14.	Mains (475)	(1,281.7)	(102.1)	52.9	16.7	(1,314.1)	2.0	(1,312.1)	(1,299.7)
15.	NGV station compressors (476)	(2.7)	(0.3)	-	-	(3.0)	-	(3.0)	(2.8)
16.	Measuring and regulating equip. (477)	(231.0)	(12.8)	1.1	(0.4)	(243.1)	0.5	(242.6)	(236.7)
17.	Meters (478)	(232.0)	(41.0)	5.5	5.5	(262.1)	-	(262.1)	(243.6)
18.	Sub-Total	(2,804.1)	(234.9)	69.6	42.6	(2,926.8)	2.9	(2,923.9)	(2,866.4)
	EGD Rate Zone General Plant								
19.	Lease improvements (482)	(0.1)	(0.0)	-	-	(0.1)	0.2	0.1	0.1
20.	Office furniture and equipment (483)	(8.2)	(2.2)	0.0	-	(10.4)	-	(10.4)	(9.2)
21.	Transportation equipment (484)	(23.2)	(5.4)	2.5	(0.2)	(26.3)	0.1	(26.2)	(24.7)
22.	NGV conversion kits (484)	0.9	(0.2)	-	-	0.7	-	0.7	0.8
23.	Heavy work equipment (485)	(5.1)	(0.6)	0.6	(0.3)	(5.3)	-	(5.3)	(5.1)
24.	Tools and work equipment (486)	(17.9)	(2.1)	0.1	-	(19.9)	-	(19.9)	(18.9)
25.	Rental equipment (487)	(1.1)	(0.0)	-	-	(1.1)	-	(1.1)	(1.1)
26.	NGV rental compressors (487)	(0.6)	(0.6)	-	-	(1.3)	-	(1.3)	(1.0)
27.	NGV cylinders (484 and 487)	(0.5)	(0.0)	-	-	(0.6)	-	(0.6)	(0.5)
28.	Communication structures & equip. (488)	(1.1)	(0.4)	0.4	-	(1.1)	-	(1.1)	(1.3)
29.	Computer equipment (490)	(25.7)	(3.9)	0.7	-	(28.9)	-	(28.9)	(27.7)
30.	Software Aquired/Developed (491)	(188.8)	(36.9)	13.6	-	(212.1)	-	(212.1)	(202.5)
31.	CIS (491)	(117.6)	(9.5)	-	-	(127.1)	-	(127.1)	(123.5)
32.	WAMS (489)	(19.9)	(9.2)	-	-	(29.1)	-	(29.2)	(24.6)
33.	Sub-Total	(408.9)	(71.1)	17.9	(0.5)	(462.5)	0.3	(462.2)	(439.1)
	EGD Rate Zone Plant held for future use								
34.	Inactive services (102)	(1.3)	(0.0)	-	-	(1.4)	-	(1.4)	(1.4)
35.	EGD Rate Zone Total	(3,352.3)	(314.2)	92.2	43.9	(3,530.4)	3.5	(3,526.9)	(3,444.2)
	Union Rate Zones Intangible Plant								
36.	Franchises and consents (401)	(0.8)	(0.1)	-	-	(0.9)	-	(0.9)	(0.8)
37.	Other intangible plant (402)	(0.3)	-	-	-	(0.3)	-	(0.3)	(0.3)
38.	Sub-Total	(1.1)	(0.1)	-	-	(1.2)	-	(1.2)	(1.1)

	Union Rate Zones Local Storage Plant								
39.	Structures and improvements (442)	(2.4)	(0.1)	-	-	(2.6)	-	(2.6)	(2.5)
40.	Gas holders - storage (443)	(3.6)	(0.1)	-	-	(3.7)	-	(3.7)	(3.6)
41.	Gas holders - equipment (443)	(8.9)	(0.7)	-	-	(9.6)	-	(9.6)	(9.2)
42.	Regulatory Overheads	(0.3)	(0.1)	-	-	(0.4)	-	(0.4)	(0.4)
43.	Sub-Total	(15.2)	(1.1)	-	-	(16.3)	-	(16.3)	(15.8)
	Union Rate Zones Underground Storage Plant								
44.	Land rights (451)	(16.8)	(0.7)	-	-	(17.4)	-	(17.4)	(17.1)
45.	Structures and improvements (452)	(39.4)	(1.7)	0.7	-	(40.4)	-	(40.4)	(39.9)
46.	Wells (453)	(30.7)	(1.2)	-	-	(31.9)	-	(31.9)	(31.3)
47.	Field Lines (455)	(26.1)	(1.2)	-	-	(27.3)	-	(27.3)	(26.7)
48.	Compressor equipment (456)	(132.5)	(12.5)	-	-	(145.0)	-	(145.0)	(138.8)
49.	Measuring & regulating equipment (457)	(41.8)	(2.7)	2.8	-	(41.6)	-	(41.6)	(41.6)
50.	Regulatory Overheads	(2.6)	(0.5)	-	-	(3.1)	-	(3.1)	(2.8)
51.	Sub-Total	(289.9)	(20.3)	3.4	-	(306.7)	-	(306.7)	(298.2)
	Union Rate Zones Transmission Plant								
52.	Land rights (461)	(15.8)	(1.1)	-	-	(16.9)	-	(16.9)	(16.4)
53.	Structures & improvements (462/463/464)	(36.8)	(3.4)	0.0	-	(40.1)	-	(40.1)	(38.4)
54.	Mains (465)	(593.8)	(35.6)	1.9	-	(627.4)	-	(627.4)	(611.4)
55.	Compressor equipment (466)	(233.2)	(30.3)	-	-	(263.5)	-	(263.5)	(248.3)
56.	Measuring & regulating equipment (467)	(89.2)	(7.2)	0.1	-	(96.3)	-	(96.3)	(92.7)
57.	Regulatory Overheads	(13.9)	(4.1)	-	-	(18.1)	-	(18.1)	(15.9)
58.	Sub-Total	(982.6)	(81.7)	2.0	-	(1,062.2)	-	(1,062.2)	(1,023.1)
	Union Rate Zones Distribution Plant - Southern Operations								
59.	Land rights (471)	(2.0)	(0.1)	-	-	(2.1)	-	(2.1)	(2.1)
60.	Structures and improvements (472)	(38.3)	(3.0)	-	-	(41.3)	-	(41.3)	(39.8)
61.	Services - metallic (473)	(103.4)	(3.5)	0.3	0.7	(105.9)	-	(105.9)	(104.8)
62.	Services - plastic (473)	(394.8)	(22.7)	1.9	7.7	(407.9)	-	(407.9)	(402.8)
63.	Regulators (474)	(32.7)	(4.3)	-	-	(37.0)	-	(37.0)	(34.8)
64.	House regulators & meter installations (474)	(26.2)	(2.0)	0.1	-	(28.1)	-	(28.1)	(27.1)
65.	Mains - metallic (475)	(339.1)	(14.9)	0.5	0.1	(353.4)	-	(353.4)	(346.5)
66.	Mains - plastic (475)	(256.2)	(15.1)	0.5	0.0	(270.7)	-	(270.7)	(263.7)
67.	Measuring & regulating equipment (477)	(18.5)	(1.6)	-	0.0	(20.1)	-	(20.1)	(19.3)
68.	Meters (478)	(92.8)	(13.1)	8.9	(0.0)	(97.1)	-	(97.1)	(96.5)
69.	Regulator Overheads	(29.6)	(6.8)	-	-	(36.4)	-	(36.4)	(33.0)
70.	Sub-Total	(1,333.5)	(87.1)	12.2	8.5	(1,399.9)	-	(1,399.9)	(1,370.3)
	Union Rate Zones Distribution Plant - Northern & Eastern Operations								
71.	Land rights intangibles (471)	(4.0)	(0.2)	-	-	(4.2)	-	(4.2)	(4.1)
72.	Structures and improvements (472)	(23.4)	(1.6)	-	-	(25.0)	-	(25.0)	(24.2)
73.	Services - metallic (473)	(72.8)	(3.5)	0.2	0.4	(75.7)	-	(75.7)	(74.4)
74.	Services - plastic (473)	(196.6)	(12.2)	1.0	0.2	(207.6)	-	(207.6)	(202.6)
75.	Regulators (474)	(11.9)	(1.8)	-	-	(13.6)	-	(13.6)	(12.7)
76.	House regulators & meter installations (474)	(14.2)	(1.2)	0.0	-	(15.3)	-	(15.3)	(14.7)
77.	Mains - metallic (475)	(312.6)	(17.8)	0.5	-	(329.9)	-	(329.9)	(321.4)
78.	Mains - plastic (475)	(103.3)	(5.6)	0.2	-	(108.6)	-	(108.6)	(106.0)
79.	Measuring & regulating equipment (477)	(67.2)	(5.3)	0.6	-	(71.8)	-	(71.8)	(69.3)
80.	Meters (478)	(22.3)	(3.5)	2.6	-	(23.2)	-	(23.2)	(23.2)
81.	Regulator Overheads	(15.5)	(4.5)	-	-	(20.0)	-	(20.0)	(17.8)
82.	Sub-Total	(843.6)	(56.9)	5.0	0.6	(894.9)	-	(894.9)	(870.5)
	Union Rate Zones General Plant								
83.	Structures & improvements (482)	(13.2)	(1.5)	-	-	(14.7)	-	(14.7)	(13.9)
84.	Office furniture and equipment (483)	(5.0)	(0.7)	-	-	(5.7)	-	(5.7)	(5.4)
85.	Office equipment - computers (483)	(37.9)	(24.3)	-	-	(62.2)	-	(62.2)	(50.2)
86.	Transportation equipment (484)	(41.1)	(8.1)	5.4	(0.4)	(44.2)	-	(44.2)	(42.5)
87.	Heavy work equipment (485)	(4.6)	(1.1)	0.7	-	(5.0)	-	(5.0)	(4.8)
88.	Tools and work equipment (486.00)	(15.9)	(2.4)	-	-	(18.4)	-	(18.4)	(17.1)
89.	NGV fuel equipment (487)	(1.3)	(0.1)	-	-	(1.3)	-	(1.3)	(1.3)
90.	Communication equipment (488)	(7.5)	(1.0)	-	-	(8.4)	-	(8.4)	(8.0)
91.	Regulatory Overheads	(19.9)	(5.2)	-	-	(25.1)	-	(25.1)	(22.5)
92.	Sub-Total	(146.3)	(44.3)	6.1	(0.4)	(184.9)	-	(184.9)	(165.6)
93.	Union Rate Zones Total	(3,612.1)	(291.5)	28.7	8.8	(3,866.1)	-	(3,866.1)	(3,744.5)
94.	EGI Total	(6,964.4)	(605.6)	120.9	52.6	(7,396.5)	3.5	(7,393.0)	(7,188.7)

EGI WORKING CAPITAL COMPONENTS
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2019 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. 9 Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	January 1	67.9	(18.8)	(92.6)	(2.8)	55.7	685.7	24.9	720.0
2.	January 31	68.7	(27.7)	(93.2)	(7.2)	55.7	573.4	24.9	594.6
3.	February	70.2	(39.8)	(90.7)	(2.0)	55.7	441.9	24.9	460.2
4.	March	71.9	(43.4)	(91.4)	2.0	55.7	289.9	24.9	309.6
5.	April	70.8	(45.9)	(91.6)	7.0	55.7	234.6	24.9	255.5
6.	May	75.3	(45.7)	(91.6)	6.0	55.7	308.4	24.9	333.0
7.	June	76.7	(40.8)	(91.1)	7.4	55.7	417.2	24.9	450.0
8.	July	77.0	(33.3)	(91.1)	7.6	55.7	517.6	24.9	558.4
9.	August	78.4	(25.6)	(90.3)	10.1	55.7	652.8	24.9	706.0
10.	September	78.9	(17.5)	(89.5)	16.3	55.7	758.6	24.9	827.4
11.	October	80.1	(12.4)	(90.9)	13.0	55.7	736.0	24.9	806.4
12.	November	79.8	(12.3)	(89.5)	8.1	59.5	675.8	24.9	746.3
13.	December	75.1	(18.2)	(88.6)	(0.6)	59.5	629.0	24.9	681.1
14.	Avg. of monthly avgs.	74.9	(30.2)	(91.0)	5.6	56.2	522.0	24.9	562.3

EGI SUMMARY OF CAPITAL STRUCTURE & COST OF CAPITAL
2019 ACTUAL

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5 (Col. 1x Col. 3)
Line No.		Utility Capital Structure Principal	Component	Cost Rate	Return Component	Interest & Return
		($Millions)	%	%	%	($Millions)
1.	Long and Medium-Term Debt	8,002.0	60.90	4.45	2.710	356.1
2.	Short-Term Debt	407.0	3.10	2.04	0.063	8.3
3.	Total Debt	8,408.9	64.00		2.773	
4.	Preference Shares	-	-	-	-	-
5.	Common Equity	4,730.0	36.00	10.48	3.773	495.7
6.	Total Rate Base	13,139.0	100.00		6.546	860.1

CALCULATION OF COST RATES
FOR EGI CAPITAL STRUCTURE COMPONENTS
2019 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		8,295.0		366.5
2.	Unamortized Finance Costs		(58.1)		-
3.	(Profit)/Loss on Redemption		-		-
4.			8,236.9		366.5
5.	Percentage Allocation of Debt to Unregulated	2.85%	(234.9)		(10.5)
6.	Net Regulated Long and Medium-Term Debt		8,002.0		356.0
5.	Calculated Cost Rate			4.45%	
	Short-Term Debt				
6.	Calculated Cost Rate			2.04%	
	Preference Shares				
7.	Preference Share Summary		-		-
8.	Unamortized Finance Costs		-		-
9.	(Profit)/Loss on Redemption		-		-
10.			-		-
11.	Calculated Cost Rate			0.00%	
	Common Equity				
12.	Board Formula ROE			8.98%	
13.	Threshold before earnings sharing			1.50%	
14.	ROE for earnings sharing determination			10.48%	

EGI SUMMARY STATEMENT OF PRINCIPAL
AND CARRYING COST OF
TERM DEBT
2019 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.	8.85%	October 2, 2025	20.0	8.97%	1.8
2.	7.60%	October 29, 2026	100.0	8.09%	8.1
3.	6.65%	November 3, 2027	100.0	6.71%	6.7
4.	6.10%	May 19, 2028	100.0	6.16%	6.2
5.	6.05%	July 5, 2023	100.0	6.38%	6.4
6.	6.90%	November 15, 2032	150.0	6.95%	10.4
7.	6.16%	December 16, 2033	150.0	6.18%	9.3
8.	5.21%	February 25, 2036	300.0	5.18%	15.5
9.	4.77%	December 17, 2021	175.0	5.31%	9.3
10.	4.04%	November 23, 2020	200.0	5.21%	10.4
11.	4.95%	November 22, 2050	200.0	4.99%	10.0
12.	4.95%	November 22, 2050	100.0	4.73%	4.7
13.	4.04%	November 23, 2020	200.0	2.80%	5.6
14.	4.50%	November 23, 2043	200.0	4.20%	8.4
15.	3.15%	August 22, 2024	215.0	3.24%	7.0
16.	4.00%	August 22, 2044	215.0	3.89%	8.4
17.	4.00%	August 22, 2044	170.0	4.44%	7.5
18.	3.31%	September 11, 2025	400.0	3.62%	14.5
19.	2.50%	August 5, 2026	300.0	3.42%	10.3
20.	3.51%	November 29, 2047	300.0	3.53%	10.6
21.	3.32%	September 6, 2028	187.5	3.37%	6.3
22.	2.37%	August 9, 2029	150.0	3.23%	4.8
23.	3.01%	August 9, 2049	112.5	3.03%	3.4
24.	8.65%	November 10, 2025	125.0	8.77%	11.0
25.	5.46%	September 11, 2036	165.0	5.49%	9.1
26.	4.85%	April 25, 2022	125.0	4.91%	6.1
27.	6.05%	September 2, 2038	300.0	6.10%	18.3
28.	5.20%	July 23, 2040	250.0	5.27%	13.2
29.	4.88%	June 21, 2041	300.0	4.92%	14.8
30.	3.79%	July 10, 2023	250.0	3.87%	9.7
31.	2.76%	June 2, 2021	200.0	2.85%	5.7
32.	4.20%	June 2, 2044	250.0	4.24%	10.6
33.	4.20%	June 2, 2044	250.0	4.27%	10.7
34.	3.19%	September 17, 2025	200.0	3.26%	6.5
35.	2.81%	June 1, 2026	250.0	2.87%	7.2
36.	3.80%	June 1, 2046	250.0	3.84%	9.6
37.	3.59%	November 22, 2047	250.0	3.64%	9.1
38.	2.88%	November 22, 2027	250.0	2.95%	7.4
39.	3.65%	October 1, 2028	650.0	3.65%	23.7
40.			8,210.0		358.1
Long-Term Debentures					
41.	9.85%	December 2, 2024	85.0	9.910%	8.4
42.			85.0		8.4
43.	Total Term Debt		8,295.0		366.5

EGI UNAMORTIZED DEBT DISCOUNT AND EXPENSE
AVERAGE OF MONTHLY AVERAGES
2019 ACTUAL

Line No.		Col. 1 Unamortized Debt Discount and Expense
		($Millions)
1.	January 1	47.6
2.	January 31	47.2
3.	February	46.7
4.	March	46.2
5.	April	45.8
6.	May	45.4
7.	June	45.0
8.	July	44.4
9.	August	79.7
10.	September	78.9
11.	October	78.0
12.	November	77.3
13.	December	76.8
14.	Average of Monthly Averages	58.1

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

FOR THE YEAR ENDED DECEMBER 31, 2019

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	925.5	25.5	0.0	0.0	0.2	951.2
3	Rate 6	303.1	83.7	0.0	0.0	33.9	420.8
4	Rate 9	0.0	0.0	0.0	0.0	0.0	0.0
5	**Total EGD Rate Zone**	**1,228.6**	**109.2**	**0.0**	**0.0**	**34.2**	**1,372.0**
6	Rate M1	446.7	21.8	0.0	1.3	0.0	469.8
7	Rate M2	39.0	22.5	0.0	16.3	0.0	77.9
8	Rate 01	174.8	9.8	0.0	1.1	0.0	185.7
9	Rate 10	12.3	5.9	0.0	5.6	0.3	24.0
10	**Total Union Rate Zones**	**672.8**	**59.9**	**0.0**	**24.3**	**0.3**	**757.4**
11	**Total General Service Sales & T-Service**	**1,901.4**	**169.1**	**0.0**	**24.3**	**34.5**	**2,129.3**
12	Wholesale - Utility						
13	Rate M9	0.7	0.0	0.0	1.0	0.0	1.6
14	Rate M10	0.0	0.0	0.0	0.0	0.0	0.0
15	**Total Wholesale - Utility**	**0.7**	**0.0**	**0.0**	**1.0**	**0.0**	**1.7**
16	Contract Sales						
17	Rate 100	0.1	0.0	0.0	0.0	0.0	0.1
18	Rate 110	1.4	1.0	0.0	0.0	7.5	9.8
19	Rate 115	(0.1)	0.0	0.0	0.0	1.9	1.8
20	Rate 125	0.0	0.0	11.2	0.0	0.0	11.2
21	Rate 135	0.1	0.2	0.0	0.0	1.0	1.3
22	Rate 145	0.0	0.0	0.0	0.0	0.4	0.5
23	Rate 170	0.1	0.1	0.0	0.0	1.1	1.3
24	Rate 200	1.9	0.0	0.0	0.0	1.3	3.1
25	Rate 300	0.0	0.0	0.1	0.0	0.0	0.1
26	Rate 315	0.0	0.0	0.0	0.0	0.0	0.0
27	**Total EGD Rate Zone**	**3.5**	**1.3**	**11.3**	**0.0**	**13.1**	**29.2**
28	Rate M4	2.8	1.3	0.0	26.6	0.0	30.7
29	Rate M7	1.2	0.3	0.0	13.8	0.0	15.3
30	Rate 20 Storage	0.0	0.0	0.0	0.0	0.0	0.0
31	Rate 20 Transportation	0.8	0.1	0.0	2.4	19.1	22.4
32	Rate 100 Storage	0.0	0.0	0.0	0.0	0.0	0.0
33	Rate 100 Transportation	0.0	0.0	0.0	0.0	10.7	10.7
34	Rate T-1 Storage	0.0	0.0	0.0	0.0	1.4	1.4
35	Rate T-1 Transportation	0.0	0.0	0.0	0.0	11.3	11.3
36	Rate T-2 Storage	0.0	0.0	0.0	0.0	7.4	7.4
37	Rate T-2 Transportation	0.0	0.0	0.0	0.0	64.2	64.2
38	Rate T-3 Storage	0.0	0.0	0.0	0.0	1.4	1.4
39	Rate T-3 Transportation	0.0	0.0	0.0	0.0	5.5	5.5
40	Rate M5	0.2	0.1	0.0	2.2	0.0	2.6
41	Rate 25	1.8	0.0	0.0	0.0	2.7	4.5
42	Rate 30	0.0	0.0	0.0	0.0	0.0	0.0
43	**Total Union Rate Zones**	**6.9**	**1.8**	**0.0**	**45.0**	**123.6**	**177.3**
44	**Total Contract Sales**	**10.3**	**3.2**	**11.3**	**45.0**	**136.8**	**206.5**
45	**Subtotal**	**1,912.4**	**172.3**	**11.3**	**70.3**	**171.2**	**2,337.5**
46	**Accounting Adjustments:**						
47	EGI Tax Variance						(24.1)
48	EGI Elimination of 2018 Tax Variance						4.5
49	EGI Accounting Policy Change						1.1
50	EGD Average Use/ Normalized Average Consumption						(4.1)
51	EGD Dawn Access Cost						2.2
52	EGD 2018 Earnings Sharing Adjustment						(1.7)
53	EGD Elimination of 2018 Earnings Sharing Adjustment						1.7
54	EGD Transactional Services Revenue						12.0
55	EGD LRAM						0.0
56	EGD Federal Carbon Program						0.1
57	EGD Greenhouse Gas Emissions Administration						0.2
58	EGD Reverse 2019 Gas Supply Plan Cost Consequences						(3.9)
59	Union Average Use/ Normalized Average Consumption						(4.0)
60	Union Parkway Obligation Rate Variance						0.3
61	Union Incremental Capital Module						(7.0)
62	Union Capital Pass-through						(1.0)
63	Union LRAM						0.4
64	Union Federal Carbon Program						0.4
65	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues						(17.4)
66	Miscellaneous						0.5
67	**Total Utility Revenue**						**2,297.9**

* There is no distribution volume for Rate 125 customers.
** Less than 50,000 m^3
*** Less than $50,000

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

FOR THE YEAR ENDED DECEMBER 31, 2019

		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	1,985,346	56,781	2,042,127	5,213,290	145,299	5,358,589	1,785.6	39.1	1,824.8
3	Rate 6	144,944	23,246	168,190	3,233,688	2,066,334	5,300,022	818.3	190.9	1,009.2
4	Rate 9	2		2						
5	**Total EGD Rate Zone**	**2,130,292**	**80,027**	**2,210,319**	**8,446,978**	**2,211,633**	**10,658,611**	**2,603.9**	**230.1**	**2,834.0**
6	Rate M1	1,095,866	45,414	1,141,279	3,079,559	221,840	3,301,400	861.8	23.0	884.9
7	Rate M2	4,479	3,304	7,783	663,864	685,068	1,348,932	127.7	38.8	166.5
8	Rate 01	337,741	15,902	353,643	991,238	80,169	1,071,407	384.1	17.5	401.6
9	Rate 10	1,242	902	2,144	187,742	192,950	380,691	48.8	23.7	72.5
10	**Total Union Rate Zones**	**1,439,327**	**65,523**	**1,504,850**	**4,922,402**	**1,180,027**	**6,102,429**	**1,422.4**	**103.0**	**1,525.5**
11	**Total General Service Sales & T-Service**	**3,569,619**	**145,550**	**3,715,168**	**13,369,380**	**3,391,660**	**16,761,041**	**4,026.3**	**333.1**	**4,359.5**
12	Wholesale - Utility									
13	Rate M9	1	3	4	28,114	75,875	103,989	4.4	1.0	5.4
14	Rate M10	2	0	2	391	0	391	0.1	0.0	0.1
15	**Total Wholesale - Utility**	**3**	**3**	**6**	**28,505**	**75,875**	**104,380**	**4.5**	**1.0**	**5.4**
16	Contract Sales									
17	Rate 100	2	2	4	12,577	2,800	15,377	2.7	0.4	3.1
18	Rate 110	48	234	282	68,785	806,611	875,396	5.1	37.0	42.2
19	Rate 115	1	21	22	741	440,875	441,615	0.1	9.0	9.1
20	Rate 125	4	0	4	0	0	0	0.0	11.3	11.3
21	Rate 135	3	40	43	1,631	61,389	63,020	0.3	1.9	2.2
22	Rate 145	3	23	26	1,597	28,843	30,441	0.1	1.7	1.8
23	Rate 170	3	20	23	18,233	268,125	286,358	2.2	5.5	7.8
24	Rate 200	0	0	0	152,503	44,376	196,879	28.1	2.1	30.3
25	Rate 300	1	0	1	0	0	0	0.0	0.1	0.1
26	Rate 315					0	0		0.0	0.0
27	**Total EGD Rate Zone**	**65**	**340**	**405**	**256,067**	**1,653,019**	**1,909,086**	**38.7**	**69.1**	**107.8**
28	Rate M4	28	205	232	53,246	620,765	674,011	9.9	27.9	37.8
29	Rate M7	3	34	36	25,510	515,833	541,343	4.5	14.1	18.6
30	Rate 20 Storage	0	0	0	0	0	0	0.0	2.6	2.6
31	Rate 20 Transportation	5	49	54	10,603	512,297	522,900	3.4	24.9	28.3
32	Rate 100 Storage	0	0	0	0	0	0	0.0	0.0	0.0
33	Rate 100 Transportation	0	12	12	0	1,020,510	1,020,510	0.0	10.7	10.7
34	Rate T-1 Storage	0	0	0	0	0	0	0.0	1.4	1.4
35	Rate T-1 Transportation	0	37	37	0	437,372	437,372	0.0	11.3	11.3
36	Rate T-2 Storage	0	0	0	0	0	0	0.0	7.4	7.4
37	Rate T-2 Transportation	0	25	25	0	4,136,389	4,136,389	0.0	64.2	64.2
38	Rate T-3 Storage	0	0	0	0	0	0	0.0	1.4	1.4
39	Rate T-3 Transportation	0	1	1	0	283,374	283,374	0.0	5.5	5.5
40	Rate M5	5	36	42	5,923	68,042	73,965	1.1	2.4	3.4
41	Rate 25	31	24	55	42,433	76,767	119,200	8.3	2.7	11.0
42	Rate 30	0	0	0	0	0	0	0.0	0.0	0.0
43	**Total Union Rate Zones**	**72**	**422**	**494**	**137,715**	**7,671,348**	**7,809,063**	**27.2**	**176.3**	**203.6**
44	**Total Contract Sales**	**137**	**762**	**899**	**393,781**	**9,324,367**	**9,718,149**	**65.9**	**245.4**	**311.3**
45	**Subtotal**	**3,569,759**	**146,315**	**3,716,074**	**13,791,667**	**12,791,903**	**26,583,570**	**4,096.7**	**579.5**	**4,676.2**
46	**Accounting Adjustments:**									
47	EGI Tax Variance									(24.1)
48	EGI Elimination of 2018 Tax Variance									4.5
49	EGI Accounting Policy Change									1.1
50	EGD Average Use/ Normalized Average Consumption									(8.6)
51	EGD Dawn Access Cost									2.2
52	EGD 2018 Earnings Sharing Adjustment									(1.7)
53	EGD Elimination of 2018 Earnings Sharing Adjustment									1.7
54	EGD Transactional Services Revenue									12.0
55	EGD LRAM									0.0
56	EGD Federal Carbon Program									0.1
57	EGD Greenhouse Gas Emissions Administration									0.2
58	EGD Reverse 2019 Gas Supply Plan Cost Consequences									(3.9)
59	Union Average Use/ Normalized Average Consumption									(4.7)
60	Union Parkway Obligation Rate Variance									0.3
61	Union Incremental Capital Module									(7.0)
62	Union Capital Pass-through									(1.0)
63	Union LRAM									0.4
64	Union Federal Carbon Program									0.4
65	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues									(17.4)
66	Miscellaneous									0.5
67	**Total Utility Revenue**									**4,631.5**

* There is no distribution volume for Rate 125 customers.
** Less than 50,000 m^3
*** Less than $50,000

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

FOR THE YEAR ENDED DECEMBER 31, 2019

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		Customer Meters			Volumes ($10^3 M^3$)			Revenues ($ Millions)		
Line No.		Sales	T-Service	Total	Sales	T-Service	Total	Sales	T-Service	Total
1	General Service									
2	Rate 1	1,985,346	56,781	2,042,127	4,891,003	133,229	5,024,232	1,705.4	37.8	1,743.2
3	Rate 6	144,944	23,246	168,190	3,053,332	1,904,548	4,957,881	777.2	178.4	955.6
4	Rate 9	2		2						
5	**Total EGD Rate Zone**	**2,130,292**	**80,027**	**2,210,319**	**7,944,336**	**2,037,777**	**9,982,112**	**2,482.7**	**216.1**	**2,698.8**
6	Rate M1	1,095,866	45,414	1,141,279	2,978,227	214,541	3,192,768	842.3	22.7	865.0
7	Rate M2	4,479	3,304	7,783	643,702	664,263	1,307,966	123.9	37.8	161.7
8	Rate 01	337,741	15,902	353,643	942,069	76,192	1,018,261	368.6	16.9	385.4
9	Rate 10	1,242	902	2,144	179,384	184,361	363,745	46.6	22.5	69.1
10	**Total Union Rate Zones**	**1,439,327**	**65,523**	**1,504,850**	**4,743,383**	**1,139,357**	**5,882,740**	**1,381.3**	**99.9**	**1,481.2**
11	**Total General Service Sales & T-Ser**	**3,569,619**	**145,550**	**3,715,168**	**12,687,719**	**3,177,133**	**15,864,852**	**3,864.0**	**316.0**	**4,180.0**
12	Wholesale - Utility									
13	Rate M9	1	3	4	28,114	75,875	103,989	4.4	1.0	5.4
14	Rate M10	2	0	2	391	0	391	0.1	0.0	0.1
15	**Total Wholesale - Utility**	**3**	**3**	**6**	**28,505**	**75,875**	**104,380**	**4.5**	**1.0**	**5.4**
16	Contract Sales									
17	Rate 100	2	2	4	12,577	2,800	15,377	2.7	0.4	3.1
18	Rate 110	48	234	282	68,704	805,396	874,101	5.1	37.0	42.1
19	Rate 115	1	21	22	739	440,738	441,477	0.1	9.0	9.1
20	Rate 125	4	0	4	0	0	0	0.0	11.3	11.3
21	Rate 135	3	40	43	1,631	61,389	63,020	0.3	1.9	2.2
22	Rate 145	3	23	26	1,565	28,921	30,486	0.1	1.7	1.8
23	Rate 170	3	20	23	18,299	272,993	291,292	2.2	5.5	7.8
24	Rate 200	0	0	0	143,859	44,010	187,869	26.6	2.1	28.7
25	Rate 300	1	0	1	0	0	0	0.0	0.1	0.1
26	Rate 315					0	0		0.0	0.0
27	**Total EGD Rate Zone**	**65**	**340**	**405**	**247,375**	**1,656,248**	**1,903,623**	**37.1**	**69.0**	**106.2**
28	Rate M4	28	205	232	53,246	620,765	674,011	9.9	27.9	37.8
29	Rate M7	3	34	36	25,510	515,833	541,343	4.5	14.1	18.6
30	Rate 20 Storage	0	0	0	0	0	0	0.0	2.6	2.6
31	Rate 20 Transportation	5	49	54	10,603	512,297	522,900	3.4	24.9	28.3
32	Rate 100 Storage	0	0	0	0	0	0	0.0	0.0	0.0
33	Rate 100 Transportation	0	12	12	0	1,020,510	1,020,510	0.0	10.7	10.7
34	Rate T-1 Storage	0	0	0	0	0	0	0.0	1.4	1.4
35	Rate T-1 Transportation	0	37	37	0	437,372	437,372	0.0	11.3	11.3
36	Rate T-2 Storage	0	0	0	0	0	0	0.0	7.4	7.4
37	Rate T-2 Transportation	0	25	25	0	4,136,389	4,136,389	0.0	64.2	64.2
38	Rate T-3 Storage	0	0	0	0	0	0	0.0	1.4	1.4
39	Rate T-3 Transportation	0	1	1	0	283,374	283,374	0.0	5.5	5.5
40	Rate M5	5	36	42	5,923	68,042	73,965	1.1	2.4	3.4
41	Rate 25	31	24	55	42,433	76,767	119,200	8.3	2.7	11.0
42	Rate 30	0	0	0	0	0	0	0.0	0.0	0.0
43	**Total Union Rate Zones**	**72**	**422**	**494**	**137,715**	**7,671,348**	**7,809,063**	**27.2**	**176.3**	**203.6**
44	**Total Contract Sales**	**137**	**762**	**899**	**385,090**	**9,327,597**	**9,712,686**	**64.3**	**245.4**	**309.7**
45	**Subtotal**	**3,569,759**	**146,315**	**3,716,074**	**13,101,313**	**12,580,606**	**25,681,919**	**3,932.8**	**562.4**	**4,495.2**
46	**Accounting Adjustments:**									
47	EGI Tax Variance									(24.1)
48	EGI Elimination of 2018 Tax Variance									4.5
49	EGI Accounting Policy Change									1.1
50	EGD Average Use/ Normalized Average Consumption									(8.6)
51	EGD Dawn Access Cost									2.2
52	EGD 2018 Earnings Sharing Adjustment									(1.7)
53	EGD Elimination of 2018 Earnings Sharing Adjustment									1.7
54	EGD Transactional Services Revenue									12.0
55	EGD LRAM									0.0
56	EGD Federal Carbon Program									0.1
57	EGD Greenhouse Gas Emissions Administration									0.2
58	EGD Reverse 2019 Gas Supply Plan Cost Consequences									(3.9)
59	Union Average Use/ Normalized Average Consumption									(4.7)
60	Union Parkway Obligation Rate Variance									0.3
61	Union Incremental Capital Module									(7.0)
62	Union Capital Pass-through									(1.0)
63	Union LRAM									0.4
64	Union Federal Carbon Program									0.4
65	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues									(17.4)
66	Miscellaneous									0.5
67	**Total Utility Revenue**									**4,450.4**

* There is no distribution volume for Rate 125 customers.
** Less than 50,000 m^3
*** Less than $50,000

EGI REVENUE FROM REGULATED STORAGE
& TRANSPORTATION OF GAS
2019 ACTUAL

Line No.	Particulars ($000s)	2019 Actual
	Revenue from Regulated Storage Services:	
1.	C1 Off-Peak Storage	418
2.	Supplemental Balancing Services	869
3.	Gas Loans	2
4.	C1 Short Term Firm Peak Storage	2,125
5.	Short Term Storage and Balancing Services Deferral	2,630
6.	Rate 325: Transmission, Compression, & Storage	2,114
7.	Less: Elimination of charges between EGD and Union rate zones	(2,162)
8.	Total Regulated Storage Revenue Net of Deferral	$ 5,996
	Revenue from Regulated Transportation Services:	
9.	M12 Transportation	198,610
10.	M12-X Transportation	21,314
11.	C1 Long Term Transportation	22,002
12.	Rate 332: Gas Transmission	17,440
13.	C1 Short Term Transportation	9,076
14.	Gross Exchange Revenue	2,279
15.	Rate 331: Gas Transmission	76
16.	M13 Local Production	195
17.	M16 Transportation	1,002
18.	S&T:Transportation Carbon Facility Collection	758
19.	Other S&T Revenue	1,501
20.	Less: Elimination of charges between EGD and Union rate zones	(132,009)
21.	Total Regulated Transportation Revenue Net of Deferral	$ 142,244

EGI UTILITY OTHER REVENUE AND OTHER INCOME
2019 ACTUALS

Line No.		Col. 1 Utility Revenue ($Millions)
1.	Service charges & DPAC	19.0
2.	NGV program rental revenue	1.6
3.	Late payment penalties	19.4
4.	Open bill revenue	5.4
5.	Mid Market Transactions	1.4
6.	Other operating revenue	2.8
7.	Other operating revenue	49.6
8.	Miscellaneous other income (incl. gain / (loss) on foreign exchange	(1.8)
9.	Gain / (loss) on sale of assets	-
10.	Other income	(1.8)
11.	Total other revenue and other income	47.8

UTILITY O&M
2019 ACTUAL

Line No.		($Millions)
1.	Compensation and Benefits	566.9
2.	Employee Related Services and Development	5.5
3.	Materials and Supplies	101.7
4.	Outside Services	360.5
5.	Transportation Related Repairs and Maintenance	8.8
6.	Vehicle Aircraft and Other Repairs and Maintenance	18.5
7.	Rents and Leases	13.2
8.	Telecommunications	3.5
9.	Travel and Entertainment	13.6
10.	Donations and Memberships	11.6
11.	Admin Expenses	(6.9)
12.	Inventory Adjustments	(0.1)
13.	Allocations & Recoveries	70.2
14.	Miscellaneous O and A Expense	9.8
15.	Capitalization	(239.9)
16.	**O&M Subtotal before Eliminations**	**937.2**
17.	Donations	(3.0)
18.	CDM Program	0.2
19.	ABC T-service Program	(0.3)
20.	Amalgamation Transaction Costs	(0.1)
21.	Unregulated Adjustments	(19.5)
22.	**Total Unregulated/Non-Utility Eliminations**	**(22.6)**
23.	**Total Net Utility O&M Expense**	**914.6**

UTILITY CAPITAL EXPENDITURES

1. The purpose of this evidence is to provide information on Enbridge Gas's 2019 utility capital expenditures within the EGD and Union rate zones

Table 1

Summary of Capital Expenditures 2019 Actual

	Col 1	Col 2	Col 3
	EGD RZ	UG RZ	TOTAL EGI
Distribution Plant	456.88	290.96	747.84
Transmission Plant	-	157.32	157.32
General & Other Plant	84.04	55.10	139.14
Underground Storage Plant	35.80	7.27	43.07
	576.72	**510.65**	**1,087.37**

2. Table 2 below shows the spend by Asset Class for each of the legacy rate zones. Alignment of Asset Classes was completed in 2020, however the presentation for 2019 is based on the legacy Asset Plans. Further commentary regarding the nature of spend are provided below the tables.

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

	Asset Class	2019
A	Customer Growth	135.98
B	Pipe	85.39
C	Stations	24.19
D	Storage	31.43
E	Customer Assets	40.86
F	Fleet, Equipment & Tools	12.90
G	Information Technology	30.62
H	Real Estate & Workplace Services	30.86
I	Business Development	0.08
J	Capitalized Overheads	150.85
K	Integration Capital	12.95
L	Community Expansion	16.71
M	Other	3.91
	Total Capital Expenditures	**576.72**

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

	Asset Class	2019
A	Compression & Dehydration	7.82
B	Pipe	108.68
C	Stations	14.00
D	Growth	199.12
E	Utilization	43.31
F	Transmission Pipe & Underground Storage	3.85
G	Fleet, Equipment & Tools	13.15
H	Information Technology	18.24
I	Real Estate & Workplace Services	11.13
J	Capitalized Overheads	82.34
K	Integration Capital	8.77
L	Community Expansion	0.24
	Total Capital Expenditures	**510.65**

A. EGD Rate Zone

3. Descriptions of the types of investments included in each asset class are:

a. Customer Growth

In the EGD rate zone, EGI delivers safe and reliable natural gas to over 2.1 million customers made up of residential, commercial, apartment, and industrial customers. The customer growth asset class involves:

- Addition of new customers based on new housing or business starts
- Customers converting to natural gas from another fuel source
- 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.

Expenditures in 2019 include attaching 25,893 customers.

a. *Pipe*

4. This asset class includes pipelines and piping components (such as valves and fittings) used to transport natural gas within the distribution systems or to end-use customers. It includes steel and plastic pipe, as well as services to customers. This asset class includes maintaining, replacing, renewing and reinforcing these assets.

Expenditures in 2019 include steel main replacements, AMP fittings replacement program, service relay program, NPS 30 Don River replacement and the Bathurst pipeline reinforcement project.

b. *Stations*

5. System stations 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.

Expenditures in 2019 include the Gate and Feeder station program and distribution station rebuild program. Specific projects include Blackhorse Gate station, Deep River Gate station and Westmall Gate station.

c. *Storage*

6. The Storage asset class includes:
   - Compressor Stations: compression and flow control facilities that move gas to and from reservoirs.

- Pipelines: pipe that transports gas between custody transfer points and reservoirs.
- Reservoirs: storage area that traps and holds natural gas.

EGD rate zone storage assets are located in three areas of southwestern Ontario: St. Clair Township near Sarnia, Crowland Township in Welland, and in Chatham-Kent.

Expenditures in 2019 include the Corunna compressor station meter upgrade.

d. *Customer Assets*

7. The Customer Assets asset class includes: Measurement Systems, Regulation, Safety, Device and Piping Systems, Below ground and Internal Piping Systems, and Customer-owned Systems[1].

Expenditures in 2019 were mainly driven by meter purchases and the meter exchange program.

[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.

e. ***Fleet, Equipment, Tools***

8. The Fleet, Equipment and Tools asset class includes the vehicles, trailers, heavy equipment and tools owned by EGI to support the business needs for the EGD rate zone.

   Expenditures in 2019 include vehicle replacements, and purchase of tools and work equipment.

f. ***Technology Information Services (TIS)***

9. 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 consist of packaged applications, developed applications, and application infrastructure software.
   - Communications assets include mobile phones and field devices (such as GPS devices, push-to-talk radios, leak survey field technology, and truck modems).

Expenditures in 2019 include desktop replacements, Geographic Information System ("GIS") upgrade and Customer Information System ("CIS") hardware replacement.

g. *Real Estate and Workplace Services*

10. The Real Estate and Workplace Services (REWS) asset class includes properties (buildings and land) and furnishings.

Expenditures in 2019 include Victoria Park Centre (VPC) renovations, and land purchases to protect the area surrounding the TOC building from encroachment due to urban sprawl.

h. *Business Development*

11. The Business Development asset class evaluates emerging technologies and trends in the industry. Natural gas for transportation (NGT), and lower carbon strategies. (The addition of new customers as part of community expansion are managed through this asset class, however, expenditures are listed separately)

i. *Overheads*

12. The overheads in the EGD rate zone include departmental labour costs, capitalized

administrative and general, EA fixed overheads and interest during construction.

j. *Integration Capital*

13. Integration capital includes expenditures required to integrate the two legacy companies. Examples include the work to integrate the customer billing systems. These expenditures are excluded when calculating the thresholds for ICM capital.

k. *Community Expansion*

14. Community expansion is a growth opportunity to provide natural gas services to communities not currently being serviced. In response to the Ontario Energy Board's (OEB) initiative to address the Government of Ontario's desire to expand natural gas distribution systems to communities that currently do not have access to natural gas, EGI 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 the province.

Expenditures in 2019 include the Fenelon Falls project.

B. UG Rate Zone

15. Descriptions of the types of investments included in each asset class are:

a. Compression and Dehydration

EGI (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 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.

Expenditures in 2019 include compressor and dehydrator maintenance including Dawn H, Bright C and Lobo D compressors.

b. Pipe

16. This asset class includes pipelines and piping components (such as valves and fittings) used to transport natural gas within the distribution systems or to end-use customers. It includes steel and plastic pipe, as well as services to customers. This asset class includes maintaining, replacing and renewing these assets. For Union rate zones, reinforcement is included in the Growth asset class.

Expenditures in 2019 include general maintenance and replacement, integrity management program, and class location work.

c. Stations

17. System stations 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 operating pressure pipeline systems which supply natural gas to cities and towns.

Expenditures in 2019 include obsolete heating equipment and capital maintenance of stations. Specific projects include work at Hamilton Gate and London North Gate stations.

d. Growth

18. In the Union rate zones, EGI delivers safe and reliable natural gas to approximately 1.5 million customers made up of residential, commercial and industrial customers, both contract and non-contract.

The Growth asset class involves:

- Addition of new customers based on new housing or business starts
- Customers converting to natural gas from another fuel source

- 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 Union rate zones, this asset class also includes the costs to reinforce distribution and transmission systems and stations, to ensure reliable service is maintained. These projects are important to meet the forecasted growth and will ensure EGI is able to serve and satisfy those customers.

Expenditures in 2019 include attaching 18,301 customers and reinforcement projects including Stratford, Kingsville and Sudbury reinforcements.

e. <u>Utilization</u>

19. The Utilization asset class includes: Measurement Systems, Regulation, Safety, Device and Piping Systems, Belowground and Internal Piping Systems.

The majority of expenditures in this asset class are driven by meter purchases and the meter exchange program.

f. <u>Transmission Pipe & Underground Storage</u>

20. Transmission pipe asset class consists of storage gathering systems, Union rate zone's major transmission systems and associated laterals connecting to the distribution networks, and the laterals feeding from the TransCanada pipeline system (Union North rate zone) to the distribution systems and major customer stations.

Underground Storage assets are subsurface facilities used for natural gas storage, including pipelines, wells and reservoirs.

Storage expenditures relate to:

- storage improvements to improve the performance, condition and safety of the storage wells through well testing, or wellhead pressure and flow monitoring
- Storage Integrity for remediation identified by well inspections

Expenditures in 2019 include general maintenance and replacement, integrity management program, class location and Dawn E header replacement project.

g. Fleet, Equipment & Tools

21. The Fleet, Equipment and Tools asset class includes the vehicles, trailers, heavy equipment and tools owned by EGI to support the business needs for the Union rate zones.

Expenditures in 2019 are mainly driven by vehicle purchases.

h. Technology Information Services (TIS)

22. 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 consist of packaged applications, developed applications, and application infrastructure software.
- Communications assets include mobile phones and field devices (such as GPS devices, push-to-talk radios, leak survey field technology, and truck modems).

Expenditures in 2019 include Contrax modifications, desktop sustainment and service suite upgrade.

i. <u>Real Estate and Workplace Services (REWS)</u>

23. Union's Corporate Real Estate Services (CRES) asset class (now REWS) includes properties (buildings and land) and furnishings.

Expenditures in 2019 include service facility maintenance, and 50 Keil facility modernization, powerhouse and parking lot projects.

j. <u>Overheads</u>

24. The overheads in the UG rate zone include indirect overheads and EA fixed overheads.

k. <u>Integration capital</u>

25. Integration capital includes expenditures required to integrate the two legacy companies. Examples include the work to integrate the customer billing systems. These expenditures are excluded when calculating the thresholds for ICM capital.

l. <u>Community Expansion</u>

26. Community expansion is a growth opportunity to provide natural gas services to communities not currently being serviced. In response to the Ontario Energy Board's

(OEB) initiative to address the Government of Ontario's desire to expand natural gas distribution systems to communities that currently do not have access to natural gas, EGI 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 the province.

Expenditures in 2019 relate to community expansion projects to serve Chippewas of the Thames First Nation, Prince Township, and Delaware Nation of Moraviantown.

ENBRIDGE GAS

SUMMARY OF CAPITAL COST ALLOWANCE (CCA)

Line No.	Class	Particulars ($000s)	Col. 1 UCC at Prior Year Filing EB-2019-0105 (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)	CCA FY2019 (j)	Ending UCC (k)
1.	1	Buildings, structures and improvements, services, meters, mains	2,494,243.2	-	2,494,243.2	-	-	-	-	2,494,243.2	4%	99,769.7	2,394,473.5
2.	1	Non-residential building acquired after March 19, 2007	119,482.3	-	119,482.3	8,160.0	6,704.0	-	10,784.0	130,266.3	6%	7,816.0	119,826.3
3.	2	Mains acquired before 1988	183,609.2	-	183,609.2	-	-	-	-	183,609.2	6%	11,016.5	172,592.6
4.	3	Buildings acquired before 1988	3,320.6	-	3,320.6	-	-	-	-	3,320.6	5%	166.0	3,154.6
5.	6	Other buildings	99.1	-	99.1	-	-	-	-	99.1	10%	9.9	89.2
6.	7	Compression equipment acquired after February 22, 2005	668,237.1	-	668,237.1	6,305.3	951.9	-	4,104.5	672,341.6	15%	100,851.2	573,691.2
7.	8	Compression assets, office furniture, equipment	215,612.9	-	215,612.9	35,831.9	33,927.8	-	51,843.7	267,456.7	20%	53,491.3	197,953.5
8.	10	Transportation, computer equipment	33,344.7	-	33,344.7	23,018.5	19,868.5	(358.8)	31,198.3	64,543.0	30%	19,362.9	36,641.5
9.	12	Computer software, small tools	14,492.8	-	14,492.8	36,311.5	27,696.6	-	32,004.0	46,496.8	100%	46,496.8	4,307.4
10.	13	Leasehold improvements	1,369.9	-	1,369.9	-	-	-	-	1,369.9	0%	394.8	975.1
11.	14.1	Intangibles	5,693.1	-	5,693.1	3,829.1	3,476.0	-	5,390.5	11,083.6	5%	554.2	8,968.0
12.	14.1	Intangibles (pre 2017)	54,108.7	-	54,108.7	-	-	-	-	54,108.7	7%	3,787.6	50,321.0
13.	17	Roads, sidewalk, parking lot or storage areas	593.8	-	593.8	-	-	-	-	593.8	8%	47.5	546.3
14.	38	Heavy work equipment	5,004.0	-	5,004.0	4,552.8	4,552.5	(261.0)	6,698.4	11,702.4	30%	3,510.7	5,785.1
15.	41	Storage assets	44,737.6	-	44,737.6	3,689.4	725.0	-	2,569.7	47,307.3	25%	11,826.8	36,600.2
16.	45	Computers - Hardware acquired after March 22, 2004	20.7	-	20.7	-	-	-	-	20.7	45%	9.3	11.4
17.	49	Transmission pipeline additions acquired after February 23, 2005	707,092.0	-	707,092.0	96,987.0	88,321.7	-	136,815.2	843,907.2	8%	67,512.6	736,566.4
18.	50	Computers hardware acquired after March 18, 2007	23,869.8	-	23,869.8	33,517.2	15,232.3	-	31,990.9	55,860.7	55%	30,723.4	26,663.6
19.	51	Distribution pipelines acquired after March 18, 2007	4,638,829.7	(357.2)	4,638,472.5	686,369.7	565,879.1	-	909,064.0	5,547,536.5	6%	332,852.2	4,991,990.0
20.		Total	9,213,761.3	(357.2)	9,213,404.1	938,572.4	767,335.2	(619.8)	1,222,463.2	10,435,867.3		790,199.6	9,361,157.1

ACCOUNTS NOT BEING REQUSTED FOR CLEARANCE

1. The Company is not seeking clearance of the following accounts in this proceeding. For the following accounts, Enbridge Gas will carry the balances forward and seek clearance in appropriate future proceedings:
    - Accounting Policy Changes Deferral Account – Pension - EGI
    - Incremental Capital Module Deferral Account
    - Tax Variance – Accelerated CCA – EGI

2. For the following account, Enbridge Gas will not carry the balances forward and seek clearance in appropriate future:
    - 2019 Gas Supply Plan Cost Consequences Deferral Account ("2019 GSPCCDA") – EGD Rate Zone

3. The Company is no longer requesting clearance of the 2019 GSPCCDA, which has a balance of $3.9 million that would have been collected from ratepayers. The balance balance will not be carried forward, and Enbridge Gas will not maintain the account in future years.

4. In its Decision and Procedural Order No. 2 dated April 1, 2019 for Enbridge Gas' 2019 Rates Proceeding (EB-2018-0305), the OEB determined that gas supply planning was

out of scope in the 2019 proceeding and directed Enbridge Gas to no longer include gas supply related-evidence for the EGD rate zone in annual rate applications. Enbridge Gas was permitted to establish the 2019 GSPCCDA to capture the revenue deficiency impact of changes to the 2019 gas supply portfolio, for disposition at a later date.

5. In light of the Board's direction in EB-2018-0305, Enbridge Gas informed the Board and its stakeholders as part of EB-2019-0273, January 1, 2020 QRAM application that it will no longer update elements of the EGD rate zone's gas supply plan in rates on an annual basis. Instead, Enbridge Gas will continue to update prices in the EGD rate zone quarterly through QRAM applications while holding the gas supply plan constant, and will capture variances between actual and forecast prices in existing deferral and variance accounts. This approach is currently applied to the Union rate zones. In this manner Enbridge Gas is able to respond to the Board's direction without requiring modifications to existing QRAM methodologies or additional or amended deferral and variance accounts.

6. Enbridge Gas has determined that it is appropriate to treat the 2019 year in the same manner as other remaining years during the deferred rebasing term, and not separately recover the gas supply plan cost consequences for 2019 that were recorded in the 2019 GSPCCDA. This ensures consistency through all years of the deferred rebasing term.

7. Given that Enbridge Gas is no longer requesting clearance of the 2019 GSPCCDA, the balance in the 2019 Storage and Transportation Deferral Account (S&TDA) is benchmarked against 2018 forecast of storage and transportation tolls / costs and the balance in the 2019 Unaccounted for Gas Variance account (UAFVA) is benchmarked against 2018 forecast of UAF volumes (as would be the case for both accounts if 2019 gas supply plan and gas costs had not been filed with the Board as part of 2019 rate adjustment application). Enbridge Gas' current delivery rates include 2018 forecast of costs for storage and transportation and for unaccounted for gas as Enbridge Gas did not adjust its rates for 2019 forecasts of these costs.

8. Enbridge Gas plans to follow this same approach (i.e. utilizing existing deferral and variance accounts) for the remaining years within the deferred rebasing period (2019 – 2023), which dispenses with the need for the 2019 Gas Cost Consequences Deferral Account or another approach for subsequent years.

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

1. On August 30, 2018 the Ontario Energy Board ("the Board") 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 rate-setting framework[1]. In its Decision, the Board established a deferral account to record the impact of any accounting changes required as a result of amalgamation that affect revenue requirement.[2] The Board approved wording of the accounting order for the APCDA effective January 1, 2019 in its Decision and Order on Enbridge Gas's 2019 Rates application[3].
2. The total 2019 APCDA balance is a receivable of $192.003 million, driven by four accounting changes arising from amalgamation, which are detailed in the table below.

3. However, the balance being requested for disposal is a payable (revenue requirement reduction, or sufficiency) to ratepayers of $1.750 million, plus interest of $0.027 million, for a total credit to ratepayers of $1.776 million. The balance payable reflects the sum of the first three accounting changes noted in the table below

[1] EB-2017-0306/0307, MAAD's Decision and Order dated August 30, 2018; The Decision and Order was later amended by the Board 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, Section 12, p. 6.

(Capitalization vs Expense, Interest During Construction, and Depreciation Expense). The outstanding balance related to Pension Expense is not being requested for disposal at this time, as described below.

	Revenue Requirement $millions					
	Capitalization vs Expense	Interest During Construction	Depreciation Expense	**Subtotal**	Pension Expense[4]	Total
Balance at January 1, 2019	-	-	-	**-**	211.262	211.262
Impact to 2019 revenue requirement:						
Expense	4.359	(0.001)	(4.675)	**(0.317)**	(17.509)	
Cost of capital	(0.011)	0.002	0.240	**0.231**	-	
Income tax	0.054	(0.071)	(1.647)	**(1.664)**	-	
Total	4.402	(0.070)	(6.082)	**(1.750)**	(17.509)	(19.259)
Balance at December 31, 2019	4.402	(0.070)	(6.082)	**(1.750)**	193.753	192.003

Refer to Exhibit C, Tab 1, Schedule 2 for the detailed revenue requirement calculation.

Capitalization vs Expense

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

[4] Enbridge Gas is not proposing to dispose of the balance related to pension, at this time. Instead, Enbridge Gas proposes to continue to draw down this regulatory asset balance throughout the deferred rebasing period similar to pre-amalgamation, and propose a disposition strategy for the remaining balance at rebasing (see below for further details).

	Union Policy	EGD Policy	EGI Policy
EGD • 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
Union • Integrity Digs resulting from integrity inspections	Expensed as incurred	Capitalized	Capitalize

4. 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 in 2019 resulted in:

- Incremental OM&A expense of approximately $4.359 million, offset by lower capitalization; and,
- Gross revenue requirement increase, or deficiency of $4.402 million.

Interest During Construction

5. 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

6. Upon amalgamation, it was necessary for Enbridge Gas to align its accounting treatment of IDC. The policy alignment in 2019 resulted in:

- Incremental accumulated IDC of approximately $0.196 million; and,
- Gross revenue requirement decrease, or sufficiency of $0.070 million.

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

Depreciation Expense

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

8. 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

9. 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.

10. The policy alignment in 2019 resulted in:

- A decrease in depreciation expense of approximately $4.675 million; and,
- A gross revenue requirement decrease, or sufficiency of $6.083 million.

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

11. Prior to December 31, 2018, Union recorded actuarial gains/losses and past service costs ("Actuarial Losses") in Accumulated Other Comprehensive Income ("AOCI") and amortized the balance over the expected average remaining service life ("EARSL") of employees in accordance with ASC 715-30-35-24. This amortization expense was part of pension cost that was recognized annually and included in the forecast that underpinned rates. As a result of the Enbridge Inc. ("EI") and Spectra merger on February 27, 2017, EI recorded the acquisition of Union through a purchase price allocation ("PPA") in accordance with ASC 805. As a result, Union's pension assets were adjusted on EI's books to fair value and the unamortized Actuarial Losses of $250 million were reclassified from AOCI to Goodwill. These adjustments were not required to be pushed down[6] and were not pushed down to the Union stand alone statements. Therefore, this adjustment did not impact Union financial statements or accounting at the time of the merger.

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

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

13. Upon amalgamation, US GAAP required the PPA recorded by Enbridge Inc. related to Union to be pushed down into the combined financial statements of Enbridge Gas Inc ("Enbridge Gas").[7] This resulted in the remaining unamortized Actuarial Losses on Union's balance sheet to be reclassified from AOCI to Goodwill.

14. Although this appears to be a balance sheet reclassification only, the adjustment would have a significant impact on Enbridge Gas if not for regulatory accounting. AOCI is amortized as an annual expense whereas Goodwill is not. As such, this treatment would result in stranding the balance in Goodwill that would never be expensed. This is an accounting change that occurred only because of the amalgamation. Otherwise, Union would have continued to amortize Actuarial Losses as pension expense, just as it it had done in the past.

15. The change in accounting policy has not altered the fact that Union has incurred the Actuarial Losses and should recover these costs over time, as is currently approved by the Board. As noted previously, the balances represent the accumulation of Actuarial Losses incurred in relation to the pension assets that Enbridge Gas needs

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

to continue to fund through cash contributions to the pension plans. Enbridge Gas's funding requirements do not change simply because the accounting treatment has changed. Therefore, continued recovery in rates through the deferred rebasing period is appropriate and is consistent with the Board's approved approach for utilities. As noted in the *"Report of the Ontario Energy Board – Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs – EB-2015-0040,"* accrual based accounting for pensions under ASC 715 would result in a match to actual cash contributions by the end of the life of the plans.

16. Accordingly, the Company adjusted the opening balance sheet at January 1, 2019, to record the $211 million balance previously recognized as AOCI in the financial records of Enbridge Gas as a regulatory asset (within the APCDA), instead of Goodwill. Enbridge Gas continues to draw down the regulatory asset by amortizing this balance as part of pension expense resulting in a regulatory asset balance of $194 million recognized in the APCDA at December 31, 2019. By continuing to follow this approach, Enbridge Gas ensures that its results during the deferred rebasing period reflect the accrual based pension expense recognized annually through amortization of the noted balance.

17. In an effort to manage the impact to ratepayers, Enbridge Gas proposes to continue with this approach throughout the deferred rebasing period and will propose a

methodology for disposal of the applicable residual balance in the APCDA related to pension costs at December 31, 2023, as part of rebasing.

ENBRIDGE GAS - TAX VARIANCE DEFERRAL ACCOUNT

1. The balance in this deferral account is a credit balance $30.030 million plus interest to December 31, 2020 of $0.698 million, for a total of $30.728 million. Enbridge Gas is not requesting clearance of the balance in this account as part of the current proceeding.

2. Establishment of the Enbridge Gas - Tax Variance Deferral Account was approved in the Board's 2019 Rates (EB-2018-0305) Final Rate Order Decision[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

[1] EB-2018-0305, Final Rate Order Decision dated September 30, 2019, Exhibit F1, Tab 3, Rate Order, Appendix I, page 10.

Incremental Capital Module Deferral Account and respective Capital Pass-through Project Deferral Accounts).

3. In accordance with the OEB's July 25, 2019 letter*,* impacts arising from CCA rule changes, together with carrying charges, will be disposed of in manner designated by the Board in a future rate hearing. The OEB states, *"Unless the OEB orders otherwise, this would generally coincide with the Utility's next cost-based rate application."*

4. Of the balance in the account, there is a credit balance of $4.897 million that is related to the 2018 impact of the enactment of Bill C-97 which contains accelerated Capital Cost Allowance ("CCA") measures, and a credit balance of $25.134 million that is related to the 2019 impact. Aside from the impacts of Bill C-97, there were no further tax rate changes that impacted 2019.

Income Tax - Bill C-97 (Accelerated CCA)

5. To calculate the income tax (or earnings) impact of the accelerated CCA, Enbridge Gas determined total capital additions which qualified for accelerated CCA and removed additions related to any capital pass-through/incremental capital module projects. For the remaining qualifying additions, CCA was calculated utilizing the accelerated rates and compared against CCA calculated at the non-accelerated rates. The income tax (or earnings) impact of the variance between the two methodologies was then grossed-up for taxes to determine the revenue requirement

impact. This amount, representing 100% of the revenue requirement impact, was recorded in the Enbridge Gas – Tax Variance Deferral Account. Please see Exhibit C, Tab 1, Schedule 3 for the calculation of the accelerated CCA impact in the Enbridge Gas - Tax Variance Deferral Account.

6. The accelerated CCA impact related to capital pass-through projects/incremental capital module project was fully reflected in the determination of the variances recorded in the respective project deferral accounts.

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
				Forecast for clearance at January 1, 2021			
	EGD Rate Zone Commodity Related Accounts						
1.	Storage and Transportation D/A	2019 S&TDA		2,472.3	34.5	2,506.9	D-1, Page 3
2.	Transactional Services D/A	2019 TSDA		134.3	1.8	136.1	D-1, Page 4
3.	Unaccounted for Gas V/A	2019 UAFVA		4,879.7	70.6	4,950.3	D-1, Page 6
4.	Total commodity related accounts			7,486.3	106.9	7,593.3	
	EGD Rate Zone Non Commodity Related Accounts						
5.	Average Use True-Up V/A	2019 AUTUVA		(8,768.8)	(120.6)	(8,889.4)	D-1, Page 11
6.	Gas Distribution Access Rule Impact D/A	2019 GDARIDA		-	-	-	
7.	Deferred Rebate Account	2019 DRA		991.2	27.1	1,018.3	D-1, Page 13
8.	Transition Impact of Accounting Changes D/A	2019 TIACDA		4,435.8	-	4,435.8	D-1, Page 1
9.	Electric Program Earnings Sharing D/A	2019 EPESDA		(174.7)	(5.1)	(179.8)	D-1, Page 14
10.	OEB Cost Assessment V/A	2019 OEBCAVA		3,233.1	77.5	3,310.6	D-1, Page 16
11.	Dawn Access Costs D/A	2019 DACDA		2,152.7	29.6	2,182.3	D-1, Page 20
12.	Gas Supply Plan Cost Consequences D/A	2019 GSPCCDA		-	-	-	
13.	Pension and OPEB Forecast Accrual vs. Actual Cash F	2019 P&OPEBFAVACPDVA		-	-	-	
14.	**Total EGD Rate Zone (for clearance)**			**9,355.6**	**115.4**	**9,471.1**	
	Union Rate Zones Gas Supply Accounts	Number					
15.	Upstream Transportation Optimization	179-131	2019	12,122.4	165.9	12,288.3	E-1, Page 6
16.	Spot Gas Variance Account	179-107	2019	-	-	-	
17.	Unabsorbed Demand Costs Variance Account	179-108	2019	(11,957.6)	(311.1)	(12,268.7)	E-1, Page 1
18.	Deferral Clearing Variance Account - Supply	179-132	2019	(1,096.1)	(27.9)	(1,123.9)	E-1, Page 16
19.	Deferral Clearing Variance Account - Transport	179-132	2019	69.2	1.8	71.0	E-1, Page 16
20.	Total Gas Supply Accounts			(862.0)	(171.3)	(1,033.4)	
	Union Rate Zones Storage Accounts						
21.	Short-Term Storage and Other Balancing Services	179-70	2019	2,821.9	32.9	2,854.8	E-1, Page 8
	Union Rate Zones Other Accounts						
22.	Normalized Average Consumption	179-133	2019	(4,675.9)	(120.2)	(4,796.1)	E-1, Page 19
23.	Deferral Clearing Variance Account	179-132	2019	(721.6)	(18.4)	(739.9)	E-1, Page 16
24.	OEB Cost Assessment Variance Account	179-151	2019	1,562.8	36.3	1,599.1	E-1, Page 53
25.	Unbundled Services Unauthorized Storage Overrun	179-103	2019	-	-	-	
26.	Gas Distribution Access Rule Costs	179-112	2019	-	-	-	
27.	Conservation Demand Management	179-123	2019	(137.6)	(4.5)	(142.1)	E-1, Page 14
28.	Parkway West Project Costs	179-136	2019	(493.0)	(12.5)	(505.5)	E-1, Page 30
29.	Brantford-Kirkwall/Parkway D Project Costs	179-137	2019	(39.0)	(0.3)	(39.3)	E-1, Page 34
30.	Lobo C Compressor/Hamilton-Milton Pipeline Project C	179-142	2019	277.0	2.3	279.3	E-1, Page 39
31.	Lobo D/Bright C/Dawn H Compressor Project Costs	179-144	2019	(1,569.1)	(30.1)	(1,599.2)	E-1, Page 44
32.	Burlington-Oakville Project Costs	179-149	2019	(49.0)	(0.7)	(49.7)	E-1, Page 50
33.	Panhandle Reinforcement Project Costs	179-156	2019	(1,180.0)	(17.8)	(1,197.8)	E-1, Page 55
34.	Sudbury Replacement Project	179-162	2019	-	-	-	
35.	Parkway Obligation Rate Variance	179-138	2019	-	-	-	
36.	Unauthorized Overrun Non-Compliance Account	179-143	2019	(432.4)	(14.2)	(446.6)	E-1, Page 43
37.	Base Service North T-Service TransCanada Capacity	179-153	2019	-	-	-	
38.	Pension and OPEB Forecast Accrual vs. Actual Cash F	179-157	2019	-	(961.4)	(961.4)	E-1, Page 59
39.	Unaccounted for Gas Volume Variance Account	179-135	2019	1,560.9	19.4	1,580.4	E-1, Page 28
40.	Unaccounted for Gas Price Variance Account	179-141	2019	458.5	6.6	465.1	E-1, Page 37
41.	Total Other Accounts			(5,438.4)	(1,115.3)	(6,553.7)	
42.	**Total Union Rate Zones (for clearance)**			**(3,478.5)**	**(1,253.7)**	**(4,732.3)**	
	EGI Accounts						
43.	Accounting Policy Changes D/A - Pension - EGI	179-120	2019	(1,749.5)	(26.9)	(1,776.5)	C-1, Page 4
44.	Earnings Sharing D/A	179-382	2019	-	-	-	
45.	Expansion of Natural Gas Distribution Systems V/A	179-380	2019	-	-	-	
46.	**Total EGI Accounts (for clearance)**			**(1,749.5)**	**(26.9)**	**(1,776.5)**	
47.	**Total Deferral and Variance Accounts (for clearance)**			**4,127.6**	**(1,165.2)**	**2,962.3**	
	Not Being Requested for Clearance						
48.	Accounting Policy Changes D/A - Pension - EGI	179-120	2019	193,753.1	-	193,753.1	
49.	Incremental Capital Module Deferral Account	179-159	2019	(6,869.6)	(94.6)	(6,964.2)	
50.	Tax Variance - Accelerated CCA - EGI	179-383	2019	(30,030.4)	(697.6)	(30,728.0)	
51.	**Total of Accounts not being requested for clearance**			**156,853.1**	**(792.2)**	**156,060.9**	

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

Line No.	($000's)	Col. 1 Capitalization Policy Alignment	Col. 2 IDC Policy Alignment	Col. 3 Depreciation Expense Policy Alignment	Col. 4 **APCDA Total**	Not Requesting Clearance Col. 5 Actuarial Gains/Losses on UGL Pension
	Cost of capital					
1.	Rate base	(181.7)	13.7	3,281.2	**3,113.2**	0.0
2.	Cost of capital*	(10.6)	2.0	239.6	**231.0**	0.0
	Cost of service					
3.	Gas costs	-	-	-	**-**	-
4.	Operation and Maintenance	4,359.2	-	-	**4,359.2**	(17,509.3)
5.	Depreciation and amortization	-	(0.7)	(4,675.4)	**(4,676.1)**	-
6.	Municipal and other taxes	-	-	-	**-**	-
7.	Cost of service	4,359.2	(0.7)	(4,675.4)	**(316.9)**	(17,509.3)
	Income taxes on earnings					
8.	Excluding tax shield	(1,114.1)	(52.1)	-	**(1,166.2)**	4,640.0
9.	Tax shield provided by interest expe	1.3	(0.3)	(34.8)	**(33.8)**	-
10.	Income taxes on earnings	(1,112.8)	(52.4)	(34.8)	**(1,200.0)**	4,640.0
	Taxes on (def) / suff.					
11.	Gross (def.) / suff.	(4,402.3)	69.5	6,082.4	**1,749.6**	17,509.3
12.	Net (def.) / suff.	(3,235.7)	51.1	4,470.6	**1,286.0**	12,869.3
13.	Taxes on (def.) / suff.	1,166.6	(18.4)	(1,611.8)	**(463.6)**	(4,640.0)
14.	Revenue requirement	4,402.4	(69.5)	(6,082.4)	**(1,749.5)**	(17,509.3)
15.	Gross revenue (def.) / suff.	(4,402.4)	69.5	6,082.4	**1,749.5**	17,509.3

*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	**2018 Year-End** Particulars ($000s)	Opening UCC Accel. CCA	Opening UCC Regular CCA	Total Additions Qualifying for Accel. CCA	ICM & Capital Pass-Through Additions	Additions Net of ICM & Capital Pass-Through	Accel. CCA Depreciable UCC Balance	Regular CCA Depreciable UCC Balance	Rate (%)	Accelerated CCA	Regular CCA	Closing UCC Accel. CCA	Closing UCC Regular CCA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1.	1	Buildings, structures and improvements, services, meters, mains	-	-	-	-	-	-	-	4%	-	-	-	-
2.	1	Non-residential building acquired after March 19, 2007	-	-	2,952.7	1,724.3	1,228.4	1,842.6	614.2	6%	110.6	36.9	1,117.8	1,191.5
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	-	-	7,775.4	4,438.3	3,337.1	5,005.6	1,668.5	15%	750.8	250.3	2,586.2	3,086.8
7.	8	Compression assets, office furniture, equipment	-	-	7,616.0	100.0	7,516.0	11,274.0	3,758.0	20%	2,254.8	751.6	5,261.2	6,764.4
8.	10	Transportation, computer equipment	-	-	1,874.7	-	1,874.7	2,812.1	937.4	30%	843.6	281.2	1,031.1	1,593.5
9.	12	Computer software, small tools	-	-	11,185.5	-	11,185.5	11,185.5	5,592.8	100%	11,185.5	5,592.8	-	5,592.8
10.	13	Leasehold improvements	-	-	-	-	-	-	-	N/A	-	-	-	-
11.	14.1	Intangibles	-	-	82.2	-	82.2	123.3	41.1	5%	6.2	2.1	76.0	80.1
12.	14.1	Intangibles (pre 2017)	-	-	-	-	-	-	-	7%	-	-	-	-
13.	17	Roads, sidewalk, parking lot or storage areas	-	-	-	-	-	-	-	8%	-	-	-	-
14.	38	Heavy work equipment	-	-	823.6	-	823.6	1,235.4	411.8	30%	370.6	123.5	453.0	700.1
15.	41	Storage assets	-	-	379.1	141.0	238.1	357.2	119.1	25%	89.3	29.8	148.8	208.3
16.	45	Computers - Hardware acquired after March 22, 2004	-	-	-	-	-	-	-	45%	-	-	-	-
17.	49	Transmission pipeline additions acquired after February 23, 2005	-	-	1,870.0	584.3	1,285.7	1,928.5	642.8	8%	154.3	51.4	1,131.4	1,234.2
18.	50	Computers hardware acquired after March 18, 2007	-	-	2,286.8	-	2,286.8	3,430.2	1,143.4	55%	1,886.6	628.9	400.2	1,657.9
19.	51	Distribution pipelines acquired after March 18, 2007	-	-	62,357.7	1,078.0	61,279.7	91,919.6	30,639.9	6%	5,515.2	1,838.4	55,764.5	59,441.3
20.		Total	$ -	-	99,203.7	8,066.0	91,137.7	131,113.8 $	45,568.8		$ 23,167.4 $	9,586.7	67,970.2	81,550.9

Line No.	Class	**2019 Year-End** Particulars ($000s)	Opening UCC Accel. CCA	Opening UCC Regular CCA	Total Additions Qualifying for Accel. CCA	ICM & Capital Pass-Through Additions	Additions Net of ICM & Capital Pass-Through	Accel. CCA Depreciable UCC Balance	Regular CCA Depreciable UCC Balance	Rate (%)	Accelerated CCA	Regular CCA	Closing UCC Accel. CCA	Closing UCC Regular CCA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1.	1	Buildings, structures and improvements, services, meters, mains	-	-	-	-	-	-	-	4%	-	-	-	-
2.	1	Non-residential building acquired after March 19, 2007	1,117.8	1,191.5	7,938.6	871.0	7,067.6	11,719.2	4,725.3	6%	703.2	283.5	7,482.3	7,975.6
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	2,586.2	3,086.8	6,244.1	5,218.0	1,026.1	4,125.3	3,599.8	15%	618.8	540.0	2,993.5	3,572.9
7.	8	Compression assets, office furniture, equipment	5,261.2	6,764.4	34,091.6	15,202.5	18,889.1	33,594.8	16,208.9	20%	6,719.0	3,241.8	17,431.3	22,411.7
8.	10	Transportation, computer equipment	1,031.1	1,593.5	19,172.1	-	19,172.1	29,789.2	11,179.5	30%	8,936.7	3,353.9	11,266.4	17,411.7
9.	12	Computer software, small tools	-	5,592.8	26,830.9	-	26,830.9	26,830.9	19,008.2	100%	26,830.9	19,008.2	-	13,415.4
10.	13	Leasehold improvements	-	-	-	-	-	-	-	N/A	-	-	-	-
11.	14.1	Intangibles	76.0	80.1	3,595.2	1,836.0	1,759.2	2,714.9	959.8	5%	135.7	48.0	1,699.5	1,791.4
12.	14.1	Intangibles (pre 2017)	-	-	-	-	-	-	-	7%	-	-	-	-
13.	17	Roads, sidewalk, parking lot or storage areas	-	-	-	-	-	-	-	8%	-	-	-	-
14.	38	Heavy work equipment	453.0	700.1	4,392.7	-	4,392.7	7,042.0	2,896.4	30%	2,112.6	868.9	2,733.1	4,223.8
15.	41	Storage assets	148.8	208.3	735.5	-	735.5	1,252.1	576.1	25%	313.0	144.0	571.3	799.8
16.	45	Computers - Hardware acquired after March 22, 2004	-	-	-	-	-	-	-	45%	-	-	-	-
17.	49	Transmission pipeline additions acquired after February 23, 2005	1,131.4	1,234.2	90,992.5	55,507.0	35,485.5	54,359.7	18,977.0	8%	4,348.8	1,518.2	32,268.1	35,201.6
18.	50	Computers hardware acquired after March 18, 2007	400.2	1,657.9	26,453.0	-	26,453.0	40,079.7	14,884.4	55%	22,043.8	8,186.4	4,809.4	19,924.5
19.	51	Distribution pipelines acquired after March 18, 2007	55,764.5	59,441.3	573,688.0	988.6	572,699.4	914,813.6	345,791.0	6%	54,888.8	20,747.5	573,575.1	611,393.3
20.		Total	$ 67,970.2	81,550.9	794,134.1	79,623.1	714,511.0	1,126,321.4 $	438,806.5		$ 127,651.3 $	57,940.3	654,830.0	738,121.7

	2018	2019
CCA Variance (g) - (h)	13,580.7	69,711.0
Tax Rate	26.5%	26.5%
Earnings Impact of Accelerated CCA	3,598.9	18,473.4
Earnings Impact Grossed-up for Taxes Recorded in the TVDA	4,896.4	25,133.9

2020 TRANSITION IMPACT OF ACCOUNTING CHANGES DEFERRAL ACCOUNT – EGD RATE ZONE

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

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

3. Enbridge Gas is now requesting recovery of the eighth, or 2020 installment of the Board-Approved TIACDA amount, in the amount of $4.436 million (1/20 of

$88.716 million). As per the approved description and scope of the account, interest is not applicable to the balances to be cleared from the TIACDA.

2019 STORAGE & TRANSPORTATION DEFERRAL ACCOUNT – EGD RATE ZONE

1. The purpose of the 2019 S&TDA is to record the difference between the forecast of Storage and Transportation rates (both cost of service and market based pricing) included in the Company's EGD Rate Zone approved rates and the final Storage and Transportation rates (both cost of service and market based pricing) incurred by the EGD Rate Zone.

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 EGD Rate Zone related to deferral account dispositions of Union's deferral accounts.

3. The balance in the 2019 S&TDA that the Company is proposing to collect from customers is $2.5 million plus interest.

4. The primary driver for the balance in the 2019 S&TDA is due to EGD Rate Zone incurring higher than forecasted M12 toll in 2019, partially offset by a $4 million refund from the Union South Rate Zone as part of the 2017 deferral disposition. A detailed breakdown of the variance please see Exhibit D, Tab 1, Schedule 1.

2019 TRANSACTIONAL SERVICES DEFERRAL ACCOUNT ("2019 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 storage or the loan of gas between two points in time at the same location (i.e., Dawn). Transportation optimization transactions typically rely on the exchange of gas on the day between two locations.

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

4. During 2019 the Company generated a total of $13.1 million in net Transactional Services revenue, of which the ratepayer portion represents $11.8 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, $0.1 million proposed to be collected from customers through the disposition of the 2019 TSDA. For comparison purposes the schedule also includes amounts recorded in the applicable TSDA accounts for years 2018, 2017, 2016, 2015 and 2014.

5. The transactions that Enbridge Gas entered into in 2019 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.

2019 UNACCOUNTED-FOR GAS VARIANCE ACCOUNT – EGD RATE ZONE

1. This evidence provides the volumetric variance underpinning the balance in the 2019 Unaccounted-For Gas Variance Account ("UAFVA"). It will describe the 2019 variance relative to historical Unaccounted-For Gas ("UAF") volumes for the EGD Rate Zone.

2. UAF is the difference between natural gas delivered into the distribution system as billed by third-party transmission entities (namely, TC Energy and Union Gas[1]), and natural gas consumed by the customers in the EGD Rate Zone and EGD own use gas and line pack gas. Owing to its residual nature, UAF cannot be measured directly. UAF can arise from meter differences, operational or external factors such as line leakage, unmetered uses, and third party damages. In addition, because gas volumes are affected by temperature and pressure, measurement is made more difficult.

3. The 2019 level of UAF for the EGD Rate Zone was determined to be 140,594 10^3m^3. The variance of 33,917 10^3m^3, which is the difference between actual UAF volume and the forecast UAF volume of 106,677 10^3m^3, underpins the $4.9 million balance

[1] As of January 1, 2019, Union Gas Limited and Enbridge Gas Distribution have merged as Enbridge Gas Inc.

that is captured in the UAFVA.

4. Although the root causes of UAF are generally known as noted earlier, it continues to be difficult to quantify the individual factors due to their nature. No significant factors are known to have occurred in 2019 that would have contributed to a higher UAF than previous years. As part of the MAADs Decision and Order dated August 30, 2018 on the amalgamation of Enbridge Gas Distribution and Union Gas (EB-2017-0306), Enbridge Gaswas directed to file a report on the issue of Unaccounted for Gas for both the legacy Union Gas and legacy Enbridge Gas Distribution service areas by December 31, 2019. Among the objectives of the UAF study was an analysis of UAF causes to identify possible points of gas losses and to review functional capabilities of the measurement system used to produce UAF values.

5. The 2019 UAF study was filed as part of the 2020 rate application (EB-2019-0194). The report found that the primary sources for UAF include physical losses, retail meter variation and gate station meter variations. The report found that the UAF levels are generally lower than competitive gas utilities over the past 10 years. The year-to-year fluctuations are a result of many factors including weather, estimation variation, measurement variation, and billing and accounting adjustments. The practices and initiatives to monitor and manage sources of UAF are generally consistent with those of other gas utilities. Enbridge Gas has

committed to report on its progress in implementing the recommendations set out in the 2019 UAF Study in its 2022 rates application.[2]

6. As shown in Tables 1 and 2 in the following pages, UAF within the EGD rate zone has been quite volatile over the years, showing some stability from 2010-2012, and followed by higher levels especially in 2014, 2016 and 2018. The 2019 UAF level falls within the 95% confidence interval, bounded by (12,789) 10^3m^3 and 162,237 10^3m^3.

[2] EB-2019-0194, Decision and Order, pages 18-19.

Table 1: Unaccounted-For Gas Volumes (10^3 m^3), 1991-2019

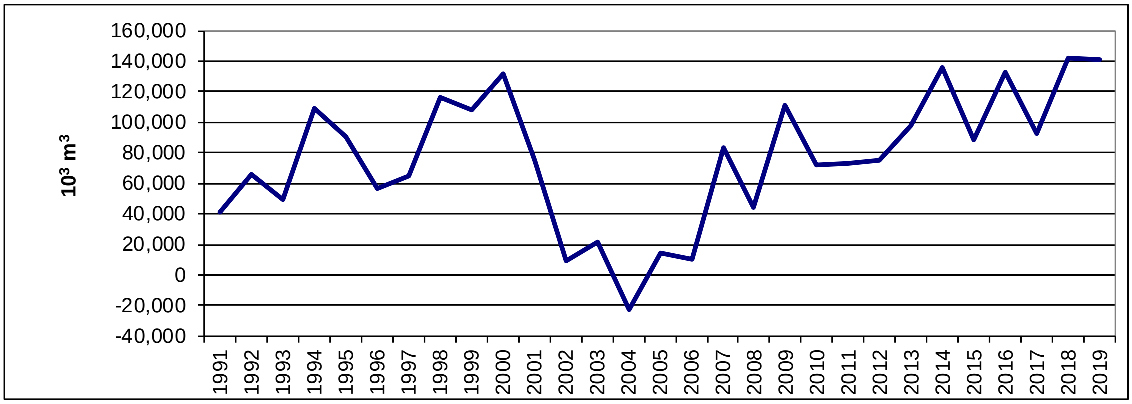


Table 2

Col.1	*Col.2*
Calendar Year	**UAF Volumes (10^3 m^3)**
1991	40,662
1992	66,028
1993	49,782
1994	108,765
1995	90,655
1996	56,739
1997	65,228
1998	116,376
1999	108,201
2000	132,021
2001	75,606
2002	9,284
2003	21,412
2004	-22,406
2005	14,815
2006	10,274
2007	83,823
2008	44,424
2009	110,917
2010	72,104
2011	73,355
2012	74,762
2013	97,361
2014	135,380
2015	88,438
2016	133,112
2017	93,077
2018	142,086
2019	140,594

	1991-2018
Standard deviation	42,648
Mean	74,724
Lower bound*	-12,789
Upper bound*	162,237

*95% confidence interval with 27 degrees of freedom (number of observations-1)

2019 AVERAGE USE TRUE-UP VARIANCE ACCOUNT – EGD RATE ZONE

1. The purpose of this evidence is to provide information in support of the EGD Rate Zone 2019 Average Use True-up Variance Account ("AUTUVA") balance.

2. Exhibit D, Tab 1, Schedule 3 details the calculations that result in the amount of $8.77 million that will constitute a refund to ratepayers. The refund is attributable to actual Rate 1 (residential) and Rate 6 (apartment, small commercial and industrial) average uses being higher than 2019 forecast levels.

3. Higher weather-normalized average use is primarily attributable to lower actual natural gas prices and better economic conditions in 2019 than were forecast. Lower gas prices have led to higher consumption for both Rate 1 and Rate 6 customers. In addition, higher employment levels and stronger GDP support stronger economic conditions, which also lead to higher consumption.

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 customer 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 Exhibit D, Tab 1, Schedule 3 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 2019 DSM activities will not be available until a later date, the 2019 Board Approved Budget DSM volumes are used as an estimate of 2019 actuals. Without the exclusion of a DSM volumetric variance in the AUTUVA calculation, the impacts of DSM are inherently included. As a result, 2019 LRAM amounts, which will be filed at a later date, will exclude the impact of Rate 1 and Rate 6 customers.

2019 DEFERRED REBATE ACCOUNT – EGD RATE ZONE

1. The purpose of the 2019 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 $1.0 million recorded in the 2019 DRA and requested for clearance (and corresponding interest of $27.1 thousand), reflects the outstanding amount resulting from the clearance of deferral and variance accounts in the EGD Rate Zone which occurred during 2019 and the inability to locate all the intended customers. In January of 2019, the Company cleared 2017 deferral and variance accounts which were approved within the EB-2018-0131 proceeding. In July of 2019, the Company cleared 2016 DSM related deferral and variance accounts which were approved within the EB-2018-0301 proceeding. Finally, in October through December of 2019, the Company cleared 2016-2018 Cap and Trade related deferral and variance accounts which were approved within the EB-2018-0331 proceeding.

2019 ELECTRIC PROGRAM EARNINGS SHARING DEFERRAL ACCOUNT – EGD RATE ZONE

1. The description and scope of the 2019 Electric Program Earnings Sharing Deferral Account (“EPESDA”), consistent with prior fiscal years, is to track and account for the ratepayer share of all net revenues generated by DSM services provided for electric Conservation and Demand Management (“CDM”) activities. The ratepayer share is 50% of net revenues, using fully allocated costs, as was determined in the DSM guidelines proceeding EB-2008-0346.

2. On June 10, 2016, the Minister of Energy provided a direction to the IESO whereby, the IESO shall, in consultation with the Distributors, centrally design, fund and deliver “a province-wide home Conservation and Demand Management (“CDM”) pilot program for residential consumers.” The IESO Whole Home Pilot was launched on May 29, 2017 and leverages the existing Enbridge Gas DSM Home Energy Conservation (“HEC”) program offering by adding an electric assessment component and offering prescriptive electric incentives to participants. The aim of this “one stop shop” approach was to increase Enbridge Gas Distribution participant satisfaction, provide additional energy literacy to Ontario residents, and remove the barriers around access to incentives from different parties. The pilot program was extended into 2018, with enrollments of residential homeowners into the Whole

Home Pilot continuing to the pilot end date of October 31st, 2018. Participants who completed a pre-assessment by this date were eligible for the rebates available through the Pilot upon completion of the home retrofit offering process.

3. The ($0.175) million recorded in the 2019 EPESDA and requested for clearance, reflects the ratepayers' 50% share of the net recovery generated by providing CDM activities, using fully allocated costs, as determined in the DSM guidelines proceeding EB-2008-0346.

2019 ONTARIO ENERGY BOARD COST ASSESSMENT VARIANCE ACCOUNT – EGD RATE ZONE

1. The purpose of the 2019 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 2019 OEBCAVA was approved as part of the EB-2018-0305 Decision and Accounting Order, dated October 24, 2019. The scope of the account is consistent with prior OEBCAVAs. The OEBCAVA was originally approved for establishment by Board letter dated February 9, 2016, entitled: *Revisions to the Ontario Energy Board Cost Assessment Model.*

2. The amount recorded within the 2019 OEBCAVA is $3.233 million. This amount reflects the variance between OEB costs assessed to Enbridge Gas (relevant to EGD Rate Zone) in each quarter of fiscal 2019, utilizing the revised CAM, and EGD's average quarterly OEB cost assessment under the prior CAM. For purposes of calculating amounts to be recovered through the 2019 OEBCAVA, the Company used the OEB's fiscal 2015 / 2016 cost assessment amount of $2.8 million (or an average of $0.7 million per quarter) as the comparator, as it was the most recent

amount which EGD was expected to accommodate through its Custom Incentive Regulation established rates. This methodology is consistent with the determination of amounts which were approved for recovery through the 2016 through 2018 OEBCAVAs. As of the OEB's fiscal first quarter of 2019 (for the period April 1, 2019 through June 30, 2019), the Company began receiving one consolidated bill for the amalgamated utility. For the purposes of calculating the OEBCAVA amounts for each rate zone, these bills were prorated based on the total invoices received by both utilities in the prior fiscal year (for the period April 1, 2018 through March 31, 2019). Table 1 below, shows the calculation of the amount recorded in the 2019 OEBCAVA for each Rate Zone, while Table 2 shows the calculation of the average 2015 / 2016 OEB costs assessed to EGD under the prior CAM.

3. Within this proceeding, the Company is requesting clearance of the principal and interest balances recorded in the 2019 OEBCAVA, in the amount of $3.233 million and $0.078 million respectively, as shown in Exhibit B, Tab 1, Appendix A, Schedule 1.

Table 1

OEB 2018/2019 Cost Assessments

	EGD	UGL	Total
Apr. 1 to Jun. 30, 2018	1,467,963.00	988,479.00	2,456,442.00
Jul. 1 to Sep. 30, 2018	1,356,860.00	913,873.00	2,270,733.00
Oct. 1 to Dec. 31, 2018	1,356,860.00	913,873.00	2,270,733.00
Jan. 1 to Mar. 31, 2019	1,356,860.00	913,873.00	2,270,733.00
	5,538,543.00	3,730,098.00	9,268,641.00
Percentage of Total	59.76%	40.24%	100.00%

OEB 2019/2020 Cost Assessments to EGI

Period	EGI Assessment	EGD Rate Zone Share (59.76%)	Average cost assessment based on previous CAM*	Variance recorded in EGD Rate Zone OEBCAVA
Q4 2018/19 - Jan. 1, 2019	billed separately	1,356,860.00	699,845.75	657,014.25
Q1 2019/20 - Apr. 1, 2019	2,456,442.00	1,467,864.56	699,845.75	768,018.81
Q2 2019/20 - July 1, 2019	2,684,063.00	1,603,881.12	699,845.75	904,035.37
Q3 2019/20 - Oct. 1, 2019	2,684,063.00	1,603,881.12	699,845.75	904,035.37
				3,233,103.81

* EGD utilized the average of the OEB's fiscal 2015/2016 quarterly invoiced amounts, determined under the previous CAM, as representative of the OEB costs embedded in 2019 rates.

Period	EGI Assessment	UGL Rate Zone Share (40.24%)	Amount in UGL Rate Zone Rates*	Variance recorded in UGL Rate Zone OEBCAVA
Q4 2018/19 - Jan. 1, 2019	billed separately	913,873.00	625,000.00	288,873.00
Q1 2019/20 - Apr. 1, 2019	2,456,442.00	988,577.44	625,000.00	363,577.44
Q2 2019/20 - July 1, 2019	2,684,063.00	1,080,181.88	625,000.00	455,181.88
Q3 2019/20 - Oct. 1, 2019	2,684,063.00	1,080,181.88	625,000.00	455,181.88
				1,562,814.19

* UGL included $2.5M in rates under the old CAM methodology as representative of the OEB costs embedded in 2019 rates.

Table 2

OEB Cost Assessment Based on prior CAM	Qtr. #	Quarterly Assessment	Total for the year	Average/Qtr
		$	$	$
OEB Fiscal 2015/2016	1	656,800		
	2	656,800		
	3	655,137		
	4	830,646	2,799,383	699,846

2019 DAWN ACCESS COSTS DEFERRAL ACCOUNT – EGD RATE ZONE

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

2. As was indicated in the EB-2018-0131 and EB-2019-0105 proceedings (in support of the clearance of the 2017 and 2018 revenue requirement amounts recorded in the 2017 and 2018 DACDAs), all incremental costs incurred by the Company to implement the DTS (and functionality for 2 additional receipt points) and heat value

conversion modification were capital in nature. Capital costs of $6.5 million were incurred to develop, test, and integrate enhancements to the functionality of Enbridge's EnTRAC and connected systems. The systems modifications were placed into service effective November 1, 2017, in conjunction with the implementation of Phase 2 of the Dawn Access Settlement. The annual revenue requirement amounts sought for refund/recovery in association with those capital costs, includes the typical items in a cost of service revenue requirement, such as total return on rate base, including interest and return on equity, depreciation, and income taxes.

3. Within this proceeding, the Company is requesting clearance of the 2019 revenue requirement, or principal balance, of $2.153 million (and corresponding interest of $0.030 million) as part of the requested one time rate rider adjustment in January 2021, as shown in the proposed clearance balances at Exhibit C, Tab 1, Schedule 1. As indicated above, this amount represents the 2019 revenue requirement associated with the capital spending incurred to accommodate the DTS and heat value changes, which were placed into service in 2017. The Company has used the 2019 actual required capital structure within the 2019 revenue requirement calculation (consistent with the use of the actual capital structures which were utilized in determining previous revenue requirements which were approved for clearance). There will also be revenue requirement amounts to be recorded in relation to this spending within future DACDAs. The 2019 amount was higher than

the prior year amounts as both the 2017 and 2018 revenue requirements benefited from a significant Capital Cost Allowance (“CCA”) tax deduction that does not repeat in subsequent years beyond 2018.

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

5. The determination of the 2019 DACDA revenue requirement deferral account amount and related costs is shown in pages 4 through 8. The approved 2017 & 2018 revenue requirement amounts are also shown for continuity.

UTILITY CAPITAL STRUCTURE
2019 DACDA IMPACTS

Line No.		Col. 1 Component	Col. 2 Indicated Cost Rate	Col. 3 Return Component	Col. 1 Component	Col. 2 Indicated Cost Rate	Col. 3 Return Component	Col. 1 Component	Col. 2 Indicated Cost Rate	Col. 3 Return Component
		2017 Actual Capital Structure			2018 Actual Capital Structure			2019 Actual Capital Structure		
		%	%	%	%	%	%	%	%	%
1.	Long-term debt	56.88	4.86	2.76	57.05	4.72	2.69	61.13	4.44	2.71
2.	Short-term debt	5.57	1.05	0.06	5.65	1.81	0.10	2.87	2.04	0.06
3.		62.45		2.82	62.70		2.80	64.00		2.77
4.	Preference shares	1.55	2.32	0.04	1.30	2.98	0.04	0.00	0.00	0.00
5.	Common equity	36.00	8.78	3.16	36.00	9.00	3.24	36.00	8.98	3.23
6.		100.00		6.02	100.00		6.07	100.00		6.01

	($ 000's)	2017	2018	2019
7.	Ontario Utility Income	685.0	(521.2)	(1,324.9)
8.	Rate base	259.7	5,623.8	4,283.2
9.	Indicated rate of return	263.77 %	(9.27)%	(30.93)%
10.	(Def.) / suff. in rate of return	257.75 %	(15.34)%	(36.94)%
11.	Net (def.) / suff.	669.4	(862.7)	(1,582.2)
12.	Gross (def.) / suff.	910.7	(1,173.7)	(2,152.7)

UTILITY RATE BASE
2019 DACDA IMPACTS

($ 000's)

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

UTILITY INCOME
2019 DACDA IMPACTS

($ 000's)

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

UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2019 DACDA IMPACTS

($ 000's)

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

UTILITY REVENUE REQUIREMENT
2019 DACDA IMPACTS

($ 000's)

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

ACCOUNTS WITH A ZERO BALANCE – EGD RATE ZONE

1. The following 2019 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
   - Pension and OPEB Forecast Accural vs. Actual Cash Payment Differential Variance Account

BREAKDOWN OF THE 2019 STORAGE AND TRANSPORTATION DEFERRAL ACCOUNT ("2019 S&TDA") - EGD RATE ZONE

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
Line No.	Contracted Union Capacity	Budgeted Daily Contract Demand Volume	Monthly Demand Toll Assumed in 2019 Budget	Forecasted Annual Cost (3)	Actual Daily Contract Demand Volume	Monthly Demand Toll Effective January 1, 2019 to March 31, 2019	Monthly Demand Toll Effective April 1, 2019 to December 31, 2019	January 1, 2019 to March 31, 2019 (4)	April 1, 2019 to December 31, 2019 (5)	Annual Cost (6)	Balance in the 2019 S&TDA (7)
		(GJ)	($/GJ)	($Millions)	(GJ)	($/GJ)	($/GJ)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Union Gas Dawn to Lisgar	67,929	2.865	2.3	67,929	3.154	3.058	0.6	1.9	2.5	
2.	Union Gas Dawn to Parkway	2,717,173	3.402	110.9	2,717,173	3.716	3.602	30.3	88.1	118.4	
3.	Union Gas Dawn to Parkway (1)	75,000	3.402	0.5	75,000	3.716	3.602	-	0.5	0.5	
4.	Union Gas Dawn to Parkway - M12X	200,000	4.239	10.2	200,000	4.59	4.45	2.8	8.0	10.8	
5.	Union Gas Parkway to Dawn - C1	236,586	0.719	0.5	236,586	0.874	-	0.6	-	0.6	
6.	Union Gas F24 T	85,000	0.069	0.1	85,000	0.07	0.071	-	0.1	0.1	
7.	Union Transmission Costs			124.5				34.3	98.6	132.9	(8.4)
8.	Dawn T Service Costs			(11.2)				(3.6)	(11.3)	(14.9)	3.7
9.	Cap and Trade costs			-				-	0.3	0.3	(0.3)
10.	Union & Third Party Market Based Storage			20.1				5.0	16.6	21.6	(1.5)
11.	2017 Deferral Disposition - UG (2)			-				(4.0)	-	(4.0)	4.0
12.	Total			133.4				31.7	104.2	135.9	(2.5)

Notes
(1) Demand volumes increase by 75K for M12234
(2) M12 Transporation Deferral adjustment related to 2017 S&TDA reduced actual costs by $4M
(3) Col. 1 * Col. 2 * 12
(4) Col. 4 * Col. 5 * 3
(5) Col. 4 * Col. 6 * 9
(6) Col. 7 + Col. 8
(7) Col. 9 - Col. 3

BREAKDOWN OF TRANSACTIONAL SERVICES REVENUE BY TYPE OF TRANSACTION ("2019 TSDA") - EGD RATE ZONE

Line No.	Particulars	Col. 1 2019 Transactional Services Revenue	Col. 2 2018 Transactional Services Revenue	Col. 3 2017 Transactional Services Revenue	Col. 5 2016 Transactional Services Revenue	Col. 6 2015 Transactional Services Revenue	Col. 7 2014 Transactional Services Revenue
		($000's)	($000's)	($000's)	($000's)	($000's)	($000's)
1.	Storage Optimization	60.7	423.9	1,550.1	7,277.2	517.4	1,703.4
2.	Transportation Optimization	13,084.5	14,292.4	10,393.3	10,463.5	22,727.1	12,910.3
3.	Transactional Services Revenue	13,145.2	14,716.2	11,943.5	17,740.6	23,244.6	14,613.7
4.	Amount Included in Rates	12,000.0	12,000.0	12,000.0	12,000.0	12,000.0	12,000.0
5.	Less Ratepayer Portion of TS	11,830.7	13,244.6	10,749.1	15,966.6	20,920.1	13,152.4
6.	TSDA sub-total	169.3	(1,244.6)	1,250.9	(3,966.6)	(8,920.1)	(1,152.4)
7.	ETT Revenue - Rider H	35.1	60.1	44.5	69.7	154.7	104.4
8.	TSDA Total	134.3	(1,304.7)	1,206.4	(4,036.3)	(9,074.8)	(1,256.7)

2019 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
Period	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)
Jan-Mar	1	1,180	1,188	9	2,046,299	17.5	(5.1)	(5.1)	0.0	17.5	0.0702	1.23
Apr-Dec	1	1,232	1,275	43	2,046,299	87.1	(5.1)	(5.1)	0.0	87.1	0.0716	6.24
Jan-Mar	6	13,934	14,054	121	168,065	20.3	(15.1)	(15.1)	0.0	20.3	0.0400	0.81
Apr-Dec	6	15,220	15,293	73	168,065	12.3	(15.1)	(15.1)	0.0	12.3	0.0403	0.49
Total												8.77

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

UNABSORBED DEMAND COSTS (“UDC”) VARIANCE ACCOUNT – UNION RATE ZONES

1. The balance in the UDC Variance Account deferral account is a credit to ratepayers of $11.958 million plus interest as of December 31, 2020 of $0.311 million, for a total of $12.269 million. The $11.958 million balance is the difference between the actual UDC incurred by Union Rate Zones and the amount of UDC collected in rates.

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 2019 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 rates are based on the Gas Supply Plan filed in Union’s Dawn Reference Price proceeding[1] and included in the 2019 Rates proceeding[2].

3. As discussed in the Gas Supply Memorandum in the 2019 Rates proceeding[2], in Union North, the upstream transportation capacity (long-haul, short-haul and STS) is

[1] EB-2015-0181, Exhibit A, Tab 2, Appendix A, Schedule 1.
[2] EB-2018-0305.

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 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. 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.

4. Enbridge Gas collected $12.882 million in rates for UDC for Union rate zones during 2019 and recorded an associated interest credit of $0.311 million (see Table 1). Actual UDC costs in 2019 were $1.573 million offset by $0.649 million in released capacity value, resulting in a net cost of $0.924 million (see Table 2).

5. The variance between the amounts collected in rates and the actual UDC costs, including the interest credit of $0.311 million, results in a net credit to ratepayers in the UDC Variance Account of $12.269 million.

6. The balance of $12.269 million is allocated to Union North West, Union North East and Union South in proportion to the actual excess supply and UDC costs incurred

for each respective area. The balance applicable to sales service and bundled DP customers in Union North West is a credit of $10.739 million and in Union North East, a credit of $1.530 million. There is a $0 balance applicable to sales service customers in Union South.

7. Table 1 provides the derivation of the UDC variance account balances by operations area.

Table 1
UDC Variance Account by Operational Area

Line No.	Particulars ($000's)	Union North East	Union North West	Union South	Total Franchise Area
1	UDC Collected in Rates	(1,844)	(11,038)	-	(12,882)
2	UDC Costs Incurred (Table 2)	353	571	-	924
3	Variance (line 1 + line 2)	(1,491)	(10,467)	-	(11,958)
4	Interest	(39)	(272)	-	(311)
5	(Credit)/Debit to Operations Area	(1,530)	(10,739)	-	(12,269)

A description of each item follows:

UDC Collected in Rates

8. The 2019 Board-approved rates include $10.822 million of UDC associated with 14.4 PJ of planned unutilized pipeline capacity in Union North West and Union North East and no planned unutilized pipeline capacity in Union South. The total cost of UDC in rates assumes TC Energy final tolls effective February 1, 2019. On an actual basis in 2019, Enbridge Gas recovered $12.882 million in Union North West and Union North East and $0.0 million in Union South.

UDC Costs Incurred

9. The actual unutilized capacity in 2019 was 2.3 PJ. The level of unutilized capacity experienced in 2019 was due to planned unutilized capacity (and resulting UDC), offset, in part, by higher consumption relative to plan resulting in a reduction in planned UDC.

10. The costs reflected in the UDC Variance Account are the total demand charges for unutilized pipeline capacity totaling $1.573 million, offset, in part, by the value of $0.649 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 2 below.

Table 2
UDC Costs Incurred

Line No.	Particulars ($000's)	Union North East	Union North West	Union South	Total Franchise Area
1	UDC Costs Incurred	601	972	-	1,573
2	Released Capacity Revenue	(248)	(401)	-	(649)
3	Net UDC Costs (Credit)/Debit	353	571	-	924

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

1. The Upstream Transportation Optimization Deferral Account was approved by the Board in its EB-2011-0210 Decision to capture the variance between the ratepayer's 90% share of actual net revenues from optimization activities, and the amount refunded to ratepayers in rates. The balance in this deferral account is a debit from ratepayers of $12.122 million plus interest of $0.166 million for a total debit from ratepayers of $12.288 million.

2. In setting rates for 2019, the Board approved a forecast of optimization revenue of $14.918 million. Of that amount, 90% or $13.426 million, was credited to ratepayers in the Board-approved 2019 rates.[1] On an actual basis, consistent with the method approved in its EB-2011-0210 Decision and Rate Order, Union credited $17.489 million in rates to ratepayers during 2019, $4.063 million greater than the Board-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.

[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.

3. The Company earned $5.963 million in net revenues from upstream transportation optimization during 2019 in the Union rate zones. In accordance with the Board-approved sharing methodology, 90% of this net revenue, or $5.367 million, is to be credited to customers. As stated above, $17.489 million has already been credited through rates; therefore, the deferral balance is a debit from ratepayers of $12.122 million ($17.489 million less $5.367 million).

4. Exhibit E, Tab 1, Schedule 1, provides a summary of the calculation of the balance in this deferral account. 2019 actual Upstream Transportation Optimization revenue in the Union rate zones is lower than 2013 Board-approved revenue due to:
   1) The elimination of the TransCanada FT-RAM program ($5.800 million);
   2) Changing market dynamics as evidenced by an increase in firm contracting on the TransCanada Mainline to major export points such as East Hereford, and the reversal of Niagara from an export point to an import point; and,
   3) Changing market dynamics as evidenced by a decrease in market spreads for the year between Dawn and major export points, such as Iroquois.

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 $2.822 million, plus interest of $0.033 million for a total debit from ratepayers of $2.855 million.

2. As shown in Table 3, the balance is calculated by comparing $1.729 million (ratepayer 90% share of the actual 2019 Short-Term Storage and Other Balancing Services net revenue of $1.921 million) to the net revenue included in Union Rate Zone rates of $4.551 million.[1] The details of the balance are found at Exhibit E, Tab 1, Schedule 2.

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

Table 3

Deferral Summary: Short-term Storage and Other Storage Services

Line No.	Particulars ($000's)	Actual 2019
1	Net Revenue	1,921
2	Ratepayer Portion (90%)	1,729
3	Approved in Rates	4,551
4	Deferral Balance Payable to/(Collectable from) Ratepayers	(2,822)

3. Actual 2019 revenues from C1 Off-Peak Storage, Gas Loans and all other Balancing services of $1.289 million were $1.211 million lower than the 2013 Board-approved forecast of $2.500 million.

4. The C1 Short-Term Firm Peak Storage revenues of $2.125 million were $5.758 million lower than the 2013 Board-approved forecast of $7.883 million. Actual Union Rate Zone utility storage requirements for 2019 were 8.4 PJ higher than the 2013 Board-approved forecast, resulting in a decrease in the C1 Short-Term Firm Peak Storage available for sale (from 11.3 PJ in 2013 Board-approved to 2.9 PJ in 2019). 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.

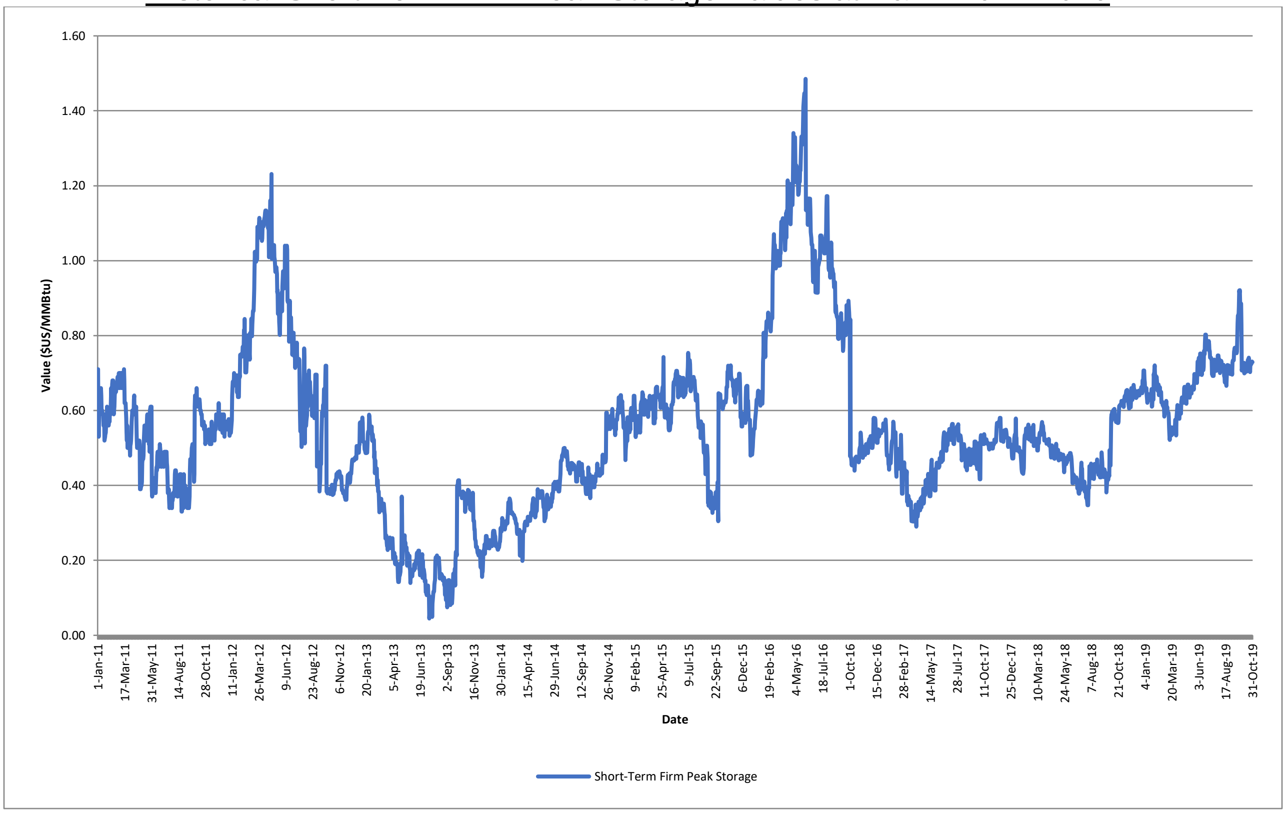
5. Year-over-year, actual utility storage requirements for 2019 were 4.7 PJ higher than the requirement in 2018, resulting in a decrease in the C1 Short-Term Peak Storage

available for sale (from 7.6 PJ in 2018 to 2.9 PJ in 2019). 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 Board-approved aggregate excess methodology. The storage requirement for the contract market was calculated specifically for each customer using either the Board-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]

6. The 2013 Board-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 2019 was $0.73/GJ ($2.125 million/2.9 PJ). Please see Figure 1 for Short-Term Peak Storage values in US dollars.

[2] EB-2016-0245, Decision and Rate Order, Schedule 1, Settlement Proposal, p.7.

Figure 1
Historical Short-Term Firm Peak Storage Values at Dawn 2011-2019



Non-Utility Storage Balances for 2019

7. In its EB-2011-0210 Decision, the Board directed Legacy 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 2019 (for legacy Union storage).

8. During the 2019 injection season, the non-utility storage balance peaked on November 6, 2019 at 98% full with a balance of 111.4 PJ compared to available

space of 113.9 PJ. At October 31, 2019, the date to which the Company manages its storage balance, the non-utility balance was 96.6% of available space. The balance stayed below the total non-utility available space of 100% for the rest of 2019.

9. In EB-2011-0210, the Board 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 2019 and therefore no calculation applies.

<u>Sale of Non-Utility Storage Space</u>

10. Enbridge Gas prioritizes the sale of its legacy 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 Board in EB-2011-0210.[3] 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 2019, Enbridge Gas sold a total of 5.9 PJ of short-term peak storage (legacy Union). Of this total, 2.9 PJ was excess utility space, calculated by deducting 97.1 PJ

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

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 storage sales of 3.0 PJ was sold as non-utility space. Total revenue from the sale of C1 Short-Term Peak Storage (Utility) in 2019 was $2.125 million. Details of the above sales are reflected in Exhibit E, Tab 1, Schedule 4.

CONSERVATION DEMAND MANAGEMENT ("CDM") DEFERRAL ACCOUNT– UNION RATE ZONES

1. The purpose of the CDM Deferral Account is to track revenues associated with CDM activities, to be shared 50/50 between the Company and ratepayers. The Board approved the accounting order for the CDM Deferral Account in Union's 2011 Rates application (EB-2010-0148). The balance in this deferral account is a credit to ratepayers of $0.138 million plus interest of $0.004 million for a total credit to ratepayers of $0.142 million.

2. This balance represents 50% of the net revenue from the "Whole Home Pilot Delivery" between Union and the Independent Electric Systems Operators ("IESO") for 2019. The Minister of Energy issued a direction to the IESO dated June 10, 2016 clarifying the direction to the IESO in its Conservation First Framework Directive to coordinate and integrate the CDM Programs with that of the Gas Distributors by requiring the IESO to: (a) design and fund a province-wide whole home pilot program for residential consumers ("Pilot"); (b) deliver the Pilot in coordination with the Gas Distributors; and (c) commence implementation of the Pilot by the end of the Fall of 2016. Union and the IESO entered into an agreement in May 2017 to be responsive to the June 2016 Direction, to further the province's conservation objectives, and provide a mechanism for electrically heated homes to participate in home energy conservation initiatives. The Whole Home Pilot enrollment ended on

September 30, 2018. Participants who completed a pre-assessment by this date were eligible for the rebates available through the Pilot upon completion of the home retrofit offering process. These participants were also granted additional time to complete their post-assessment by February 28, 2019 to be eligible for the Pilot offering. All activity and payments related to the Pilot concluded in Q2 2019.

DEFERRAL CLEARING VARIANCE ACCOUNT– UNION RATE ZONES

1. The purpose of the Deferral Clearing Variance Account 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 credit to Union Rate Zone ratepayers of $1.748[1] million plus interest to December 31, 2020 of $0.045 million, for a total of $1.793 million. The $1.748 million balance represents an over-recovery of $0.914 million from the Board-approved disposition of deferral account balances from Union Gas Limited's 2017 Non-Commodity Deferrals Disposition and Earnings Sharing proceeding (EB-2018-0105). In addition, the balance also reflects an over-recovery of $0.835 million from the Board-approved disposition of deferral account balances from Union's 2015 Demand Side Management ("DSM") Deferrals Disposition proceeding (EB-2017-0323). Please see Exhibit E, Tab 1, Schedule 5, page 1 for a summary of the deferral account balance.

[1] $1.748 million credit (total of ($1.096) gas supply commodity, $69.2 gas supply transportation, and ($721.6) delivery).

Union Gas Limited's 2017 Non-Commodity Deferrals Disposition and Earnings Sharing (EB-2018-0105)

3. In its EB-2018-0105 Decision, the Board approved the prospective disposition of the balances in the approved deferral accounts to rate classes through a temporary rate adjustment from January 1, 2019 to June 30, 2019. The total amount approved for prospective recovery from rate classes was $7.653 million. Please see Exhibit E, Tab 1, Schedule 5, page 1, column (e), for the forecast amount to be recovered by rate class, based on the forecasted volumes as noted in column (a) of the same exhibit.

4. Actual volumes for the period January 1, 2019 to June 30, 2019 averaged approximately 11% greater than forecast due to colder weather in the same period. As a result of the actual volumes being greater than the forecasted volumes, the Company recovered $8.566 million, which is $0.913 million greater than the final deferral account balances approved for disposition in EB-2018-0105. Please see Exhibit E, Tab 1, Schedule 5, page 2, column (f) for the actual disposition amounts by rate class, based on the actual volumes as shown in column (b). Column (g) of the same exhibit shows the variance between forecast and actual disposition.

Union Gas Limited's 2015 DSM Deferrals Disposition (EB-2017-0323)

5. In its EB-2017-0323 Decision, the Board approved the prospective disposition of the balances in the approved deferral accounts to rate classes through a temporary rate adjustment from October 1, 2018 to March 31, 2019. The total amount approved for prospective recovery from rate classes was $6.609 million. Please see Exhibit E, Tab 1, Schedule 5, page 2, column (e), for the forecast amount to be recovered by rate class, based on the forecasted volumes as noted in column (a) of the same exhibit.

6. Actual volumes for the period October 1, 2018 to March 31, 2019 averaged approximately 12% greater than forecast due to colder weather in the same period. As a result of the actual volumes being greater than the forecasted volumes, the Company recovered $7.431 million, which is $0.822 million more from Union rate zones than the final deferral account balances approved for disposition in EB-2017-0323. Please see Exhibit E, Tab 1, Schedule 5, page 2, column (f) for the actual disposition of deferral accounts and Exhibit E, Tab 1, Schedule 5, page 2, column (g) for the variance between forecast and actual disposition.

NORMALIZED AVERAGE CONSUMPTION ("NAC") DEFERRAL ACCOUNT– UNION RATE ZONES

1. The purpose of the NAC deferral account is to record, in relation to the Union rate zones, the variance in delivery revenue and storage revenue and costs resulting from the difference between the target NAC included in Board-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 proceeding (EB-2015-0010), 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 2019, the balance in the NAC deferral account is a credit to ratepayers of $4.676 million plus interest of $0.120 million for a total credit to ratepayers of $4.796 million.

3. The NAC Deferral Account follows the same methodology agreed to by parties in Union's 2014-2018 Incentive Regulation ("IR") Settlement Agreement (EB-2013-0202) and as subsequently modified in Union's 2015 Rates proceeding (EB-2014-0271).

Target and Actual NAC

4. The 2019 target NAC used to calculate base rates for each Union rate zone rate class was approved by the Board in Enbridge Gas's 2019 Rates proceeding (EB-2018-0305). The 2017 actual NAC, weather normalized using the 2019 weather normal, was used to determine the 2019 target NAC for each rate class to calculate base rates. Setting the 2019 target NAC based on the 2017 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.

5. The 2019 forecast usage used to calculate Y factor unit rates (DSM and PDO unit rates) for each Union Rate Zones rate class was approved by the Board in Enbridge Gas's 2019 Rates proceeding (EB-2018-0305). The unit rates for pass through (Y factor) costs are derived based on Board-approved cost allocation and rate design methodologies and are passed through to customers at cost.

6. The 2019 actual NAC for each rate class is weather normalized using the 2019 weather normal, which is produced using the Board-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.

Table 1 provides the 2019 target NAC and 2019 actual NAC by rate class for base rates.

TABLE 1
2019 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.	2019 Target NAC	2,852.7	164,301.2	2,766.5	167,038.5
2.	2019 Actual NAC	2,880.0	171,056.3	2,780.2	168,624.3
3.	Variance (Target - Actual NAC)	(27.2)	(6,755.1)	(13.6)	(1,585.8)

Table 2 provides the 2019 target and 2019 actual NAC by rate class for Y factor rates.

TABLE 2
2019 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.	2019 Target NAC	2,762.1	180,360.4	2,682.3	167,410.8
2.	2019 Actual NAC	2,880.0	171,056.3	2,780.2	168,624.3
3.	Variance (Target - Actual NAC)	(117.9)	9,304.1	(97.9)	(1,213.5)

Delivery and Storage Revenues

7. 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 Board-approved number of customers and the 2019 Board-approved delivery and storage rates for each Union rate zones 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.

8. 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 6.

TABLE 3
2019 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	(906.1)	(650.2)	(1,357.7)	(598.3)	(3,512.3)
2.	Storage Revenue Balances	(374.8)	(517.2)	(112.7)	(67.1)	(1,071.8)
3.	Storage Cost Balances	62.7	151.1	436.8	(742.3)	(91.8)
4.	Interest	(19.4)	(37.5)	(14.8)	(48.4)	(120.2)
5.	Total NAC Deferral Balance	(1,237.7)	(1,053.8)	(1,048.4)	(1,456.2)	(4,796.1)

Deferral Account Impacts

9. For Rate M1, the 2019 actual NAC is higher than the target NAC used to derive base rates by 14 m^3/customer (Table 1, Line 3) and higher than the target NAC used to derive Y factor rates by 98 m^3/customer (Table 2, Line 3). As shown in Table 3 above, this results in a delivery and storage revenue credit of $1.470 million ($1.358 million and $0.113 million respectively). In addition, the NAC volume variance increases the Rate M1 storage requirement by 0.730 PJ. Accordingly,

Enbridge Gas must collect an additional $0.437 million (Table 3, Line 3) from Rate M1 customers to recognize the increased Rate M1 storage requirements.

10. For Rate M2, the 2019 actual NAC is higher than the target NAC used to derive base rates by 1,586 m^3/customer (Table 1, Line 3) and higher than the target NAC used to derive Y factor rates by 1,214 m^3/customer (Table 2, Line 3). As shown in Table 3 above, this results in a delivery and storage revenue credit of $0.665 million ($0.598 million and $0.067 million respectively). In addition, the NAC volume variance decreases the Rate M2 storage requirement by 1.240 PJ. Accordingly, Enbridge Gas must refund $0.742 million (Table 3, Line 3) to Rate M2 customers to recognize the decreased Rate M2 storage requirements.

11. For Rate 01, the 2019 actual NAC is higher than the target NAC used to derive base rates by 27 m^3/customer (Table 1, Line 3) and higher than the target NAC used to derive Y factor rates by 118 m^3/customer (Table 2, Line 3). As shown in Table 3 above, this results in a delivery and storage revenue credit of $1.281 million ($0.906 million and $0.375 million respectively). In addition, the NAC volume variance increased the Rate 01 storage requirement by 0.080 PJ. Accordingly, Enbridge Gas must collect an additional $0.063 million (Table 3, Line 3) from Rate 01 customers to recognize the increased Rate 01 storage requirements.

12. For Rate 10, the 2019 actual NAC is higher than the target used to derive base rates NAC by 6,755 m^3/customer (Table 1, Line 3) and lower than the target NAC used to derive Y factor rates by 9,304 m^3/customer (Table 2, Line 3). As shown in Table 3 above, this results in a delivery and storage revenue credit of $1.167 million ($0.650 million and $0.517 million respectively). In addition, the NAC volume variance increases the Rate 10 storage requirement by 0.200 PJ. Accordingly, Enbridge Gas must collect $0.151 million (Table 3, Line 3) from Rate 10 customers to recognize the increased Rate 10 storage requirements.

13. *Storage Costs*

14. The storage costs recognize that variances between the 2019 target NAC and the 2013 Board-approved NAC change the storage requirements for each general service rate class. As Board-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 Board's Decision in Union's 2013 Deferrals Disposition proceeding (EB-2014-0145), p. 9, *"starting in 2014, the NAC Deferral Account, which replaces the Average Use Per Customer Deferral Account, will include storage related revenues and costs for general service rate classes."*

15. 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 Union rate zones customer between its 2019/2020 Gas Supply Plan and the 2013 Board-approved volumes multiplied by the 2013 Board-approved number of customers.

16. Using the Board-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 2019/2020 Gas Supply Plan volumes represent the April 1, 2019 to March 31, 2020 period, which are used to determine the storage requirements for general service rate classes effective November 1, 2019. 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, 2019. 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, 2019.

17. For Rate M1, the NAC volume variance between the 2019/2020 Gas Supply Plan and the 2013 Board-approved volumes was a decrease of 3.916 PJ. The majority of the NAC volume variance decrease occurred in the summer months, which increased the Rate M1 storage requirement by 0.730 PJ. This resulted in increased storage costs of $0.437 million (Table 3, Line 3).

18. For Rate M2, the NAC volume variance between the 2019/2020 Gas Supply Plan and the 2013 Board-approved volumes was an increase of 6.336 PJ. The majority of the NAC volume variance increase occurred in the summer months, which decreased the Rate M2 storage requirement by 1.240 PJ and resulted in decreased storage costs of $0.742 million (Table 3, Line 3).

19. For Rate 01, the NAC volume variance between the 2019/2020 Gas Supply Plan and the 2013 Board-approved volumes was an increase of 0.432 PJ. The majority of the NAC volume variance increase occurred in the winter months, which increased the Rate 01 storage requirement by 0.080 PJ and increased storage costs by $0.063 million (Table 3, Line 3).

20. For Rate 10, the NAC volume variance between the 2019/2020 Gas Supply Plan and the 2013 Board-approved volumes was an increase of 1.088 PJ. The majority of the NAC volume variance increase occurred in the winter months, which increased the Rate 10 storage requirement by 0.200 PJ and resulted in increased storage costs of $0.151 million (Table 3, Line 3).

21. Overall, the NAC volume variance between the 2019/2020 Gas Supply Plan and the 2013 Board-approved volumes resulted in a decrease in general service storage requirements of 0.230 PJ. Accordingly, Enbridge Gas has included a storage cost

credit of $0.092 million in the NAC Deferral Account. Please see Table 4 below 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 BOARD-APPROVED
(BASED ON WEATHER-NORMALIZED NAC)

	PJ		PJ
Rate M1	0.730	Rate 01	0.080
Rate M2	(1.240)	Rate 10	0.200
Total South	(0.510)	Total North	0.280

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

23. The 0.230 PJ reduction in general service storage requirements due to NAC volume variances forms part of the 2.9 PJ of excess utility space available for sale for winter 2019/2020. The revenue from the sale of the 2.9 PJ of excess utility space is recorded in the Short-Term Storage and Other Balancing Deferral Account (Account No. 179-70).

UNACCOUNTED FOR GAS ("UFG") VOLUME DEFERRAL ACCOUNT – UNION RATE ZONES

1. The purpose of the UFG Volume Deferral Account is to capture the difference between the unit cost of UFG recovered in the rates approved by the Board and actual UFG costs incurred, in excess of $5.0 million. The account has a $1.561 million receivable balance, plus interest of $0.019 million, for a total balance of $1.580 million.

2. Union rate zones 2019 Board Approved rates included $8.268 million in UFG costs. Based on 2019 actual volumes, Enbridge Gas recovered $9.187 million in UFG costs for 2019. In comparison, Enbridge Gas's actual 2019 UFG costs were $15.748 million. The difference of $6.561 million is above the $5.0 million threshold established by the Board for the UFG Volume Variance Account. As a result, the UFG Volume Variance Account balance is a debit of $1.561 million from Union rate zones ratepayers. See Table 1 below.

TABLE 1
2019 UTILITY UFG VARIANCES FROM BOARD-APPROVED

Line No.	Particulars	2019 Actual	Collected in 2019 Rates	Variance
		($Millions)	($Millions)	($Millions)
1.	Net Utility UFG	$ 15.7	$ 8.3	7.5
2.	Net Recovery Variance			-0.9
3.	Total Utility UFG Variance			6.6
4.	$5M UFG Symmetrical Deadband			5.0
5.	UFG Volume Deferral (receivable)			$ 1.6

(1) Board Approved throughput was 32,010 106m3 versus actual throughput of 35,978 106m3
(2) Board Approved UFG % is 0.219% versus actual UFG % of 0.376% for 2019. Subject to Deferral Account when in excess of +/- $5 million vs Board approved

PARKWAY WEST PROJECT COSTS DEFERRAL ACCOUNT – UNION RATE ZONES

1. In its Parkway West Project (EB-2012-0433) Decision, the Board 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. The balance in this deferral account is a credit to Union rate zone ratepayers of $0.493 million plus interest of $0.013 million for a total credit balance of $0.506 million. The balance of $0.493 million represents the difference between the revenue requirement of $19.227 million included in 2019 rates (EB-2018-0305) and the calculation of the actual revenue requirement for 2019 of $18.734 million as shown in Table 1

TABLE 1
2019 PARKWAY WEST PROJECT RATE BASE AND REVENUE REQUIREMENT

Line No.	Particulars ($000's)	Col. 1 2019 Board-approved (a)	Col. 2 2019 Actuals (b)	Col. 3 Difference (c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	1,504.0	(23.0)	(1,527.0)
2.	Cumulative Capital Expenditures	233,147.0	231,670.0	(1,477.0)
3.	Average Investment	210,033.2	209,308.1	(725.1)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	2,120.5	1,827.0	(293.5)
5.	Depreciation Expense (1)	5,507.8	5,490.6	(17.2)
6.	Property Taxes	556.6	386.0	(171.0)
7.	Total Operating Expenses	8,185.0	7,703.6	(481.3)
8.	Required Return (2)	11,887.0	11,846.8	(40.2)
9.	Total Operating Expense and Return	20,072.0	19,550.5	(521.5)
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	2,434.8	2,426.3	(8.4)
11.	Income Taxes - Utility Timing Differences (4	(3,279.8)	(3,242.4)	37.5
12.	Total Income Taxes	(845.1)	(816.0)	29.1
13.	Total Revenue Requirement	19,226.9	18,734.4	(493.5)

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 2019 required return
$209.308 million * 64% * 3.82% = $5.117 million plus
$209.308 million * 36% * 8.93% = $6.730 million for a total of $11.847 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.

Capital Expenditures

3. The actual 2019 capital expenditures on in-service assets are $1.527 million lower than 2019 Board-approved as shown in Table 2.

TABLE 2
PARKWAY WEST CAPITAL EXPENDITURES

Line No.	Particulars ($000's)	2019 Board-approved	2019 Actuals	Difference
		(a)	(b)	(c) = (b - a)
1.	Plant Infrastructure	1,504.0	(12.0)	(1,516.0)
2.	Compressor Equipment	-	(11.0)	(11.0)
3.	Total Capital Expenditures	1,504.0	(23.0)	(1,527.0)

4. Plant infrastructure costs were $1.516 million lower than costs included in 2019 Board-approved rates largely due to the demolition of two heritage homes not proceeding as forecast, as well as the return of miscellaneous material not required for the project. The anticipated demolition of two heritage homes did not proceed as forecast, as demolition permits are still pending approval by the municipality.

5. Compressor equipment costs were $0.011 million lower than 2019 Board-approved rates due to the return of miscellaneous material not required for the project.

Average Investment

6. The actual average investment underage of $0.725 million from Board-approved was primarily due to lower than forecast 2019 capital expenditures, as discussed above.

Operating Expenses

7. Operating and maintenance expenses were $0.294 million below the costs included in the 2019 Board-approved rates. The decrease is a result of a Long-term Service Agreement that the Company elected not to enter, the costs of which were included in 2019 Board-approved rates.

8. Property taxes were $0.171 million lower than costs included in 2019 Board-approved rates. The decrease is as a result of the Municipal Property Assessment Corporation ("MPAC") deciding not to apply a Land Classification tax change that was expected for 2019.

BRANTFORD KIRKWALL/PARKWAY D PROJECT COSTS – UNION RATE ZONES

1. In its Brantford-Kirkwall/Parkway D (EB-2013-0074) Decision, the Board 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 $0.039 million plus interest of $0.000 million for a total of $0.039 million. The balance of $0.039 million represents the difference between the $14.874 million revenue requirement included in 2019 rates (EB-2018-0305) and the calculation of the 2019 actual revenue requirement of $14.835 million, as shown in Table 1.

TABLE 1
2019 BRANTFORD-KIRKWALL PIPELINE/PARKWAY D PROJECT RATE BASE AND REVENUE REQUIREMENT

Line No.	Particulars ($000's)	2019 Board-approved (a)	2019 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	-	(26.0)	(26.0)
2.	Cumulative Capital Expenditures	197,404.0	197,378.0	(26.0)
3.	Average Investment	177,699.8	177,698.8	(1.0)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	-	-	-
5.	Depreciation Expense (1)	4,995.5	4,995.2	(0.3)
6.	Property Taxes	995.0	955.8	(39.0)
7.	Total Operating Expenses	5,990.5	5,951.1	(40.0)
8.	Required Return (2)	10,057.1	10,057.8	0.7
9.	Total Operating Expense and Return	16,048.6	16,008.8	(39.8)
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	2,059.9	2,059.9	(0.0)
11.	Income Taxes - Utility Timing Differences (4	(3,234.0)	(3,233.7)	0.2
12.	Total Income Taxes	(1,174.0)	(1,173.8)	0.2
13.	Total Revenue Requirement	14,873.6	14,835.0	(38.6)

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 2019 required
$177.699 million * 64% * 3.82% = $4.344 million plus
$177.699 million * 36% * 8.93% = $5.714 million for a total of $10.058 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.

Capital Expenditures

The actual 2019 capital expenditures on in-service assets were $0.026 million lower than 2019 Board-approved as shown in Table 2.

TABLE 2
BRANTFORD-KIRKWALL PIPELINE/PARKWAY D COMPRESSOR
CAPITAL EXPENDITURES

Line No.	Particulars ($000's)	2019 Board-approved	2019 Actuals	Difference
		(a)	(b)	(c) = (b - a)
	Brantford-Kirkwall Pipeline			
1.	Pipelines	-	(12.0)	(12.0)
	Parkway D Compressor			
2.	Compressor Equipment	-	(14.0)	(14.0)
3.	Total Capital Expenditures	-	(26.0)	(26.0)

For the Brantford-Kirkwall/Parkway D Compressor Project, the costs were $0.026 million lower than costs included in the 2019 Board-approved rates due to the return of miscellaneous material.

Average Investment

The average investment underage of $0.001 million from Board-approved is due to the impact of 2019 capital expenditures discussed above.

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 Union Rate Zones and the applicable Board-approved reference price, applied to the Company’s actual UFG volumes for the Union Rate Zones. During 2019, the Company purchased 57,849 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”).

2. The actual cost of the UFG purchases in 2019 is $7.925/$10^3m^3$ higher than the Board-approved reference prices included in rates based on the Union South Rate Zone gas portfolio cost of $141.439/$10^3m^3$. The result is a $0.458 million balance, plus interest of $0.007, for a total of $0.465 million to be collected from Union Rate Zones ratepayers, as shown in Table 1 below.

Table 1
Calculation of 2019 UFG Price Variance

Line. No.		UFG Volumes (10^3m^3)
1	Experienced UFG (1)	121,079
2	UFG Collected through CSF	63,229
3	UFG Volumes – Company Supplied (2)	57,850
		Deferral Calculation
4	UFG Volumes (10^3m^3) – Company Supplied (2)	57,850
5	Price Variance ($/$10^3m^3$) (3)	$7.925
6	Variance Account Balance ($ millions)	$0.458

1) Converted using the following heat values (38.89 Jan-Mar) (38.98 Apr – Dec).
2) UFG Volumes represent gas supply related to actual UFG volumes on behalf of ratepayers who do not provide UFG in kind as part of CSF.
3) Price variance represents weighted average cost, relative to Board-approved reference prices.

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 Board 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 the Lobo C Compressor/Hamilton-Milton Pipeline Deferral Account is a debit from ratepayers of $0.277 million plus interest of $0.002 million for a total of $0.279 million. The debit of $0.277 million represents the difference between the $25.059 million of costs included in 2019 rates (EB-2018-0305) and the calculation of the actual revenue requirement for 2019 of $25.336 million as shown in Table 1.

TABLE 1
2019 LOBO C COMPRESSOR/HAMILTON-MILTON PIPELINE PROJECT RATE BASE AND REVENUE REQUIREMENT

Line No.	Particulars ($000's)	2019 Board-approved	2019 Actuals	Difference
		(a)	(b)	(c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	-	(762.2)	(762.2)
2.	Cumulative Capital Expenditures	347,980.0	347,061.8	(918.2)
3.	Average Investment	323,388.1	323,161.6	(226.5)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	825.0	1,052.9	227.9
5.	Depreciation Expense (1)	8,260.7	8,264.7	3.9
6.	Property Taxes	1,162.6	1,099.7	(63.0)
7.	Total Operating Expenses	10,248.3	10,417.3	169.0
8.	Required Return (2)	17,350.4	17,353.8	3.4
9.	Total Operating Expense and Return	27,598.7	27,771.0	172.4
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	3,753.9	3,751.3	(2.6)
11.	Income Taxes - Utility Timing Differences (4	(6,293.6)	(6,185.9)	107.7
12.	Total Income Taxes	(2,539.7)	(2,434.6)	105.1
13.	Total Revenue Requirement	25,059.1	25,336.4	276.4

Notes:

(1) Depreciation expense at 2013 Board-approved depreciation rates.

(2) The 2019 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 2019 required return calculation is as follows:
$323.162 million * 64% * 3.36% = $6.949 million plus
$323.162 million * 36% * 8.93% = $10.405 million for a total of $17.354 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.

Capital Expenditures

3. The actual 2019 capital expenditures on in-service assets were a credit of ($0.762) million, lower than 2019 Board-approved as shown in Table 2.

TABLE 2
LOBO C COMPRESSOR/HAMILTON-MILTON PIPELINE
CAPITAL EXPENDITURES

Line No.	Particulars ($000's)	2019 Board-approved	2019 Actuals	Difference
		(a)	(b)	(c) = (b - a)
	Lobo C Compressor			
1.	Land	-	-	-
2.	Structures	-	-	-
3.	Pipelines	-	-	-
4.	Compressor Equipment	-	7.0	7.0
	Hamilton-Milton Pipeline			
5.	Land Rights	-	-	-
6.	Structures and Improvements	-	-	-
7.	Mains	-	(769.0)	(769.0)
8.	Total Capital Expenditures	-	(762.0)	(762.0)

4. Lobo C structures and pipelines costs were $0.007 million higher than the costs included in 2019 Board-approved rates as a result of a final progress invoice payment made for start-up commissioning costs.

5. The NPS 48 Mains for Hamilton-Milton Pipeline was $0.769 million lower than the costs included in 2019 Board-approved rates due to a reimbursement settlement payment received from the contractor.

Average Investment

6. The average investment decrease of $0.226 million from Board-approved is due to cumulative capital expenditures being $0.918 million lower than Board-approved.

Operating Expenses

7. Operating and maintenance expenses were $0.228 million higher than the costs included in 2019 Board-approved rates. The increase is a result of unanticipated Lobo C incurring storm water management costs.

Income Taxes

8. The $0.108 million increase in "Income Taxes-Utility Timing Differences" relates to a lower Capital Cost Allowance deduction due to the lower average investment in 2019 versus Board-approved and partially offset by the impact of Bill C-97 accelerated CCA.

UNAUTHORIZED OVERRUN NON-COMPLIANCE DEFERRAL ACCOUNT – UNION RATE ZONES

1. In Union's 2016 Rates Decision and Order (EB-2015-0116), the Board 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 2019, three interruptions were called for a total of five days impacting 44 customers. Three customers did not comply, primarily because of technical issues. As a result, the balance in this deferral account is a credit to ratepayers of $0.432 million, plus interest of $0.014 million, for a total credit to ratepayers of $0.446 million.

3. The charge was intentionally set to provide customers with the appropriate price signal to comply with distribution service interruptions in the Union rate zones.[1]

[1] EB-2015-0116, Application and Evidence, Exhibit A, Tab 1, pp.14-17.

LOBO D/BRIGHT C/DAWN H COMPRESSOR PROJECT COSTS

1. In its EB-2015-0116 Decision, the Board 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 credit balance of $1.569 million plus interest of $0.030 million, for a total balance of $1.599 million. The balance of $1.569 million includes a credit of $0.245 million which represents the difference between the $40.916 million of costs included in 2019 rates (EB-2018-0305) and the calculation of the actual revenue requirement for 2019 of $40.671 million as shown in Table 1.

3. The remaining $1.324 million credit relates to the 2019 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 2019 year is calculated based on the approved M12 Dawn-Parkway rate of $3.716/GJ for January to March

2019 and $3.602/GJ for April to December 2019. A schedule supporting the 2019 revenue calculation is provided at Exhibit E, Tab 1, Schedule 7.

TABLE 1
DAWN H/LOBO D/BRIGHT C COMPRESSOR PROJECT RATE BASE
AND REVENUE REQUIREMENT

Line No.	Particulars ($000's)	2019 Board-approved	2019 Actuals	Difference
		(a)	(b)	(c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	6,960.0	6,108.0	(852.0)
2.	Cumulative Capital Expenditures	622,505.0	619,947.0	(2,558.0)
3.	Average Investment	583,664.3	581,453.0	(2,211.3)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	1,626.7	2,401.0	774.3
5.	Depreciation Expense (1)	17,305.9	16,524.0	(781.9)
6.	Property Taxes	1,089.0	1,121.0	32.0
7.	Total Operating Expenses	20,021.6	20,046.0	24.4
8.	Required Return (2)	31,053.3	30,933.2	(120.1)
9.	Total Operating Expense and Return	51,074.9	50,979.2	(95.7)
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	6,764.3	6,738.0	(26.3)
11.	Income Taxes - Utility Timing Differences (4	(16,923.4)	(17,046.0)	(122.6)
12.	Total Income Taxes	(10,159.1)	(10,308.0)	(148.9)
13.	Total Revenue Requirement	40,915.8	40,671.2	(244.6)

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 2019 required return
$581.453 million * 64% * 3.29% = $12.243 million plus
$581.453 million * 36% * 8.93% = $18.690 million for a total of $30.933 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

Capital Expenditures

4. The actual 2019 capital expenditures on in-service assets were $0.852 million lower than 2019 Board-approved as shown in Table 2.

TABLE 2
DAWN H/LOBO D/BRIGHT C COMPRESSOR CAPITAL EXPENDITURES

Line No.	Particulars ($000's)	2019 Board-approved	2019 Actuals	Difference
		(a)	(b)	(c) = (b - a)
	Dawn H			
1.	Land	-	-	-
2.	Structures	-	155	155
3.	Compressor Equipment	3,660	4,263	603
4.	Salvage	-	-	-
	Bright C			
5.	Land	-	-	-
6.	Structures	-	359	359
7.	Compressor Equipment	300	506	206
	Lobo D			
8.	Land	-	-	-
9.	Structures	-	48	48
10.	Compressor Equipment	3,000	777	(2,223)
11.	Total Capital Expenditures	6,960	6,108	(852)

5. Structures costs for Dawn H were $0.155 million higher due to final infrastructure cleanup not completed in 2018.

6. Dawn H Compression Equipment costs were $0.603 higher due to final compression cleanup not completed in 2018.

7. Bright C structures costs were $0.359 million higher than the costs included in 2019 Board-approved rates due to the site road infrastructure clean-up work not completed in 2018.

8. Bright C compressor costs were $0.206 million higher than the costs included in 2019 Board-approved rates due to additional yard piping work not completed in 2018.

9. Lobo D structures costs were $0.048 million higher than the costs included in the 2019 Board-approved rates due to the site road and drainage infrastructure clean-up work not completed in 2018.

10. Lobo D compressor equipment costs were $2.223 million lower due to additional compressor work being completed in 2018.

Average Investment

11. The average investment decrease of $2.211 million from 2019 due to the cumulative capital expenditures being $2.558 million lower than 2019 Board-approved.

Operating Expenses

12. Operating and maintenance expenses were $0.744 million higher than the costs included in 2019 Board-approved rates. The increase is as a result of additional

operating costs and utility expenses as a result of additional hours required being higher than planned.

13. The $0.782 million depreciation expense decrease is due to lower depreciable plant balances resulting from delays in the project's in-service timing of capital additions, as well as to the impact of cumulative capital expenditures being $2.558 million lower than Board-approved.

Required Return

14. The decrease in the required return of $0.120 million is the result of the decrease in the average rate base investment, as well as a decrease in the long-term rate used in the calculation.

Income Taxes

15. The $0.123 million increase in "Income Taxes – Utility Timing Difference" relates to a lower Capital Cost Allowance deduction due to the lower average investment in 2019 versus Board-approved, partially offset by an increase in Capital Cost Allowance deduction related to enactment of Bill C-97 accelerated CCA.

BURLINGTON OAKVILLE PROJECT COSTS DEFERRAL ACCOUNT – UNION RATE ZONES

1. In its EB-2015-0116 Decision, the Board 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 ratepayers of \$0.049 million plus interest of \$0.001 million for a total balance of \$0.050 million. The \$0.049 million represents the difference between the \$5.447 million in costs included in 2019 rates (EB-2018-0305) and the calculation of the actual revenue requirement for 2019 of \$5.397 million as shown in Table 1.

TABLE 1
2019 BURLINGTON OAKVILLE PIPELINE PROJECT RATE BASE
AND REVENUE REQUIREMENT

Line No.	Particulars ($000's)	2019 Board-approved	2019 Actuals	Difference
		(a)	(b)	(c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	-	(41.0)	(41.0)
2.	Cumulative Capital Expenditures	83,349.0	83,262.0	(87.0)
3.	Average Investment	78,276.7	78,218.9	(57.9)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	16.4	-	(16.4)
5.	Depreciation Expense (1)	1,731.6	1,737.5	5.9
6.	Property Taxes	130.6	123.1	(8.0)
7.	Total Operating Expenses	1,878.5	1,860.5	(18.0)
8.	Required Return (2)	4,199.7	4,200.4	0.6
9.	Total Operating Expense and Return	6,078.2	6,060.9	(17.4)
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	908.6	908.0	(0.7)
11.	Income Taxes - Utility Timing Differences (4	(1,539.5)	(1,571.6)	(32.2)
12.	Total Income Taxes	(630.8)	(663.7)	(32.8)
13.	Total Revenue Requirement	5,447.4	5,397.2	(49.2)

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 2019 required return calculation is as follows:
$78.219 million * 64% * 3.36% = $1.682 million plus
$78.219 million * 36% * 8.93% = $2.518 million for a total of $4.200 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.

Capital Expenditures

3. The actual capital expenditures on in-service assets were lower than 2019 Board-approved by $0.041 million as shown in Table 2.

TABLE 2
BURLINGTON OAKVILLE PIPELINE PROJECT CAPITAL EXPENDITURES

Line No.	Particulars ($000's)	2019 Board-approved	2019 Actuals	Difference
		(a)	(b)	(c) = (b - a)
1.	Land Rights	-	-	-
2.	Structures	-		-
3.	Pipelines	-	(41.0)	(41.0)
4.	Station Equipment	-	-	-
5.	Total Capital Expenditures	-	(41.0)	(41.0)

4. Pipeline costs were $0.041 million lower than costs included in 2019 Board-approved rates due to the Project being incorrectly assigned expenses in 2018 belonging to a different project. The reversal of expenditures is to correct the system error.

Average Investment

5. The average investment decrease of $0.058 million from Board-approved is due to the cumulative capital expenditures being $0.087 million lower than Board-approved.

ONTARIO ENERGY BOARD ("OEB") COST ASSESSMENT VARIANCE ACCOUNT – UNION RATE ZONES

1. The balance in this deferral account is a debit from Union rate zones ratepayers of $1.563 million plus interest to December 31, 2020 of $0.036 million, for a total of $1.599 million.

2. On February 9, 2016 the Board issued a letter to Regulated Entities subject to the OEB's Cost Assessment notifying stakeholders of changes to the OEB's Cost Assessment Model ("CAM"). As part of these changes, the Board established a variance account to record any material differences between OEB cost assessments currently built into rates, and cost assessments that will result from the applications of the new cost assessment model effective April 1, 2016. Further clarification on this account was provided in the Board's Decision and Order on Union's 2017 Deferrals Disposition and Earnings Sharing Mechanism proceeding.[1]

3. There is $2.5 million in OEB cost assessment amounts in Board-approved rates for Union rate zones. Entries to the account are made on a quarterly basis, when the OEB's cost assessment invoices are received. Entries are calculated as the difference between OEB cost assessment invoices received and the amounts collected in rates for the quarter. As of the OEB's fiscal first quarter of 2019 (for the

[1] EB-2018-0105, 2017 Deferrals Disposition and Earnings Sharing Mechanism, Decision and Order, November 26, 2018, p. 13.

period April 1, 2019 through June 30, 2019), Enbridge Gas began receiving one consolidated bill for the amalgamated utility. For the purposes of calculating the OEB Cost Variance Account for each rate zone, these bills were prorated based on the total invoices received by both utilities in the prior fiscal year (for the period April 1, 2018 through March 31, 2019). Please see EGD rate zone OEBCAVA evidence for the proration calculation in Exhibit D, Tab 1. In 2019, the total amount of cost assessment invoiced to Enbridge Gas was $10.095 million (including $2.271 million prior to combined billing). Of this amount, 40.24%, or $4.063 million, was assigned to Union rate zones. Consistent with the amounts presented in EGD rate zones OEBCAVA evidence, please see the calculation of Union rate zones in Table 1 below.

TABLE 1
OEB COST ASSESSMENT VARIANCE - UNION RATE ZONES

Date	Actual OEB Cost Assessment	2013 Board-approved OEB Cost Assessment in Rates (1)	Incremental OEB Cost Assessment
	($000's)	($000's)	($000's)
	(a)	(b)	(c) = (a) – (b)
01-Jan-19	913.9	625.0	288.9
01-Apr-19	988.6	625.0	363.6
01-Jul-19	1,080.2	625.0	455.2
01-Oct-19	1,080.2	625.0	455.2
Total	4,062.8	2,500.0	1,562.8

Notes:
(1) Quarterly amount of annual $2.5 million.

PANHANDLE REINFORCEMENT PROJECT COSTS DEFERRAL ACCOUNT – UNION RATE ZONES

1. In its Panhandle Reinforcement Project (EB-2016-0186) Decision, the Board 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 ratepayers of $1.180 million plus interest of $0.018 million for a total of $1.198 million. The balance of $1.180 million represents the difference between the net revenue requirement of $11.715 million included in 2019 rates (EB-2018-0305) and the calculation of the actual net revenue requirement for 2019 of $10.535 million as shown in Table 1.

TABLE 1
2019 PANHANDLE REINFORCEMENT PROJECT RATE BASE
AND REVENUE REQUIREMENT

Line No.	Particulars ($000's)	2019 Board-approved	2019 Actuals	Difference
		(a)	(b)	(c) = (b - a)
	Rate Base Investment			
1.	Capital Expenditures	500.0	1,840.0	1,340.0
2.	Cumulative Capital Expenditures	232,844.0	228,137.4	(4,706.6)
3.	Average Investment	223,843.6	218,490.9	(5,352.7)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4.	Operating and Maintenance Expenses	15.6	-	(15.6)
5.	Depreciation Expense (1)	4,939.4	4,894.2	(45.2)
6.	Property Taxes	1,741.6	1,712.0	(30.0)
7.	Total Operating Expenses	6,696.6	6,606.2	(90.4)
8.	Required Return (2)	11,909.4	11,623.7	(285.7)
9.	Total Operating Expense and Return	18,606.0	18,229.9	(376.1)
	Income Taxes:			
10.	Income Taxes - Equity Return (3)	2,594.2	2,532.2	(62.0)
11.	Income Taxes - Utility Timing Differences (4	(5,144.6)	(5,271.7)	(127.2)
12.	Total Income Taxes	(2,550.4)	(2,738.6)	(188.2)
13.	Total Revenue Requirement	16,055.6	15,490.3	(565.3)
14.	Incremental Project Revenue	4,340.5	4,955.0	614.5
15.	Net Revenue Requirement	11,715.1	10,535.3	(1,179.8)

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 2019 required
$218.491 million * 64% * 3.29% = $4.600 million plus
$218.491 million * 36% * 8.93% = $7.024 million for a total of $11.624 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.

Capital Expenditures

3. The actual 2019 capital expenditures on in-service assets were $1.340 million higher than 2019 Board-approved as shown in Table 2.

TABLE 2
PANHANDLE REINFORCEMENT CAPITAL EXPENDITURES

Line No.	Particulars ($000's)	2019 Board-approved	2019 Actuals	Difference
		(a)	(b)	(c) = (b - a)
1.	Land	-	-	-
2.	Land Rights	-	-	-
3.	Pipelines	350.0	1,273.0	923.0
4.	Measuring & Regulating - Transmiss	100.0	273.0	173.0
5.	Measuring & Regulating - Storage	50.0	294.0	244.0
6.	Salvage	-	-	-
7.	Total Capital Expenditures	500.0	1,840.0	1,340.0

4. Pipeline costs for the Panhandle NPS 36 were $0.923 million higher due to final clean up after in-service date on the portion of right-of-way which was deferred in 2018 due to inclement weather in 2017. This included tile repair, easement settlement and tree planting.

5. Measuring & Regulating costs were $0.417 million higher than Board-approved costs due to delayed clean up costs.

Average Investment

6. The average investment decrease of $5.353 million from 2019 Board-approved is due to the capital expenditures being $4.707 million lower than Board-approved on a cumulative basis.

Required Return

7. The decrease in the required return of $0.286 million is the result of a decrease in the average rate base investment, as well as a decrease in the long-term debt rate used in the calculation.

Income Taxes

8. The $0.127 million decrease in “Income Taxes-Timing Differences” relates to impacts of enactment of Bill C-97 accelerated CCA, offset by lower actual Capital Cost Allowance deduction due to the lower average investment in 2018 versus Board-approved.

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 Board 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 2019, 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 $27 million, resulting in an annual $20.4 million credit variance. The variance carried forward from 2018 is a $20.9 million credit variance, resulting in a

[1] EB-2015-0040, Regulatory Treatment of Pension and Other Post-employment Benefits ("OPEB") Costs, September 14, 2017, p. 2.

cumulative $41.3 million credit variance through 2019.

4. In accordance with the Board'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 2019 is an interest credit to ratepayers of $0.961 million to December 31, 2019[2]. Please see Table 1 for a detailed calculation of the forecast accrual versus actual cash payments, and associated interest.

TABLE 1
DETAILS OF 2019 INTEREST CALCULATED ON FORECAST ACCRUALS VS ACTUAL CASH PAYMENTS
IN PENSION AND OPEB VARIANCE ACCOUNT (NO. 179-157)

Particulars ($000's)	18-Dec	19-Jan	19-Feb	19-Mar	19-Apr	19-May	19-Jun	19-Jul	19-Aug	19-Sep	19-Oct	19-Nov	19-Dec	Total
Forecast accrual amounts		3,951	3,951	3,951	3,951	3,951	3,951	3,951	3,951	3,951	3,951	3,951	3,951	47,416
Actual cash payments		1,868	4,502	662	105	4,463	792	88	6,511	819	5,007	1,120	1,072	27,008
Monthly variance		-2,084	550	-3,290	-3,847	511	-3,160	-3,863	2,560	-3,133	1,055	-2,831	-2,879	-20,408
Cumulative variance	-20,942	-23,025	-22,475	-25,765	-29,611	-29,100	-32,260	-36,123	-33,562	-36,695	-35,640	-38,471	-41,350	
OEB prescribed CWIP rate		3.82	3.82	3.82	3.39	3.39	3.39	2.88	2.88	2.88	2.88	2.88	2.88	
Asymmetrical interest		-68	-67	-73	-72	-85	-81	-79	-88	-79	-90	-84	-94	-961

[2] Interest is as of December 31, 2019 as interest on this account is calculated on a cumulative account balance basis.

ACCOUNTS WITH A ZERO BALANCE – UNION RATE ZONES

1. The following 2019 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 Rules (“GDAR”) Costs Deferral Account
    - Sudbury Replacement Project Costs Deferral Account
    - Parkway Obligation Rate Variance Deferral Account
    - Base Service North T-Service TransCanada Capacity Deferral Account

TRANSPORTATION OPTIMIZATION DEFERRAL ACCOUNT - UNION RATE ZONES

Line No.	Particulars	Col. 1 2013 Board Approved ($000's)	Col. 2 2018 Actual Total ($000's)	Col. 3 2019 Actual Total ($000's)
1.	Base Exchange Revenue	(9,118.00)	(7,296.32)	(5,963.32)
2.	FT RAM Exchange Revenue	(5,800.00)		
3.	Total Exchange Revenue	(14,918.00)	(7,296.32)	(5,963.32)
4.	Exchange Revenue Subject to Deferral		(7,296.32)	(5,963.32)
5.	Ratepayer portion - 90%	(13,426.20)	(6,566.68)	(5,366.99)
6.	10% Union Incentive Payment		(729.63)	(596.33)
7.	Less: Gas Supply Optimization Margin in Rates	13,426.00	16,839.33	17,489.36
8.	2019 Deferral Account Balance receivable from Ratepayers		10,272.65	12,122.38

BREAKDOWN OF SHORT TERM STORAGE DEFERRAL ACCOUNT ("STSDA") - UNION RATE ZONES

Line No.	Particulars ($000's)	Col .1 Board-Approved 2013	Col. 2 Actual 2018	Col. 3 Actual 2019
	Revenue			
1.	C1 Off-Peak Storage	500,000.0	141,035.6	418,074.9
2.	Supplemental Balancing Services	2,000,000.0	1,152,681.6	862,750.6
3.	Gas Loans		15,494.5	2,098.4
4.	Enbridge LBA		430,200.5	5939.5 (5)
5.		2,500,000.0	1,739,412.2	1,282,923.8
6.	C1 ST Firm Peak Storage	7,882,625.5	5,010,999.4	2,125,411.3
7.	Total Revenue (1)	10,382,625.5	6,750,411.6	3,408,335.2
	Costs			
8.	O&M (2)	3,810,000.0	2,633,848.0	960,188.3
9.	UFG (3)	316,000.0	247,422.9	204,110.4
10.	Compressor Fuel (4)	1,201,000.0	382,278.9	328,750.3
11.	Total Costs	5,327,000.0	3,263,549.9	1,493,049.0
12.	Net Revenue (line 7 - 11)	5,055,625.5	3,486,861.7	1,915,286.2
13.	Less Shareholder Portion (10%)	505,000.0	348,686.2	191,528.6
14.	Ratepayer Portion	4,550,625.5	3,138,175.5	1,723,757.6
15.	Approved in Rates	4,551,000.0	4,551,000.0	4,551,000.0
16.	Deferral balance payable to/(collectable from) ratepayers	-	(1,412,824.5)	(2,827,242.4)

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
(5) Prior Period Adjustment from 2018

SUMMARY OF NON-UTILITY STORAGE BALANCES - UNION RATE ZONES

	Col. 1	Col. 2	Col. 3	Col. 4		Col. 5	Col. 6	Col. 7	Col. 8
Line No.	Date	Entitlement	Balance	% Full	Line No.	Date	Entitlement	Balance	% Full
		(PJ)	(PJ)	(%)			(PJ)	(PJ)	(%)
1.	1-Oct-19	113.9	110.0	97%	32.	1-Nov-19	113.9	110.3	97%
2.	2-Oct-19	113.9	109.9	96%	33.	2-Nov-19	113.9	110.6	97%
3.	3-Oct-19	113.9	109.7	96%	34.	3-Nov-19	113.9	110.7	97%
4.	4-Oct-19	113.9	110.0	97%	35.	4-Nov-19	113.9	111.0	97%
5.	5-Oct-19	113.9	110.1	97%	36.	5-Nov-19	113.9	111.1	98%
6.	6-Oct-19	113.9	110.3	97%	37.	6-Nov-19	113.9	111.4	98%
7.	7-Oct-19	113.9	110.5	97%	38.	7-Nov-19	113.9	111.2	98%
8.	8-Oct-19	113.9	110.6	97%	39.	8-Nov-19	113.9	111.0	97%
9.	9-Oct-19	113.9	110.7	97%	40.	9-Nov-19	113.9	110.8	97%
10.	10-Oct-19	113.9	110.8	97%	41.	10-Nov-19	113.9	110.5	97%
11.	11-Oct-19	113.9	110.9	97%	42.	11-Nov-19	113.9	109.9	96%
12.	12-Oct-19	113.9	110.9	97%	43.	12-Nov-19	113.9	108.3	95%
13.	13-Oct-19	113.9	110.9	97%	44.	13-Nov-19	113.9	107.4	94%
14.	14-Oct-19	113.9	110.9	97%	45.	14-Nov-19	113.9	106.8	94%
15.	15-Oct-19	113.9	110.8	97%	46.	15-Nov-19	113.9	106.5	93%
16.	16-Oct-19	113.9	110.6	97%	47.	16-Nov-19	113.9	106.2	93%
17.	17-Oct-19	113.9	110.4	97%	48.	17-Nov-19	113.9	106.0	93%
18.	18-Oct-19	113.9	110.3	97%	49.	18-Nov-19	113.9	105.5	93%
19.	19-Oct-19	113.9	110.3	97%	50.	19-Nov-19	113.9	105.3	92%
20.	20-Oct-19	113.9	110.4	97%	51.	20-Nov-19	113.9	105.1	92%
21.	21-Oct-19	113.9	110.5	97%	52.	21-Nov-19	113.9	105.3	92%
22.	22-Oct-19	113.9	110.7	97%	53.	22-Nov-19	113.9	105.8	93%
23.	23-Oct-19	113.9	110.8	97%	54.	23-Nov-19	113.9	105.9	93%
24.	24-Oct-19	113.9	110.9	97%	55.	24-Nov-19	113.9	106.1	93%
25.	25-Oct-19	113.9	110.9	97%	56.	25-Nov-19	113.9	106.4	93%
26.	26-Oct-19	113.9	110.9	97%	57.	26-Nov-19	113.9	107.2	94%
27.	27-Oct-19	113.9	111.0	97%	58.	27-Nov-19	113.9	107.4	94%
28.	28-Oct-19	113.9	109.8	96%	59.	28-Nov-19	113.9	107.5	94%
29.	29-Oct-19	113.9	109.9	97%	60.	29-Nov-19	113.9	107.2	94%
30.	30-Oct-19	113.9	110.0	97%	61.	30-Nov-19	113.9	107.0	94%
31.	31-Oct-19	113.9	110.1	97%					

ALLOCATION OF SHORT TERM PEAK STORAGE REVENUES
BETWEEN UTILITY AND NON UTILITY - UNION RATE ZONES

Line No.	Particulars	Col 1. Utility Storage Space (PJ)	Col. 2 Short Term Peak Storage Sold (PJ)	Col.3 Revenue from Short Term Peak Storage ($Millions)
1.	Net Revenues from Short Term Peak Storage			4.4
2.	Total Short Term Peak Storage Sales		5.9	
3.	Storage Space reserved for Utility	100.0		
4.	Utility Space Requirement	97.1		
5.	Excess Utility Storage Space (1)	2.9		
6.	Total Utility Short Term Peak Storage Sales (2)		2.9	
7.	Total Non Utility Short Term Peak Storage Sales		3.0	
8.	Short Term Peak Storage Net Revenues - Utility (3)			2.1
9.	Short Term Peak Storage Net Revenues - Non Utility (4)			2.2

Notes
(1) line 3 - line 4
(2) line 2
(3) line 6 / line 2 * line 1
(4) line 7 / line 2 * line 1

DEFERRAL VARIANCE CLEARING ACCOUNT - UNION RATE ZONES
2017 DEFERRAL DISPOSITION (EB-2018-0105) AND 2016 DSM DEFERRAL DISPOSITION (EB-2017-0323)
DISPOSITIONS DISPOSED OF DURING 2019

		Col. 1	Col. 2	Col. 3	Col. 4
		2019			
Line No.	Particulars	2017 Deferral Disposition EB-2018-0105	2015 DSM Deferral Disposition EB-2017-0323	Interest (1)	Total (3)
		($000)	($000)	($000)	($000)
1.	Total General Service for Prospective Recovery (Refund) - Delivery (2)	113.2	(834.7)	(18.4)	(740.0)
2.	Total General Service for Prospective Recovery (Refund) - Gas Supply Transporta	69.2		1.8	71.0
3.	Total Prospective Recovery (Refund) - Gas Supply Commodity	(1,096.1)		(27.9)	(1,124.0)
4.	Total	(913.7)	(834.7)	(44.5)	(1,792.9)

(1) Interest forecasted to December 31, 2020.
(2) Line 1, column (a) includes a credit for rebillables of $0.001 million. Line 2, column (b) includes a credit of $0.013 million.
(3) Col. 4 = Col. 1 + Col. 2 + Col. 3

DEFERRAL VARIANCE CLEARING ACCOUNT - UNION RATE ZONES
2017 DEFERRAL DISPOSITION (EB-2018-0105)
DISPOSITION PERIOD - JANUARY 1, 2019 TO JUNE 30, 2019

Line No.	Particulars	Rate Class	2019 Forecast Volume (10^3m^3) (1)	Actual Volume (10^3m^3)	Volume Variance (10^3m^3)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3)	Forecast ($000)	Actual ($000)	Variance ($000)
			(a)	(b)	(c)	(d)	(e) = (a) * (d)/100	(f) = (b) * (d)/ 100	(g) = (c) - (f)
	General Service for Prospective Recovery(Refund) - Delivery								
1	Small Volume General Service	01	609,769	672,160	(62,391)	0.2630	1,604	1,764	(161)
2	Large Volume General Service	10	198,813	225,424	(26,611)	0.1097	218	252	(34)
3	Small Volume General Service	M1	1,904,866	2,085,925	(181,058)	(0.0273)	(520)	(571)	51
4	Large Volume General Service	M2	683,530	798,065	(114,535)	(0.2263)	(1,547)	(1,805)	258
5	Total General Service for Prospective Recovery (Refund) - Delivery		3,396,979	3,781,574	(384,595)		(245)	(359)	114.202
	General Service for Prospective Recovery(Refund) - Gas Supply Transportation								
6	Small Volume General Service - NW	01	176,259	188,614	(12,355)	(1.3036)	(2,298)	(2,459)	161
	Small Volume General Service-NE	01	433,510	483,546	(50,036)	0.1814	786	872	(86)
7	Large Volume General Service-NW	10	49,064	52,092	(3,028)	(0.9299)	(456)	(484)	28
	Large Volume General Service-NE	10	147,889	170,909	(23,019)	0.1414	209	244	(34)
8	Total General Service for Prospective Recovery (Refund) - Gas Supply Transportation		806,722	895,161	(88,439)		(1,758)	(1,828)	69.219
	Prospective Recovery/(Refund) - Gas Supply Commodity								
9	Small Volume General Service	M1	1,764,164	1,943,615	(179,451)	0.4487	7,916.646	8,709	(792)
10	Large Volume General Service	M2	334,383	397,019	(62,635)	0.4487	1,500.378	1,777	(277)
11	Firm Com/Ind Contract	M4	26,702	30,357	(3,655)	0.4487	119.812	136	(16)
12	Interruptible Com/Ind Contract	M5	3,159	4,116	(957)	0.4487	14.176	18	(4)
13	Special Large Volume Contract	M7	8,819	9,069	(250)	0.4487	39.573	41	(1)
14	Large Wholesale	M9	13,837	15,597	(1,760)	0.4487	62.087	70	(8)
15	Small Wholesale	M10	960	265	695	0.4487	4.308	1	3
16	Total Prospective Recovery (Refund) - Gas Supply Commodity		2,152,025	2,400,038	(248,013)		9,657	10,753	(1,096.051)
17	Total Excluding Rebill Activity Adjustments						7,653	8,566	(913)
18	Rebill Activity Adjusments								(1)
19	Total								(914)

Notes:
(1) Forecast volume for the period January 1, 2019 to June 30, 2019.

DEFERRAL VARIANCE CLEARING ACCOUNT - UNION RATE ZONES
2015 DSM DEFERRAL DISPOSITION (EB-2017-0323)
DISPOSITION PERIOD - OCTOBER 1, 2018 TO MARCH 31, 2019

			2019						
Line No.	Particulars	Rate Class	Forecast Volume (10^3m^3) (1)	Actual Volume (10^3m^3)	Volume Variance (10^3m^3)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3)	Forecast ($000)	Actual ($000)	Variance ($000)
			(a)	(b)	(c)	(d)	(e) = (a) * (d)/100	(f) = (b) * (d)/ 100	(g) = (c) - (f)
	General Service for Prospective Recovery(Refund) - Delivery								
1	Small Volume General Service	01	763,829	846,230	(82,401)	(0.0391)	(299)	(331)	32
2	Large Volume General Service	10	249,771	275,592	(25,820)	(0.1115)	(279)	(307)	29
3	Small Volume General Service	M1	2,284,778	2,562,175	(277,397)	0.2716	6,206	6,959	(753)
4	Large Volume General Service	M2	870,022	986,656	(116,634)	0.1127	980	1,110	(130)
5	Total General Service for Prospective Recovery (Refund) - Delivery		4,168,400	4,670,652	(502,252)		6,609	7,431	(822)
6	Total Excluding Rebill Activity Adjustments						6,609	7,431	(822)
7	Rebill Activity Adjusments								(13)
8	Total								(835)

Notes:
(1) Forecast volume for the period October 1, 2018 to March 31, 2019.

CALCULATION OF BALANCES BY RATE CLASS IN THE NAC DEFERRAL ACOUNT (BASE RATES AND Y-FACTOR) - UNION RATE ZONES

Line No.	Particulars		Col . 1 Rate 01	Col. 2 Rate 10	Col. 3 Rate M1	Col. 4 Rate M2	Col.5 Net Account Balance
	Base Rates						
1.	2019 Target NAC: m³		2,852.7	164,301.2	2,766.5	167,038.5	
2.	2019 Actual NAC: m³		2,880.0	171,056.3	2,780.2	168,624.3	
3.	Actual change in NAC: m³ (line 1 - 2)		(27.2)	(6,755.1)	(13.6)	(1,585.8)	
	Y Factor Rates						
4.	2019 Target NAC: m³		2,762.1	180,360.4	2,682.3	167,410.8	
5.	2019 Actual NAC: m³		2,880.0	171,056.3	2,780.2	168,624.3	
6.	Actual change in NAC: m³ (line 4 - 5)		(117.9)	9,304.1	(97.9)	(1,213.5)	
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)	(8,769.9)	(13,821.5)	(14,612.7)	(11,053.9)	(48,257.9)
9.	2019 Net Annual Average Delivery Rate ($/m^3)	(2)	0.1	0.1	0.0	0.1	
10.	2019 Net Annual Average Storage Rate ($/m^3)	(3)	0.0	0.0	0.0	0.0	
11.	Delivery Rate Annual Balance Amount ($000)	(4)	(736.2)	(797.1)	(466.7)	(797.1)	(2,797.0)
12.	Storage Rate Annual Balance Amount ($000)	(4)	(374.6)	(517.3)	(112.7)	(67.1)	(1,071.7)
	Y Factor Rates						
13.	Annual Volume Impact (10^3m^3)	(1)	(37,753.0)	19,122.3	(103,790.6)	(8,429.0)	(130,850.2)
14.	2019 Net Annual Average Delivery Rate ($/m^3)	(2)	0.0	0.0	0.0	(0.0)	
15.	2019 Net Annual Average Storage Rate ($/m^3)	(3)	0.0	0.0	-	-	
16.	Delivery Rate Annual Balance Amount ($000)	(4)	(170.0)	146.8	(890.9)	198.8	(715.3)
17.	Storage Rate Annual Balance Amount ($000)	(4)	(0.2)	0.1	-	-	(0.1)
	Total Annual Balance Amounts ($000)						
18.	Total Delivery Rate Annual Balance Amount (line 11+16)		(906.1)	(650.2)	(1,357.7)	(598.3)	(3,512.3)
19.	Total Storage Rate Annual Balance Amount (line 12+17)		(374.8)	(517.2)	(112.7)	(67.1)	(1,071.8)
20.	Storage Cost Annual Balance Amount ($000)		62.7	151.1	436.8	(742.3)	(91.8)
21.	Interest ($000)	(5)	(19.4)	(37.5)	(14.8)	(48.4)	(120.2)
22.	Total Deferral Account Amounts ($000) (line 18+19+20+21)		(1,237.7)	(1,053.8)	(1,048.4)	(1,456.2)	(4,796.1)

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 to December 31, 2020.

CALCULATION OF 2019 TRANSPORTATION REVENUES ON THE PROJECT EXCESS CAPACITY
LOBO D/BRIGHT C/ DAWN H COMPRESSOR PROJECT COST DEFERRAL ACCOUNT -
UNION RATE ZONES

Line No.	Particulars (000's)	Volume TJ/D (1)	Actual Revenue (2)	Project Surplus Allocation	Revenue Allocation
		(a)	(b)	(c) = 30.393 TJ/d / (a)	(d) = (b) x (c)
	2019				
1	January	30.393	113	100%	113
2	February	30.393	113	100%	113
3	March	30.393	113	100%	113
4	April	30.393	109	100%	109
5	May	30.393	109	100%	109
6	June	30.393	109	100%	109
7	July	30.393	109	100%	109
8	August	30.393	109	100%	109
9	September	30.393	109	100%	109
10	October	30.393	109	100%	109
11	November	30.393	109	100%	109
12	December	30.393	109	100%	109
13	Total		1,324		1,324

Notes
(1) Capacity of 30,393 GJ/d deemed to be sold long term.
(2) Revenue calculated at the M12 Dawn to Parkway rate of $3.716/GJ for Jan to Mar and $3.602/GJ for Apr to Dec approved in EB-2018-0305 (2019 Rates).

CALCULATION OF ALLOCATION OF 2018 SHORT TERM TRANSPORTATION REVENUES TO THE LOBO D/BRIGHT C/ DAWN H COMPRESSOR PROJECT COST DEFERRAL ACCOUNT - UNION RATE ZONES

Particulars (000's)	Volume TJ/D (1)	Actual Revenue (2)	Project Surplus Allocation	Revenue Allocation
	(a)	(b)	(a)	(d) = (b) x (c)
January 2018	307	$ 1,613	9.9%	$ 160
February 2018	196	$ 880	15.5%	$ 136
March 2018	124	$ 735	24.5%	$ 180
April 2018	134	$ 149	22.6%	$ 34
May 2018	7	$ 14	100%	$ 14
June 2018	15	$ 34	100%	$ 34
July 2018	58	$ 58	52.4%	$ 30
August 2018	63	$ 78	48.5%	$ 38
September 2018	83	$ 72	36.7%	$ 26
October 2018	67	$ 87	45.3%	$ 40
November 2018 (3)	30	$ 113	100%	$ 113
December 2018 (3)	30	$ 113	100%	$ 113
Total		$ 3,946		$ 917

Notes
(1) Actual average short-term firm daily contract demand plus interruptible average daily throughput volumes for easterly Dawn-Parkway system paths.
(2) Actual short-term transportation revenues earned on easterly Dawn Parkway system paths.
(3) Sold long-term at Dawn to Parkway M12 Rate of $3.716 $/GJ.

CALCULATION OF ALLOCATION OF 2017 SHORT TERM TRANSPORTATION REVENUES TO THE LOBO D/BRIGHT C/ DAWN H COMPRESSOR PROJECT COST DEFERRAL ACCOUNT - UNION RATE ZONES

Particulars (000's)	Volume TJ/D (1)	Actual Revenue (2)	Project Surplus Allocation	Revenue Allocation
	(a)	(b)	(c) = 30.393 TJ/d /	(d) = (b) x (c)
October 2017	243	$ 65	12.5%	$ 1
November 2017	323	$ 752	9.4%	$ 71
December 2017	244	$ 1,154	12.5%	$ 144
Total		$ 1,972		$ 216

Notes
(1) Actual average short-term firm daily contract demand plus interruptible average daily throughput volumes for easterly Dawn-Parkway system paths.
(2) Actual short-term transportation revenues earned on easterly Dawn Parkway system paths.
(3) All compressors in-service as of October 27, 2017. October Revenue Allocation prorated for 4 days (4/31).

ALLOCATION AND DISPOSITION OF 2019 DEFERRAL ACCOUNT BALANCES

1. The purpose of this evidence is to address the allocation and disposition of 2019 deferral account balances identified at Exhibit C, Tab 1, Schedule 1.

2. Enbridge Gas proposes to dispose of the approved 2019 deferral and variance account balances with the first QRAM application following the Board's approval, as early as January 1, 2021.

3. This exhibit of evidence is organized as follows:
    1. Allocation of Deferral and Variance Accounts
        - 1.1 EGI Accounts
        - 1.2 EGD Rate Zone Accounts
        - 1.3 Union Rate Zones' Accounts
    2. Disposition of Deferral and Variance Accounts
    3. General Service Bill Impacts

1. ALLOCATION OF DEFERRAL AND VARIANCE ACCOUNTS

4. In accordance with the Board's EB-2017-0306/EB-2017-0307 Decision and Order ("MAADs Decision"), the OEB approved new EGI deferral and variance accounts that apply to both the EGD rate zone and Union rate zones effective January 1, 2019. The applicability of other deferral and variance accounts that were

approved to continue during the deferred rebasing period is for either the EGD rate zone or the Union rate zones.

1.1. EGI ACCOUNTS

5. The OEB has approved[1] the following deferral and variance accounts for Enbridge Gas that are applicable to both the EGD and Union rate zones:

- Accounting Policy Changes Deferral Account (APCDA),
- Earnings Sharing Mechanism Deferral Account (ESMDA),
- Tax Variance Deferral Account (TVDA), and
- Expansion of Natural Gas Distribution System Variance Account (ENGDSVA).

6. Enbridge Gas is proposing to dispose of part of the balance in the APCDA as part of this application. Any 2019 balance in the TVDA, ESMDA and ENGDSVA is not proposed for disposition as part of this application as described at Exhibit C, Tab 1.

APCDA

7. In the Board's MAADs Decision, Enbridge Gas was ordered to establish the Accounting Policy Changes Deferral Account (APCDA) to record the impact to revenue requirement of any accounting changes required as a result of the amalgamation of Enbridge Gas Distribution and Union Gas Limited into Enbridge Gas Inc.

[1] EB-2017-0306/EB-2017-0307 Decision and Order. The ENGDSVA was established in accordance with Section 4 of Ontario Regulation 24/19.

8. As described at Exhibit C, Tab 1, Enbridge Gas proposes to clear part of the 2019 APCDA balance in this Application. The applicable balance, including interest, is $1.776 million at December 31, 2019 as described at Exhibit C, Tab 1. Enbridge Gas is proposing a common disposition methodology for the account balance that a) splits the account balance between the EGD and Union rate zones, and b) allocates the split balance to rate classes in each rate zone.

9. The Company proposes to split the account balance of $1.776 million between the EGD and Union rate zones in proportion to the 2018 actual rate base for each rate zone of $6,729 million and $6,018 million, respectively. Splitting the $1.776 million APCDA balance in proportion to 2018 actual rate base results in $0.938 million being cleared to the EGD rate zone and $0.839 million being cleared to the Union rate zones. The details of the split to rate zones is provided at Exhibit F, Tab 1, Schedule 1.

10. The Company further proposes to allocate the split balance 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. 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.

11. The proposed approach recognizes that the balance in the APCDA is driven by the amalgamation of the two legacy utilities and customers' rates will not be affected by the accounting changes until rebasing in 2024. The use of rate base to allocate the deferral account balance is appropriate for this account as it encompasses all aspects of the Company's assets and is the most comprehensive representation of how the costs of providing gas distribution and transmission service are allocated and recovered from each customer class.

ESMDA

12. In the MAADs Decision, Enbridge Gas was ordered to establish an earnings sharing mechanism deferral account (ESMDA) to record earnings in excess of 150 basis points from the OEB-approved return on equity. As described at Exhibit B and Exhibit C, Tab 1, there is no balance in the ESMDA for 2019.

13. Consistent with the proposed allocation of the APCDA, Enbridge Gas would propose a disposition methodology for an ESMDA account balance that a) splits the account balance between the EGD and Union rate zones, and b) allocates the split balance to rate classes in each rate zone in proportion to rate base. The Company would further allocate the split balance 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. The rate base allocation for each rate zone represents the last fully allocated cost study prepared for each rate zone.

14. The use of rate base to allocate the deferral account balance is consistent with the allocation methodology that underpins 2019 approved rates for the return on rate base for the EGD and Union rate zones and is also consistent with the allocation of earnings sharing in previous utility earnings and disposition of deferral and variance accounts proceedings for the legacy utilities.

14.1 EGD RATE ZONE ACCOUNTS

15. The 2019 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. 2019 EGD rate zone deferral and variance account balances are allocated to the customer classes using the same methodologies that the Board approved in previous years.

17. 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.

17.1 UNION RATE ZONES' ACCOUNTS

18. The 2019 deferral and variance account balances to be cleared to the Union rate zones are provided at Exhibit F, Tab 3, Schedule 1, including the Union rate zones allocation of the EGI accounts.

19. 2019 Union rate zones' deferral and variance account balances are allocated to the customer classes using the same methodologies that the Board approved in previous years. The allocation of account balances to Union South and Union North rate classes is provided at Exhibit F, Tab 3, Schedule 2.

2. DISPOSITION OF DEFERRAL AND VARIANCE ACCOUNTS

20. Enbridge Gas proposes to dispose of the approved 2019 deferral and variance account balances with the first QRAM application following the Board's approval, as early as January 1, 2021.

21. For general service customers in the Union rate zones (Rate M1, Rate M2, Rate 01 and Rate 10), Enbridge Gas proposes to dispose of the 2019 deferral and variance account balances prospectively over three-months. The prospective refund/recovery

disposition is consistent with Enbridge Gas's current practice of disposition of deferral and variance account balances to these customers.

22. For all remaining customers in the EGD and Union rate zones, Enbridge Gas proposes to dispose of the 2019 deferral and variance account balances as a one-time billing adjustment. The billing adjustment will appear as a separate line item on customer's bills, the earliest being January 2021. The one-time billing adjustment will be derived for each customer individually by applying the disposition unit rates to each customer's actual consumption volume for the period January 1, 2019 to December 31, 2019.

23. Enbridge Gas anticipates that mid-2021 is the earliest it will be able to adopt a common disposition period, as well as a common disposition approach between the EGD and Union rate zones once integrated systems and processes are implemented.

24. 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 for ex-franchise rate classes are provided at Exhibit F, Tab 3, Schedule 3.

3. GENERAL SERVICE BILL IMPACTS

25. For a Rate 1 customer in the EGD rate zone with annual consumption of 2,400 m^3, the one-time billing adjustment charge is $0.74.

26. For a Rate M1 sales service residential customer in Union South with annual consumption of 2,200 m^3, the charge for the period January 1, 2021 to March 30, 2021 is $4.97. For a Rate M1 bundled direct purchase (“DP”) residential customer, the credit for the same time period is $1.15.

27. For a Rate 01 sales service and bundled DP residential customer in Union North West with annual consumption of 2,200 m^3, the credit for the period January 1, 2021 to March 30, 2021 is $61.53.

28. For a Rate 01 sales service and bundled DP residential customer in Union North East with annual consumption of 2,200 m^3, the credit for the period January 1, 2021 to March 30, 2021 is $5.94.

29. 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 4 for the Union rate zones.

ENBRIDGE GAS INC.
Split of EGI Account Balances to Rate Zones

Line No.	Particulars ($000's)	Allocator 2018 Actual Rate Base (1)	Account Balance Principal (2)	Interest (2)	Total
		(a)	(b)	(c)	(d) = (b+c)
	Accounting Policy Changes Deferral Account				
1	EGD	6,729	(924)	(14)	(938)
2	Union	6,018	(826)	(13)	(839)
3	Total	12,748	(1,750)	(27)	(1,776)

Note:
(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) Allocated in proportion to column (a).

UNIT RATE AND TYPE OF SERVICE: CLEARING IN JAN 2021

		COL.1
		Unit Rate (¢/m³)
Bundled Services:		
RATE 1	- SYSTEM SALES	0.0310
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0295
	- DAWN T-SERVICE	0.0295
	- WESTERN T-SERVICE	0.0310
RATE 6	- SYSTEM SALES	0.0973
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0958
	- DAWN T-SERVICE	0.0958
	- WESTERN T-SERVICE	0.0973
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	0.0998
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0983
	- DAWN T-SERVICE	0.0983
	- WESTERN T-SERVICE	0.0000
RATE 110	- SYSTEM SALES	0.0774
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0759
	- DAWN T-SERVICE	0.0759
	- WESTERN T-SERVICE	0.0774
RATE 115	- SYSTEM SALES	0.0752
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0736
	- DAWN T-SERVICE	0.0736
	- WESTERN T-SERVICE	0.0000
RATE 135	- SYSTEM SALES	0.0738
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0000
	- DAWN T-SERVICE	0.0723
	- WESTERN T-SERVICE	0.0738
RATE 145	- SYSTEM SALES	0.1020
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0000
	- DAWN T-SERVICE	0.1005
	- WESTERN T-SERVICE	0.0000
RATE 170	- SYSTEM SALES	0.0761
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0746
	- DAWN T-SERVICE	0.0746
	- WESTERN T-SERVICE	0.0000
RATE 200	- SYSTEM SALES	0.0870
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0000
	- DAWN T-SERVICE	0.0855
	- WESTERN T-SERVICE	0.0000
Unbundled Services (Billing based on CD):		
RATE 125	- All	0.7018
RATE 300	- All	3.2985
RATE 332	- All	0.6905

DETERMINATION OF BALANCES TO BE CLEARED
FROM THE 2019 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	134.3	1.8	136.1
2.	UNACCOUNTED FOR GAS V/A	4,879.7	70.6	4,950.3
3.	STORAGE AND TRANSPORTATION D/A	2,472.3	34.5	2,506.9
4.	DEFERRED REBATE ACCOUNT	991.2	27.1	1,018.3
5.	OEB COST ASSESSMENT VARIANCE ACCOUNT	3,233.1	77.5	3,310.6
6.	AVERAGE USE TRUE-UP V/A	(8,768.8)	(120.6)	(8,889.4)
7.	ELECTRIC PROGRAM EARNINGS SHARING D/A	(174.7)	(5.1)	(179.8)
8.	TRANSITION IMPACT OF ACCT CHANGE D/A	4,435.8	-	4,435.8
9.	DAWN ACCESS COSTS D/A	2,152.7	29.6	2,182.3
10.	EGD RATE ZONE SUB-TOTAL	9,355.6	115.4	9,471.1
EGI ACCOUNTS				
11.	ACCOUNTING POLICY CHANGES D/A - PENSION - EGI	(923.5)	(14.2)	(937.8)
12.	EGI SUB-TOTAL	(923.5)	(14.2)	(937.8)
13.	TOTAL	8,432.1	101.2	8,533.3

Classification and Allocation of Deferral and Variance Account Balances

ITEM NO.		COL.1 TOTAL ($000)	COL. 2 SALES AND WBT ($000)	COL. 3 TOTAL SALES ($000)	COL. 4 TOTAL DELIVERIES ($000)	COL. 5 SPACE ($000)	COL. 6 DELIVE-RABILITY ($000)	COL. 7 DIRECT ($000)	COL. 8 NUMBER OF CUSTOMERS ($000)	COL. 9 RATE BASE ($000)	COL. 10 BUNDLED ANNUAL DELIVERIES ($000)
	CLASSIFICATION										
1.	TRANSACTIONAL SERVICES D/A	136.1	135.1			0.3	0.7				
2.	UNACCOUNTED FOR GAS V/A	4,950.3			4,950.3						
3.	STORAGE AND TRANSPORTATION D/A	2,506.9				837.1	1,669.8				
4.	DEFERRED REBATE ACCOUNT	1,018.3			1,018.3						
5.	OEB COST ASSESSMENT VARIANCE ACCOUNT	3,310.6								3,310.6	
6.	ACCOUNTING POLICY CHANGES D/A - PENSION - EGI	(937.8)								(937.8)	
8.	AVERAGE USE TRUE-UP V/A	(8,889.4)						(8,889.4)			
10.	GAS SUPPLY PLAN COST CONSEQUENCES D/A	0.0			0.0			0.0			
11.	ELECTRIC PROGRAM EARNINGS SHARING D/A	(179.8)								(179.8)	
12.	TRANSITION IMPACT OF ACCT CHANGE D/A	4,435.8								4,435.8	
13.	DAWN ACCESS COSTS D/A	2,182.3									2,182.3
	TOTAL	8,533.3	135.1	0.0	5,968.6	837.4	1,670.5	(8,889.4)	0.0	6,628.8	2,182.3
	ALLOCATION										
1.1	RATE 1	1,658.9	79.0	0.0	2,544.9	410.4	933.7	(7,567.6)	0.0	4,344.3	914.2
1.2	RATE 6	5,127.0	51.9	0.0	2,517.1	391.5	718.9	(1,321.7)	0.0	1,857.1	912.3
1.3	RATE 9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.4	RATE 100	15.3	0.2	0.0	7.3	0.3	2.1	0.0	0.0	5.4	0.0
1.5	RATE 110	665.5	1.2	0.0	415.7	12.6	0.0	0.0	0.0	79.1	156.8
1.6	RATE 115	325.3	0.0	0.0	209.7	0.0	2.3	0.0	0.0	26.8	86.5
1.7	RATE 125	65.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	65.0	0.0
1.8	RATE 135	45.7	0.1	0.0	29.9	0.0	0.0	0.0	0.0	3.6	12.0
1.9	RATE 145	30.6	0.0	0.0	14.5	1.4	0.0	0.0	0.0	6.3	8.5
1.10	RATE 170	213.9	0.3	0.0	136.0	8.6	0.0	0.0	0.0	9.4	59.7
1.11	RATE 200	170.6	2.3	0.0	93.5	12.5	13.6	0.0	0.0	16.3	32.4
1.12	RATE 300	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.0
1.13	RATE 332	215.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	215.0	0.0
1.		8,533.3	135.1	0.0	5,968.6	837.4	1,670.5	(8,889.4)	0.0	6,628.8	2,182.3

ALLOCATION BY TYPE OF SERVICE

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DIRECT	NUMBER OF CUSTOMERS	RATE BASE	BUNDLED ANNUAL DELIVERIES
		($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Bundled Services:											
RATE 1	- SYSTEM SALES	1,615.5	78.5	-	2,475.9	399.3	908.4	(7,362.5)	-	4,226.5	889.4
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	0.1	-	-	0.2	0.0	0.1	(0.5)	-	0.3	0.1
	- DAWN T-SERVICE	32.1	-	-	51.7	8.3	19.0	(153.7)	-	88.3	18.6
	- WBT	11.2	0.5	-	17.2	2.8	6.3	(51.0)	-	29.3	6.2
RATE 6	- SYSTEM SALES	3,145.1	48.7	-	1,535.7	238.9	438.6	(806.4)	-	1,133.0	556.6
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	63.1	-	-	31.3	4.9	8.9	(16.4)	-	23.1	11.3
	- DAWN T-SERVICE	1,709.0	-	-	847.6	131.8	242.1	(445.1)	-	625.3	307.2
	- WBT	209.8	3.2	-	102.4	15.9	29.3	(53.8)	-	75.6	37.1
RATE 9	- SYSTEM SALES	-	-	-	-	-	-	-	-	-	-
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	-	-	-	-	-	-	-	-	-	-
	- DAWN T-SERVICE	-	-	-	-	-	-	-	-	-	-
	- WBT	-	-	-	-	-	-	-	-	-	-
RATE 100	- SYSTEM SALES	12.6	0.2	-	6.0	0.3	1.7	-	-	4.4	-
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	0.4	-	-	0.2	0.0	0.1	-	-	0.1	-
	- DAWN T-SERVICE	2.4	-	-	1.2	0.1	0.3	-	-	0.8	-
	- WBT	-	-	-	-	-	-	-	-	-	-
RATE 110	- SYSTEM SALES	53.2	1.0	-	32.7	1.0	-	-	-	6.2	12.3
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	24.0	-	-	15.0	0.5	-	-	-	2.9	5.7
	- DAWN T-SERVICE	579.5	-	-	362.7	11.0	-	-	-	69.0	136.8
	- WBT	8.8	0.2	-	5.4	0.2	-	-	-	1.0	2.0
RATE 115	- SYSTEM SALES	0.6	0.0	-	0.4	0.0	0.0	-	-	0.0	0.1
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	133.9	-	-	86.3	0.0	0.9	-	-	11.0	35.6
	- DAWN T-SERVICE	190.8	-	-	123.1	0.0	1.3	-	-	15.7	50.7
	- WBT	-	-	-	-	-	-	-	-	-	-
RATE 135	- SYSTEM SALES	1.2	0.0	-	0.8	-	-	-	-	0.1	0.3
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	-	-	-	-	-	-	-	-	-	-
	- DAWN T-SERVICE	40.0	-	-	26.3	-	-	-	-	3.2	10.5
	- WBT	4.5	0.1	-	2.9	-	-	-	-	0.4	1.2
RATE 145	- SYSTEM SALES	1.6	0.0	-	0.8	0.1	-	-	-	0.3	0.4
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	-	-	-	-	-	-	-	-	-	-
	- DAWN T-SERVICE	29.0	-	-	13.7	1.3	-	-	-	5.9	8.0
	- WBT	-	-	-	-	-	-	-	-	-	-
RATE 170	- SYSTEM SALES	13.9	0.3	-	8.7	0.5	-	-	-	0.6	3.8
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	105.6	-	-	67.2	4.2	-	-	-	4.6	29.5
	- DAWN T-SERVICE	94.4	-	-	60.1	3.8	-	-	-	4.1	26.4
	- WBT	-	-	-	-	-	-	-	-	-	-
RATE 200	- SYSTEM SALES	132.7	2.3	-	72.4	9.7	10.5	-	-	12.7	25.1
	- BUY/SELL	-	-	-	-	-	-	-	-	-	-
	- T-SERVICE EXCL WBT	-	-	-	-	-	-	-	-	-	-
	- DAWN T-SERVICE	37.9	-	-	21.1	2.8	3.1	-	-	3.7	7.3
	- WBT	-	-	-	-	-	-	-	-	-	-
Unbundled Services: (Billing based on CD)											
RATE 125		65.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	65.0	
RATE 300		0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	
RATE 332		215.0						0.0		215.0	
		8,533.3	135.1	0.0	5,968.6	837.4	1,670.5	(8,889.4)	0.0	6,628.8	2,182.3

UNIT RATE AND TYPE OF SERVICE

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DIRECT	NUMBER OF CUSTOMERS	RATE BASE	BUNDLED ANNUAL DELIVERIES
		(¢/m^3)	(¢/m^3)	(¢/m^3)	(¢/m^3)	(¢/m^3)	(¢/m^3)	(¢/m^3)	(¢/m^3)	(¢/m^3)	(¢/m^3)
Bundled Services:											
RATE 1	- SYSTEM SALES	0.0310	0.0015	0.0000	0.0475	0.0077	0.0174	(0.1412)	0.0000	0.0811	0.0171
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0295	0.0000	0.0000	0.0475	0.0077	0.0174	(0.1412)	0.0000	0.0811	0.0171
	- DAWN T-SERVICE	0.0295	0.0000	0.0000	0.0475	0.0077	0.0174	(0.1412)	0.0000	0.0811	0.0171
	- WESTERN T-SERVICE	0.0310	0.0015	0.0000	0.0475	0.0077	0.0174	(0.1412)	0.0000	0.0811	0.0171
RATE 6	- SYSTEM SALES	0.0973	0.0015	0.0000	0.0475	0.0074	0.0136	(0.0249)	0.0000	0.0350	0.0172
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0958	0.0000	0.0000	0.0475	0.0074	0.0136	(0.0249)	0.0000	0.0350	0.0172
	- DAWN T-SERVICE	0.0958	0.0000	0.0000	0.0475	0.0074	0.0136	(0.0249)	0.0000	0.0350	0.0172
	- WESTERN T-SERVICE	0.0973	0.0015	0.0000	0.0475	0.0074	0.0136	(0.0249)	0.0000	0.0350	0.0172
RATE 9	- SYSTEM SALES	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- DAWN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 100	- SYSTEM SALES	0.0998	0.0015	0.0000	0.0475	0.0022	0.0136	0.0000	0.0000	0.0350	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0983	0.0000	0.0000	0.0475	0.0022	0.0136	0.0000	0.0000	0.0350	0.0000
	- DAWN T-SERVICE	0.0983	0.0000	0.0000	0.0475	0.0022	0.0136	0.0000	0.0000	0.0350	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 110	- SYSTEM SALES	0.0774	0.0015	0.0000	0.0475	0.0014	0.0000	0.0000	0.0000	0.0090	0.0179
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0759	0.0000	0.0000	0.0475	0.0014	0.0000	0.0000	0.0000	0.0090	0.0179
	- DAWN T-SERVICE	0.0759	0.0000	0.0000	0.0475	0.0014	0.0000	0.0000	0.0000	0.0090	0.0179
	- WESTERN T-SERVICE	0.0774	0.0015	0.0000	0.0475	0.0014	0.0000	0.0000	0.0000	0.0090	0.0179
RATE 115	- SYSTEM SALES	0.0752	0.0015	0.0000	0.0475	0.0000	0.0005	0.0000	0.0000	0.0061	0.0196
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0736	0.0000	0.0000	0.0475	0.0000	0.0005	0.0000	0.0000	0.0061	0.0196
	- DAWN T-SERVICE	0.0736	0.0000	0.0000	0.0475	0.0000	0.0005	0.0000	0.0000	0.0061	0.0196
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 135	- SYSTEM SALES	0.0738	0.0015	0.0000	0.0475	0.0000	0.0000	0.0000	0.0000	0.0058	0.0190
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- DAWN T-SERVICE	0.0723	0.0000	0.0000	0.0475	0.0000	0.0000	0.0000	0.0000	0.0058	0.0190
	- WESTERN T-SERVICE	0.0738	0.0015	0.0000	0.0475	0.0000	0.0000	0.0000	0.0000	0.0058	0.0190
RATE 145	- SYSTEM SALES	0.1020	0.0015	0.0000	0.0475	0.0046	0.0000	0.0000	0.0000	0.0205	0.0278
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- DAWN T-SERVICE	0.1005	0.0000	0.0000	0.0475	0.0046	0.0000	0.0000	0.0000	0.0205	0.0278
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 170	- SYSTEM SALES	0.0761	0.0015	0.0000	0.0475	0.0030	0.0000	0.0000	0.0000	0.0033	0.0209
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0746	0.0000	0.0000	0.0475	0.0030	0.0000	0.0000	0.0000	0.0033	0.0209
	- DAWN T-SERVICE	0.0746	0.0000	0.0000	0.0475	0.0030	0.0000	0.0000	0.0000	0.0033	0.0209
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 200	- SYSTEM SALES	0.0870	0.0015	0.0000	0.0475	0.0064	0.0069	0.0000	0.0000	0.0083	0.0165
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- DAWN T-SERVICE	0.0855	0.0000	0.0000	0.0475	0.0064	0.0069	0.0000	0.0000	0.0083	0.0165
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unbundled Services (Billing based on CD, ¢/m3):											
RATE 125	- All	0.7018	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.7018	0.0000
	- Customer-specific **										
RATE 300	- All	3.2985	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	3.2985	0.0000
	- Customer-specific **										
RATE 332	- All	0.6905	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.6905	0.0000

Notes:

* Unit Rates derived based on 2019 actual volumes

Enbridge Gas Distribution Inc.
2019 Deferral and Variance Account Clearing
Bill Adjustment in Jan 2021 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 Rates				Bill Adjustment			
	GENERAL SERVICE	Annual Volume m3	Sales cents/m3	Ontario TS cents/m3	Dawn TS cents/m4	Western TS cents/m3	Sales Customers $	Ontario TS Customers $	Dawn TS Customers $	Western TS Customers $
1.1	**RATE 1 RESIDENTIAL**									
1.2	Heating & Water Heating	2,400	0.0310	0.0295	0.0295	0.0310	0.7	0.7	0.7	0.7
2.1	**RATE 6 COMMERCIAL**									
2.2	General Use	43,285	0.0973	0.0958	0.0958	0.0973	42.1	41.4	41.4	42.1
	CONTRACT SERVICE									
3.1	**RATE 100**									
3.2	Industrial - small size	339,188	0.0998	0.0983	0.0983	0.0000	338.5	333.4	333.4	-
4.1	**RATE 110**									
4.2	Industrial - small size, 50% LF	598,568	0.0774	0.0759	0.0759	0.0774	463.2	454.2	454.2	463.2
4.3	Industrial - avg. size, 75% LF	9,976,121	0.0774	0.0759	0.0759	0.0774	7,720.3	7,570.1	7,570.1	7,720.3
5.1	**RATE 115**									
5.2	Industrial - small size, 80% LF	4,471,609	0.0752	0.0736	0.0736	0.0000	3,360.6	3,293.3	3,293.3	-
6.1	**RATE 135**									
6.2	Industrial - Seasonal Firm	598,567	0.0738	0.0000	0.0723	0.0738	441.8	-	432.8	441.8
7.1	**RATE 145**									
7.2	Commercial - avg. size	598,568	0.1020	0.0000	0.1005	0.0000	610.3	-	601.3	-
8.1	**RATE 170**									
8.2	Industrial - avg. size, 75% LF	9,976,121	0.0761	0.0746	0.0746	0.0000	7,593.9	7,443.7	7,443.7	-

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
2019 Deferral Account Balances
Year Ending December 31, 2019

Line No.	Account Number	Account Name ($000's)	Balance (a)	Interest (b)	Total (c)
1	179-131	Upstream Transportation Optimization	12,122	166	12,288
2	179-107	Spot Gas Variance Account	-	-	-
3	179-108	Unabsorbed Demand Costs Variance Account	(11,958)	(311)	(12,269)
4	179-132	Deferral Clearing Variance Account - Supply	(1,096)	(28)	(1,124)
5	179-132	Deferral Clearing Variance Account - Transport	69	2	71
6	179-070	Short-Term Storage and Other Balancing Services	2,822	33	2,855
7	179-133	Normalized Average Consumption	(4,676)	(120)	(4,796)
8	179-132	Deferral Clearing Variance Account	(722)	(18)	(740)
9	179-151	OEB Cost Assessment Variance Account	1,563	36	1,599
10	179-103	Unbundled Services Unauthorized Storage Overrun	-	-	-
11	179-112	Gas Distribution Access Rule Costs	-	-	-
12	179-123	Conservation Demand Management	(138)	(4)	(142)
13	179-136	Parkway West Project Costs	(493)	(12)	(505)
14	179-137	Brantford-Kirkwall/Parkway D Project Costs	(39)	(0)	(39)
15	179-142	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	277	2	279
16	179-144	Lobo D/Bright C/Dawn H Compressor Project Costs	(1,569)	(30)	(1,599)
17	179-149	Burlington-Oakville Project Costs	(49)	(1)	(50)
18	179-156	Panhandle Reinforcement Project Costs	(1,180)	(18)	(1,198)
19	179-162	Sudbury Replacement Project	-	-	-
20	179-138	Parkway Obligation Rate Variance	-	-	-
21	179-143	Unauthorized Overrun Non-Compliance Account	(432)	(14)	(447)
22	179-153	Base Service North T-Service TransCanada Capacity	-	-	-
23	179-157	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Differential V/A	-	(961)	(961)
24	179-135	Unaccounted for Gas Volume Variance Account	1,561	19	1,580
25	179-141	Unaccounted for Gas Price Variance Account	458	7	465
26	**Total for Union Rate Zone Specific Accounts (Lines 1 through 25)**		(3,479)	(1,254)	(4,732)
27	179-120	Accounting Policy Changes D/A - Pension - EGI (Union Rate Zone Portion)	(826)	(13)	(839)
28	179-382	Earnings Sharing (Union Rate Zone Portion)	-	-	-
29	179-380	Expansion of Natural Gas Distribution Systems V/A (Union Rate Zone Portion)	-	-	-
30	**Total for EGI Accounts allocated to Union Rate Zone**		(826)	(13)	(839)
31	**Total Union Rate Zone Deferral Account Balances (Line 26 + Line 30)**		(4,305)	(1,266)	(5,571)

ENBRIDGE GAS INC.
Union Rate Zones
Allocation of Deferral Account Balances

			Union North					Union South															
Line No.	Particulars ($000's)	Acct No.	Rate 01	Rate 10	Rate 20	Rate 100	Rate 25	M1	M2	M4	M5A	M7	M9	M10	T1	T2	T3	M12	M13	Excess Utility	C1	M16	Total (1)
		(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	1,457	409	138	-	60	8,146	1,774	143	16	70	75	1	-	-	-	-	-	-	-	-	12,288
2	Spot Gas Variance Account	179-107	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(9,824)	(2,126)	(319)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(12,269)
4	Deferral Clearing Variance Account - Supply (2)	179-132	-	-	-	-	-	(812)	(284)	(17)	(4)	(1)	(8)	3	-	-	-	-	-	-	-	-	(1,124)
5	Deferral Clearing Variance Account - Transport (2)	179-132	77	(6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	71
6	Total Gas Supply Related Deferrals		(8,289)	(1,723)	(181)	-	60	7,333	1,490	126	11	69	66	4	-	-	-	-	-	-	-	-	(1,033)
	Storage Related Deferrals:																						
7	Short-Term Storage and Other Balancing Services	179-70	389	110	60	2	-	908	309	171	1	78	13	0	64	676	74	-	-	-	-	-	2,855
	Delivery Related Deferrals:																						
8	Normalized Average Consumption (NAC)	179-133	(1,238)	(1,054)	-	-	-	(1,048)	(1,456)	-	-	-	-	-	-	-	-	-	-	-	-	-	(4,796)
9	Deferral Clearing Variance Account - Delivery (2)	179-132	(134)	(6)	-	-	-	(734)	134	-	-	-	-	-	-	-	-	-	-	-	-	-	(740)
10	OEB Cost Assessment Variance Account	179-151	321	28	24	21	10	808	76	28	32	8	1	0	21	57	6	150	0	6	3	0	1,599
11	Unbundled Services Unauthorized Storage Overrun	179-103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Gas Distribution Access Rule (GDAR) Costs	179-112	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Conservation Demand Management	179-123	(14)	(7)	(4)	(2)	-	(61)	(24)	(10)	(1)	(5)	-	-	(3)	(10)	-	-	-	-	-	-	(142)
14	Parkway West Project Costs	179-136	3	(7)	(1)	2	1	90	4	2	3	0	(0)	0	3	17	(1)	(626)	0	1	3	0	(505)
15	Brantford-Kirkwall/Parkway D Project Costs	179-137	(6)	(1)	(1)	(1)	(0)	(15)	(3)	(1)	(1)	(0)	(0)	(0)	(1)	(2)	(0)	(8)	(0)	(0)	(0)	(0)	(39)
16	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	179-142	(12)	3	(1)	(2)	(1)	(91)	(9)	(4)	(3)	(1)	0	(0)	(4)	(21)	0	424	(0)	(0)	0	(0)	279
17	Lobo D/Bright C/ Dawn H Compressor Project Costs	179-144	(145)	(12)	(11)	(11)	(4)	(420)	(49)	(16)	(14)	(4)	(1)	(0)	(15)	(72)	(4)	(803)	(0)	(9)	(7)	(1)	(1,599)
18	Burlington-Oakville Project Costs	179-149	(4)	(1)	(1)	(0)	(0)	(24)	(7)	(2)	(0)	(1)	(0)	(0)	(2)	(11)	(1)	4	0	(0)	0	0	(50)
19	Panhandle Reinforcement Project Costs	179-156	(22)	(4)	(3)	(2)	(1)	(271)	(85)	(81)	(3)	(21)	(0)	(0)	(62)	(457)	(0)	(18)	(0)	(1)	(139)	(29)	(1,198)
20	Sudbury Replacement Project	179-162	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Parkway Obligation Rate Variance	179-138	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Unauthorized Overrun Non-Compliance Account	179-143	-	-	-	-	-	(177)	(60)	(33)	(0)	(15)	(3)	(0)	(12)	(132)	(14)	-	-	-	-	-	(447)
23	Base Service North T-Service TransCanada Capacity Account	179-153	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Pension & OPEB Forecast Accrual vs Actual Cash Payment Differential Variance A	179-157	(193)	(18)	(17)	(15)	(7)	(473)	(46)	(19)	(22)	(5)	(1)	(0)	(13)	(33)	(4)	(91)	(0)	(3)	(2)	(0)	(961)
25	Unaccounted for Gas (UFG) Volume Variance Account	179-135	35	12	5	-	1	200	82	42	5	34	7	0	22	194	17	701	2	-	207	12	1,580
26	Unaccounted for Gas (UFG) Price Variance Account	179-141	22	8	3	-	1	123	51	26	3	21	4	0	4	28	2	102	1	-	62	3	465
27	Accounting Policy Changes DA - Pension - EGI	179-120	(149)	(23)	(16)	(13)	(4)	(326)	(49)	(12)	(10)	(4)	(1)	(0)	(9)	(38)	(5)	(173)	(0)	(5)	(2)	(0)	(839)
28	Total Delivery-Related Deferrals		(1,537)	(1,080)	(21)	(23)	(5)	(2,417)	(1,441)	(80)	(13)	7	7	(0)	(71)	(480)	(5)	(337)	3	(11)	127	(14)	(7,392)
29	Total 2019 Storage and Delivery Disposition (Line 7 + Line 28)		(1,148)	(970)	38	(21)	(5)	(1,509)	(1,132)	91	(12)	86	20	0	(7)	197	69	(337)	3	(11)	127	(14)	(4,538)
30	Total 2019 Deferral Account Disposition (Line 6 + Line 29)		(9,437)	(2,693)	(143)	(21)	54	5,824	358	217	(1)	155	86	4	(7)	197	69	(337)	3	(11)	127	(14)	(5,571)
31	Earnings Sharing Deferral Account	179-382	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Grand Total (Line 30 + Line 31)		(9,437)	(2,693)	(143)	(21)	54	5,824	358	217	(1)	155	86	4	(7)	197	69	(337)	3	(11)	127	(14)	(5,571)

Notes:

(1) Exhibit F, Tab 3, Schedule 1.
(2) Exhibit E, Tab 1, Schedule 6.

ENBRIDGE GAS INC.
Union Rate Zones
Allocation of 2019 Gas Supply Related Deferral Accounts by Union North East and Union North West

Line No.	Particulars ($000's)	Acct No. (a)	Rate 01 (b)	Rate 10 (c)	Rate 20 (d)	Rate 100 (e)	Rate 25 (f)	Total (1) (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	(8,631)	(1,820)	(289)	-	-	(10,739)
3	Upstream Transportation Optimization	179-131	1,188	316	107	-	55	1,666
4	Deferral Clearing Variance Account - Supply	179-132	-	-	-	-	-	-
5	Deferral Clearing Variance Account - Transport	179-132	165	29	-	-	-	194
6	Total Gas Supply Related Deferrals		(7,278)	(1,475)	(182)	-	55	(8,879)
	Storage Related Deferrals:							
7	Short-Term Storage and Other Balancing Services (2)	179-70	111	28	6	-	-	144
8	Total North West Deferral Account Disposition (Line 6 + Line 7)		(7,167)	(1,447)	(176)	-	55	(8,735)
	Union North East							
	Gas Supply Related Deferrals:							
9	Spot Gas Variance Account	179-107	-	-	-	-	-	-
10	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(1,193)	(307)	(30)	-	-	(1,529)
11	Upstream Transportation Optimization	179-131	269	93	31	-	5	398
12	Deferral Clearing Variance Account - Supply	179-132	-	-	-	-	-	-
13	Deferral Clearing Variance Account - Transport	179-132	(88)	(35)	-	-	-	(123)
14	Total Gas Supply Related Deferrals		(1,011)	(249)	0	-	5	(1,255)
	Storage Related Deferrals:							
15	Short-Term Storage and Other Balancing Services (2)	179-70	278	82	36	-	-	396
16	Total North East Deferral Account Disposition (Line 14 + Line 15)		(733)	(166)	37	-	5	(858)
	Total North							
	Gas Supply Related Deferrals:							
17	Spot Gas Variance Account	179-107	-	-	-	-	-	-
18	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(9,824)	(2,126)	(319)	-	-	(12,269)
19	Upstream Transportation Optimization	179-131	1,457	409	138	-	60	2,064
20	Deferral Clearing Variance Account - Supply	179-132	-	-	-	-	-	-
21	Deferral Clearing Variance Account - Transport	179-132	77	(6)	-	-	-	71
22	Total North Gas Supply Related Deferrals		(8,289)	(1,723)	(181)	-	60	(10,134)
	Storage Related Deferrals:							
23	Short-Term Storage and Other Balancing Services (2)	179-70	389	110	42	-	-	541
24	Total North Deferral Account Disposition (Line 22 + Line 23)		(7,900)	(1,613)	(139)	-	60	(9,593)

Notes:
(1) Exhibit F, Tab 3, Schedule 2, p.1.
(2) Excludes allocation to Rate 20/100 bundled storage service.

ENBRIDGE GAS INC.
Union Rate Zones
General Service Unit Rates for Prospective Recovery/(Refund) - Delivery
2019 Deferral Account Disposition

Line No.	Particulars	Rate Class	2019 Deferral Balances ($000's)	2019 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	Forecast Volume (10^3m^3) (1)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3)
			(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
1	Small Volume General Service	01	(1,148)	-	(1,148)	483,387	(0.2374)
2	Large Volume General Service	10	(970)	-	(970)	151,357	(0.6408)
3	Small Volume General Service	M1	(1,509)	-	(1,509)	1,472,365	(0.1025)
4	Large Volume General Service	M2	(1,132)	-	(1,132)	534,753	(0.2117)

Notes:
(1) Forecast volume for the period January 1, 2021 to March 31, 2021.

ENBRIDGE GAS INC.
Union Rate Zones
General Service Unit Rates for Prospective Recovery/(Refund) - Gas Supply Transportation
2019 Deferral Account Disposition

Line No.	Particulars	Rate Class	2019 Deferral Balances ($000's)	2019 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	Forecast Volume (10^3m^3) (1)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3)
			(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
	Union North West						
1	Small Volume General Service	01	(7,278)	-	(7,278)	138,453	(5.2569)
2	Large Volume General Service	10	(1,475)	-	(1,475)	35,427	(4.1624)
	Union North East						
3	Small Volume General Service	01	(1,011)	-	(1,011)	344,935	(0.2931)
4	Large Volume General Service	10	(249)	-	(249)	114,673	(0.2169)

Notes:
(1) Forecast volume for the period January 1, 2021 to March 31, 2021.

ENBRIDGE GAS INC.
Union Rate Zones
Unit Rates for Prospective Recovery/(Refund) - Gas Supply Commodity
2019 Deferral Account Disposition

Line No.	Particulars	Rate Class	2019 Deferral Balances ($000's)	2019 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	Forecast Volume (10^3m^3) (1)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3) (2)
			(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
1	Small Volume General Service	M1	7,333	-	7,333	1,367,498	0.5465
2	Large Volume General Service	M2	1,490	-	1,490	257,822	0.5465
3	Firm Com/Ind Contract	M4	126	-	126	19,253	0.5465
4	Interruptible Com/Ind Contract	M5	11	-	11	2,528	0.5465
5	Special Large Volume Contract	M7	69	-	69	5,411	0.5465
6	Large Wholesale	M9	66	-	66	12,173	0.5465
7	Small Wholesale	M10	4	-	4	631	0.5465
8	Total				9,100	1,665,315	0.5465

Notes:
(1) Forecast sales service volumes for the period January 1, 2021 to March 31, 2021.
(2) Unit rate for prospective recovery/refund for each rate class equal to the gas supply commodity weighted-average unit rate.

ENBRIDGE GAS INC.
Union Rate Zones
Contract Unit Rates for One-Time Adjustment - Delivery
2019 Deferral Account Disposition

Line No.	Particulars	Rate Class	2019 Deferral Balances ($000's)	2019 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2019 Actual Volume (10^3m^3)	Unit Rate ($cents/m^3$)
			(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
	Union North						
1	Medium Volume Firm Service (1)	20	20	-	20	519,819	0.0039
2	Large Volume High Load Factor (2)	100	(23)	-	(23)	1,019,749	(0.0022)
3	Large Volume Interruptible	25	(5)	-	(5)	118,440	(0.0046)
	Union South						
4	Firm Com/Ind Contract	M4	91	-	91	673,776	0.0134
5	Interruptible Com/Ind Contract	M5	(12)	-	(12)	73,541	(0.0169)
6	Special Large Volume Contract	M7	86	-	86	541,821	0.0158
7	Large Wholesale	M9	20	-	20	103,774	0.0190
8	Small Wholesale	M10	0	-	0	391	0.0188
9	Contract Carriage Service	T1	(7)	-	(7)	437,245	(0.0017)
10	Contract Carriage Service	T2	197	-	197	4,136,946	0.0048
11	Contract Carriage- Wholesale	T3	69	-	69	283,374	0.0244

ENBRIDGE GAS INC.
Union Rate Zones
Contract Unit Rates for One-Time Adjustment - Gas Supply Transportation and Bundled Storage
2019 Deferral Account Disposition

Line No.	Particulars	Rate Class	2019 Deferral Balances ($000's)	2019 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2019 Actual Volume/ Demand	Billing Units	Unit Volumetric/ Demand Rate (cents/m3)
			(a)	(b)	(c) = (a + b)	(d)		(e) = (c / d) * 100
	Gas Supply Charges							
	Union North West							
1	Medium Volume Firm Service	20	(182)	-	(182)	1,644	$10^3m^3/d$	(11.0414)
2	Large Volume Interruptible	25	55	-	55	21,431	10^3m^3	0.2581
	Union North East							
3	Medium Volume Firm Service	20	0	-	0	4,241	$10^3m^3/d$	0.0114
4	Large Volume Interruptible	25	5	-	5	20,210	10^3m^3	0.0228
	Storage ($/GJ)							
5	Bundled-T Storage Service	20T/100T	20	-	20	141,504	GJ/d	0.141

ENBRIDGE GAS INC.
Union Rate Zones
Storage and Transportation Service Amounts for Disposition
2019 Deferral Account Disposition

Line No.	Particulars ($000's) (1)	Rate Class	2019 Deferral Balances	2019 Earnings Sharing Mechanism	Deferral Balance for Disposition
			(a)	(b)	(c)
1	Transportation	M12	(337)	-	(337)
2	Transportation of Locally Produced Gas	M13	3	-	3
3	Cross Franchise Transportation	C1	127	-	127
4	Storage and Transportation Services	M16	(14)	-	(14)

Notes:
(1) Ex-franchise Rate M12, Rate M13, Rate M16 and Rate C1 customer specific amounts determined using approved deferral account allocation methodologies.

ENBRIDGE GAS INC.
Union Rate Zones
General Service Customer Bill Impacts

Line No.	Particulars	Unit Rate for Prospective Recovery/(Refund) (cents/m^3) (1)	Volume (m^3) (2)	Bill Impact ($)
		(a)	(b)	(c) = (a x b) / 100
	Small Volume General Service			
	Rate M1 - Union South			
1	Delivery	(0.1025)	1,120	(1.15)
2	Commodity	0.5465	1,120	6.12
3		0.4440		4.97
4	Sales Service			4.97
5	Direct Purchase			(1.15)
	Rate 01 - Union North West			
6	Delivery	(0.2374)	1,120	(2.66)
7	Commodity	-	1,120	-
8	Transportation	(5.2569)	1,120	(58.87)
9		(5.4943)		(61.53)
10	Sales Service			(61.53)
11	Direct Purchase Bundled T			(61.53)
	Rate 01 - Union North East			
12	Delivery	(0.2374)	1,120	(2.66)
13	Commodity	-	1,120	-
14	Transportation	(0.2931)	1,120	(3.28)
15		(0.5305)		(5.94)
16	Sales Service			(5.94)
17	Direct Purchase Bundled T			(5.94)
	Large Volume General Service			
	Rate M2 - Union South			
18	Delivery	(0.2117)	36,281	(76.81)
19	Commodity	0.5465	36,281	198.28
20		0.3348		121.47
21	Sales Service			121.47
22	Direct Purchase			(76.81)
	Rate 10 - Union North West			
23	Delivery	(0.6408)	38,640	(247.60)
24	Commodity	-	38,640	-
25	Transportation	(4.1624)	38,640	(1,608.35)
26		(4.8032)		(1,855.95)
27	Sales Service			(1,855.95)
28	Direct Purchase Bundled T			(1,855.95)
	Rate 10 - Union North East			
29	Delivery	(0.6408)	38,640	(247.60)
30	Commodity	-	38,640	-
31	Transportation	(0.2169)	38,640	(83.81)
32		(0.8577)		(331.41)
33	Sales Service			(331.41)
34	Direct Purchase Bundled T			(331.41)

Notes:
(1) Exhibit F, Tab 3, Schedule 3, pp. 1-3, column (e).
(2) Average consumption, per customer, for the period January 1,2021 to March 31, 2021.
Rate 01 volume based on annual consumption of 1,498 m^3.
Rate 10 volume based on annual consumption of 54,302 m^3.
Rate M1 volume based on annual consumption of 1,498 m^3.
Rate M2 volume based on annual consumption of 49,129 m^3.

ENBRIDGE GAS INC.
Union Rate Zones
Calculation of One-Time Adjustments for Typical Small and Large Customers

Line No.	Particulars	Deferral Unit Rate (1) (cents/m^3) (a)	Billing Units (m^3) (b)	Annual Bill Impact ($) (2) (c)
	Union North			
	Small Rate 20 - Union North West			
1	Delivery	0.0039	3,000,000	116
2	Transportation (3)	(11.0414)	14,000	(18,550)
3		(11.0375)		(18,433)
4	Sales Service Impact			(18,433)
5	Bundled-T (Direct Purchase) Impact			(18,433)
	Large Rate 20 - Union North West			
6	Delivery	0.0039	15,000,000	581
7	Transportation (3)	(11.0414)	60,000	(79,498)
8		(11.0375)		(78,917)
9	Sales Service Impact			(78,917)
10	Bundled-T (Direct Purchase) Impact			(78,917)
	Small Rate 20 - Union North East			
11	Delivery	0.0039	3,000,000	116
12	Transportation (3)	0.0114	14,000	19
13		0.0153		135
14	Sales Service Impact			135
15	Bundled-T (Direct Purchase) Impact			135
	Large Rate 20 - Union North East			
16	Delivery	0.0039	15,000,000	581
17	Transportation (3)	0.0114	60,000	82
18		0.0153		663
19	Sales Service Impact			663
20	Bundled-T (Direct Purchase) Impact			663
	Average Rate 25 - Union North West			
28	Delivery	(0.0046)	2,275,000	(105)
29	Transportation	0.2581	2,275,000	5,872
30		0.2535		5,767
31	Sales Service Impact			5,767
32	Bundled-T (Direct Purchase) Impact			5,767
	Average Rate 25 - Union North East			
33	Delivery	(0.0046)	2,275,000	(105)
34	Transportation	0.0228	2,275,000	520
		0.0182		415
35	Sales Service Impact			415
36	Bundled-T (Direct Purchase) Impact			415
	Small Rate 100			
37	T-Service (Direct Purchase) Impact	(0.0022)	27,000,000	(602)
	Large Rate 100			
38	T-Service (Direct Purchase) Impact	(0.0022)	240,000,000	(5,354)
	Union South			
	Small Rate M4			
39	Delivery	0.0134	875,000	118
40	Commodity	0.5465	875,000	4,782
41		0.5599		4,899
42	Sales Service Impact			4,899
43	Direct Purchase Impact			118
	Large Rate M4			
44	Delivery	0.0134	12,000,000	1,612
45	Commodity	0.5465	12,000,000	65,580
46		0.5599		67,192
47	Sales Service Impact			67,192
48	Direct Purchase Impact			1,612

Notes:
(1) Exhibit F, Tab 3, Schedule 3, pp. 4-5, column (e)
(2) 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 (1) (cents/m^3) (b)	Billing Units (m^3) (c)	Annual Bill Impact ($) (d)
	Union South (continued)			
	Small Rate M5 Interruptible			
1	Delivery	(0.0169)	825,000	(140)
2	Commodity	0.5465	825,000	4,509
3		0.5296		4,369
4	Sales Service Impact			4,369
5	Direct Purchase Impact			(140)
	Large Rate M5 Interruptible			
6	Delivery	(0.0169)	6,500,000	(1,101)
7	Commodity	0.5465	6,500,000	35,523
8		0.5296		34,421
9	Sales Service Impact			34,421
10	Direct Purchase Impact			(1,101)
	Small Rate M7			
11	Delivery	0.0158	36,000,000	5,681
12	Commodity	0.5465	36,000,000	196,740
13		0.5623		202,421
14	Sales Service Impact			202,421
15	Direct Purchase Impact			5,681
	Large Rate M7			
16	Delivery	0.0158	52,000,000	8,206
17	Commodity	0.5465	52,000,000	284,180
18		0.5623		292,386
19	Sales Service Impact			292,386
20	Direct Purchase Impact			8,206
	Small Rate M9			
21	Delivery	0.0190	6,950,000	1,323
22	Commodity	0.5465	6,950,000	37,982
23		0.5655		39,304
24	Sales Service Impact			39,304
25	Direct Purchase Impact			1,323
	Large Rate M9			
26	Delivery	0.0190	20,178,000	3,840
27	Commodity	0.5465	20,178,000	110,273
28		0.5655		114,113
29	Sales Service Impact			114,113
30	Direct Purchase Impact			3,840
	Rate M10			
31	Delivery	0.0188	94,500	18
32	Commodity	0.5465	94,500	516
33		0.5653		534
34	Sales Service Impact			534
35	Direct Purchase Impact			18
	Small Rate T1			
36	Direct Purchase Impact	(0.0017)	7,537,000	(129)
	Average Rate T1			
37	Direct Purchase Impact	(0.0017)	11,565,938	(197)
	Large Rate T1			
38	Direct Purchase Impact	(0.0017)	25,624,080	(438)
	Small Rate T2			
39	Direct Purchase Impact	0.0048	59,256,000	2,820
	Average Rate T2			
40	Direct Purchase Impact	0.0048	197,789,850	9,412
	Large Rate T2			
41	Direct Purchase Impact	0.0048	370,089,000	17,610
	Large Rate T3			
42	Direct Purchase Impact	0.0244	272,712,000	66,642

Notes:
(1) Exhibit F, Tab 3, Schedule 3, pp. 4-5, column (e)

2019 SCORECARD RESULTS – ENBRIDGE GAS

1. The purpose of the scorecard is to measure and monitor performance over the deferred rebasing period. The scorecard is produced annually, with 2019 being the first delivery of the scorecard. Enbridge Gas met or exceeded all elements of the scorecard apart from two measures.

2. The measure Time to Reschedule Missed Appointments ("TRMA") tracks the percentage of customers contacted to reschedule the work within two hours of the end of the original appointment time. The annual standard for TRMA is 100% and Enbridge Gas achieved 97% in 2019. Efforts towards meeting the target of 100% are on-going. A cross functional team meets regularly to review performance on this metric, to address issues and to re-enforce training when necessary.

3. The measure Meter Reading Performance represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the metric is 0.5% and Enbridge Gas achieved a level of 0.7% in 2019. Enbridge Gas was unable to meet the Meter Reading Performance Measurement metric due to two main factors: extreme weather in the first and second quarters, and transition to a new vendor due to vendor-driven termination of the contract.

OEB SCORECARD 2019

#	Performance Measure	Target	Actual
#	**CUSTOMER FOCUS (Service Quality & Customer Satisfaction)**		
1	Reconnection Response Time (# of days to reconnect a customer) (# of reconnections completed within 2 business days/# of reconnections completed)	85.0%	98.2%
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%	98.5%
3	Telephone calls answered on time (call answering service level) (# of calls answered within 30 seconds / # of calls received)	75.0%	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%
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.'		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%	2.5%
7	Time to Reschedule Missed Appointments (% of rescheduled work within 2 hours of the end of the original appointment time)	100.0%	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%	0.7%
9	% of Emergency Calls Responded within One Hour (# of emergency calls responded within 60 minutes / # of emergency calls)	90.0%	96.7%
10	Compression Reliability % reliable for transmission compression		99.9%
11	Damages per 1000 locate requests		1.97
12	Total Cost per Customer		654
13	Total Cost per km of Distribution Pipe		16735
	PUBLIC POLICY RESPONSIVENESS (Conservation & Demand Management & Connection of Renewable Generation)		
14	Total Cumulative Cubic Meters of Natural Gas Saved		1796.5
	FINANCIAL PERFORMANCE (Financial Ratios)		
15	Current Ratio (Current Assets / Current Liabilities)		0.75
16	Debt Ratio (Total Debt / Total Assets)		0.40
17	Debt to Equity Ratio (Total Debt / Shareholders' Equity)		0.98
18	Interest Coverage (EBIT / Interest Charges)		2.53
19	Financial Statement Return on Assets (Net Income / Total Assets)		2.25%
20	Financial Statement Return on Equity (Net Income / Shareholders' Equity)		5.56%