ENBRIDGE

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September 9, 2022

VIA RESS AND EMAIL

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

Dear Nancy Marconi:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File No.: EB-2022-0110
2021 Utility Earnings and Disposition of Deferral & Variance Account Balances - Updated Interrogatory Responses

Further to the submission dated September 2, 2022, enclosed please find the following updated interrogatory responses:

Exhibit	Updates /Correction
I.FRPO.5, Attachment 1, Table 1, page 1	An attachment with missing information for column 2020R, lines 19 to 23, was provided in the original submission. The missing information has been updated along with the year over year $ and % change for those lines.
I.FPRO. 14 including Attachments 1 to 3	The response has been updated to include all assignments as requested in the FRPO letter, dated September 6, 2022. Portions of the response have been redacted consistent with the original response.
I.SEC.1, Attachment 1	Due to a technical error, the incorrect attachment was provided in the original submission. The correct version of Attachment 1 provides further explanation with regards to, year over year variances.

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

Exhibit	Description of Document	Brief Description	Basis for Confidentiality Claim
I.FRPO.14 - Attachments 1 to 3	Capacity Released to Third Party for UDC Mitigation	Attachments 1 to 3 provide further details on the capacity released (assigned) to third parties.	Details provided in the attachments meets the categories of information to be treated as confidential in the OEB's Practice Direction on Confidential Filings under: • Appendix A (i) prejudice to any person's competitive position, and • Appendix B (i) Unit pricing of a third party

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

Sincerely,

(Original Digitally Signed)

Richard Wathy
Technical Manager, Regulatory Applications

cc.: D. Stevens (Aird & Berlis)
EB-2022-0110 Intervenors

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, p. 3

Question(s):

In the discussion on Utility O&M for 2020 and 2021, Enbridge Gas noted that outside services increased by $11.3 million over the prior year due to an increase in integrity spending, higher locates costs due to higher contact rates, higher postage costs from lower e-bill utilization, higher contract costs for call centre, back-office billing and collections support.

a) Please provide the postage costs and e-bill utilization rates for 2020 and 2021

b) Please explain the reasons for the drop in e-bill utilization and confirm if the trend is likely to continue in future years.

Response:

Evidence review has revealed that the variance explanation originally provided and referenced above was incorrectly stated. While outside services increased by $11.3 million and all other explanations are accurate, the statement on postage costs should have been expressed as a decrease, not an increase. It follows from an increase, not decrease, in e-bill utilization. The corrected paragraph is as follows:

> Outside services (Line 4) increased $11.3 million over the prior year primarily due to an increase in integrity spending, higher locates costs due to higher contract rates, higher contract costs for call center, back-office billing and collections support, and increases in regulatory consulting costs related to rebasing preparations as well as higher regulatory fees reflecting the volume of proceedings including Integrated Resource Planning (IRP), offset by lower postage costs from higher e-bill utilization.

Responses to parts a) and b) follow.

a)		
2021 Postage Costs	$14.7 million
2020 Postage Costs	$15.5 million
	$ (0.8 million) decrease in postage costs

b) E-bill utilization has increased from 60.4% at the end of 2020 to 62.0% at the end of 2021. Enbridge Gas expects the adoption rate to increase but at a slower pace.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Accounting Policy Changes Deferral Account
Exhibit C, Tab 1, p. 2

Question(s):

As part of the settlement proposal in the 2019 Deferral and Variance Account (DVA) disposition proceeding (EB-2020-0134), parties agreed to defer the review, allocation and disposition of all balances in the Accounting Policy Changes Deferral Account (APCDA) until the end of Enbridge Gas's deferred rebasing term (2023). The company continues to track the annual revenue requirement impact of accounting policy changes made as of the amalgamation date (January 1, 2019) as well as any further accounting policy changes adopted since that time.

Please identify any accounting policy changes made in 2021 that are in addition to those made in 2019 and 2020. Please provide details of the additional changes and the impact of those changes on the balances in the APCDA.

Response:

There were no new accounting policy changes made in 2021 and, therefore, there are no further impacts recognized in the APCDA beyond those impacts resulting from changes made in 2019 and 2020.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Enbridge Gas Tax Variance Deferral Account
Exhibit C / Tab 1 / pp. 12-14

Question(s):

The balance in the 2021 Tax Variance Deferral Account (TVDA) also includes balances related to accelerated CCA impacts of capital additions related to amalgamation/ integration capital projects. In accordance with the Decision and Order in the 2020 DVA proceeding (EB-2021-0149), the balances related to amalgamation/integration capital projects will be reviewed in Enbridge Gas's 2024 rebasing application. The 2021 balance for amalgamation/integration projects is $10.463 million.

a) Please provide a table identifying the specific projects categorized as amalgamation/integration spending and the accelerated CCA amount associated with each project. Please also provide the reasons for classifying these projects as amalgamation/integration related capital spending.

b) Please confirm if Enbridge Gas funded amalgamation/integration capital projects in 2021 through synergies. If yes, please establish a link between the achieved synergies and the related amalgamation/integration projects.

Response:

a) Please see Attachment 1 of this response, which contains the 2021 in-service capital for amalgamation/integration projects, the associated accelerated versus regular CCA variance, as well as the resultant income tax (or earnings) impact, and grossed-up revenue requirement impact in the TVDA. Attachment 1 also includes the 2020 opening UCC amounts and associated CCA impacts recognized in the 2021 TVDA balance of $10.463 million.

As noted at Exhibit B, Tab 3, Schedule 2, pages 11 and 12, integration capital includes expenditures required to integrate EGD and Union. Enbridge Gas continues to evaluate projects to determine whether they meet the criteria of integration capital: a one-time incremental cost related to the amalgamation of EGD and Union. Projects can be newly identified to address integration needs, or they may be driven by a need to replace an asset due to obsolescence. In either case, the project is classified as integration as it drives a harmonized solution that adds value to the integrated utility. It's important to note that the work being addressed through some integration projects would have been required for either or both rate zones in the absence of amalgamation (because of factors such as obsolescence or growth), but the projects are nonetheless included as integration capital because the project supports the amalgamated utility.

Each of the projects noted in Attachment 1 has been determined to have met the criteria noted above.

b) During the deferred rebasing period, Enbridge Gas is leveraging amalgamation/ integration synergies derived from initiatives to fund, in whole or in part, the annual costs related to amalgamation/integration capital (and amalgamation/integration period charges). This is premised on the fact that during the deferred rebasing term, Enbridge Gas retains the benefits from amalgamation, but also pays the associated costs (the benefits follow the costs principle). It is further evidenced by the fact that capital related to amalgamation/integration capital projects has been excluded from the capital forecasts utilized to determine Incremental Capital Module (ICM) eligible capital amounts over the deferred rebasing term. As a result, funding for such projects is not provided through ICM rates for capital amounts above the ICM threshold, nor is it provided through base rates (i.e., they are not pushing other capital projects above the ICM threshold).

   The Company notes that each individual amalgamation/integration capital project may or may not be funded, in whole or in part, by savings it creates over the deferred rebasing term. Certain individual projects may not generate synergies/savings but it does support amalgamation. For projects that do result in savings, the realization of those savings may not occur until after the project has gone into service. As such, at any point in time over the deferred rebasing term, costs for an individual project may be occurring without the realization of savings to that point. One such example is the 2021 Customer Information System (CIS) implementation.

Capital Cost Allowance - 2021 In-Service Capital for Amalgamation/Integration Projects

	CCA Pool Opening UCC Accelerated CCA	CCA Pool Opening UCC Regular CCA	CCA Pool Capital Additions	CCA Class / Rate	Accelerated CCA	Regular CCA	CCA Variance	Earnings Impact (26.5% tax rate)	Grossed-up Earnings Impact
2020 Projects									
Scada and Gas Control Consolidation	-	355,967		Class 12 100%	-	355,967	(355,967)	(94,331)	(128,342)
Scada and Gas Control Consolidation	195,042	808,030		Class 50 55%	107,273	444,416	(337,143)	(89,343)	(121,555)
CIS Phase 1 (Hana Upgrade)	2,978,584	12,339,848		Class 50 55%	1,638,221	6,786,916	(5,148,695)	(1,364,404)	(1,856,332)
Customer Experience	-	22,427		Class 12 100%	-	22,427	(22,427)	(5,943)	(8,086)
Bill Print and Presentment	-	10,180		Class 12 100%	-	10,180	(10,180)	(2,698)	(3,670)
	3,173,626	13,536,452	-		1,745,494	7,619,907	(5,874,413)	(1,556,719)	(2,117,986)
2021 Projects									
Meter Shop			1,723,054	Class 1 6%	155,075	51,692	103,383	27,397	37,274
Meter Shop			53,290	Class 8 20%	15,987	5,329	10,658	2,824	3,843
CIS Integration (plus Web Integration/My Account)			53,797,855	Class 12 100%	53,797,855	26,898,927	26,898,927	7,128,216	9,698,253
SCADA			10,699	Class 50 55%	8,827	2,942	5,885	1,559	2,122
AWS/Customer Connections			14,316,869	Class 50 55%	11,811,417	3,937,139	7,874,278	2,086,684	2,839,025
CIS (Hana)			546	Class 12 100%	546	273	273	72	98
	-	-	69,902,314		65,789,707	30,896,302	34,893,404	9,246,752	12,580,615
Total Impact of Accelerated versus Regular CCA - 2021									**10,462,630**

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Storage & Transportation Deferral Account – EGD
Exhibit D, Tab 1, p. 2

Question(s):

The balance in the EGD rate zone Storage and Transportation Deferral Account (S&TDA) is $7.9 million plus interest to be recovered from ratepayers. The primary driver for the balance in the 2021 S&TDA is higher than forecasted transportation prices and higher than forecast market-based storage costs in 2021.

Please provide the average market-based storage costs for 2020 and 2021. Why have market-based storage costs increased in 2021?

Response:

The market-based storage costs for 2020 and 2021 are $23.3 million and $22.4 million respectively. The average storage costs for 2020 and 2021 are $0.88 / GJ and $0.85 / GJ respectively. The reduction in 2021 market-based storage costs relative to 2020 is driven by lower storage prices. The market-based storage costs for 2021 are higher than the 2018 OEB-approved forecast by $2.3 million, driven by higher in-franchise storage requirements for EGD rate zone customers and higher storage prices compared to the OEB-approved forecast from 2018.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Transactional Services Deferral Account - EGD
Exhibit D / Tab 1 / p. 4 and Exhibit D / Tab 1 / Schedule 2

Question(s):

Transactional services refer to optimization of storage and transportation assets. Storage optimization transactions rely on the storage of or the loan of gas between two points in time at the same location. The evidence indicates that there were no storage optimization revenues for 2021.

Why was Enbridge Gas not able to optimize any storage transactions for the EGD rate zone in 2021?

Response:

Enbridge Gas has not been able to optimize any storage transactions for the EGD rate zone in 2021 because of reduced demand and value for short term storage services.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Unabsorbed Demand Costs Variance Account – Union Gas
Exhibit E, Tab 1, pp. 1-4

Question(s):

In order to meet customer demands across the Union rate zones and to meet the planned storage inventory levels as of October 31, approved rates for the Union rate zones in 2021 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 actual unutilized capacity in 2021 was 28.5 PJ of which 19.6 PJ was in Union South. There is a debit balance of $3.145 million applicable to sales service customers related to the cost of the unutilized capacity in Union South.

a) Please confirm that the planned unutilized capacity in Union South is set at 0 PJ as any excess pipeline capacity is used to fill storage at Dawn in a typical year.

b) Please explain why the 19.6 PJ of unutilized pipeline capacity in 2021 was not used to fill storage levels.

c) Please outline the measures that Enbridge Gas implemented in order to reduce the total actual unutilized capacity in 2021.

Response:

a) Confirmed. For the Union South rate zone, Enbridge Gas plans for upstream pipeline capacity to flow at 100% utilization each day of the year. During times when usage is less than upstream supply, the excess supply is injected into storage at Dawn. When demands are greater than upstream supply, gas is withdrawn from storage and transported to Union South in-franchise customers. Consequently, there is no planned unutilized capacity in Union South.

b - c)

Enbridge Gas manages the Union rate zone transportation portfolio on an integrated basis, and the decisions of which planned supply purchase to reduce is determined based on achieving the greatest avoided cost while meeting both customer demands in the summer and storage injection requirements. As a result, Enbridge Gas fills storage using the most cost-effective supply paths.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Upstream Transportation Optimization Variance Account – Union Gas
Exhibit E / Tab 1 / p. 6

Question(s):

Consistent with the method approved in EB-2011-0210 Decision and Rate Order, the legacy Union Gas credited $15.392 million in rates to ratepayers during 2021. The company earned $7.529 million in net revenues from upstream transportation optimization during 2021, of which 90% or $6.776 million was credited to ratepayers. The balance in account is a debit of $8.616 ($15.392 minus $6.776) million to be recovered from ratepayers.

a) In response to an interrogatory in the 2020 DVA and Earnings Sharing proceeding (OEB Staff IRR#16, EB-2021-0149), Enbridge Gas noted that reduced price volatility and market spreads limit Enbridge Gas's ability to earn optimization revenues. Please explain whether the same drivers resulted in lower optimization revenues for 2021. Was the price volatility greater in 2021 than 2020?

b) Considering the recent natural gas price volatility, does Enbridge Gas expect to earn higher transportation revenues for 2022 as compared to 2020 and 2021? Please explain your response.

Response:

a) The same drivers as noted in response to EB-2021-0149, Exhibit I.OEB STAFF.16 remain applicable. There was greater price volatility in 2021 as compared to 2020.

b) Yes, Enbridge Gas expects to earn higher transportation optimization revenues in 2022 vs. 2020 and 2021 as a result of continued price volatility, market spreads and market demand.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Short-term Storage and Other Balancing Services Deferral Account – Union Gas
Exhibit E, Tab 1, pp. 8-9 and Exhibit E, Tab 1, Schedule 2

Question(s):

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 net revenues from services provided was 1.082 million of which the ratepayer share is $974,000. The balance in the deferral account is a debit from ratepayers of $3.577 million ($4.551 million - $0.974 million). The schedule (Exh. E, Tab 1, Sch. 2) provides a calculation of the net revenues for 2020 and 2021.

a) The Short-term Storage and Other Balancing Services revenue for 2020 was $4.735 million, which dropped to $2.610 million in 2021. However, O&M costs for 2021 ($1.0 million) are significantly greater than the $782,000 observed in 2020.
Please explain why the O&M costs for 2021 are greater than 2020 despite lower revenues.

b) The unaccounted for gas (UFG) costs for 2021 were $266,000 as compared to $114,000 in 2020. Please explain why UFG costs increased for 2021 considering that revenues for 2021 were lower than 2020.

Response:

a) The O&M cost allocation is based on the amount of Excess Utility Storage Space available for sale. Space available for sale in 2021 was 3.0PJ (Exhibit E, Tab 1, Schedule 4) in comparison to 2.3PJ in 2020. Therefore, O&M costs in 2021 were approximately $0.2 million more than 2020.

b) The UFG costs allocated to the Short-Term Storage deferral account is a function of total UFG costs and is the main driver for the Year over Year change. The "Unaccounted for Gas Volume Deferral Account" evidence for the Union Rate Zone provides more detail regarding total UFG costs for the Union Rate Zone, as found in Exhibit E, Tab 1, pages 31 to 37.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Normalized Average Consumption Deferral Account – Union Gas
Exhibit E / Tab 1 / pp. 12-15

Question(s):

The Normalized Average Consumption (NAC) deferral account balance is calculated by multiplying the variance between the weather normalized target NAC and the weather normalized actual NAC by the 2013 OEB-approved number of customers and the 2021 OEB-approved delivery and storage rates for each general service rate class. For the rate classes M1, M2, 01 and 10, two variances have been calculated for each rate class to determine delivery and storage revenues: one is the variance between target and actual NAC for base rates and the other similar variance for Y-factor rates. The Variance (Target minus Actual NAC) differs under both calculations (Base Rates and Y Factor Rates)

Please provide a detailed calculation that shows how the variance calculations (Target minus Actual NAC) for base rates and Y-factor rates are used to determine the NAC deferral account balance. Please identify the specific components to which the base and Y-factor rates adjustments apply.

Response:

Please refer to Exhibit E, Tab 1, Schedule 6 which provides the detailed calculation that shows how the variance calculations for base rates and Y-factor rates determine the NAC deferral account balance. Schedule 6 also specifies which components the base and Y-factor rate adjustments are applied to.

In summary, the specific components are as follows:

Table 1

Base Rate & Y-Factor Rate Components

Base Rate Components	Y-Factor Rate Components
Target (forecasted) NAC	Target (forecasted) NAC
Actual NAC	Actual NAC
Total Delivery Base Rate	Total Delivery Y-Factor Rate
Total Storage Base Rate	Total Storage Y-Factor Rate
2013 Board-approved number of customers	2013 Board-approved number of customers

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

NAC Deferral Account – Union Gas
Exhibit E, Tab 1, pp. 13-15

Question(s):

For 2021, the balance in the NAC deferral account is a debit to ratepayers of $18.998 million plus interest. The 2019 actual NAC, weather normalized using the 2021 weather normal was used to determine the 2021 target NAC for each rate class to calculate base rates. The 2021 actual NAC for each rate class is weather normalized using the 2021 weather normal, which is produced using the OEB-approved weather methodology. For 2021, the target NAC was greater than the actual NAC across all rate classes (Rate 01, Rate 10, Rate M1, Rate M2).

Please provide a rate class graphical representation of normalized average use per customer for the years 2019 to 2021(show forecast and actual).

Response:

The charts below provide a graphical representation of normalized average use per customer and illustrates the actual NAC and target (forecasted) NAC for Rate 01, Rate 10, Rate M1, and Rate M2 for 2019-2021. Note that the actual and target (forecasted) NAC are weather normalized at each year's respective OEB-approved weather normal.

Figure 1
Rate M1 Normalized Average Consumption: Actual vs Target (Forecast)

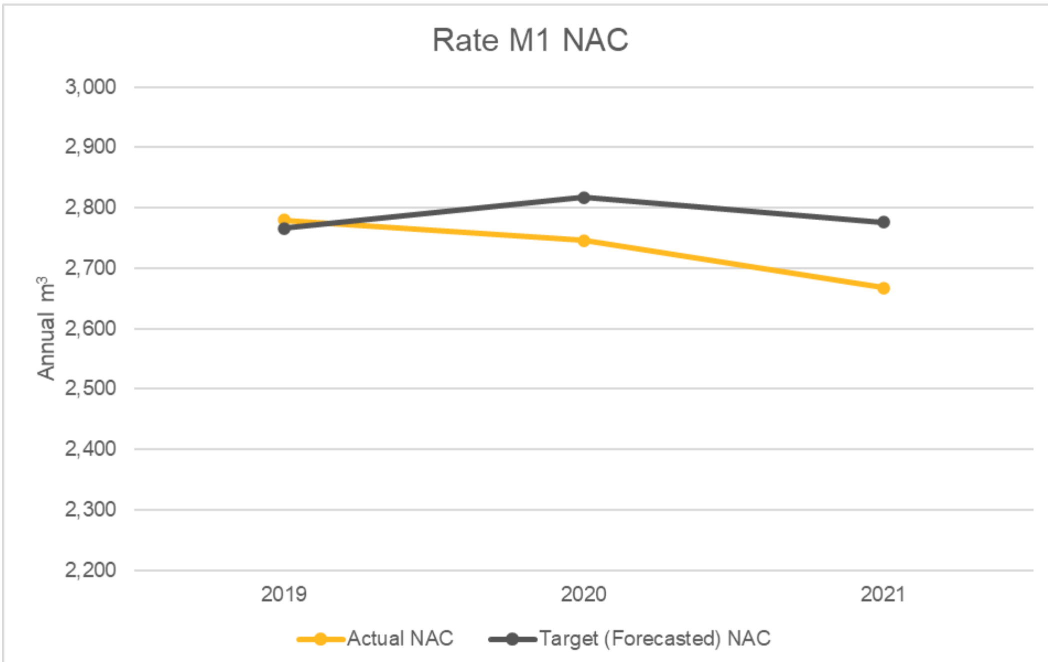


Figure 2
Rate M2 Normalized Average Consumption: Actual vs Target (Forecast)

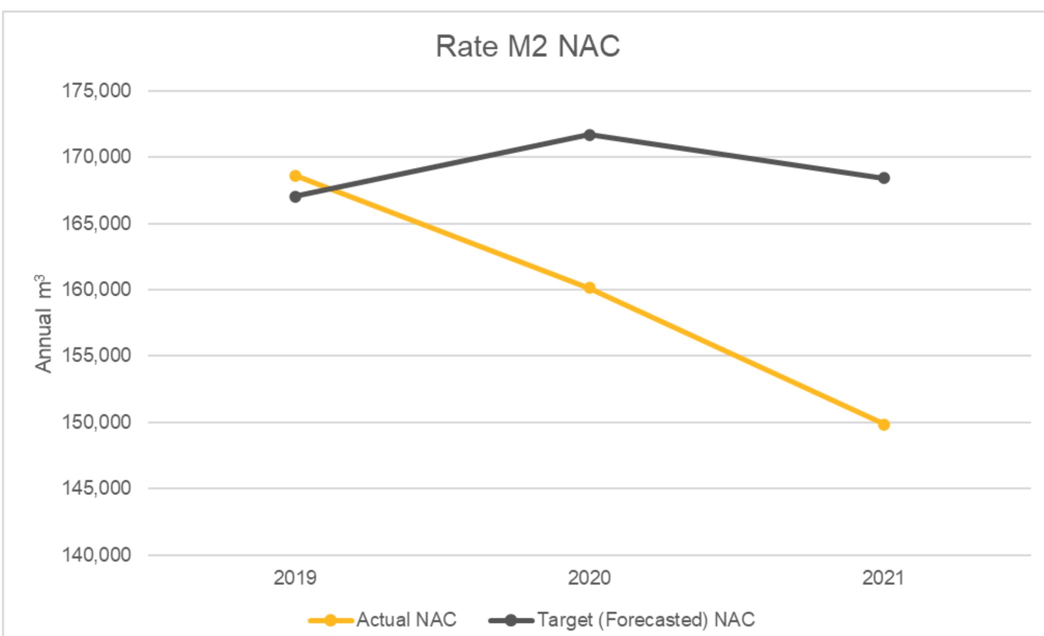


Figure 3
Rate 01 Normalized Average Consumption: Actual vs Target (Forecast)

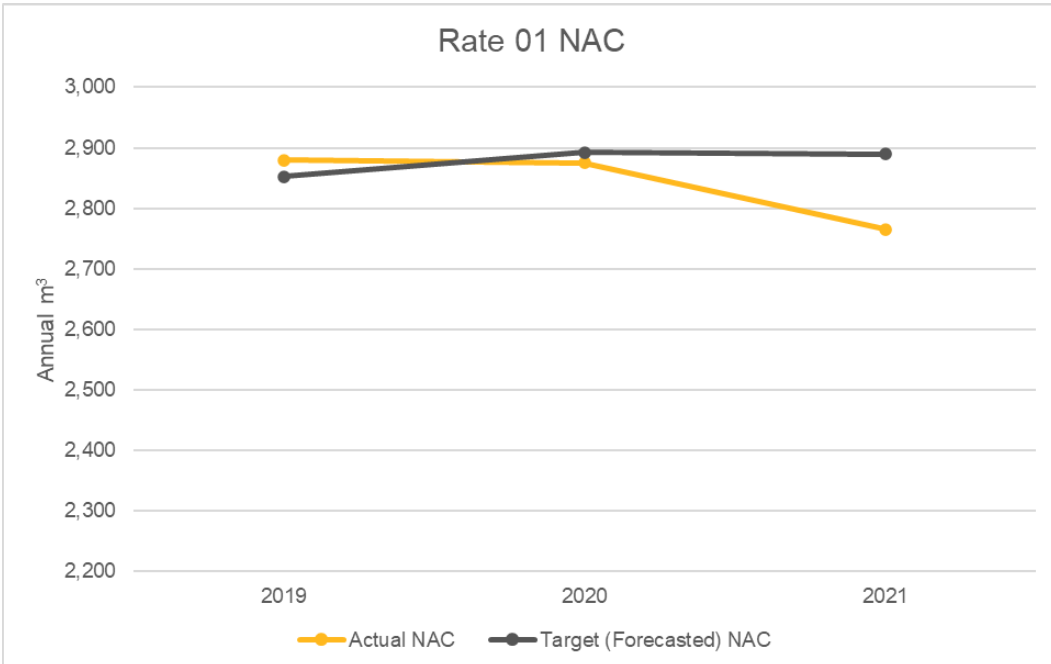
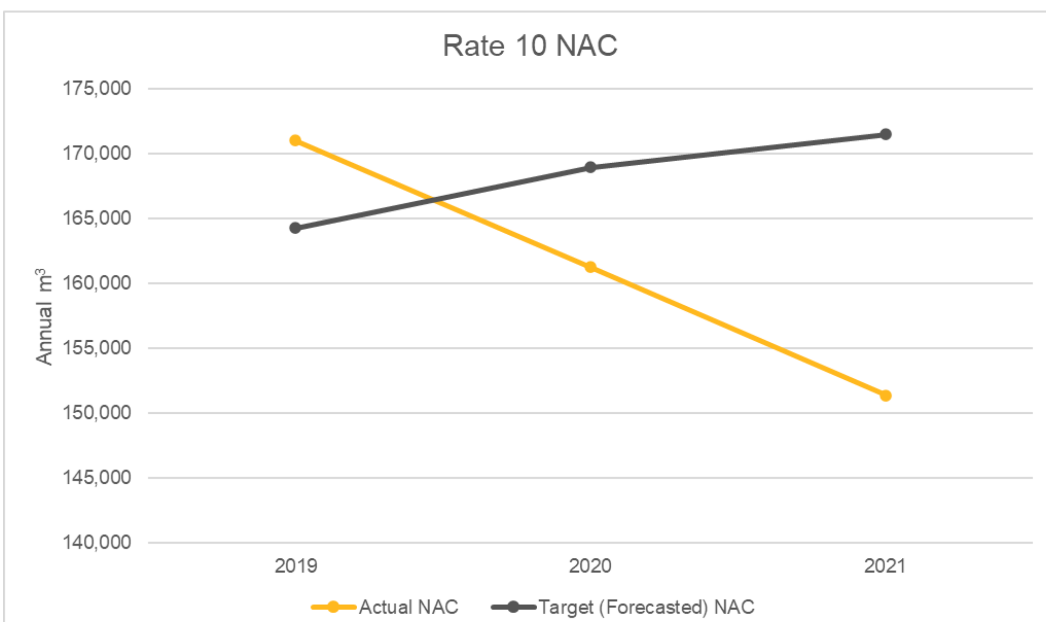


Figure 4
Rate 10 Normalized Average Consumption: Actual vs Target (Forecast)



ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Unaccounted for Gas Volume Deferral Account – Union Gas
Exhibit E, Tab 1, pp. 31-37

Question(s):

Union Gas's 2021 approved rates includes $10.1 in Unaccounted for Gas (UFG) costs. Enbridge Gas's actual UFG costs for 2021 were $35.9 million of which Enbridge Gas recovered $10.4 million. After considering the symmetrical dead-band of $5.0 million, the balance in the UFG Volume Deferral Account is $20.5 million plus interest. The average UFG percentage has been 0.356% for the years 2013 through 2021. However, the UFG percentage for 2021 was 0.672%. The UFG volume for 2020 was 74,120 103 m3 while for 2021, the UFG volume was 252,582 103 m3. The company has identified that the true-up of estimated consumption based on the calendarization of UFG volumes has contributed to volatility between 2020 and 2021. The true-up between the December 2020 estimate and the actual billed volumes resulted in a decrease to the delivery volumes recorded in January 2021. When billings related to December 2020 were completed over the following month, it was determined that there was an over-estimate of gas deliveries for December 2020.

a) Please provide the average volume and UFG percentage for the years 2013 through 2020.

b) Please provide detailed calculations supporting the 2021 actual UFG costs similar to that provided in response to Staff IRR# 20c in EB-2021-0149.

c) The evidence notes that the primary sources of UFG include physical losses (eg. leaks, third-party damage and venting), metering variations, non-registering meters, theft, line pack and billing/accounting adjustments. Please provide a breakdown (if possible) for the UFG volumes in 2021. If UFG volumes for certain categories cannot be determined, please classify them as "Other".

d) Enbridge Gas has indicated that the true-up between December 2020 and January 2021 resulted in higher UFG volumes for 2021. Please provide the contribution of this adjustment to the UFG volumes in 2021 and the costs. Please also confirm that there was no double counting as a result of the true-up between the December 2020 estimate and the actual billed volumes. In other words, please confirm that amounts recorded in the UFG Volume Deferral Account were not recovered through billing adjustments.

e) Please outline the measures that Enbridge Gas has implemented in order to reduce UFG.

Response:

a) Please refer to Table 1 below. The average volume for the years 2013 through 2020 is 106,778 10^3m^3. The average UFG percentage for the years 2013 through 2020 is 0.318%.

Table 1

Historical UFG Volumes & Percentage – Union Rate Zones

Calendar Year	UFG Volumes (10^3m^3)	UFG %
2013	113,997	0.320%
2014	97,109	0.318%
2015	54,408	0.174%
2016	131,588	0.427%
2017	108,901	0.342%
2018	136,447	0.379%
2019	137,652	0.376%
2020	74,120	0.208%
Average	106,778	0.318%

b) Please refer to Table 2 below.

Table 2

Calculation of 2021 UFG Costs – Union Rate Zones

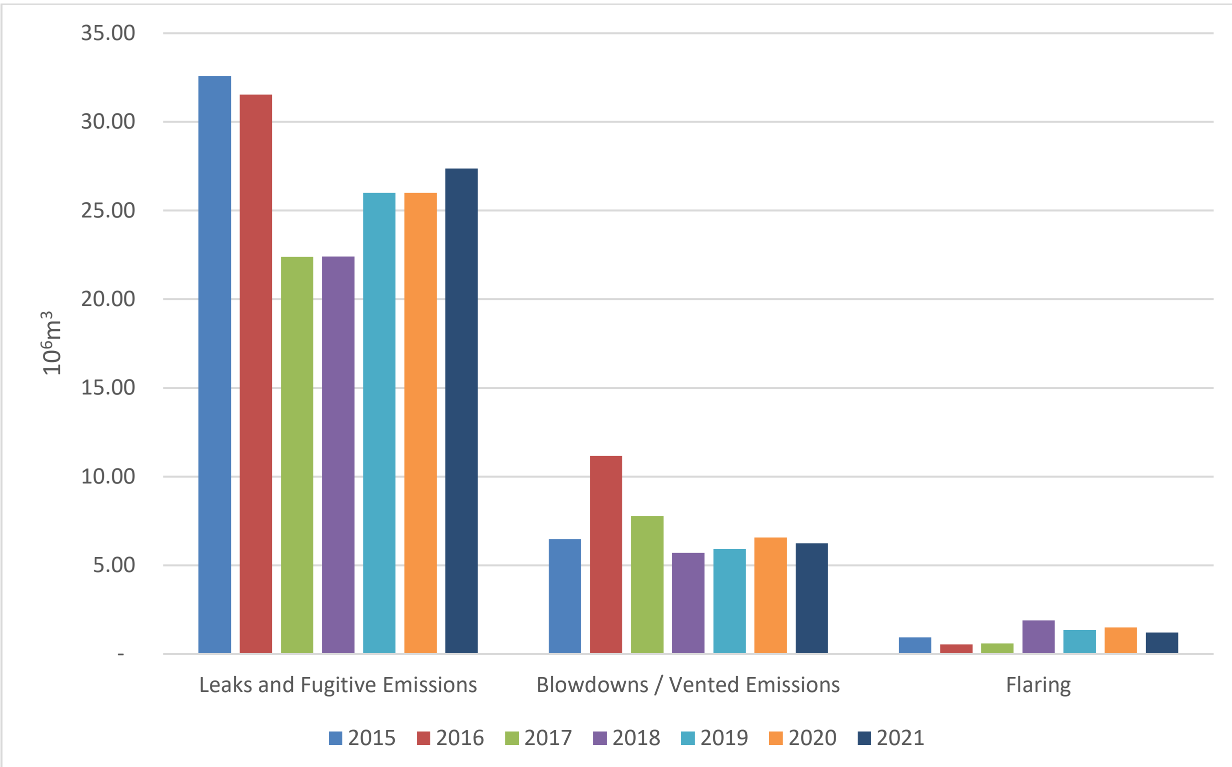
Line No.			2021 Actual	Notes
1	UFG %		0.672%	Line 2 / Line 3
2	Throughput (10^3m^3)		37,612,361	
3	UFG Volume (10^3m^3)		252,582	
4	Approved Reference Price (WACOG)		$160.39	2021 weighted average cost
5	2021 UFG Expense		$40,512,883	Line 3 * Line 4
6	Less:	L/T Non-Utility Allocation	$4,103,955	
7		S/T Excess Utility Allocation	$538,821	
8	Net 2021 Utility UFG Expense		$35,870,106	

c) The primary sources of UFG noted in evidence were based on the 2019 Report on UFG (“UFG Report”) filed in EB-2019-0194. Although the root causes of UFG are generally known, it is difficult to quantify or estimate the individual factors due to their nature. The breakdown of the contribution of individual sources provided in the UFG Report leveraged internal reports and analysis completed at specific points in time and this level of detail is not available on an ongoing basis. The specific sources that have been quantified for UFG volumes in 2021 are relating to physical losses and billing/accounting adjustments.

Enbridge Gas reports fugitive, vented and flared emissions annually to Environment and Climate Change Canada and the Ontario Ministry of Environment, Conservation and Parks. Figure 1 below provides data regarding lost gas from leaks and emission in a format consistent with what was provided in the UFG Report.

Figure 1

Lost Gas from Leaks and Emissions



Billing and accounting adjustments include true-ups related to estimates of gas delivered but not yet billed, as described in evidence. This is estimated to be 46,000 10^3m^3 in 2021 as described in d) below. Billing and accounting adjustments also include prior period adjustments (PPA's), as described in evidence. This is estimated to be 78,000 10^3m^3 in 2021.

The remaining balance of UFG volumes in 2021 are deemed to be classified as "Other".

d) UFG is broadly defined as the difference between gas receipts and gas deliveries. Gas deliveries to customers are comprised of both billed and unbilled volumes. Billed volumes are based on both estimated and actual meter reads. Unbilled volumes are recorded at the end of each reporting period to quantify the amount of gas delivered but not yet billed. This ensures that both billed and unbilled volumes are incorporated into the formulaic determination of UFG.

In the subsequent reporting period(s), adjustments to customer accounts once an actual read is received are processed. In addition, the estimate of gas delivered but not yet billed is reversed and the actual billed volumes for the prior reporting period are recorded. These true-ups relating to both estimated reads as well as unbilled estimates are incorporated into the formulaic determination of UFG.

The true-up noted in evidence between December 2020 and January 2021 is related to the unbilled estimation for December 2020. December 2020 estimated volumes were higher than the December 2020 actual billed volumes by approximately 46,000 10^3m^3. The true up that occurred in January 2021 resulted in the 2021 UFG volumes being higher by approximately 46,000 10^3m^3 at a cost of approximately $6.1 million.

Confirmed, there was no double counting of UFG volumes in the UFG Volume Deferral account as a result of the true-up between the December 2020 estimated volumes and the actual December 2020 billed volumes.

e) Enbridge Gas filed a Report on Unaccounted for Gas (UFG Report) prepared by ScottMadden Management Consultants in 2019, which was considered as part of the 2020 Rate Application Phase 2[1]. In that proceeding, Enbridge Gas committed to report upon its progress in implementing the recommendations set out in the UFG Report in its 2022 rates filing. Enbridge Gas also committed in the same application to assess its UFG forecasting methodology in the 2024 rebasing proceeding and to include information about the implementation of the UFG Report recommendations and other activities to address UFG, and the impacts of such activities.

A UFG Progress Report outlining progress in implementing the recommendations from the 2019 UFG Report, including measures taken to reduce UFG, was prepared in 2020. Some of the updates include the following:

1. Implementation of a harmonized leak operating standard
2. Development of a three-year program to eliminate backlog of leaks identified prior to the roll out of the new standard
3. Leverage best practices in the area of controlled releases of gas during maintenance and construction activities
4. Implementation of a more robust leak detection and report (LDAR) program within Storage and Transmission operations
5. Implementation of a measurement and compliance program with respect to compressor venting
6. Implementation of a program to replace continuous high bleed pneumatic devices
7. Utilization of an incinerator during pipeline maintenance activities to combust the gas entering the atmosphere rather than venting methane
8. Development of a Damage Reduction Strategy
9. Standardization of meter shop testing processes

[1] EB-2019-0194

10. Standardization of super compressibility factors
11. Alignment and standardization of best practices for the Gas Measurement function and Gas Measurement Accounting System
12. Creation of a cross-functional measurement working group
13. Completion of the redesign of the Victoria Square Gate Station
14. Refinement of the tracking and recording of company use gas

The UFG progress report was filed as part of the 2022 Rates application[2], however the OEB determined that issues relating to UFG were out of scope of that proceeding. The UFG Progress report, prepared in 2022, as well as supplemental updates, will be filed as part of the 2024 Rebasing application.

[2] EB-2021-0148, Exhibit C, Tab, Schedule 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

IRP Operating Cost Deferral Account
Exhibit F, Tab 1, p.3

Question(s):

The 2021 Integrated Resource Planning (IRP) Operating Cost Deferral Account has a debit balance of $0.058 million (including interest). Consistent with the allocation of the TVDA balance, Enbridge Gas has proposed to split the debit balance of $0.058 million between the EGD and Union rate zones in proportion to the actual rate base for each rate zone.

a) Did Enbridge Gas consider other allocation methodologies to allocate the balance in the IRP Operating Cost Deferral Account? If yes, please describe the alternate allocation methodologies.

b) Please explain the rationale for allocating operating costs in proportion to rate base.

c) Has Enbridge Gas allocated operating costs in other deferral accounts to rate base? If yes, please provide details.

Response:

a) Enbridge Gas reviewed the current approved deferral allocation methodologies used by the EGD and Union rate zones when considering a common approach that could be used to split the IRP Operating Cost Deferral Account balance between rate zones and also to allocate the balance to rate classes. Rate base was the most appropriate current approved deferral allocation methodology for which common information was also available to split the balance between rate zones. Rate base was approved to split and allocate the Tax Variance Deferral Account which is the only other Enbridge Gas account that has been proposed for disposition since amalgamation.

b) Enbridge Gas considers rate base a reasonable allocation methodology for the IRP Operating Cost Deferral Account given the main function of IRP is to assess alternatives to future facility expansion/reinforcement projects to address system needs. In the absence of IRP, investment in facility expansion/reinforcement projects would be capitalized and form part of rate base.

c) The EGD rate zone has two deferral and variance accounts where rate base is used to allocate operating related costs: the OEB Cost Assessment Variance Account and the Transition Impact of Account Changes Deferral Accounts. Please see Exhibit F, Tab 2, Schedule 3 for the classification and allocation of deferral and variance account balances in the EGD rate zone. Please see Exhibit D, Tab 1, page. 1 and page 13, for an overview of these deferral and variance accounts

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

2021 Performance Scorecard Results
Exhibit G / Tab 1 / pp. 1-2

Question(s):

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 97.0% in 2019, 97.3% in 2020 and 97.0% in 2021. The company has implemented several initiatives through 2019 and 2020 to improve performance and meet the metric.

a) Please explain why measures implemented in 2019 and 2020 have failed to improve the metric.

b) Has Enbridge Gas considered the option of contacting customers through text messaging or other means to reschedule the work within two hours of the end of the original appointment time.

Response:

a) Measures implemented in 2019 and 2020 have not improved the TRMA metric performance as the TRMA performance standard of 100% does not allow for human or technical error.

b) Enbridge Gas has considered contacting customers through text messaging or other technological means, however, currently Enbridge Gas does not have technology in place for automatic text messaging to reschedule missed appointments. There would be a cost involved with implementing this technology and it would not necessarily ensure a 100% result for this metric, as it does not account for technical issues nor that all 3.8 million customers have provided mobile contact information.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

2021 Performance Scorecard Results
Exhibit G / Tab 1 / pp. 2-3

Question(s):

The measure Meter Reading Performance Metric (MRPM) represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the metric is 0.5% and Enbridge Gas achieved a level of 0.7% in 2019, 4.4% in 2020 and 5.0% in 2021. Enbridge Gas has attributed the reduction in performance to the COVID pandemic, extreme weather events and the move to a new vendor.

a) What are the reasons for further deterioration in the 2021 metric as compared to 2019 and 2020?

b) One of the factors that Enbridge Gas attributes to missing the performance standard is extreme weather events. In its evidence, Enbridge Gas noted that the 2021 winter was warmer than normal. Considering that winter related events are a normal occurrence in Ontario, why have extreme weather events impacted the performance standard in 2020 and 2021?

Response:

a) MRPM is a cumulative metric whereby the total number of unread meters fluctuates as some meters are read and come off the totals, other meters remain as unread from the previous month, and new meters reach their four-month timeline and are added to the current consecutive estimate results. This metric does not reset at the beginning of each year, which means that even though a percentage of meters have successfully been read, Enbridge Gas will continue to have meters that have consecutive estimates at the start of the year. On January 1, 2021, 149,094 meters had consecutive estimates. In 2021, weather events and increased illness/absence due to Covid and public health quarantine requirements resulted in continuing challenges meeting the metric. The impact was more significant in Legacy Union Gas regions due to extreme weather events listed in b) affecting the Northern and Eastern regions.

With over 3.8M customers, if 19,000 meters have consecutive estimates on average each month the metric is not achieved. If Enbridge Gas experiences a challenging one or two months for meter reading during a year, the MRPM is very difficult to achieve. For example, meter readers have three days to read their routes within the billing cycle. When one reader becomes ill with Covid and needs to quarantine for 5 to 10 days, they will miss routes for 2 to 3 cycles (5,000-10,000 reads). In addition, there was increased customer sensitivity to contact with meter readers, access issues and staffing challenges experienced by the vendor.

b) As noted above in the response to a), the cumulative nature of MRPM combined with other factors, including an increasing number of extreme weather events, impacted MRPM performance in 2020 and 2021. Temperature is not the only factor in extreme conditions that limits the ability to travel to properties and access meters safely. Examples include:

- Heavy snowfall greater than 20 cm. occurred between January 6 and 14, 2020 throughout Ontario, particularly in Northern Ontario and the Greater Toronto Area (GTA).
- Between February 17 and February 20, 2020, over 50 cm. in Northern Ontario.
- Between February 15 and February 24, 2020, over 65 cm. in Eastern Ontario.
- In April and May 2020, flooding in parts of Ontario including Kawartha Lakes, Eastern and Northern Ontario due to melting snow combined with rain.
- In the month of February 2021, the GTA had over 38 cm. of snowfall.
- In April and May 2021, heavy flooding in North Bay and Kapuskasing area washed out roads and readers could not get to meters; and
- Between November 22 and December 21, 2021, Sudbury and Northern Ontario received over 76 cm. of snow.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

2021 Performance Scorecard Results
Exhibit G / Tab 1 / p. 3

Question(s):

The Call Answering Service Level (CASL) measures the number of calls reaching the general inquiry number answered within 30 seconds divided by the number of calls received. The annual performance standard for CASL is 75% with a minimum monthly standard of 40%. The 2021 result was 64.3% while the result for 2019 was 79.0% and 75.2% in 2020. In July 2021, Enbridge Gas harmonized the two legacy utilities' Customer Information Systems (CIS), which involved moving 1.6 million customers and their associated data from one CIS system to another. The changes post integration resulted in higher call volumes. COVID also impacted the contact centres due to increased illness and absence. In order to improve performance on the CASL metric, Enbridge Gas implemented several initiatives including recruiting temporary employees to assist with high call volumes.

a) Please provide the monthly CASL data for 2021.

b) Why did Enbridge Gas not anticipate higher call volumes from migrating a large volume of customers to a different CIS?

c) Considering that both events were not unexpected (higher call volumes from moving customers to a different CIS and the fact that COVID has increased absences across all industries), why was Enbridge Gas not able to plan for these events and recruit temporary employees at the same time as the migration was implemented?

d) The evidence notes that Enbridge Gas implemented several initiatives to improve performance on the CASL metric. Please describe these initiatives.

Response:

a) The number of calls received and answered within 30 seconds for 2021 is detailed in the response at Exhibit I.LPMA.10.

b) Enbridge Gas did anticipate higher call volumes due to integration and hired additional temporary employees, however, the size of the increase in call volumes, the extended period there was an increase in call volumes and the complexity of the calls with longer call time was not anticipated. Prior to integration Enbridge Gas developed customer communications including bill inserts, web site information, interactive voice response (IVR) messaging, and emails for MyAccount customers.

c) Enbridge Gas did plan for these events, however, the significance of the prolonged impact of COVID-19 on illness/absence and the challenges experienced that resulted in higher volumes because of system integration were larger than expected. Recruitment and training of contact centre agents takes approximately three months before an employee can answer move calls and an additional two weeks before an employee can answer billing related inquiries. In addition, new agents have longer call times. Enbridge Gas has continued to hire temporary agents to assist with the increased work and to manage the ongoing COVID-19 impacts on illness/absence, however, like other industries the current labour market hiring temporary employees is challenging.

d) To improve performance on the CASL measure, Enbridge Gas has identified and implemented several initiatives including:

- Ongoing recruitment of temporary employees to assist with high call volumes.
- Workshops to drive optimization and identify opportunities for improved performance.
- Increased coaching of agents to decrease average call times.
- A weekly review of customer survey feedback to identify opportunities to improve customer experience.
- Prioritization of billing exception work to improve resolution of customer inquiries.
- Continuous review of system enhancements to improve customer experience in customer self-service channels such as MyAccount, Chatbot, and IVR.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2, Page 1

Preamble:

Under footnote iv), the line item states: "*Adjust EGD rate zone OBA costs to reflect EB-2013-0099 approved unit costs agreed to be used for determining net revenue*"

We would like to understand this adjustment.

Question(s):

Please provide a description of the adjustment

a) Please provide a breakdown of component costs and the resulting determination of the $4.3M figure.

Response:

Consistent with utility adjustments made in prior years, the $4.3 million adjustment to EGD rate zone Open Bill Access (OBA) net revenue reflects the difference between actual direct OBA program costs and the approved program costs, determined in accordance with terms included in approved OBA program settlement agreements. The terms of these agreements are used to determine net OBA revenues and any resultant impacts to be captured in the Open Bill Revenue Variance Account. The approved cost components for OBA shared and standalone bills are Accenture Charges, Customer Care, and other charges. Postage costs are also included for standalone bills.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 4, Page 3

Preamble:

In the EGD Rate Zone Underground Storage Plant table, column 2 provides additions in the total of $73.8M.

We would like to understand the nature of these additions and the allocation to utility storage plant.

Question(s):

For each project over a million dollars that contribute to the additions, please provide:

a) A description of the project
b) A Board approval reference, if any
c) A specific description of the functionality created, improved or replaced as a result of the capital invested

Response:

Corunna (SCOR) Meter Area Upgrade Phase 1 (IC 1811)

The meter area upgrade within the Corunna Compressor station is driven by process safety and operational risk as a result of an outdated design for an area of the facility that has experienced a significant change in function. As a result of the 2013 Inventory Meter Upgrade project, which moved measurement from the Corunna Compression Station closer to the storage pool, the Meter Area simply became flow paths connecting Corunna Compressor Station to the associated pool pipelines. Limited cross flow functionality is provided in the current meter area piping creating an inefficient operational configuration to accommodate for the previous functionality. Scope of work includes: Installation of Electrical Control building, replacement of meter run piping and installation of new header cross-over and isolation valves for Ladysmith and Dow-Moore pool lines and installation of west section of new NPS 30 A, B, C headers. Upon completion of Phase 1 and 2, this eliminates the flow induced vibration risk associated with existing cross flow header. The new design eliminates thermal expansion stresses in piping that are exceeding allowable range as per CSA Z662. A reduction of fittings decreases the number of potential leak points. 2021 in-service capital was $21.3 million.

Wilkesport MOP Remediation (IC 101017)

The Wilkesport MOP Assessment, completed in 2019, identified that a number of records were missing. To maintain the current established MOP and to address missing records, the scope of this work includes field verifications, replacement of specific pipe and fittings and pressure testing the TW10 lateral in-place. 2021 in-service capital was $13 million.

NPS 16 LAD-WLK Interconnect MOP (IC 502483)

Remediate issues raised in the Ladysmith MOP Verification study. Scope of work to replace NPS 16 insulator at the Ladysmith-Wilkesport Interconnect. 2021 in-service capital was $3.3 million.

Wilkesport (LWLK) Well Debris Filter (IC 500484)

Replace previously removed underground in-line separator with above ground filter separator system to achieve sufficient filtration and to capture well tailings to prevent build-up in pipe fittings/valves and measurement equipment. During withdrawal, debris from gas storage wells collect in the in-line separator and build up in the valve port, preventing them from functioning as intended and restricting gas flow. The debris is likely the tailings from the drilling of new wells. It travels with gas flow during withdrawal into the storage pipeline system. Debris build-up, which has been observed at the removed in-line separator at the Wilkesport metering station, has also been affecting the valves at the meter station and rendering them non-functional. 2021 in-service capital was $2.0 million.

NPS 16 Coveny Trans. Retrofit (IC 1908)

The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and replacement of pipeline segments with integrity issues that are identified through the inspections. As a result, the installation of permanent launcher and receiver facilities prior to the next scheduled inspection in 2022 has been completed. Installing permanent launcher and receiver facilities saves O&M spend which would otherwise be required to install and remove temporary facilities each inspection cycle. Permanent launcher/receiver facilities also provide a high degree of flexibility with respect to the timing of inspections which leads to system optimization and reduces disruption to normal pipeline operations. 2021 in-service capital was $1.8 million.

NPS 16 COV Gathering Retrofit (IC 1907)

The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and replacement of pipeline segments with integrity issues that are identified through the inspections. As a result, the installation of permanent launcher and receiver facilities prior to the next scheduled inspection in 2022 has been completed. Installing permanent launcher and receiver facilities saves O&M spend which would otherwise be required to install and remove temporary facilities each inspection cycle. Permanent launcher/receiver facilities also provide a high degree of flexibility with respect to the timing of inspections which leads to system optimization and reduces disruption to normal pipeline operations. 2021 in-service capital was $1.8 million.

SCOR:60004 iBalance – Upgrade (IC3451)

The power cylinder balancing for eight of the compressors at the Corunna Compressor Station is performed manually compared to the current industry best practice monitoring technology (auto-balancing). These compressors are over 50 years old. Auto-balancing systems provide improved reliability, reduced probability of crankshaft failure, more precise control of NOx emissions and reduced operating costs (fuel and maintenance). Without this change reliability and NOx emissions cannot improve further. Auto-balancing has the potential to provide early detection, and prevention of detonation events. 2021 in-service capital was $1.0 million.

PMKC:TKC67H New Hwell (IC 6363) - Horizontal Well – TCK 67H.

The horizontal gas storage well is needed to replace the deliverability lost in the Kimball-Colinville Storage Pool due to the abandonment of three gas storage wells. One well was abandoned in 2002 and two wells were abandoned in 2018. The drilling of well TKC 67H is a ‘like for like’ replacement and will not result in an increase in storage capacity or an increase in deliverability in the Kimball-Colinville Storage Pool. The abandoned wells were part of the regulated storage operations. The new horizontal well will form part of regulated storage operations. OEB Case Number: EB-2020-0105. 2021 in-service capital was $2.4 million.

SCOR:Methane

By January 1, 2020, packing must emit less than 0.023 m^3/min/packing while in operation. Generally, it is expected that packing vent rate will be higher for integral compressors, than for separable compressors. By January 1, 2023, methane vents - excluding packing vents - must be controlled to be less than 15000 m^/year/facility. Without an upgrade to the associated methane vents EGD will be out of compliance with requirements of the Canadian Environmental Protection Act. 2021 in-service capital was $1.5 million.

SCOR:100MOD Hdr Valves-Replace (IC 12957)

Operations has identified compressor station yard isolation valves that do not provide sufficient seal quality to provide isolation during normal maintenance activities or emergency situations. Leaking valve seals are not necessarily valves that leak to atmosphere or pose a loss of containment threat. The valves referenced in this investment are those that allow gas to flow, when in the closed position. If valve condition is not maintained at a reasonable level, the ability to isolate assets during an emergency will be compromised. Valves in question are sometimes used to separate piping with different MOPs. If these valves are allowed to leak, there is an increased threat of over pressuring lower MOP pipe as gas bleeds through the valve from higher MOP pipe. Project targets all Mode (MOD) valves associated with K704 & K707. There are dozens of these valves in service. 2021 in-service capital was $1.4 million.

SCOR:100MOD Hdr Vlves-Repl (IC 12956)

Operations have identified compressor station yard isolation valves that do not provide sufficient seal quality to provide isolation during normal maintenance activities or emergency situations. Leaking valve seals are not necessarily valves that leak to atmosphere or pose a loss of containment threat. The valves referenced in this investment are those that allow gas to flow when in the closed position. If valve condition is not maintained at a reasonable level, the ability to isolate assets during an emergency will be compromised. Valves in question are sometimes used to separate piping with different MOPs. If these valves are allowed to leak, there is an increased threat of over pressuring lower MOP pipe as gas bleeds through the valve from higher MOP pipe. This project targets a specified header to replace all associated MOD valves. All MOD valves on the Dow Moore pool Header will be replaced. There are a total of 5 valves - all valves are PN150 pressure classification. It is assumed that valves sizes match the size of the Dow Moore pool Header (NPS20). Valves include: 66104-MV-017; 66104-MV-010; 66104-MV-017; 66104-MV-010; 120-MV-030. 2021 in-service capital was $1.5 million.

LCHT:Pipeline-ILI Retrofits (IC 16836)

The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. It includes installation costs for permanent launcher and receiver facilities prior to the next scheduled inspection. Installing permanent launcher and receiver facilities saves O&M spend which would otherwise be required to install and remove temporary facilities each inspection cycle. Permanent launcher/receiver facilities also provide a high degree of flexibility with respect to the timing of inspections which leads to system optimization and reduces disruption to normal pipeline operations. 2021 in-service capital was $1.8 million.

SCOR:60007-Fdn Blk-Replace (IC 3460)

Due to the age of the compressor infrastructure, operating hours and oil contamination, engine block foundations are deteriorating. Industry benchmarks suggest that reciprocating engine block foundations degrade in 25 years or less for engines that run 24/7. Excessive bearing deflections place cyclic stresses on the crankshaft of the unit leading to increased frequency of bearing failure and increased potential for a crankshaft fatigue failure. Unit reliability will diminish dramatically if repairs are not performed. The worst case consequence is unit unavailability during a design day. Compressor foundations have been considered in the Asset Health Review. Condition assessment is largely visual. A telltale sign of poor foundation condition is the existence of cracks on the surface of the foundation with oil seeping out of the crack. Cracks typically extend to a depth that is consistent with the bottom of the anchor bolts. Without remediation, failing foundations will allow unit settlement, creating a misalignment of bearings. Frequency of bearing failures increases - reducing operation reliability. Collateral damage to the crankshaft is also common. This project replaced the entire foundation of the compressor. 2021 in-service capital was $2.5 million.

NPS 16 LAD-WLK Inter Rfit (IC 1910)

The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. It includes installation costs for permanent launcher and receiver facilities prior to the next scheduled inspection in 2022. Installing permanent launcher and receiver facilities saves O&M spend which would otherwise be required to install and remove temporary facilities each inspection cycle. Permanent launcher/receiver facilities also provide a high degree of flexibility with respect to the timing of inspections which leads to system optimization and reduces disruption to normal pipeline operations. 2021 in-service capital was $1 million.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 4, Page 4

Preamble:

In the Union Gas Rate Zone Underground Storage Plant table, column 2 provides additions in the total of ($12.1M).

We would like to understand the nature of these changes and the allocation to utility storage plant.

Question(s):

For each project over a million dollars in absolute value that contribute to the total for additions, please provide:

a) A description of the project
b) A Board approval reference, if any
c) A specific description of the functionality created, improved or replaced as a result of the capital invested

Response:

Payne Pool – New Well Lateral (IC 101688)

To install new NPS 10 60m lateral for new well. The Payne Pool New Well project is intended to recover lost design day deliverability at the Payne pool. Design day deliverability of the Payne pool had declined due to the abandonment of one injection/withdrawal well and relining (with a smaller casing) of four injection/withdrawal wells. OEB Case Number: EB-2020-0105. 2021 in-service capital was $1.1 million.

STO Property - Turner Property Purchase (IC 735985)

Purchase of the property will increase compliance and reduce public safety risk, will reduce the likelihood of later compliance issues and land use that will be incompatible with existing facilities, and will provide for the potential expansion of facilities and additional swing space when facilities require work to be completed. 2021 in-service capital was $1.1 million.

STO Property - Sanderson Property Purchase (IC 735983)

Purchase of the property will increase compliance and reduce public safety risk, will reduce the likelihood of later compliance issues and land use that will be incompatible with existing facilities, and will provide for the potential expansion of facilities and additional swing space when facilities require work to be completed. 2021 in-service capital was $1.4 million.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 3 and EB-2020-0149 Exhibit I.FRPO.13

Preamble:

We would like to understand the cost changes and source of inter-legacy company transactions.

Question(s):

For line 21, please break-out the aggregate transactions between legacy EGD and UG into the respective lines 9 to 19 similar to FRPO. 13 from last year providing the last 3 years including 2021.

a) Please provide a description of M16 service transactions between legacy companies and drivers for differences over time.

b) Please provide a description of S&T Transport Carbon Facility Collection transaction between legacy companies and drivers for differences over time.

Response:

Table below provides breakdown of transactions between legacy EGD (LEGD) and legacy UG (LUG) for years 2019, 2020 and 2021. Please note that all charges below are LEGD paying LUG.

Table 1
Revenue from Regulated Transportation Services between legacy EGD and UG

Line No.	Particulars ($000s)	2021 Actual	2020 Actual	2019 Actual
	Revenue from Regulated Transportation Services:			
9.	M12 Transportation	126,332	124,282	119,850
10.	M12-X Transportation	10,872	10,779	10,764
11.	C1 Long Term Transportation	-	-	620
12.	Rate 332: Gas Transmission	-	-	-
13.	C1 Short Term Transportation	53	-	-
14.	Gross Exchange Revenue	-	-	90
15.	Rate 331: Gas Transmission	-	-	-
16.	M13 Local Production	-	-	-
17.	M16 Transportation	332	407	417
18.	S&T: Transportation Carbon Facility Collection	890	677	259
19.	Other S&T Revenue	10	10	9
20.	Less: Elimination of charges between EGD and Union rate zones	-	-	-
21.	Total Regulated Transportation Revenue Net of Deferral	$138,489	$136,155	$132,009

a) The M16 transportation service is used to transport gas between LEGD storage pools and the Dawn hub. Decrease in revenues in 2021 from 2020 is driven by lower approved M16 demand rates and lower volumes.

b) The calculation of carbon facility charge is based on actual volumes multiplied by the approved carbon facility rate. The higher revenue is driven by higher volumes.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, Tables and Appendix

Preamble:

We would like to understand the changes in O&M as the relate to integration including Corporate Shared Services and EGI's request to eliminate Appendix A.

Question(s):

For line 13 of Table 1, please provide a description of the major components leading to the 67% increase.

a) Please reconcile the gross and net numbers provided in Table 3 and those in Appendix A.

b) Please specify why the continuation of the presentation in Appendix A does not assist the Board in understanding these cost changes in greater detail?

Response:

Please see the updated submission filed on June 17, 2022 that provided a correction to Exhibit B, Tab 3, Schedule 1 in Table 1 and Appendix A. In the updated exhibit, Corporate Shared Services in Line 13 shows an increase of 16.1%. The major drivers of that increase are explained at paragraph 8 on page 3 and Attachment 1 to the response at Exhibit I.SEC.1.

a) Gross and Net Corporate Shared Services (CSS) amounts are shown in both Table 3 and Appendix A. To derive or reconcile both amounts, CSS-related Capitalization is required.

The following table shows where Net CSS, Gross CSS, and capitalization of CSS amounts for 2020 and 2021 are shown or can be derived across all tables in the exhibit.

Table 1

Reference Table for CSS in B-3-1

			2020 Values	2021 Values
Net CSS:				
	Table 1	Line 13	Column 2	Column 3
	Table 3	Line 3	Column 2	Column 3
	App A	Line 13	Column 3	Column 7
Capitalization of CSS:				
	Table 2	Line 1	Column 2	Column 3
	Table 3	Line 2	Column 2	Column 3
Gross CSS:				
	Table 3	Line 1	Column 2	Column 3
	App A	Line 13+ Line 17	Column 3	Column 7

b) The presentation of CSS Costs (Columns 3 and 7), DSM and Integration Costs (Columns 4 and 8) in Appendix A have been replaced by separate lines (Lines 13 to 15) within Table 1. The Company believes that Table 1 allows for CSS, DSM and Integration costs to be identified more directly as they are no longer embedded within the different expense categories. As well, CSS costs in Line 13 reflect the true costs allocated to Enbridge Gas for its share of central functions costs.

CSS costs are allocated by functional area and not at the expense category level. The expense category details in Appendix A Columns 3 and 7, Lines 1 through 12, represent Enbridge Gas central functions expenses that were removed from Enbridge Gas O&M to become part of the enterprise cost pool, pulled into the Central Functions Cost Allocation Methodology (CFCAM) and ultimately allocated through the CFCAM to EGI as CSS costs in Line 13. The most relevant and useful analysis is presented for overall CSS cost levels and variances for Line 13 (CSS costs). Please see Exhibit I.SEC.1, Attachment 1 for a cost breakdown and variance analysis by Central Function.

In addition, Enbridge Gas has made the following corrections in evidence so that the characterization of Central Functions Cost Allocations and CSS are consistent with the upcoming rebasing filing. See Attachment 1 for details of the changes below.

Change #1:

The CFCAM changed in 2021 so that costs are now allocated prior to capitalization (gross). Before 2021, costs were pulled into the CFCAM net of capitalization. The evidence has been updated using the gross model as it will apply to all results leading up to the test year in the rebasing case. The increase to Compensation and Benefits line (Line 1) is offset by the increase in Capitalization on Non-CSS (Line 17), a negative value, resulting in no impact to total O&M or capitalization.

Change #2:

Subsequent to the initial filing and evidence update dated June 17th, 2022, Enbridge Gas identified a further misclassification for amounts relating to the amortization of pre-2017 pension costs for the Union rate zone. These amounts have been re-evaluated and should not be included in CSS costs, but classified to compensation and benefits applicable to the business unit.

This change reduces CSS costs (Line 13) and increases Compensation and Benefits (Line 1). There is no impact to total O&M or capitalization.

The restated table has been updated in evidence.

Table 1

UTILITY O&M
19-21 ACTUALS

Line No.	Expense Categories	Original 2019 Actual ($M)	Revised 2019R Actual ($M)	$ Change	Original 2020 Actual ($M)	Revised 2020R Actual ($M)	$ Change	Original 2021 Actual ($M)	Revised 2021R Actual ($M)	$ Change	Original 2020-21 $ change	Revised 2020-21 $ change	Original 2020-21 % change	Revised 2020-21 % change
1	Compensation and Benefits	393.6	442.4	(48.7)	354.7	405.8	(51.2)	369.8	404.3	(34.5)	15.1	(1.5)	4.3%	-0.4%
2	Employee Related Services and Development	0.9	0.9		1.5	1.5		1.5	1.5		(0.0)	(0.0)	-2.0%	-2.0%
3	Materials and Supplies	39.5	39.5		29.9	29.9		32.5	32.5		2.6	2.6	8.6%	8.6%
4	Outside Services	242.2	242.2		220.8	220.8		232.1	232.1		11.3	11.3	5.1%	5.1%
5	Transportation Related Repairs and Maintenance	5.5	5.5		6.9	6.9		5.7	5.7		(1.2)	(1.2)	-17.8%	-17.8%
6	Vehicle Related Repairs and Maintenance	18.5	18.5		14.3	14.3		19.8	19.8		5.5	5.5	38.1%	38.1%
7	Rents and Leases	10.3	10.3		9.9	9.9		11.1	11.1		1.2	1.2	11.7%	11.7%
8	Telecommunications	0.2	0.2		0.3	0.3		0.2	0.2		(0.1)	(0.1)	-35.1%	-35.1%
9	Travel and Entertainment	9.1	9.1		3.1	3.1		3.7	3.7		0.6	0.6	20.1%	20.1%
10	Donations and Memberships	10.1	10.1		3.2	3.2		11.3	11.3		8.1	8.2	258.1%	258.1%
11	Admin Expenses	(1.8)	(1.8)		(1.6)	(1.6)		(4.1)	(4.1)		(2.5)	(2.5)	162.1%	162.1%
12	Allocations & Recoveries	(30.3)	(30.3)		(17.8)	(17.8)		(16.5)	(16.5)		1.3	1.3	-7.1%	-7.1%
13	Corporate Shared Services (CSS)	190.9	175.1	15.8	187.8	175.6	12.3	218.1	218.1		30.3	42.6	16.1%	24.3%
14	DSM	133.0	133.0		132.3	132.3		132.1	132.1		(0.2)	(0.2)	-0.1%	-0.1%
15	Integration-Related Costs	48.9	48.9		125.2	125.2		49.8	49.8		(75.4)	(75.3)	-60.2%	-60.2%
16	Miscellaneous Expense	9.8	9.8		14.7	14.7		9.8	9.8		(4.9)	(4.9)	-33.4%	-33.4%
17	Capitalization on Non-CSS	(143.3)	(176.2)	32.9	(119.5)	(158.4)	38.9	(138.2)	(172.7)	34.5	(18.7)	(14.4)	15.7%	9.1%
18	O&M Subtotal before Eliminations	937.1	937.1	0.0	965.7	965.7	0.0	938.7	938.7	0.0	(27.0)	(27.0)	-2.8%	-2.8%
19	Donations	(3.0)	(3.0)		(0.6)	(0.6)		(3.6)	(3.6)		(3.0)	(3.0)	465.1%	465.1%
20	CDM Program	0.2	0.2		0.1	0.1		0.0	0.0		(0.1)	(0.1)	-100.0%	-100.0%
21	ABC T-service Program	(0.3)	(0.3)		(0.2)	(0.2)		(0.3)	(0.3)		(0.1)	(0.1)	76.3%	76.3%
22	Other Eliminations	(0.1)	(0.1)		0.0	0.0		(0.1)	(0.1)		(0.1)	(0.1)		
23	Unregulated Adjustments	(19.5)	(19.5)		(16.6)	(16.6)		(18.5)	(14.1)		(1.9)	2.5	11.6%	-15.1%
24	Total Unregulated/Non-Utility Eliminations	(22.6)	(22.6)		(17.3)	(17.3)		(22.5)	(18.1)		(5.3)	(0.8)	30.5%	4.9%
25	Total Net Utility O&M Expense	914.5	914.5		948.5	948.5		916.2	920.6		(32.3)	(27.9)	-3.4%	-2.9%

Table 2

Total Overhead Capitalization Impact on O&M

Line No.	Categories	Original 2019 Actual ($M)	Revised 2019R Actual ($M)	$ Change	Original 2020 Actual ($M)	Revised 2020R Actual ($M)	$ Change	Original 2021 Actual ($M)	Revised 2021R Actual ($M)	$ Change	Original 2021-2020 Variance ($M)	Revised 2021-2020 Variance ($M)
1	CSS-related Capitalization	(96.6)	(63.7)	32.9	(105.0)	(65.9)	(39.1)	(96.7)	(61.6)	(35.1)	8.3	4.4
2	Capitalization on Non-CSS	(143.3)	(176.2)	(32.9)	(119.5)	(158.4)	38.9	(138.2)	(172.7)	34.5	(18.7)	(14.4)
3	Total Overhead Capitalization	(239.9)	(239.9)	-	(224.5)	(224.3)	(0.2)	(234.9)	(234.3)	(0.6)	(10.4)	(10.0)

Table 3

CF Cost Allocations and CSS

Categories	Original 2019	Revised 2019R	$ Change	Original 2020	Revised 2020R	$ Change	Original 2021	Revised 2021R	$ Change	Original 2020-2021	Revised 2020-2021
CF Cost Allocations	287.5	238.7	48.7	292.8	241.5	51.4	314.8	279.7	35.1	22.0	38.2
Less: Capitalization of CSS	(96.6)	(63.7)	(32.9)	(105.0)	(65.9)	(39.1)	(96.7)	(61.6)	(35.1)	8.3	4.4
Net CSS	190.9	175.1	15.8	187.8	175.6	12.3	218.1	218.1	0.0	30.3	42.6

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, Tables and Appendix

Preamble:

We would like to understand the changes in O&M as the relate to integration including Corporate Shared Services and EGI's request to eliminate Appendix A.

Question(s):

For line 10, please provide a breakout of all organizational memberships and their respective costs in 2019 through 2021.

a) Please provide the value to ratepayers associated with the memberships included

b) Please explain the fluctuations in those membership costs

Response:

Enbridge Gas is a member of a number of organizations representing various stakeholders within the industry. Total membership costs amounted to $3.8 million in 2019, $2.8 million in 2020, and $2.6 million in 2021. A partial listing of membership affiliations is provided below:

- Canadian Gas Association
- Ontario Energy Association
- The Toronto Region Board of Trade
- Ontario Chamber of Commerce
- Energy Storage Canada
- Hydrogen Council
- Canadian Manufacturers and Exporters
- Association of Energy Services
- Ontario Sustainable Energy Association

- Ontario Waste Management
- Association of Power Producers
- Canadian Biogas Association
- Utilization Technology Development
- Consumers Council of Canada
- Various Home Builders Associations

a) Participation in member-driven organizations allows Enbridge Gas to leverage industry partners by pooling resources to efficiently act on behalf of the sector. Representation at industry consultations, direct engagement with various levels of government, development of industry data, and sharing of best practices from across the industry are some examples of how leveraging membership adds value.

b) Membership costs have remained relatively flat in 2020 and 2021. The reduction in membership costs from 2019 to 2020 was driven by productivity and integration savings achieved by pooling services and membership fees.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 2, Page 13

Preamble:

We would like to understand more about the respective compressor and the Compressor and Transmission and Underground Storage projects, their function and the allocation of costs between utility and non-utility.

Question(s):

For each of the projects listed, please provide a description of the project and an itemized description of the function provided and the rationale for the allocation of costs.

Response:

A summary by project is listed below including the project description and function. Costs are allocated to either regulated or unregulated operations in conjunction with Enbridge Gas's unregulated cost allocation methodology.

Corunna (SCOR) Meter Area Upgrade Phase 1 (IC 1811)

The meter area upgrade within the Corunna Compressor station is driven by process safety and operational risk as a result of an outdated design for an area of the facility that has experienced a significant change in function. As a result of the 2013 Inventory Meter Upgrade project, which moved measurement from the Corunna Compression Station closer to the storage pool, the Meter Area simply became flow paths connecting Corunna Compressor Station to the associated pool pipelines. Limited cross flow functionality is provided in the current meter area piping creating an inefficient operational configuration to accommodate for the previous functionality. Scope of work includes: Installation of Electrical Control building, replacement of meter run piping and install new header cross-over and isolation valves for Ladysmith and Dow-Moore pool lines and installation of west section of new NPS 30 A, B, C headers. Upon completion of Phase 1 and 2, this eliminates the flow induced vibration risk associated with the existing cross flow header. The new design eliminates thermal expansion stresses in piping that are exceeding allowable range as per CSA Z662. A reduction of fittings decreases the number of potential leak points. 2021 capital expenditures were $14 million and the project is 100% regulated.

Corunna (SCOR) Meter Area Upgrade Phase 2 (IC 500440)

The meter area upgrade within the Corunna Compressor station is driven by process safety and operational risk as a result of an outdated design for an area of the facility that has experienced a significant change in function. As a result of the 2013 Inventory Meter Upgrade project, which moved measurement from the Corunna Compression Station closer to the storage pool, the Meter Area simply became flow paths connecting Corunna Compressor Station to the associated pool pipelines. Limited cross flow functionality is provided in the current meter area piping creating an inefficient operational configuration to accommodate for the previous functionality. Scope of work includes: Replaced meter run piping and install new header cross-over and isolation valves for the Wilkesport, South Kimball, Seckerton, Corunna and Mid Kimball pool lines. Installed east section of new NPS 30 A, B, C headers and tie in east & west header sections. 2021 capital expenditures were $2.2 million and the project is 100% regulated.

SCOR: 100MODHdr Valves – Replace (IC 12957)

Operations has identified compressor station yard isolation valves that do not provide sufficient seal quality to provide isolation during normal maintenance activities or emergency situations. Leaking valve seals are not necessarily valves that leak to atmosphere or pose a loss of containment threat. The valves referenced in this investment are those that allow gas to flow, when in the closed position. If valve condition is not maintained at a reasonable level, the ability to isolate assets during an emergency will be compromised. Valves in question are sometimes used to separate piping with different MOPs. If these valves are allowed to leak, there is an increased threat of over pressuring lower MOP pipe as gas bleeds through the valve from higher MOP pipe. Project targets all MOD valves associated with K704 & K707. There are dozens of these valves in service. 2021 capital expenditures were $1.4M and the project is 100% regulated.

SCOR: 60004 iBalance-Upgrade (IC 3451)

The power cylinder balancing for eight of the compressors at the Corunna Compressor Station is performed manually compared to the current industry best practice monitoring technology (auto-balancing). These compressors are over 50 years old. Auto-balancing systems provide improved reliability, reduced probability of crankshaft failure, more precise control of NOx emissions and reduced operating costs (fuel and maintenance). Without this change reliability and NOx emissions cannot improve further. Auto-balancing has the potential to provide early detection, and prevention of detonation events. 2021 capital expenditures were $1.3 million and the project is 100% regulated.

Wilkesport MOP Remediation (IC 101017)

The Wilkesport MOP Assessment, completed in 2019, identified that a number of records were missing. In order to maintain the current established MOP and to address missing records, the scope of this work includes field verifications, replacement of specific pipe and fittings and to pressure test TW10 lateral in-place. 2021 capital expenditures were $6.2 million and the project is 100% regulated.

NPS16 LAD-WLK Interconnect MOP (IC 502483)

Remediated issues raised in the Ladysmith MOP Verification study. Scope of work to replace NPS 16 insulator at the Ladymisth-Wilkesport interconnect. 2021 capital expenditures were $4.1 million and the project is 100% regulated.

LLAD: Strategic land purchases at two locations around the underground storage facilities (IC 735640/734521)

(1) Williams Property
Acquired land in proximity to compressor stations providing additional setback and buffer to ensure properties do not become noise sensitive and to reduce risk related to public safety and encroachment. Property may also be purchased to support expansion or provide ease of access.

(2) Joyce/Maitland Property
Provides additional setback and buffer from existing neighbours. Farmland will continue to be rented out. Future development at Corunna is expected to take place to the east of the station, thus providing additional buffer for those projects. 2021 capital expenditures were $5 million and the project is 100% regulated.

Wilksport (LWLK) Well Debris Filter (IC 500484)

During withdrawal, debris from gas storage wells collect in the in-line separator and build up in the valve port, preventing them from functioning as intended and restricting gas flow. The debris is likely the tailings from the drilling of new wells and travels with gas flow during withdrawal into the storage pipeline system. The debris build-up has been affecting the valves at the metering station and making them non-functional. Build-up is also observed at the inline separator at the Wilkesport metering station, which is now removed and needing a replacement. 2021 capital expenditures were $2.5 million and the project is 100% regulated.

NPS 16 Coveny Trans. Retrofit (IC 1908)

The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The project includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and replacement of pipeline segments with integrity issues that are identified through the inspections. As a result, the installation of permanent launcher and receiver facilities prior to the next scheduled inspection in 2022 has been completed. Installing permanent launcher and receiver facilities saves O&M spend which would otherwise be required to install and remove temporary facilities each inspection cycle. Permanent launcher/receiver facilities also provide a high degree of flexibility with respect to the timing of inspections which leads to system optimization and reduces disruption to normal pipeline operations. 2021 capital expenditures were $2.3 million and the project is 100% regulated.

NPS 16 COV Gathering Retrofit (IC 1907)

The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and replacement of pipeline segments with integrity issues that are identified through the inspections. As a result, the installation of permanent launcher and receiver facilities prior to the next scheduled inspection in 2022 has been completed. Installing permanent launcher and receiver facilities saves O&M spend which would otherwise be required to install and remove temporary facilities each inspection cycle. Permanent launcher/receiver facilities also provide a high degree of flexibility with respect to the timing of inspections which leads to system optimization and reduces disruption to normal pipeline operations. 2021 capital expenditures were $2.2 million and the project is 100% regulated.

Pipeline and Meter Station – Upgrade (IC 102893)

Increasing the Delta Pressure of reservoirs will result in a corresponding increase in the pressure of the pipeline system delivering gas to the reservoir on injection. In most cases, affected pipeline systems have traditionally operated below the qualified MOP of the system. A formal pressure elevation of these piping systems is needed to ensure safety operation during high end injection. Scope of work - installation of a flow control valve at the meter station along with required air systems and insulation. This included design, stakeholder consultations, retaining a construction contractor, prefabricating piping, hydrotesting at shop, laying plates, isolating the system with a full station outage, cut out of existing valves, installing supports as required, install new piping coating as required, Non-destructive examination (NDE), energizing the system and remediating the site. This project is part of the Storage Enhancement Delta Pressuring Phase 1 and includes various locations. (OEB Case Number: EB-2020-0256) 2021 Capital expenditures were $6.2 million and the project is 100% unregulated.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit D, Tab 1, Page 1

Question(s):

Please provide the EGI annual financial report for 2021.

Response:

Please see Attachment 1 to this response.

ENBRIDGE GAS INC.

(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2021

MANAGEMENT'S REPORT

TO THE SHAREHOLDERS OF ENBRIDGE GAS INC.

Financial Reporting
Management of Enbridge Gas Inc. (Enbridge Gas) is responsible for the accompanying consolidated financial statements. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (US GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors is responsible for all aspects related to governance of Enbridge Gas. Enbridge Gas does not have an Audit Committee, having received an exemption from such requirement.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. Enbridge Gas's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with US GAAP and to provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of Enbridge Gas, have conducted an audit of the consolidated financial statements of Enbridge Gas in accordance with Canadian generally accepted auditing standards and have issued an unqualified audit report, which is accompanying the consolidated financial statements.

/s/ Cynthia L. Hansen	/s/ Tanya M. Ferguson
Cynthia L. Hansen	Tanya M. Ferguson
President	Vice President, Finance

February 11, 2022

Independent auditor's report

To the Shareholders of Enbridge Gas Inc.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Inc. (the Company) as at December 31, 2021 and 2020, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America (US GAAP).

What we have audited
The Company's consolidated financial statements comprise:

- the consolidated statements of earnings for the years ended December 31, 2021 and 2020;
- the consolidated statements of comprehensive income for the years ended December 31, 2021 and 2020;
- the consolidated statements of changes in equity for the years ended December 31, 2021 and 2020;
- the consolidated statements of cash flows for the years ended December 31, 2021 and 2020;
- the consolidated statements of financial position as at December 31, 2021 and 2020; and
- the notes to the consolidated financial statements, which include significant accounting policies and other explanatory information.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence
We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215

pwc

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis.

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with US GAAP, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Ontario
February 11, 2022

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Operating revenues		
Gas commodity and distribution	**3,996**	3,631
Storage, transportation and other	**897**	884
Total operating revenues *(Note 4)*	**4,893**	4,515
Operating expenses		
Gas commodity and distribution costs	**2,146**	1,812
Operating and administrative	**1,105**	1,137
Depreciation and amortization	**677**	655
Total operating expenses	**3,928**	3,604
Operating income	**965**	911
Other income	**43**	56
Interest expense, net *(Note 10)*	**(394)**	(412)
Earnings before income taxes	**614**	555
Income tax expense *(Note 15)*	**(63)**	(58)
Earnings	**551**	497

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Earnings	**551**	497
Other comprehensive income/(loss), net of tax *(Notes 12 and 13)*		
Change in unrealized gain/(loss) on cash flow hedges	**21**	(37)
Reclassification to earnings of loss on cash flow hedges	**12**	15
Actuarial gain/(loss) on other postretirement benefits (OPEB)	**22**	(10)
Other comprehensive income/(loss), net of tax	**55**	(32)
Comprehensive income	**606**	465

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Common shares *(Note 11)*		
Balance at beginning of year	**3,517**	3,517
Capital contribution	**975**	800
Return of capital	**(1,050)**	(800)
Balance at end of year	**3,442**	3,517
Additional paid-in capital		
Balance at beginning and end of year	**7,253**	7,253
Deficit		
Balance at beginning of year	**(675)**	(720)
Earnings	**551**	497
Common share dividends declared	**(200)**	(450)
Adoption of new accounting standard	**—**	(2)
Balance at end of year	**(324)**	(675)
Accumulated other comprehensive loss *(Note 12)*		
Balance at beginning of year	**(78)**	(46)
Other comprehensive income/(loss), net of tax	**55**	(32)
Balance at end of year	**(23)**	(78)
Total equity	**10,348**	10,017

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Operating activities		
Earnings	**551**	497
Adjustments to reconcile earnings to net cash provided by operating activities:		
Depreciation and amortization	**677**	655
Deferred income tax recovery	**(15)**	(25)
Net defined pension and OPEB costs	**(24)**	(31)
Expected credit loss	**14**	15
Other	**10**	13
Changes in operating assets and liabilities *(Note 17)*	**(473)**	78
Net cash provided by operating activities	**740**	1,202
Investing activities		
Capital expenditures	**(1,308)**	(1,109)
Additions to intangible assets	**(72)**	(76)
Net cash used in investing activities	**(1,380)**	(1,185)
Financing activities		
Net change in short-term borrowings	**394**	223
Repayment of loan from affiliate	**—**	(650)
Term note issuances, net of issue costs	**896**	1,192
Term note repayments	**(375)**	(400)
Common share dividends	**(200)**	(450)
Return of capital	**(1,050)**	(800)
Capital contribution received	**975**	800
Net cash provided by/(used in) financing activities	**640**	(85)
Net change in cash	**—**	(68)
Cash at beginning of year	**9**	77
Cash at end of year	**9**	9
Supplementary cash flow information		
Cash paid/(received) for income taxes	**(5)**	66
Cash paid for interest, net of amounts capitalized	**374**	385
Property, plant and equipment non-cash accruals	**75**	20

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2021**	2020
(millions of Canadian dollars)		
Assets		
Current assets		
Cash	**9**	9
Accounts receivable and other *(Note 6)*	**1,228**	1,161
Accounts receivable from affiliates	**156**	92
Gas inventory	**897**	659
	2,290	1,921
Property, plant and equipment, net *(Note 7)*	**16,662**	15,866
Intangible assets, net *(Note 8)*	**177**	174
Deferred amounts and other assets	**2,677**	2,492
Goodwill	**4,784**	4,784
Total assets	**26,590**	25,237
Liabilities and equity		
Current liabilities		
Short-term borrowings *(Note 10)*	**1,515**	1,121
Accounts payable and other *(Note 9)*	**1,458**	1,295
Accounts payable to affiliates	**113**	134
Current portion of long-term debt *(Note 10)*	**126**	376
	3,212	2,926
Long-term debt *(Note 10)*	**9,352**	8,606
Other long-term liabilities	**2,012**	2,166
Deferred income taxes *(Note 15)*	**1,666**	1,522
	16,242	15,220
Commitments and contingencies *(Note 19)*		
Equity		
Share capital *(Note 11)*		
Common shares *(522 million shares outstanding at December 31, 2021 and 2020)*	**3,442**	3,517
Additional paid-in capital	**7,253**	7,253
Deficit	**(324)**	(675)
Accumulated other comprehensive loss *(Note 12)*	**(23)**	(78)
	10,348	10,017
Total liabilities and equity	**26,590**	25,237

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

/s/ Cynthia L. Hansen
Cynthia L. Hansen
Director

/s/ David G. Unruh
David G. Unruh
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. BUSINESS OVERVIEW

The terms "we", "our", "us" and "Enbridge Gas" as used in these financial statements refer collectively to Enbridge Gas Inc. and its subsidiaries unless the context suggests otherwise. Enbridge Gas is a wholly-owned indirect subsidiary of Enbridge Inc. (Enbridge). Enbridge provides administrative and general support services to us.

Enbridge Gas is a rate-regulated natural gas distribution, storage and transmission utility, serving residential, commercial and industrial customers in Ontario.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (US GAAP). Amounts are stated in Canadian dollars unless otherwise noted. We are permitted to use US GAAP as our primary basis of accounting for the purposes of meeting our continuous disclosure obligations under an exemption granted by securities regulators in Canada.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities *(Note 5)*; unbilled revenues; estimates of revenue; expected credit losses; depreciation rates and carrying value of property, plant and equipment *(Note 7)*; amortization rates and carrying value of intangible assets *(Note 8)*; measurement of goodwill; fair value of asset retirement obligations (ARO); fair value of financial instruments *(Note 13)*; provisions for income taxes *(Note 15)*; assumptions used to measure retirement benefits and OPEB *(Note 16)*; and commitments and contingencies *(Note 19)*. Actual results could differ from these estimates.

Certain comparative figures in our consolidated financial statements have been reclassified to conform to the current year's presentation.

REGULATION

Our utility operations within Ontario are regulated by the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under US GAAP for non-rate-regulated entities.

As a result of rate-regulated accounting, we have recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates and amounts collected from customers in advance of costs being incurred. Regulatory assets are assessed for impairment if we identify an event indicative of possible impairment.

The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. The regulator's future actions may differ from current expectations or future legislative changes may impact the regulatory environment in which we operate. To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. We believe that the recovery of our regulatory assets as at December 31, 2021 is probable over the periods described in *Note 5 - Regulatory Matters*.

With the approval of the regulator, certain operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

REVENUE RECOGNITION

Revenue from contracts with customers is generally recognized upon the fulfillment of the performance obligations for the distribution, storage, transportation and sale of natural gas. For distribution and transportation service arrangements, where the services are simultaneously received and consumed by the customer, revenues are recorded based on regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas. Revenues from storage services are recognized as the storage services are provided.

A significant portion of our operations are subject to regulation and, accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue under such circumstances is recognized in a manner that is consistent with the underlying rate-setting mechanism as approved by the regulator. This may give rise to regulatory deferral accounts pending disposition by decisions of the regulator, which are accounted for under Accounting Standards Codification (ASC) 980 *Regulated Operations*.

PUSH-DOWN ACCOUNTING

Enbridge Gas Distribution Inc. (EGD) elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge, when it first adopted US GAAP. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by EGD. Upon adopting push-down accounting, the historical cost of EGD's property, plant and equipment and related accounts were adjusted by the remaining unamortized fair value adjustment.

We have applied push-down accounting with respect to the accounts of Union Gas Limited (Union Gas). The carrying values of certain assets and liabilities of Union Gas transferred to EGD have been adjusted to reflect Enbridge's historical cost as at February 27, 2017, the date upon which Enbridge acquired common control of EGD and Union Gas.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships

We use derivative financial instruments to manage our exposure to changes in interest rates and foreign exchange rates. Hedge accounting is optional and requires us to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. We present the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges or net investment hedges. There were no outstanding derivative instruments relating to fair value or net investment hedges as at December 31, 2021 and 2020.

Cash Flow Hedges
We use cash flow hedges to manage our exposure to changes in interest rates and foreign exchange rates related to our unregulated storage revenue. The change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized in earnings concurrently with the related transaction. If an anticipated hedged transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives
We recognize the fair value of derivative instruments in the Consolidated Statements of Financial Position as current and non-current assets or liabilities depending on the timing of settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities in the Consolidated Statements of Cash Flows.

Balance Sheet Offset
Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when we have the legal right and intention to settle them on a net basis.

Transaction Costs
Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. We incur transaction costs primarily from the issuance of debt and account for these costs as a reduction to Long-term debt in the Consolidated Statements of Financial Position. These costs are amortized using the effective interest rate method over the term of the related debt instrument and are recorded in Interest expense.

INCOME TAXES
Income taxes are accounted for using the liability method. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For our regulated operations, a deferred income tax liability or asset is recognized with a corresponding regulatory asset or liability, respectively, to the extent that taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in Income tax expense.

FOREIGN CURRENCY TRANSACTIONS
Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which Enbridge Gas or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated to the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the exchange rate in effect as at the balance sheet date. Exchange gains and losses resulting from the translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period in which they arise.

CASH
We combine cash and bank indebtedness where the corresponding bank accounts are subject to cash pooling arrangements.

RECEIVABLES AND CURRENT EXPECTED CREDIT LOSSES
Accounts receivable and other are measured at cost. For accounts receivable, a loss allowance matrix is utilized to measure lifetime expected credit losses. The matrix contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations.

NATURAL GAS IMBALANCES
The Consolidated Statements of Financial Position include balances as a result of differences in gas volumes received from, and delivered for, customers. As settlement of certain imbalances is in-kind, changes in the balances do not have an effect on our Consolidated Statements of Earnings or Consolidated Statements of Cash Flows. All natural gas volumes owed to or by us are valued at natural gas market index prices as at the balance sheet dates.

GAS INVENTORY
Gas inventories primarily consist of natural gas held in storage and also include costs such as storage injection and demand costs. Natural gas held in storage is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of gas purchased is deferred as a liability for future refund, or as an asset for collection as approved by the OEB.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment is recorded at historical cost, including an allowance for interest incurred during construction as authorized by the regulator. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit.

The pool method of accounting for property, plant and equipment is followed whereby similar assets with comparable useful lives are grouped and depreciated as a pool, as approved by the regulator. When group assets are retired or otherwise disposed of, gains and losses are generally not reflected in earnings but are booked as an adjustment to accumulated depreciation until the last asset in the pool is disposed of. Gains and losses on the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the regulator, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the regulator.

LEASES
We recognize an arrangement as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. We recognize right-of-use (ROU) assets and the related lease liabilities in the Consolidated Statements of Financial Position for operating lease arrangements with a term of 12 months or longer. We do not separate non-lease components of our lessee contracts and account for both components as a single lease component. We combine lease and non-lease components within a contract for operating lessor leases when certain conditions are met. ROU assets are assessed for impairment using the same approach applied for other long-lived assets.

Lease liabilities and ROU assets require the use of judgment and estimates which are applied in determining the term of a lease, appropriate discount rates, whether an arrangement contains a lease, whether there are any indicators of impairment for ROU assets and whether any ROU assets should be grouped with other long-lived assets for impairment testing.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily consists of costs that regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, including: deferred income taxes; the fair value adjustment to long-term debt; the difference between the actual cost and approved cost of natural gas reflected in rates; and actuarial gains and losses arising from defined benefit pension plans.

INTANGIBLE ASSETS

Intangible assets consist primarily of certain software costs. We capitalize costs incurred during the application development stage of internal use software projects. Intangible assets are generally amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets upon acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. We perform our annual review of the goodwill balance on April 1.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. When performing a qualitative assessment, we determine the drivers of fair value and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, the assessment of macroeconomic trends, regulatory environments, capital accessibility, operating income trends and industry conditions. Based on our assessment of qualitative factors, if we determine it is more likely than not that the fair value is less than its carrying amount, a quantitative goodwill impairment test is performed.

The quantitative goodwill impairment assessment involves determining the fair value of goodwill and comparing that value to its carrying value. If the carrying value, including allocated goodwill, exceeds fair value, goodwill impairment is measured at the amount by which the carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. Fair value is estimated using a discounted cash flow technique. The determination of fair value using the discounted cash flow technique requires the use of estimates and assumptions related to discount rates, projected operating income, terminal value growth rates, capital expenditures and working capital levels. Cash flow projections include significant judgments and assumptions relating to revenue growth rates and expected future capital expenditures.

IMPAIRMENT

We review the carrying values of our long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, we calculate fair value based on the discounted cash flows and write the assets down to the extent that the carrying value exceeds the fair value.

ASSET RETIREMENT OBLIGATIONS

ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. Fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset’s useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

PENSION AND OTHER POSTRETIREMENT BENEFITS

We provide pension benefits through defined benefit and defined contribution pension plans and OPEB, including group health care and life insurance benefits through defined benefit OPEB plans.

Defined benefit pension obligation and net periodic benefit cost are estimated using the projected unit credit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors, including discount rates and mortality. The OPEB benefit obligation and net periodic benefit cost are estimated using the projected unit credit method, where benefits are attributed to years of service, taking into consideration projection of benefit costs.

We use mortality tables issued by the Canadian Institute of Actuaries (revised in 2014) to measure the benefit obligation of our pension plans.

We determine discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments we anticipate making under each of the respective plans.

Funded pension plan assets are measured at fair value. The expected return on funded pension plan assets is determined using market-related values and assumptions on the invested asset mix consistent with the investment policies relating to the plan assets. The market-related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period (for funded pension plans) or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount and salary inflation experience.

The excess of the fair value of a plan's assets over the fair value of a plan's benefit obligation is recognized as Deferred amounts and other assets in the Consolidated Statements of Financial Position. The excess of the fair value of a plan's benefit obligation over the fair value of a plan's assets is recognized as Accounts payable and other and Other long-term liabilities in our Consolidated Statements of Financial Position.

Net periodic benefit cost is charged to earnings and includes:

- cost of benefits provided in exchange for employee services rendered during the year (current service cost);
- interest cost of plan obligations;
- expected return on plan assets (for funded pension plans);
- amortization of prior service costs on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans; and
- amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit OPEB plans are presented as a component of Accumulated other comprehensive loss (AOCI) in our Consolidated Statements of Changes in Equity. Any unrecognized OPEB-related actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax. Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit pension plans, which have been permitted or are expected to be permitted by the regulator, to be recovered through future rates, are presented as a component of Deferred amounts and other assets in our Consolidated Statements of Financial Position.

We also record regulatory adjustments to reflect the difference between certain net periodic benefit costs for accounting purposes and net periodic benefit costs for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent net periodic benefit costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory assets or liabilities would not be recorded and net periodic benefit costs would be charged to earnings and OCI on an accrual basis.

For defined contribution plans, contributions made by us are expensed in the period in which the contribution occurs.

COMMITMENTS AND CONTINGENCIES
Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, we determine it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we recognize the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. We expense legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

CHANGES IN ACCOUNTING POLICIES
There were no changes in accounting policies during the year ended December 31, 2021.

ADOPTION OF NEW ACCOUNTING STANDARDS
Accounting for Contract Assets and Liabilities from Contracts with Customers in a Business Combination
Effective November 1, 2021, we adopted Accounting Standards Update (ASU) 2021-08 on a retrospective basis beginning January 1, 2021. The new standard was issued in October 2021 to amend business combination accounting specific to contract assets and contract liabilities resulting from contracts with customers, requiring measurement in accordance with ASC 606 The ASU is also applicable to contract assets and contract liabilities from other contracts to which ASC 606 applies, such as contract liabilities from the sale of nonfinancial assets within the scope of ASC 610-20. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting for Income Taxes
Effective January 1, 2021, we adopted ASU 2019-12 on a prospective basis. The new standard was issued in December 2019 with the intent of simplifying the accounting for income taxes. The accounting update removes certain exceptions to the general principles in ASC 740 *Income Taxes* as well as provides simplification by clarifying and amending existing guidance. The adoption of this ASU did not have a material impact on our consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES
Disclosures About Government Assistance
ASU 2021-10 was issued in November 2021 to increase the transparency of government assistance to business entities. The ASU adds new disclosure requirements for transactions with government that are accounted for using a grant or contribution accounting model by analogy. The required disclosures include information about the nature of transactions, accounting policy applied, impacted financial statement line items and significant terms and conditions. ASU 2021-10 is effective January 1, 2022 and can be applied either prospectively or retrospectively with early adoption permitted. The adoption of ASU 2021-10 is not expected to have a material impact on our consolidated financial statements.

4. REVENUES

REVENUE FROM CONTRACTS WITH CUSTOMERS
Major Services

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Gas commodity and distribution revenues - residential	**2,778**	2,560
Gas commodity and distribution revenues - commercial and industrial	**1,208**	1,077
Storage revenue	**156**	144
Transportation revenue	**686**	681
Other revenues	**71**	62
Total revenue from contracts with customers	**4,899**	4,524
Other[1]	**(6)**	(9)
Total revenues	**4,893**	4,515

1 Primarily relates to the effects of rate-regulated accounting.

We disaggregate revenues into categories which represent our principal performance obligations. These revenue categories also represent the most significant revenue streams, and consequently are considered to be the most relevant revenue information for management to consider in evaluating performance.

Contract Balances

	Receivables	Contract Liabilities
(millions of Canadian dollars)		
Balance as at December 31, 2021	**824**	**17**
Balance as at December 31, 2020	738	—

Receivables represent an unconditional right to consideration where only the passage of time is required before payment of consideration is due, and consist of trade accounts receivable, unbilled revenue and other accrued receivable balances. Receivables also consist of trade accounts receivable and unbilled revenue balances for the collection of certain federal carbon levy unit rates, for which we act as an agent.

Contract liabilities represent payments received for performance obligations which have not been fulfilled under our equal monthly payment plan. The increase in contract liabilities from cash received, net of amounts recognized as revenues during the year ended December 31, 2021, was $17 million.

Performance Obligations

Revenue category	**Nature of Performance Obligation**
Gas commodity and distribution revenue	• Supply and delivery of natural gas to customers
Storage and transportation revenue	• Storage and transportation of natural gas on behalf of customers
Other revenue	• Other billing and service fees

We recognized a reduction of revenue of $15 million during the year ended December 31, 2021 from performance obligations satisfied in previous periods, primarily resulting from differences in actual and estimated consumption. The associated reduction in gas commodity and distribution costs was also recognized in the current year.

Payment Terms
Payments from distribution customers are received on a continuous basis based on established billing cycles. Our policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. Payments from storage customers are received monthly under long-term storage capacity contracts. Payments from transportation customers are received on a continuous basis based on established billing cycles or monthly under long-term transportation capacity contracts.

Revenue to be Recognized from Unfulfilled Performance Obligations
Total revenue from performance obligations expected to be fulfilled in future periods is $602 million, of which $309 million is expected to be recognized during the year ending December 31, 2022.

The performance obligations above reflect revenues expected to be recognized in future periods from unfulfilled performance obligations pursuant to contracts with customers for the purchase of natural gas distribution, storage and transportation services. Certain revenues are excluded from the amounts above under the following ASC 606 optional exemptions:

- revenues, such as flow-through costs charged to customers, which are recognized at the amount for which we have the right to invoice our customers; and
- revenue from contracts with customers that have an original expected duration of one year or less.

Variable consideration is also excluded from the amounts above due to the uncertainty of the associated consideration, which is generally resolved when actual volumes and prices are determined. For example, we consider interruptible transportation service revenues to be variable revenues since volumes cannot be reasonably estimated.

A significant portion of our operations are subject to regulation. Accordingly, the amounts above, in addition to revenues that are not regulated, only include revenue for which the underlying rate has been approved by regulation, where applicable. The revenues excluded from the amounts above could represent a significant portion of our overall revenues and revenue from contracts with customers.

SIGNIFICANT JUDGMENTS MADE IN RECOGNIZING REVENUE
Revenue Recognition
Revenue from contracts with customers is generally recognized upon the fulfillment of the performance obligations as described above. Distribution and transportation service revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas.

Due to regulatory mechanisms, there are circumstances where revenues recognized do not match the amounts billed. Under such circumstances, revenue is recognized in a manner that is consistent with the underlying rate setting mechanism as approved by the regulator. This may give rise to regulatory deferral accounts pending disposition by decisions of the regulator.

Recognition and Measurement of Revenues

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Revenue from products and services transferred over time[1]	**4,829**	4,464
Revenue from products transferred at a point in time[2]	**70**	60
Total revenue from contracts with customers	**4,899**	4,524

1 Revenue from distribution, storage and transportation services.
2 Primarily from Other revenues.

Performance Obligations Satisfied Over Time
For arrangements involving the distribution and transportation of natural gas, where the services are simultaneously received and consumed by the customer, we recognize revenue over time using an output method based on volumes of commodities delivered. The measurement of the volumes delivered corresponds directly to the benefits received by the customers during that period. Revenue from storage services are recognized as the services are provided.

Determination of Transaction Prices
Prices for distribution and transportation services and regulated storage services are prescribed by regulation. Fees for unregulated storage services are determined through negotiations with customers and are based on market rates.

Prices for natural gas sold are driven by market prices and the Quarterly Rate Adjustment Mechanism (QRAM) in place that allows for rates to reflect changes in natural gas prices, subject to regulatory approval.

5. REGULATORY MATTERS

We record assets and liabilities that result from regulated ratemaking processes that would not be recorded under US GAAP for non-regulated entities. See *Note 2 - Significant Accounting Policies* for further discussion.

We are regulated by the OEB pursuant to the provisions of the *Ontario Energy Board Act*, (1998), which is part of a package of legislation known as the *Energy Competition Act*, (1998). This legislation provides for different forms of regulation and competition in the energy (electricity and natural gas) industry in Ontario.

RATE APPROVALS
Our distribution rates, commencing in 2019, are set under a five-year Incentive Regulation (IR) framework using a price cap mechanism. The price cap mechanism establishes new rates each year through an annual base rate escalation at inflation less a 0.3% stretch factor, annual updates for certain costs to be passed through to customers, and where applicable, the recovery of material discrete incremental capital investments beyond those that can be funded through base rates. The IR framework includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires us to share equally with customers any earnings in excess of 150 basis points over the annual OEB approved return on equity.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following regulatory assets and liabilities in the Consolidated Statements of Financial Position:

December 31,	2021	2020	Recovery/Refund Period Ends
(millions of Canadian dollars)			
Current regulatory assets			
Purchase gas variance[1]	**15**	—	2022
Other current regulatory assets	**67**	117	2022
Total current regulatory assets[2] *(Note 6)*	**82**	117	
Long-term regulatory assets			
Deferred income taxes[3]	**1,532**	1,393	Various
Long-term debt[4] *(Note 10)*	**307**	334	2023-2046
Purchase gas variance[1]	**215**	—	2023
Accounting policy changes[5]	**157**	169	Various
Transition impact of accounting changes[6]	**49**	53	2032
Pension plan receivable[7]	**26**	342	Various
Other long-term regulatory assets	**91**	34	Various
Total long-term regulatory assets[2]	**2,377**	2,325	
Total regulatory assets	**2,459**	2,442	
Current regulatory liabilities			
Purchase gas variance[1]	**—**	153	2021
Other current regulatory liabilities	**61**	73	2022
Total current regulatory liabilities[8] *(Note 9)*	**61**	226	
Long-term regulatory liabilities			
Future removal and site restoration reserves[9]	**1,543**	1,455	Various
Accelerated capital cost allowance	**17**	43	Various
Other long-term regulatory liabilities	**94**	45	Various
Total long-term regulatory liabilities[8]	**1,654**	1,543	
Total regulatory liabilities	**1,715**	1,769	

1 Represents the difference between the actual cost and the approved cost of natural gas reflected in rates. We have been granted OEB approval to refund this balance to, or collect this balance from, customers on a rolling 12 month basis as part of the QRAM process. As part of the January 1, 2022 QRAM application, the recovery of certain balances have been deferred into 2023.

2 Current regulatory assets are included in Accounts receivable and other, while long-term regulatory assets are included in Deferred amounts and other assets.

3 Represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in future regulator-approved rates and recovered from customers. The recovery period depends on the timing of the reversal of temporary differences. In the absence of rate-regulated accounting, this regulatory balance and the related earnings impact would not be recorded.

4 Represents our regulatory offset to the fair value adjustment to debt acquired in Enbridge's merger with Spectra Energy Corp. (Spectra Energy) and pushed down to Enbridge Gas. The offset is viewed as a proxy for the regulatory asset that would be recorded in the event such debt was extinguished at an amount higher than the carrying value.

5 This deferral reflects unamortized accumulated actuarial gains/losses and past service costs incurred by Union Gas, relating to the period up to Enbridge's merger with Spectra Energy, which were previously recorded in AOCI. The amortization of this balance is recognized as a component of accrual-based pension expenses, which are included in Other income and recovered in rates, as previously approved by the OEB.

6 Represents our right to recover costs resulting from the adoption of the accrual basis of accounting for pension and OPEB costs upon transition to US GAAP in 2012. Pursuant to the OEB rate order, the balance as at December 31, 2012 is to be collected in rates over a 20 year period, commencing in 2013.

7 Represents the regulatory offset to our pension liability to the extent that it is expected to be included in regulator-approved future rates and recovered from customers. The settlement period for this balance is not determinable. In the absence of rate-regulated accounting, this regulatory balance and the related pension expense would be recorded in earnings and OCI.

8 Current regulatory liabilities are included in Accounts payable and other, while long-term regulatory liabilities are included in Other long-term liabilities.

9 *Future removal and site restoration reserves consists of amounts collected from customers, with the approval of the OEB, to fund future costs of removal and site restoration relating to property, plant and equipment. These costs are collected as part of the depreciation expense charged on property, plant and equipment that is reflected in rates. The settlement of this balance will occur over the long-term as costs are incurred. In the absence of rate-regulated accounting, depreciation rates would not include a charge for removal and site restoration and costs would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Gas Inventories

Natural gas held in storage is recorded in inventory at the reference prices approved by the OEB in the determination of customers' system supply rates. Included in Gas inventory as at December 31, 2021 is $61 million (2020 - $60 million) related to storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during our off-peak months and charged to gas costs during the peak winter months. In the absence of rate-regulated accounting, these costs would be expensed as incurred, and inventory would be recorded at the lower of cost or market value.

6. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2021**	2020
(millions of Canadian dollars)		
Trade receivables and unbilled revenues, net[1]	**953**	855
Regulatory assets *(Note 5)*	**82**	117
Gas imbalances	**101**	54
Rebillables receivable	**45**	76
Other	**47**	59
	1,228	1,161

1 *Net of allowance for expected credit losses of $55 million as at December 31, 2021 (2020 - $45 million).*

7. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2021**	2020
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas transmission	2.5%	**1,854**	1,752
Gas mains, services and other	2.6%	**13,354**	12,580
Compressors, meters and other operating equipment	4.1%	**3,361**	3,246
Storage	2.7%	**1,065**	950
Land and right-of-way[1]	0.9%	**375**	361
Vehicles, office furniture, equipment and other buildings and improvements	8.4%	**453**	434
Under construction	—%	**263**	177
		20,725	19,500
Accumulated depreciation		**(4,464)**	(4,036)
		16,261	15,464
Unregulated property, plant and equipment			
Gas mains, services and other	10.2%	**13**	13
Compressors, meters and other operating equipment	1.3%	**42**	41
Storage	3.0%	**374**	365
Land and right-of-way[1]	1.5%	**38**	37
Under construction	—%	**37**	30
		504	486
Accumulated depreciation		**(103)**	(84)
		401	402
Property, plant and equipment, net		**16,662**	15,866

1 The measurement of weighted average depreciation rate excludes non-depreciable assets.

Depreciation expense, including amounts collected for future removal and site restoration costs, was $606 million for the year ended December 31, 2021 (2020 - $583 million).

Included within depreciation expense is $22 million in incremental depreciation resulting from push-down accounting for the year ended December 31, 2021 (2020 - $22 million) *(Note 2)*.

8. INTANGIBLE ASSETS

December 31,	**2021**	2020
(millions of Canadian dollars)		
Software and Customer Information System[1]	**515**	654
Less: Accumulated amortization	**(338)**	(480)
Intangible assets, net	**177**	174

1 The weighted average amortization rate for the years ended December 31, 2021 and 2020 was 12.8% and 11.8%, respectively.

Intangible assets include $26 million of work-in-progress as at December 31, 2021 (2020 - $35 million). Amortization expense for intangible assets for the years ended December 31, 2021 and 2020 was $71 million and $72 million, respectively. The following table presents our expected amortization expense associated with existing intangible assets for the years indicated as follows:

	2022	2023	2024	2025	2026
(millions of Canadian dollars)					
Forecast of amortization expense	54	25	20	20	19

9. ACCOUNTS PAYABLE AND OTHER

December 31,	**2021**	2020
(millions of Canadian dollars)		
Trade payables and operating accrued liabilities	**638**	491
Federal carbon program liability	**242**	194
Gas imbalances	**124**	54
Taxes payable	**99**	47
Construction payables and contractor holdbacks	**88**	73
Interest payable	**87**	81
Regulatory liabilities *(Note 5)*	**61**	226
Other	**119**	129
	1,458	1,295

10. DEBT

December 31,	Weighted Average Interest Rate[3]	Maturity	**2021**	2020
(millions of Canadian dollars)				
Medium-term notes	3.8%	2022-2051	**9,010**	8,485
Debentures	9.1%	2024-2025	**210**	210
Commercial paper and credit facility draws	0.5%	2023	**1,515**	1,121
Other[1]			**(49)**	(47)
Fair value adjustment from push down accounting *(Note 2)*			**307**	334
Total debt			**10,993**	10,103
Current maturities			**(126)**	(376)
Short-term borrowings[2]			**(1,515)**	(1,121)
Long-term debt			**9,352**	8,606

1 Primarily unamortized discounts, premiums and debt issuance costs.
2 Weighted average interest rate - 0.5% (2020 - 0.3%).
3 Calculated based on term notes, debentures, commercial paper and credit facility draws outstanding as at December 31, 2021.

As at December 31, 2021, all outstanding debt was unsecured.

CREDIT FACILITIES

We actively manage our bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of our external credit facility at December 31, 2021:

	Maturity	Total Facility	Draws[2]	Available
(millions of Canadian dollars)				
364 day extendible credit facility	2023[1]	**2,000**	**1,515**	**485**

1 Maturity date is inclusive of the one-year term out provision.
2 Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the credit facility.

On July 23, 2021, we extended the term out date of our 364 day extendible credit facility to July 22, 2022, with a maturity date of July 22, 2023.

The credit facility carries a standby fee of 0.1% on the unused portion and the draws bear interest at market rates.

As at December 31, 2021, we have access to Enbridge's demand letter of credit facilities totaling $1.0 billion (2020 - $495 million). As at December 31, 2021, $15 million (2020 - $14 million) of letters of credit were issued by us.

LONG-TERM DEBT ISSUANCES

During the year ended December 31, 2021, we completed the following long-term debt issuances totaling $900 million:

Issue Date		Principal Amount
(millions of Canadian dollars)		
September 2021	2.35% medium-term notes due September 2031	$475
September 2021	3.20% medium-term notes due September 2051	$425

LONG-TERM DEBT REPAYMENT

During the year ended December 31, 2021, we completed the following long-term debt repayment totaling $375 million:

Repayment Date		Principal Amount
(millions of Canadian dollars)		
May 2021	2.76% medium-term notes	$200
December 2021	4.77% medium-term notes	$175

DEBT COVENANTS

Our credit facility agreement and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or terminations of the agreements may result if we were to default on payment or violate certain covenants. We were in compliance with all terms and conditions of our committed credit facility agreement and our Trust Indenture as at December 31, 2021.

INTEREST EXPENSE

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Debentures and term notes	**378**	380
Commercial paper and credit facility draws	**5**	17
Interest on loans from affiliate	**—**	6
Other interest and finance costs	**18**	14
Capitalized interest	**(7)**	(5)
	394	412

11. SHARE CAPITAL

As at December 31, 2021, our authorized share capital consisted of an unlimited number of common shares with no par value and an unlimited number of preference shares. Our Class A and Class B common shares are held by Enbridge Energy Distribution Inc. and Great Lakes Basin Energy LP, respectively. Both classes of common shares are identical in every respect, and dividends cannot be paid to one class without paying dividends to the other. As at December 31, 2021 and 2020, no preference shares were issued and outstanding.

COMMON SHARES

	2021		2020	
December 31,	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of shares in millions)				
Class A				
Balance at beginning of year	**282**	**2,636**	282	2,636
Capital contribution	**—**	**527**	—	432
Return of capital	**—**	**(567)**	—	(432)
	282	**2,596**	282	2,636
Class B				
Balance at beginning of year	**240**	**881**	240	881
Capital contribution	**—**	**448**	—	368
Return of capital	**—**	**(483)**	—	(368)
	240	**846**	240	881
Balance at end of year	**522**	**3,442**	522	3,517

The capital contribution and return of capital transactions to the stated capital of Class A and Class B common shares had no impact on the total shares outstanding.

12. COMPONENTS OF AOCI

Changes in AOCI for the year ended December 31, 2021 and 2020 are as follows:

	2021		
	Cash Flow Hedges	OPEB Adjustment	Total
(millions of Canadian dollars)			
Balance at January 1, 2021	**(64)**	**(14)**	**(78)**
Other comprehensive income retained in AOCI	**29**	**31**	**60**
Other comprehensive loss reclassified to earnings	**17**	**—**	**17**
	(18)	**17**	**(1)**
Tax impact			
Income tax on amounts retained in AOCI	**(8)**	**(9)**	**(17)**
Income tax on amounts reclassified to earnings	**(5)**	**—**	**(5)**
	(13)	**(9)**	**(22)**
Balance at December 31, 2021	**(31)**	**8**	**(23)**

	2020		
	Cash Flow Hedges	OPEB Adjustment	Total
(millions of Canadian dollars)			
Balance at January 1, 2020	(42)	(4)	(46)
Other comprehensive loss retained in AOCI	(49)	(13)	(62)
Other comprehensive loss reclassified to earnings	17	—	17
	(74)	(17)	(91)
Tax impact			
Income tax on amounts retained in AOCI	12	3	15
Income tax on amounts reclassified to earnings	(2)	—	(2)
	10	3	13
Balance at December 31, 2020	(64)	(14)	(78)

13. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK
Our earnings, cash flows and other OCI are subject to movements in natural gas prices, foreign exchange rates and interest rates (collectively, market risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Natural Gas Price Risk
Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by our customers. The difference between the actual cost of natural gas purchased and the price approved by the OEB is deferred as a receivable from, or payable to, customers until it is approved for collection or refund. We have a quarterly rate adjustment mechanism in place that allows for the quarterly adjustment of rates to reflect changes in natural gas prices, and for the establishment of rate riders required to collect or refund gas cost variances. Adjustments are subject to OEB approval.

Foreign Exchange Risk
Foreign exchange risk is the risk of gain or loss due to the volatility of currency exchange rates. We generate certain revenues, incur expenses and hold cash balances that are denominated in United States dollars (USD). As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from USD exchange rate variability.

We have implemented a policy to hedge a portion of our USD denominated unregulated storage revenue exposures. Qualifying derivative instruments are used to hedge anticipated USD denominated revenues and to manage variability in cash flows.

A portion of our natural gas purchases are denominated in USD and, as a result, there is exposure to fluctuations in the exchange rate of the USD against the Canadian dollar. Realized foreign exchange gains and losses relating to natural gas purchases are passed on to customers, therefore, we have no net exposure to movements in the foreign exchange rate on natural gas purchases.

Interest Rate Risk
Our earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps are used to hedge against the effect of future interest rate movements. Current floating-to-fixed interest rate swaps with an average swap rate of 2.3% expire in January 2022.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have implemented a program to mitigate our exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating-to-fixed interest rate swaps with an average swap rate of 1.4%

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the Consolidated Statements of Financial Position location and carrying value of our derivative instruments.

We generally have a common practice of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce our credit risk exposure on derivative asset positions outstanding with these counterparties in those particular circumstances. The following table also summarizes the maximum potential settlement amount in the event of those specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2021	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Deferred amounts and other assets					
Interest rate contracts	**14**	**—**	**14**	**—**	**14**
	14	**—**	**14**	**—**	**14**
Accounts payable to affiliates					
Interest rate contracts	**12**	**—**	**12**	**—**	**12**
	12	**—**	**12**	**—**	**12**
Total net derivative asset					
Interest rate contracts	**26**	**—**	**26**	**—**	**26**
	26	**—**	**26**	**—**	**26**

December 31, 2020	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Deferred amounts and other assets					
Interest rate contracts	8	—	8	(1)	7
	8	—	8	(1)	7
Accounts payable to affiliates					
Interest rate contracts	(43)	—	(43)	—	(43)
	(43)	—	(43)	—	(43)
Other long-term liabilities					
Interest rate contracts	(1)	—	(1)	1	—
	(1)	—	(1)	1	—
Total net derivative liability					
Interest rate contracts	(36)	—	(36)	—	(36)
	(36)	—	(36)	—	(36)

The following table summarizes the maturity and notional principal or quantity outstanding related to our derivative instruments.

December 31, 2021	2022	2023	2024	2025	2026	Thereafter	Total
Foreign exchange contracts - United States dollar forwards - sell *(millions of USD)*	**1**	**—**	**—**	**—**	**—**	**—**	**1**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**18**	**—**	**—**	**—**	**—**	**—**	**18**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**200**	**200**	**—**	**—**	**—**	**—**	**400**

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on our consolidated earnings and comprehensive income, before the effect of income taxes.

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Amount of unrealized gain/(loss) recognized in OCI		
Interest rate contracts	**29**	(49)
	29	(49)
Amount of loss reclassified from AOCI to earnings		
Interest rate contracts[1]	**17**	17
	17	17

1 Reported within Interest expense, net in the Consolidated Statements of Earnings.

We estimate that a gain of $1 million of AOCI related to unrealized cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest and foreign exchange rates in effect when derivative contracts, that are currently outstanding, mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is 24 months as at December 31, 2021.

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments, as they become due. In order to manage this risk, we forecast cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper, draws under the committed credit facility and long-term debt, which includes debentures and medium-term notes and, if necessary, additional liquidity is available through intercompany transactions with our ultimate parent, Enbridge, and other related entities. These sources are expected to be sufficient to enable us to fund all anticipated requirements. We maintain a current medium-term note shelf prospectus with securities regulators, which enables ready access to the Canadian public capital markets, subject to market conditions. We also maintain a committed credit facility with a diversified group of banks and institutions. We were in compliance with all of the terms and conditions of our committed credit facility as at December 31, 2021. As a result, the credit facility is available to us and the banks are obligated to fund us under the terms of the facility.

CREDIT RISK

Credit risk arises from the possibility that a counterparty will default on its contractual obligations. We are primarily exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is mitigated by our large and diversified customer base and the ability to recover an estimate for expected credit losses for utility operations through the rate-making process. We actively monitor the financial strength of large industrial customers and, in select cases, have obtained additional security to minimize the risk of default of receivables. Generally, we classify receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

Our policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which generally require payment in full within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made through the expected credit loss, which totaled $55 million as at December 31, 2021 (December 31, 2020 - $45 million).

Our expected credit loss is determined based on historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations, using a loss allowance matrix. This estimate is revised each reporting period to reflect current expectations. When we have determined that collection efforts are unlikely to be successful, amounts charged to the expected credit loss account are applied against the impaired accounts receivable.

Entering into derivative financial instruments may also result in exposure to credit risk. We enter into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements. As at December 31, 2021, we have $26 million (December 31, 2020 - $8 million) in credit concentrations and credit exposure with Enbridge and its affiliates.

Derivative assets are adjusted for non-performance risk of our counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, our non-performance risk is considered in the valuation.

FAIR VALUE MEASUREMENTS

Our financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. We also disclose the fair value of other financial instruments not measured at fair value. The fair values of financial instruments reflect our best estimates of fair value based on generally accepted valuation techniques or models and are supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

We categorize our derivative instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. We do not have any derivative instruments classified as Level 1.

Level 2
Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps, for which observable inputs can be obtained.

Level 3
Level 3 includes derivative valuations based on inputs which are less observable, unavailable, or where the observable data does not support a significant portion of the derivative's fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support a Level 2 classification. We have developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. We do not have any derivative instruments classified as Level 3.

We use the most observable inputs available to estimate the fair value of our derivatives. When possible, we estimate the fair value of our derivatives based on quoted market prices. If quoted market prices are not available, we use estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, we use standard valuation techniques to calculate the estimated fair value, including discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, we use observable market prices (interest, foreign exchange and natural gas) and volatility as primary inputs to these valuation techniques. Finally, we consider our own credit default swap spread, as well as the credit default swap spreads associated with our counterparties, in our estimation of fair value.

As at December 31, 2021, we had Level 2 derivative assets with a fair value of $26 million (December 31, 2020 - $8 million) and Level 2 derivative liabilities with a fair value of nil (December 31, 2020 - $44 million).

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS
The fair value of our long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor, and is classified as a Level 2 measurement. As at December 31, 2021, our long-term debt, including the current portion, had a carrying value of $9.2 billion (December 31, 2020 - $8.7 billion) before debt issuance costs and a fair value adjustment from push down accounting, and a fair value of $10.4 billion (December 31, 2020 - $10.7 billion).

The fair value of financial assets and liabilities, other than derivative instruments and long-term debt, approximate their carrying value due to the short period to maturity.

14. LEASES

LESSEE
We incur operating lease payments related to natural gas transportation, storage and real estate assets. These lease agreements have remaining lease terms of five months to 16 years, some of which include options to terminate at our discretion.

For the years ended December 31, 2021 and 2020, we incurred operating lease expenses of $8 million and $9 million, respectively. Operating lease expenses are reported within Operating and administrative expense in the Consolidated Statements of Earnings.

For the years ended December 31, 2021 and 2020, operating lease payments made to settle lease liabilities were $9 million and $9 million, respectively. Operating lease payments are reported within Operating activities in the Consolidated Statements of Cash Flows.

Supplemental Consolidated Statements of Financial Position Information

December 31,	**2021**	2020
(millions of Canadian dollars, except lease term and discount rate)		
Operating leases		
Operating lease right-of-use assets, net[1]	**49**	53
Operating lease liabilities - current[2]	**6**	6
Operating lease liabilities - long-term[3]	**43**	47
Total operating lease liabilities	**49**	53
Weighted average remaining lease term		
Operating leases	**8 years**	9 years
Weighted average discount rate		
Operating leases	**3.1%**	3.1%

1 *Right-of-use assets are reported within Deferred amounts and other assets in the Consolidated Statements of Financial Position.*
2 *Current lease liabilities are reported within Accounts payable and other and Accounts payable to affiliates in the Consolidated Statements of Financial Position.*
3 *Long-term lease liabilities are reported within Other long-term liabilities in the Consolidated Statements of Financial Position.*

As at December 31, 2021, we have lease commitments as detailed below:

	Operating leases
(millions of Canadian dollars)	
2022	**8**
2023	**7**
2024	**7**
2025	**7**
2026	**6**
Thereafter	**20**
Total undiscounted lease payments	**55**
Less imputed interest	**(6)**
Total operating lease liabilities	**49**

LESSOR

We receive revenues from operating and sales-type leases primarily related to natural gas equipment and real estate assets. Our lease agreements have remaining lease terms of five years to 20 years as at December 31, 2021.

As at December 31, 2021, the following table sets out future lease payments to be received under operating lease and sales-type lease contracts where we are the lessor:

	Operating leases	Sales-type leases
(millions of Canadian dollars)		
2022	**2**	**1**
2023	**1**	**2**
2024	**1**	**2**
2025	**1**	**2**
2026	**1**	**2**
Thereafter	**2**	**20**
Future lease payments to be received	**8**	**29**

15. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Earnings before income taxes	**614**	555
Canadian federal statutory income tax rate	**15%**	15%
Expected federal taxes at statutory rate	**92**	83
Increase/(decrease) resulting from:		
Provincial and state income taxes	**(1)**	(13)
Effects of rate-regulated accounting[1]	**(54)**	(46)
Part VI.1 tax, net of federal Part I deduction[1]	**30**	41
Other[2]	**(4)**	(7)
Income tax expense	**63**	58
Effective income tax rate	**10.3%**	10.5%

1 The provincial tax component of these items is included in Provincial and state income taxes above.
2 Includes miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals and entertainment and a change in prior year estimates arising from the filing of tax returns in respect of the prior year.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Earnings before income taxes		
Canada	**614**	555
	614	555
Current income taxes		
Canada	**78**	84
United States	**—**	(1)
	78	83
Deferred income taxes		
Canada	**(15)**	(25)
	(15)	(25)
Income tax expense	**63**	58

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:

December 31,	**2021**	2020
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(1,697)**	(1,586)
Regulatory assets	**(409)**	(368)
Deferrals	**(8)**	(10)
Pension and OPEB plans	**(14)**	(13)
Other	**(7)**	(2)
Total deferred income tax liabilities	**(2,135)**	(1,979)
Deferred income tax assets		
Future removal and site restoration reserves	**413**	391
Minimum tax credits	**44**	40
Financial instruments	**12**	24
Other	**—**	2
Total deferred income tax assets	**469**	457
Net deferred income tax liabilities	**(1,666)**	(1,522)

Enbridge Gas is subject to taxation in Canada. The material jurisdiction in which we are subject to potential examinations is Canada (Federal and Ontario). We are open to examination by Canadian tax authorities for 2012 to 2021 tax years, and are currently under examination for income tax matters in Canada for 2017 to 2018 tax years.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**34**	39
Gross decreases for tax positions of prior year	**(16)**	(2)
Lapses of statute of limitations	**(3)**	(3)
Unrecognized tax benefits at end of year	**15**	34

The unrecognized tax benefits as at December 31, 2021, if recognized, would impact our effective income tax rate. We do not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on our consolidated financial statements.

We recognize accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Income taxes for the years ended December 31, 2021 and 2020 included no amounts of interest and penalties. As at December 31, 2021 and 2020, interest and penalties of nil and $1 million have been accrued.

16. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

We provide pension benefits, covering substantially all employees, through contributory and non-contributory registered defined benefit and defined contribution pension plans. We also provide non-registered pension benefits for certain employees through supplemental non-contributory defined benefit pension plans.

Defined Benefit Pension Plan Benefits

Benefits payable from the defined benefit pension plans are based on each plan participant's years of service and final average remuneration. Some benefits are partially inflation-indexed after a plan participant's retirement. Our contributions are made in accordance with independent actuarial valuations. Participant contributions to contributory defined benefit pension plans are based upon each plan participant's current eligible remuneration.

Defined Contribution Pension Plan Benefits

Our contributions are based on each plan participant's current eligible remuneration. Our contributions for some defined contribution pension plans are also based on age and years of service. Our defined contribution pension benefit costs are equal to the amount of contributions required to be made by us.

OTHER POSTRETIREMENT BENEFIT PLANS

We provide non-contributory supplemental health, dental, life and health spending account benefit coverage for certain qualifying retired employees, through unfunded defined benefit OPEB plans.

BENEFIT OBLIGATIONS, PLAN ASSETS AND FUNDED STATUS

The following table details the changes in the benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit pension and OPEB plans:

	Pension		OPEB	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Change in benefit obligation				
Benefit obligation at beginning of year	**2,532**	2,331	**186**	170
Service cost	**63**	68	**3**	3
Interest cost	**51**	66	**4**	5
Participant contributions	**13**	15	**—**	—
Actuarial (gain)/loss[1]	**(161)**	160	**(31)**	13
Benefits paid	**(112)**	(108)	**(5)**	(5)
Benefit obligation at end of year[2]	**2,386**	2,532	**157**	186
Change in plan assets				
Fair value of plan assets at beginning of year	**2,219**	2,108	**—**	—
Actual return on plan assets	**258**	152	**—**	—
Employer contributions	**37**	52	**5**	5
Participant contributions	**13**	15	**—**	—
Benefits paid	**(112)**	(108)	**(5)**	(5)
Fair value of plan assets at end of year	**2,415**	2,219	**—**	—
Overfunded/(underfunded) status at end of year	**29**	(313)	**(157)**	(186)
Presented as follows:				
Deferred amounts and other assets	**164**	35	**—**	—
Accounts payable and other	**(3)**	(3)	**(7)**	(7)
Other long-term liabilities	**(132)**	(345)	**(150)**	(179)
	29	(313)	**(157)**	(186)

1 Primarily due to increase in the discount rate used to measure the benefit obligations (2020 - primarily due to decrease in the discount rate used to measure the benefit obligations).

2 For pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. The accumulated benefit obligation for our pension plans was $2.2 billion and $2.4 billion as at December 31, 2021 and 2020, respectively.

Certain of our pension plans have accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the accumulated benefit obligation and fair value of plan assets were as follows:

December 31,	**2021**	2020
(millions of Canadian dollars)		
Accumulated benefit obligation	**253**	1,963
Fair value of plan assets	**181**	1,767

Certain of our pension plans have projected benefit obligations in excess of the fair value of plan assets. For these plans, the projected benefit obligation and fair value of plan assets were as follows:

December 31,	**2021**	2020
(millions of Canadian dollars)		
Projected benefit obligation	**895**	2,115
Fair value of plan assets	**760**	1,767

AMOUNT RECOGNIZED IN ACCUMULATED OTHER COMPREHENSIVE INCOME

The amount of pre-tax AOCI relating to our OPEB plans are as follows:

December 31,	**2021**	2020
(millions of Canadian dollars)		
Net actuarial (gain)/loss	**(13)**	18
Total amount recognized in AOCI	**(13)**	18

NET PERIODIC BENEFIT COST AND OTHER AMOUNTS RECOGNIZED IN COMPREHENSIVE INCOME

The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to our pension and OPEB plans are as follows:

	Pension		OPEB	
Year ended December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Service cost	**63**	68	**3**	3
Interest cost[1]	**51**	66	**4**	5
Expected return on plan assets[1]	**(131)**	(136)	**—**	—
Amortization of net actuarial loss[1,2]	**28**	20	**—**	—
Net periodic benefit cost	**11**	18	**7**	8
Defined contribution benefit cost	**2**	2	**—**	—
Net pension and OPEB cost recognized in Earnings	**13**	20	**7**	8
Amount recognized in OCI:				
Net actuarial (gain)/loss arising during the year	**—**	—	**(31)**	13
Total amount recognized in OCI	**—**	—	**(31)**	13
Total amount recognized in Comprehensive income	**13**	20	**(24)**	21

1 Reported within Other income/(expense) in the Consolidated Statements of Earnings.
2 Reflects amortization of net actuarial loss arising from pension plans that are recognized as long-term regulatory assets (Note 5).

ACTUARIAL ASSUMPTIONS

The weighted average assumptions made in the measurement of the benefit obligation and net periodic benefit cost of our defined benefit pension and OPEB plans are as follows:

	Pension		OPEB	
	2021	2020	**2021**	2020
Benefit obligations				
Discount rate	**3.2%**	2.6%	**3.2%**	2.6%
Rate of salary increase	**2.9%**	2.3%	**3.0%**	2.4%
Net benefit cost				
Discount rate	**2.6%**	3.1%	**2.6%**	3.1%
Rate of return on plan assets	**6.0%**	6.5%	**N/A**	N/A
Rate of salary increase	**2.3%**	3.2%	**2.4%**	3.3%

ASSUMED HEALTH CARE COST TREND RATES

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	2021	2020
Health care cost trend rate assumed for next year	**4.0%**	4.0%
Rate to which the cost trend is assumed to decline (ultimate trend rate)	**4.0%**	4.0%

PLAN ASSETS

We manage the investment risk of our pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) our operating environment and financial situation and our ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets.

The overall expected rate of return on plan assets is based on the asset allocation targets with estimates for returns based on long-term expectations.

The asset allocation targets and major categories of plan assets are as follows:

	Target	December 31,	
Asset Category	**Allocation**	**2021**	2020
Equity securities	**40.9%**	**44.9%**	46.3%
Fixed income securities	**34.8%**	**32.2%**	31.9%
Alternatives[1]	**24.3%**	**22.9%**	21.8%

1 Alternatives include investments in private debt, private equity, infrastructure and real estate funds. Fund values are based on the net asset value of the funds that invest directly in the aforementioned underlying investments. The values of the investments have been estimated using the capital accounts representing the plan's ownership interest in the funds.

The following table summarizes the fair value of plan assets for our pension plans recorded at each fair value hierarchy level:

	2021				2020			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Cash and cash equivalents	**42**	**—**	**—**	**42**	50	—	—	50
Equity securities								
Canada	**110**	**123**	**—**	**233**	103	111	—	214
Global	**—**	**853**	**—**	**853**	—	813	—	813
Fixed income securities								
Government	**141**	**294**	**—**	**435**	125	249	—	374
Corporate	**—**	**300**	**—**	**300**	—	284	—	284
Alternatives[4]	**—**	**—**	**552**	**552**	—	—	466	466
Forward currency contracts	**—**	**—**	**—**	**—**	—	18	—	18
Total pension plan assets at fair value	**293**	**1,570**	**552**	**2,415**	278	1,475	466	2,219

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

December 31,	**2021**	2020
(millions of Canadian dollars)		
Balance at beginning of year	**466**	427
Unrealized and realized gains/(losses)	**49**	(3)
Purchases and settlements, net	**37**	42
Balance at end of year	**552**	466

EXPECTED BENEFIT PAYMENTS

Year ending December 31,	2022	2023	2024	2025	2026	2027-2031
(millions of Canadian dollars)						
Pension	113	115	117	119	120	628
OPEB	7	7	7	7	7	38

EXPECTED EMPLOYER CONTRIBUTIONS

In 2022, we expect to contribute approximately $41 million and $7 million to the pension plans and OPEB plans, respectively.

For the year ended December 31, 2020, we incurred $74 million in severance costs related to Enbridge's voluntary workforce reduction program. For the year ended December 31, 2021, there were no such costs incurred. Severance costs are presented in Operating and administrative expense in the Consolidated Statements of Earnings.

17. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Accounts receivable and other	**(14)**	50
Accounts receivable from affiliates	**(27)**	(46)
Regulatory assets	**(222)**	156
Gas inventory	**(242)**	(39)
Deferred amounts and other assets	**(2)**	10
Accounts payable and other	**196**	(55)
Accounts payable to affiliates	**(4)**	(40)
Regulatory liabilities	**(140)**	54
Other long-term liabilities	**(18)**	(12)
	(473)	78

18. RELATED PARTY TRANSACTIONS

All related party transactions are provided in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. Affiliates refer to Enbridge and companies that are either directly or indirectly owned by Enbridge.

Enbridge and its affiliates perform centralized corporate functions for us pursuant to applicable agreements, including legal, accounting, compliance, treasury, employee benefits, information technology and other areas, as well as certain engineering and other services. We reimburse Enbridge for the expenses incurred to provide these services as well as for other expenses incurred on our behalf. In addition, we perform services and incur expenses on behalf of our affiliates, which are subsequently reimbursed. Our expenses and recoveries for these services are recorded in Operating and administrative expense in the Consolidated Statements of Earnings, and are based on the cost of actual services provided or using various allocation methodologies.

Our transactions with entities related through common or joint control and significantly influenced investees are as follows:

Year ended December 31, 2021	Operating revenues	Gas commodity and distribution costs	Operating and administrative expense	Other Income	Interest income
(millions of Canadian dollars)					
Enbridge Inc.	**—**	**—**	**153**	**5**	**2**
Tidal Energy Marketing Inc.	**18**	**16**	**—**	**—**	**—**
Tidal Energy Marketing (U.S.) LLC	**—**	**31**	**—**	**—**	**—**
Gazifère Inc.	**30**	**—**	**—**	**—**	**—**
Énergir, L.P.[1]	**35**	**—**	**—**	**—**	**—**
Vector Pipeline, L.P.	**—**	**20**	**—**	**—**	**—**
NEXUS Gas Transmission, LLC	**—**	**111**	**—**	**—**	**—**
Lakeside Performance Gas Services Ltd.	**—**	**—**	**19**	**—**	**—**
Other affiliates, net	**2**	**3**	**9**	**—**	**—**

1 The minority interest in the parent of Energir L.P. held by a subsidiary of Enbridge was sold on December 30, 2021.

Year ended December 31, 2020	Operating revenues	Gas commodity and distribution costs	Operating and administrative expense	Other Income	Interest income/ (expense)
(millions of Canadian dollars)					
Enbridge Inc.	—	—	131	6	14
Westcoast Energy Inc.	—	—	—	—	(6)
Tidal Energy Marketing Inc.	11	13	—	—	—
Tidal Energy Marketing (U.S.) LLC	—	18	—	—	—
Gazifère Inc.	26	—	—	—	—
Énergir, L.P.	37	—	—	—	—
Vector Pipeline, L.P.	—	19	—	—	—
NEXUS Gas Transmission, LLC	—	116	—	—	—
Other affiliates, net	2	3	7	—	—

Amounts due from/(to) related parties are as follows:

December 31,	**2021**	2020
(millions of Canadian dollars)		
Enbridge Employee Services Canada Inc.	**(61)**	(38)
NEXUS Gas Transmission, LLC	**(9)**	(10)
Enbridge Pipelines Inc.	**35**	45
Union Energy Solutions Limited Partnership	**28**	29
Gazifère Inc.	**25**	6
Tidal Energy Marketing Inc.[3]	**19**	—
Enbridge Inc.[1]	**18**	(68)
Other affiliates, net[2,3]	**—**	1
	55	(35)

1 Includes net qualifying interest cash flow hedges receivable and net derivative receivable balances from affiliate.
2 Includes current portion of operating lease liabilities to affiliates.
3 Includes affiliate gas imbalance receivable. As at December 31, 2021 total affiliate gas imbalance receivable was $23 million (2020 - nil).

SHARE CAPITAL
During the year ended December 31, 2021, common share dividends declared on our Class A and Class B common shares were $108 million (2020 - $243 million) and $92 million (2020 - $207 million), respectively. During 2020, we also completed the return of capital transactions, and received capital contributions, as described in *Note 11 - Share Capital*.

FINANCING TRANSACTION
On April 1, 2020, we repaid the outstanding $650 million subordinated promissory note, as well as the related interest payable, due to Westcoast Energy Inc.

GAS METER SERVICES
We purchase gas meter services from Lakeside Performance Gas Services Ltd. (Lakeside), such as ongoing meter exchanges and inspections for customers in our franchise area. As of December 1, 2020, Lakeside became an affiliate. In 2021, we purchased gas meter services from Lakeside totaling $52 million, a portion of which was expensed to Operating and administrative expense and the remainder capitalized in Property, plant and equipment. We will continue purchasing these services at prevailing market prices under normal trade terms.

HYDRO EXCAVATION SERVICES
We purchase hydro excavation and specialty gas services from Ontario Excavac Inc. (OE). As of July 31, 2021, OE became an affiliate. We will continue purchasing these services at prevailing market prices under normal trade terms.

WHOLESALE SERVICES
We provide gas procurement and transportation services to Gazifère Inc., an affiliate, pursuant to a contract negotiated between us and approved by the OEB and Régie de l'énergie.

LEASES
We incur operating lease payments related to natural gas transportation and storage services from various affiliates. Total affiliate right-of-use assets and lease liabilities as at December 31, 2021 were $48 million (2020 - $51 million) and $48 million (2020 - $51 million), respectively. See *Note 14 - Leases* for further discussion.

DERIVATIVE INSTRUMENTS
As at December 31, 2021, we had a net receivable balance of $26 million (2020 - $36 million payable) due from Enbridge in respect of derivative instruments that they have entered into on our behalf. See *Note 13 - Risk Management and Financial Instruments* for further discussion.

OTHER
Our cash balances are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

19. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As at December 31, 2021, we have commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Annual debt maturities[1]	9,220	125	350	300	745	650	7,050
Interest obligations[2]	5,681	370	367	351	336	300	3,957
Purchase of services, pipe and other materials, including transportation[3,4]	6,050	1,998	757	525	473	437	1,860
Right-of-way commitments[5]	668	11	11	11	11	11	613
Total	21,619	2,504	1,485	1,187	1,565	1,398	13,480

1 *Includes debentures and term notes, and excludes short-term borrowings, debt discounts, debt issuance costs, finance lease obligations and the fair value adjustment from push-down accounting. Changes to the planned funding requirements are dependent on the terms of any debt refinancing agreements. Therefore, the actual timing of future cash repayments could be materially different than presented above.*

2 *Includes debentures and term notes bearing interest at fixed rates.*

3 *Includes firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage; contractual obligations to purchase physical quantities of natural gas; and customer care services.*

4 *Includes capital and operating commitments.*

5 *Includes right-of-way payments related to cancellable gas storage payments that are reasonably likely to occur for the remaining life of all storage reservoirs.*

ENVIRONMENTAL

We are subject to various federal, provincial and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on us.

Environmental risk is inherent to natural gas pipeline operations, and we are, at times, subject to environmental remediation at various contaminated sites. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, we will be responsible for payment of liabilities arising from environmental incidents associated with our operating activities.

Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. We were named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by us for the operation of our MGP.

While these Statements of Claim were filed by the City and the School Board, they were never formally served on us. It was and remains our understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, we entered into an agreement with the City (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with us. To our knowledge, neither the City nor the School Board has taken any steps to advance the lawsuits.

Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time, as there are a number of potential alternative remediation, isolation and containment approaches which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the US for the recovery in rates of costs relating to the remediation of former MGP sites. From 2006 to 2018, the OEB approved the establishment of deferral accounts to record the costs of investigating, defending and dealing with ongoing MGP-related claims. We expect that if it is found that we must contribute to any remediation costs, either as a result of a lawsuit or government order, we may be generally allowed to recover in rates those substantial costs not recovered through insurance or by other means. Accordingly, we believe that the ultimate outcome of these matters will not have a significant impact on our financial position.

Hamilton Contaminated Site

In April 2016, the Ontario Ministry of the Environment, Conservation and Parks (MECP), formerly the Ministry of the Environment and Climate Change, issued a Director's Order (the Order) naming us, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of ours in Hamilton. In May 2016, we appealed the Order, and in June 2016, the Environmental Review Tribunal (the Tribunal), on consent of the MECP's Director, stayed the application of parts of the Order. The Tribunal extended the stay of the Order several times, which allowed the owner of the property, with the cooperation of the adjacent owners, to prepare a plan of action, including discussions with the MECP and other neighbors. On February 4, 2021, the MECP determined that we and other parties have complied with the Order and no further obligations are outstanding. Accordingly, we withdrew our appeal, and the Tribunal has accepted the withdrawal and has closed its file.

OTHER LITIGATION

We are subject to various legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations.

TAX MATTERS

We maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

20. GUARANTEES

In the normal course of conducting business, we may enter into agreements which indemnify third parties and affiliates. We may also be a party to agreements with subsidiaries, jointly owned entities, unconsolidated entities such as equity method investees, or entities with other ownership arrangements that require us to provide financial and performance guarantees. Financial guarantees include stand-by letters of credit, debt guarantees, surety bonds and indemnifications. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included in our Consolidated Statements of Financial Position. Performance guarantees require us to make payments to a third party if the guaranteed entity does not perform on its contractual obligations, such as debt agreements, purchase or sale agreements, and construction contracts and leases.

We typically enter into these arrangements to facilitate commercial transactions with third parties. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities and litigation and contingent liabilities. We may indemnify third parties for certain liabilities relating to environmental matters arising from operations prior to the purchase or transfer of certain assets and interests. Similarly, we may indemnify the purchaser of assets for certain tax liabilities incurred while we owned the assets, a misrepresentation related to taxes that result in a loss to the purchaser or other certain tax liabilities related to those assets.

The likelihood of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. We cannot reasonably estimate the total maximum potential amounts that could become payable to third parties and affiliates under such agreements described above; however, historically, we have not made any significant payments under guarantee or indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the guarantee or indemnification obligation, there are circumstances where the amount and duration are unlimited. As at December 31, 2021, guarantees and indemnifications have not had, and are not reasonably likely to have, a material effect on our financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit E, Tab 1, Page 5, Table 3

Preamble:

We would like to understand better how the allocation of cost for UDC for Union South was determined

Question(s):

Please provide tables of planned versus actual delivered gas by path for each month of 2021 for the Union Rate. Please ensure that the paths include Dawn discretionary purchases for each month.

a) Path
b) Planned Quantity
c) Actual Quantity

Response:

As outlined in Exhibit E, Tab 1, pages 2 and 3, “The path released does not determine where the UDC costs or associated revenue for the releases will be allocated…… Actual UDC costs are allocated to Union North West, Union North East and Union South in proportion to the actual supply and demand variances which occurred in each respective area.” Therefore, the information requested by FRPO will not enable the understanding that is sought in the preamble. However, Enbridge Gas has provided information below to be as responsive as possible.

Table 1 provides planned and actual supply volumes by purchase location for the Union rate zone. Enbridge Gas records actual supply purchases by purchase location and rate zone, and therefore is unable to provide the requested information by individual transportation path.

Table 1

Union Rate Zone Planned and Actual Supply Volumes by Purchase Location

	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
Planned (TJ)												
Appalachia (1)	4,906	4,431	4,906	4,748	4,906	4,748	4,906	4,906	4,748	4,906	4,748	4,906
Chicago (2)	2,617	2,363	2,617	2,532	2,617	2,532	2,617	2,617	2,532	2,617	3,165	3,271
Dawn (3)	4,585	4,287	3,577	3,806	4,906	3,314	4,287	3,758	4,183	4,906	4,939	5,104
Niagara Region (4)	654	591	654	633	654	633	654	654	633	654	633	654
U.S. Mid-Continent (5)	1,864	1,684	1,864	1,804	1,864	1,804	1,864	1,864	1,804	1,864	1,804	1,864
WCSB (6)	2,408	2,087	571	2,443	3,645	2,401	3,008	1,236	1,816	2,767	3,076	3,575
Actual (TJ)												
Appalachia	4,906	4,431	4,904	4,719	4,729	4,715	4,847	4,906	4,748	2,110	4,510	4,876
Chicago	2,617	2,363	2,617	1,899	1,962	1,899	1,962	2,617	1,899	1,960	3,162	3,271
Dawn	4,717	4,264	2,289	2,653	3,309	3,468	3,915	2,231	3,393	2,522	4,234	3,873
Niagara Region	654	591	654	633	654	633	653	654	633	274	316	654
U.S. Mid-Continent	1,864	1,671	1,864	1,804	1,864	1,804	1,864	1,864	1,804	1,864	1,804	1,864
WCSB	3,015	2,729	2,859	2,716	2,307	1,890	1,716	1,751	1,942	2,708	2,965	3,068

Notes:

1- Appalachia includes gas purchased at Clarington and Kensington and flows on NEXUS pipeline to Dawn.
2- Chicago includes gas purchased at Chicago and flows on Vector pipeline to Dawn.
3- Dawn is gas purchased at Dawn for use in Union South and transported to Enbridge rate zone and Union North East using Enbridge Gas and TCPL pipelines.
4- Niagara Region includes gas purchased at Niagara and Chippawa and flows on TCPL pipeline to Enbridge CDA and Dawn.
5- U.S. Mid-Continent includes gas purchased at Panhandle Field Zone and flows on Panhandle Eastern pipeline to Dawn.
6- WCSB includes gas purchased at AECO and Empress and flows on the TCPL Mainline to Union North delivery areas, Enbridge EDA, and Enbridge CDA, and on both TCPL Mainline and Great Lakes pipeline to Dawn.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit E, Tab 1, page 9 and Schedule 2 and
EB-2020-0134 Exhibit I. FRPO.19, .20 &.21
EB-2021-0149 Exhibit I.FRPO.20 & .21 and Decision on Settlement Proposal, Schedule 1, Settlement Proposal, page16

Preamble:

In the first reference, EGI evidence states: "*The C1 Short-Term Firm Peak Storage revenues of $1.536 million were $6.347million lower than the 2013 Board-approved forecast of $7.883 million. Actual Union rate zone utility storage requirements for 2021 were 8.3 PJ higher than the 2013 OEB-approved forecast, resulting in a decrease in the C1 Short-Term Firm Peak Storage available for sale (from 11.3 PJ in 2013 OEB-approved to 3.0 PJ in 2021). 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.*

The second references were interrogatories posed by FRPO in last year's deferral proceeding which yielded the values of storage space and deliverability but not the process of determination including the data requested.

In the third reference, the Board-approved settlement agreement stated: *In connection with the settlement of this issue, Enbridge Gas agrees that in future deferral and variance account clearance applications during the deferred rebasing term it will include evidence about the determination of storage space and deliverability by rate class.*

We would like to understand better the determination of storage needs to in-franchise customers in the Union Gas rate zones and the ST Storage Deferral Account. We have been pursuing the company's approach to determination of the storage space and deliverability required including the data used. However, we have not received more than "Board-approved methodologies". We are asking again for a description of the determination and the data used for that determination. To be clear, stating that the numbers are for the Winter of 2021/22 or the 2021 Gas Supply plan is not helpful.

Question(s):

For the winters used to determine the needs used in this application, please provide a description of the process, the figures used and derivation of the amount of the following in tabular form with accompanying Excel spreadsheets for:

a) the determination of the storage space for each general service rate class

b) the determination of the amount of deliverability required by each general service rate class

Response:

a) The storage space forecast is based on the needs for sales service and bundled customers calculated using the aggregate excess methodology at a rate zone level. Storage space needs for semi-unbundled and Union North T-Service customers is forecast based on the contracted or reserved storage space needs by customer. Aggregate excess is calculated as the total winter demand (the 151 days of winter from November 1 to March 31) less the total average demands multiplied by 151.

Table 1 provides the derivation of total 2021 storage space.

Table 1
2021 Storage Space

Line No.	Particulars (PJ)	Rate Zone EGD	Rate Zone Union North	Rate Zone Union South	Total
	Aggregate Excess				
1	Winter Demand	319.2	40.8	151.0	511.0
2	Annual Demand	467.1	58.7	229.7	755.5
3	Aggregate Excess (1)	125.8	16.5	56.0	198.4
	Customer Contracted/				
4	Reserved Storage Space	-	1.0	14.0	15.0
5	Total by Rate Zone	125.8	17.5	70.0	213.3
6	Excess Utility Storage Space				3.0
7	System Integrity Storage Space				9.5
8	Total Storage Space				225.8

Notes:
(1) Aggregate excess calculated as Line 1 - (Line 2 x 151/365).

The allocation of storage space to rate classes, including general service rate classes, is not prepared on an annual basis. For purposes of providing the rate class level detail at Exhibit E, Tab 1, Schedule 2, Appendix A, Enbridge Gas used the most recently available rate class allocation of storage space from the 2018 cost allocation study for the EGD rate zone and from the 2019 cost allocation study filed by Union in its 2020 Rates[1] application for the Union rate zones. The storage space allocation within each cost allocation study used the aggregate excess methodology as described above but at the individual rate class level.

b) For the EGD rate zone, the storage deliverability forecast is based on the cost-based storage deliverability of Tecumseh and Crowland storage plus the storage deliverability provided through market-based storage contracts.

For the Union rate zones, the storage deliverability forecast is calculated as the excess of sales service, bundled and semi-unbundled customer design day demand over design day deliveries.

Table 2 provides the derivation of total 2021 storage deliverability.

Table 2
2021 Storage Deliverability

		Rate Zone			
Line No.	Particulars (GJ/d)	EGD (1)	Union North	Union South	Total
1	Design Day Demands		467,280	3,288,587	
2	Design Day Deliveries		(157,876)	(1,351,971)	
3	Total	2,198,296	309,405	1,873,036	4,380,737
4	Excess Utility Storage Space Deliverability (2)				35,816
5	Total Deliverability (3)				4,416,553

Notes:
(1) EGD total storage deliverability calculated as 1,920,948 GJ/d of cost-based storage deliverability plus 277,348 GJ/d of market-based storage deliverability.
(2) Calculated as 1.2% of excess utility storage space.
(3) The in-franchise storage deliverability in Table 2 reflects the utilization by Regulated customers but does not reflect allocated costs affirmed in EB-2011-0038.

[1] EB-2019-0194.

The allocation of deliverability to rate classes, including general service rate classes, is not prepared on an annual basis. For purposes of providing the rate class level detail at Exhibit E, Tab 1, Schedule 2, Appendix A, Enbridge Gas used the most recently available rate class allocation of storage deliverability from the 2018 cost allocation study for the EGD rate zone and from the 2019 cost allocation study filed by Union in its 2020 Rates[2] application for the Union rate zones. The storage deliverability allocation to EGD rate classes was based on the rate class contribution of the excess of peak day requirements over average winter demand and the allocation to Union rate classes was based on the excess of design day demand over design day deliveries at the individual rate class level.

[2] EB-2019-0194.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit E, Tab 1, page 9 and Schedule 2 and
EB-2020-0134 Exhibit I. FRPO.19, .20 &.21
EB-2021-0149 Exhibit I.FRPO.20 & .21 and Decision on Settlement Proposal, Schedule 1, Settlement Proposal, page16

Preamble:

In the first reference, EGI evidence states: "*The C1 Short-Term Firm Peak Storage revenues of $1.536 million were $6.347million lower than the 2013 Board-approved forecast of $7.883 million. Actual Union rate zone utility storage requirements for 2021 were 8.3 PJ higher than the 2013 OEB-approved forecast, resulting in a decrease in the C1 Short-Term Firm Peak Storage available for sale (from 11.3 PJ in 2013 OEB-approved to 3.0 PJ in 2021). 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.*

The second references were interrogatories posed by FRPO in last year's deferral proceeding which yielded the values of storage space and deliverability but not the process of determination including the data requested.

In the third reference, the Board-approved settlement agreement stated: *In connection with the settlement of this issue, Enbridge Gas agrees that in future deferral and variance account clearance applications during the deferred rebasing term it will include evidence about the determination of storage space and deliverability by rate class.*

We would like to understand better the determination of storage needs to in-franchise customers in the Union Gas rate zones and the ST Storage Deferral Account. We have been pursuing the company's approach to determination of the storage space and deliverability required including the data used. However, we have not received more than "Board-approved methodologies". We are asking again for a description of the determination and the data used for that determination. To be clear, stating that the numbers are for the Winter of 2021/22 or the 2021 Gas Supply plan is not helpful.

Question(s):

a) Please provide EGI policy and practice regarding the determination of allocations of space and deliverability for general service in-franchise customers. To be more specific, we are asking for references to the policies and practices, approved by the Board for both Legacy Union Gas and Legacy Enbridge Gas.

Response:

For the EGD rate zone, a description of the OEB-approved methodology used to allocate space and deliverability costs is described in support of the Company's 2018 cost allocation study at EB-2017-0086, Exhibit G2, Tab 1, Schedule 1, page 27 an excerpt of which is reproduced below. The OEB approved EGD's application on December 7, 2017.

Appendix B ALLOCATION FACTORS		
	Col. 1	Col. 2
Allocator	Units	Description
Storage Factors		
Deliverability	10^6 m³ /d	Demand in excess of average winter demand.
Space	10^6 m³	Average winter requirement in excess of average annual demand.

For the Union rate zones, a description of the OEB-approved methodology used to allocate space and deliverability costs is described in support of the Company's 2013 cost allocation study at EB-2011-0210, Exhibit G3, Tab 1, Schedule 1, pages 11 to 13 an excerpt of which is reproduced below. The OEB approved Union's application on October 24, 2012.

> Demand from storage on design day is the excess of customers' design day demand over design day deliveries to Union's system. Design day deliveries are estimated for each firm sales and bundled-T rate class based upon the ratio of the average day for the class divided by the total average day of firm classes.
>
> Storage space costs are attributable to the storage capacity required for the movement of the deficiency of customers' summer use from average over to the winter season. For Union South, the excess of the winter period use (January-March and November-December) compared to the average annual use for the same 151-day period is calculated for each in-franchise sales and bundled-T rate class. This is referred to as the "Aggregate Excess". Costs are allocated to customers in Union North using excess peak over annual average demand (i.e., the difference between what a rate class takes on an average day and what it requires on its peak day).

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 3, Page 1 and
EB-2021-0149 Exhibit I.FRPO.24

Preamble:

The first reference provides a table entitled SUMMARY OF NON-UTILITY STORAGE BALANCES - UNION RATE ZONES that depicts an entitlement of 127.6PJ with daily balances.

The second reference response included: As posted on the Enbridge Gas website under operational information/storage reporting, the working capacity of Legacy Union Gas is 183.7 PJ of which 100 PJ is utility (as per NGEIR). The working capacity of Legacy Enbridge Gas is 122.9 PJ of which 99.4 PJ is utility (as per NGEIR).

We would like to understand the evidence provided and the actual balances in relation to the encroachment directives of the Board.

Question(s):

Please confirm or correct the title of the slide that specifies "Union Rate Zones".

a) For the 127.6 PJ, please provide the sources of non-utility space between:
    i) Legacy Union Gas
    ii) Legacy Enbridge Gas
    iii) Other sources

Response:

The title of the slide should be "Summary of Non-Utility Storage Balances".

a) As posted on the Enbridge Gas website[1] under operational information/storage reporting, the working capacity of Legacy Union Gas is 184.5 PJ of which 100 PJ is utility (as per NGEIR). The working capacity of Legacy Enbridge Gas is 126.8 PJ of which 99.4 PJ is utility (as per NGEIR). The remaining space is from other sources.

[1] Enbridge Gas Inc. Operational Information-Storage Reporting. https://www.enbridgegas.com/storage-transportation/operational-information/storage-reporting.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 3, Page 1 and
EB-2021-0149 Exhibit I.FRPO.24

Preamble:

The first reference provides a table entitled SUMMARY OF NON-UTILITY STORAGE BALANCES - UNION RATE ZONES that depicts an entitlement of 127.6PJ with daily balances.

The second reference response included: As posted on the Enbridge Gas website under operational information/storage reporting, the working capacity of Legacy Union Gas is 183.7 PJ of which 100 PJ is utility (as per NGEIR). The working capacity of Legacy Enbridge Gas is 122.9 PJ of which 99.4 PJ is utility (as per NGEIR).

We would like to understand the evidence provided and the actual balances in relation to the encroachment directives of the Board.

Question(s):

If the 127.6 PJ of space does not include space from Legacy Enbridge Gas, please provide a table for the last three years for EGD's non-utility storage space and daily values of actual balances for October and November.

Response:

The 127.6 PJ of space includes space from Legacy Enbridge Gas.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit E, Tab 1, Pages 1-5 and
EB-2022-0072 GSP UPDATE, Appendix C and Transcript Day 2 GSP Stakeholder Conference, page 68, lines 1-21

Preamble:

We would like to understand more about UDC and how EGI manages its transportation contracts through assignment to third parties and the allocation of costs to rate zones.

In the second reference, we were trying to understand the management of gas supply as it pertained to assignments. In the Stakeholder Conference, we previewed the type of information we were looking for and received assurances from EGI witnesses that the information could be provided and from EGI counsel that EGI would "provide this type of information in its pre-filed evidence". However, the prefiled evidence did not provide this data. This requested information allows the Board to understand EGI's approach to UDC, assignment and the allocation of costs and benefits.

Question(s):

For each month and for each transportation path and contract on the path that was assigned during 2021, please provide a table that provides the daily amount contracted, the daily amount of the contract assigned for each month of 2021, the total amount that was actually received at the delivery point in that month & the total transport cost, the additional revenue that was generated from the assignment, the account that received the revenue and the net impact on gas supply and transportation costs (using the table as provided in Attachment 1: DATA FOR TRANSPORT ASSIGNMENTS).

ATTACHMENT 1: DATA FOR TRANSPORT ASSIGNMENTS

PATH: ____

CONTRACT: ____________________________________

Delivery/ Utilization Month	Amount Contracted (GJ/day)	Amount Assigned (GJ/day)	Transaction/ Contracting Agreement Date	Term of Contract (Dates)	Total Amount Delivered To EGI (GJ)	Total Transport Delivered Cost[1] ($)	Incremental Revenue ($)	Account (UFG/Optimization/ Other (Specify)	Gas Cost Impact ($/GJ)	Transport Cost Impact ($)
Total for Month										

[1] Delivered Cost is zero if Assigned as a 100% Capacity Release for Load Balancing Management. Otherwise, what was paid in addition to the commodity cost at source to receive commodity at contract delivery point.

a) Please provide resulting in an appropriately formatted multi-sheet Excel workbook.

Response:

As outlined in Exhibit E, Tab 1, page 1 “the Union North and Union South transportation portfolios are managed on an integrated basis and the pipeline to leave unutilized, if necessary, is determined based on the least cost option.” Further, on page 4, Enbridge Gas explained that “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 committed in the EB-2021-0149 Settlement Proposal, Table 1 on page 2 of prefiled evidence provides the total unutilized capacity, UDC costs incurred, and the released value of capacity contracted by rate zone.

Attachment 1 provides further details on the capacity released (assigned) to third parties for the purposes of mitigating the overall UDC impact.

During periods where upstream supply deliveries to Enbridge Gas’s pipeline system are /U
not required to meet local market demands upstream of Dawn, Enbridge Gas releases this upstream pipeline capacity when supply upstream of Dawn is priced higher than the cost of purchasing supplies at Dawn. During these periods, Enbridge Gas purchases supply at Dawn instead of the upstream supply location and releases the associated transportation capacity to the market to further reduce gas costs for customers. The released value from these transactions is credited to the cost of transportation. Attachment 2 provides further details on the capacity released (assigned) to third parties as a result of these activities.

Finally, Enbridge Gas releases upstream transportation capacity on a temporary basis for the purposes of optimizing its upstream transportation portfolio. These releases are generally completed using Asset Management Agreements (AMA) whereby Enbridge Gas releases upstream capacity to third parties on a temporary basis and those parties agree to exchange gas purchased at the upstream supply zone to the delivery location. The third party pays Enbridge Gas for these AMAs, and the resulting revenue is credited to either the Upstream Transportation Optimization Account (for capacities contracted for the Union rate zones) or the Transactional Services Deferral Account (for capacities contracted for the EGD rate zone).

Enbridge Gas requires the AMA contract to include provisions to guarantee the same quality of service at the delivery point that is provided by the released upstream transportation capacity. Furthermore, since Enbridge Gas is releasing its firm upstream capacity to the third party, the Company has assurances that the third party owns firm capacity to facilitate the service. Finally, in the event of default by the third party, Enbridge Gas has the right to recall the capacity so that it can be used to move supplies to the delivery point. The result is that Enbridge Gas is able to obtain benefits from short-term market fluctuations, which are shared with ratepayers, while continuing to possess the same level of reliability afforded by owning long-term firm upstream transportation capacity. This activity aligns with the OEB direction when establishing the deferral accounts noted.[1] Attachment 3 provides further details on the capacity released (assigned) to third parties as a result of upstream transportation optimization activities.

Certain details provided in Attachments 1 to 3 meet the categories of information to be treated as confidential in accordance with the OEB's revised Practice Direction on Confidential Filings effective December 17, 2021. As a result, Enbridge Gas has requested confidential treatment of the attachment and has filed a redacted version on the public record.

[1] EB-2011-2010, Decision and Order and EBRO 492, Decision with Reasons.

Attachment 1 - Capacity Released to Third Party for UDC Mitigation

Month	Path	Monthly Volume Assigned (GJ)	Transaction Date	Term of Assignment	Total Demand ($000s)	Release Value ($000s)	Net Amount to UDC ($000s)	Account
Mar-21	Empress to CentratMDA	172,515	02/24/21	Mar 1 - 31	82	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Apr-21	Chicago to Dawn	633,034	03/26/21	Apr 1 - 30	135	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Apr-21	Empress to CentratMDA	166,950	03/26/21	Apr 1 - 30	82	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Apr-21	Empress to UnionWDA	60,000	03/26/21	Apr 1 - 30	41	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
May-21	Empress to CentratMDA	62,000	03/26/21	May 1 - 31	29	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
May-21	Empress to CentratMDA	110,515	03/26/21	May 1 - 31	52	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
May-21	Empress to UnionWDA	155,000	03/26/21	May 1 - 31	104	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
May-21	Empress to UnionWDA	155,000	03/26/21	May 1 - 31	104	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
May-21	Empress to UnionWDA	155,000	03/26/21	May 1 - 31	104	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
May-21	Empress to UnionSSMDA	93,000	03/26/21	May 1 - 31	87	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
May-21	Chicago to Dawn	654,135	04/27/21	May 1 - 31	133	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Jun-21	Empress to CentratMDA	166,950	05/26/21	Jun 1 - 30	82	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Jun-21	Empress to UnionWDA	855,000	05/26/21	Jun 1 - 30	591	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Jun-21	Empress to UnionSSMDA	30,000	05/26/21	Jun 1 - 30	29	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Jun-21	Chicago to Dawn	633,034	05/27/21	Jun 1 - 30	134	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Jun 21 (1)	Empress to Dawn (Great Lakes)	1,756	n/a	n/a	2	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Jul-21	Empress to CentratMDA	172,515	06/24/21	Jul 1 - 31	82	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Jul-21	Empress to UnionWDA	68,200	06/24/21	Jul 1 - 31	46	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Jul-21	Empress to UnionWDA	1,047,800	06/24/21	Jul 1 - 31	701	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Jul-21	Empress to UnionSSMDA	31,000	06/24/21	Jul 1 - 31	29	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Jul-21	Chicago to Dawn	654,135	06/25/21	Jul 1 - 31	137	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Jul 21 (1)	Empress to Dawn (Great Lakes)	628	n/a	n/a	1	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Aug-21	Empress to CentratMDA	172,515	07/28/21	Aug 1 - 31	82	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Aug-21	Empress to UnionWDA	1,085,000	07/28/21	Aug 1 - 31	726	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Aug-21	Empress to UnionSSMDA	31,000	07/28/21	Aug 1 - 31	29	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Aug 21 (1)	Empress to Dawn (Great Lakes)	539	n/a	n/a	0	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Sep 21	Empress to CentratMDA	166,950	08/26/21	Sep 1 - 30	82	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Sep 21	Empress to UnionWDA	240,000	08/26/21	Sep 1 - 30	166	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Sep 21	Empress to UnionWDA	150,000	08/26/21	Sep 1 - 30	104	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Sep 21	Empress to UnionWDA	300,000	08/26/21	Sep 1 - 30	207	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Sep 21	Empress to UnionSSMDA	120,000	08/26/21	Sep 1 - 30	116	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Sep 21	Chicago to Dawn	633,034	08/26/21	Sep 1 - 30	139	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Sep 21 (1)	Empress to Dawn (Great Lakes)	15,071	n/a	n/a	14	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
Oct-21	Niagara to Kirkwall	379,818	09/28/21	Oct 1 - 31	82	[redacted]	[redacted]	179-198 Unabsorbed Demand Cost
					4,530	**1,361**	**3,169**	

Notes:

(1) Not reflective of released capacities. UDC was taken as a result of an upstream pipeline outage. Pipelines which provided toll relief related to the upstream outage have been included in the listing as the toll relief amounts were included in the "released value" calculation in Table 1 of Exhibit E, Tab 1, page 2.

Attachment 2 - Capacity Released to Third Party for Supply Purchase Relocations

Month	Path	Portfolio	Monthly Volume Assigned (GJ)	Transaction Date	Term of Assignment	Total Demand ($000s)	Release Value ($000s)	Account for Release
Jun-21	Chicago to Dawn	EGD	791,292	27-May-21	Jun 1 - 30	167	[redacted]	EGD PGVA
Jul-21	Chicago to Dawn	EGD	817,668	25-Jun-21	Jul 1 - 31	172	[redacted]	EGD PGVA
Sep-21	Chicago to Dawn	Union	633,034	26-Aug-21	Sep 1 - 30	139	[redacted]	179-106 Union South PGVA
Oct-21	Chicago to Dawn	Union	654,135	28-Sep-21	Oct 1 - 31	136	[redacted]	179-106 Union South PGVA
Oct-21	Chicago to Dawn	EGD	817,668	28-Sep-22	Oct 1 - 31	170	[redacted]	EGD PGVA
Oct-21	Empress to Centrat MDA	Union	172,515	28-Sep-21	Oct 1 - 31	82	[redacted]	179-145 Union North West Tolls & Fuel
Oct-21	Empress to Union WDA	Union	155,000	28-Sep-21	Oct 1 - 31	104	[redacted]	179-145 Union North West Tolls & Fuel
Nov-21	Niagara Falls to Kirkwall	Union	316,830	27-Oct-21	Nov 1 - 31	56	[redacted]	179-106 Union South PGVA
						1,025	**291**	

Attachment 3 - Capacity Released to Third Party for Upstream Transportation Optimization

Month	Path	Portfolio	Monthly Volume Assigned (GJ)	Transaction Date	Term of Assignment	Total Demand ($000s)	Release Value ($000s)	Account for Release
Jan-21	Chicago to Dawn	Union	981,202	10/19/20	Nov 1, 2020 - Oct 31, 2022	209	[redacted]	179-131 Upstream Transportation Optimization
Jan-21	Chicago to Dawn	Union	1,308,269	06/01/20	Nov 1, 2020 - Mar 31, 2021	279	[redacted]	179-131 Upstream Transportation Optimization
Jan-21	Chicago to Dawn	Union	327,035	10/01/20	Nov 1, 2020 - Mar 31, 2021	70	[redacted]	179-131 Upstream Transportation Optimization
Jan-21	Chicago to Dawn	EGD	817,668	10/27/20	Nov 1, 2020 - Mar 31,2021	174	[redacted]	EGD Transactional Services Deferral Account
Jan-21	Chicago to Dawn	EGD	1,308,269	10/19/20	Nov 1, 2020-Oct 31, 2021	279	[redacted]	EGD Transactional Services Deferral Account
Jan-21	Empress to Dawn (Great Lakes)	Union	654,135	10/23/20	Nov 1, 2020 - Mar 31, 2021	468	[redacted]	179-131 Upstream Transportation Optimization
Jan-21	Kensington to Dawn	EGD	873,957	10/20/20	Nov 1, 2020 - Mar 31, 2021	991	[redacted]	EGD Transactional Services Deferral Account
Jan 21 (1)	Kensington to Dawn	EGD	654,135	07/16/18	Nov 1, 2018 - Oct 31, 2021	741	[redacted]	N/A
Jan 21 (1)	Kensington to Dawn	EGD	490,601	10/01/18	Nov 1, 2018 - Oct 31, 2021	556	[redacted]	N/A
Jan-21	PEPL FZ to Dawn	Union	1,144,736	11/30/20	Dec 1, 2020 - Mar 31, 2021	920	[redacted]	179-131 Upstream Transportation Optimization
Jan-21	PEPL FZ to Dawn	Union	719,548	11/30/20	Dec 1, 2020 - Mar 31, 2021	578	[redacted]	179-131 Upstream Transportation Optimization
Feb-21	Chicago to Dawn	Union	949,550	10/19/20	Nov 1, 2020 - Oct 31, 2022	209	[redacted]	179-131 Upstream Transportation Optimization
Feb-21	Chicago to Dawn	Union	1,266,067	06/01/20	Nov 1, 2020 - Mar 31, 2021	278	[redacted]	179-131 Upstream Transportation Optimization
Feb-21	Chicago to Dawn	Union	316,485	10/01/20	Nov 1, 2020 - Mar 31, 2021	70	[redacted]	179-131 Upstream Transportation Optimization
Feb-21	Chicago to Dawn	EGD	791,292	10/27/20	Nov 1, 2020 - Mar 31,2021	174	[redacted]	EGD Transactional Services Deferral Account
Feb-21	Chicago to Dawn	EGD	1,266,067	10/19/20	Nov 1, 2020-Oct 31, 2021	278	[redacted]	EGD Transactional Services Deferral Account
Feb-21	Empress to Dawn (Great Lakes)	Union	633,034	10/23/20	Nov 1, 2020 - Mar 31, 2021	468	[redacted]	179-131 Upstream Transportation Optimization
Feb-21	Kensington to Dawn	EGD	845,765	10/20/20	Nov 1, 2020 - Mar 31, 2021	988	[redacted]	EGD Transactional Services Deferral Account
Feb 21 (1)	Kensington to Dawn	EGD	633,034	07/16/18	Nov 1, 2018 - Oct 31, 2021	740	[redacted]	N/A
Feb 21 (1)	Kensington to Dawn	EGD	474,775	10/01/18	Nov 1, 2018 - Oct 31, 2021	555	[redacted]	N/A
Feb-21	PEPL FZ to Dawn	Union	1,107,809	02/01/21	Feb 1, 2021 - Mar 31, 2021	917	[redacted]	179-131 Upstream Transportation Optimization
Feb-21	PEPL FZ to Dawn	Union	696,337	11/30/20	Dec 1, 2020 - Mar 31, 2021	577	[redacted]	179-131 Upstream Transportation Optimization
Mar-21	Chicago to Dawn	Union	981,202	10/19/20	Nov 1, 2020 - Oct 31, 2022	207	[redacted]	179-131 Upstream Transportation Optimization
Mar-21	Chicago to Dawn	Union	1,308,269	06/01/20	Nov 1, 2020 - Mar 31, 2021	275	[redacted]	179-131 Upstream Transportation Optimization
Mar-21	Chicago to Dawn	Union	327,035	10/01/20	Nov 1, 2020 - Mar 31, 2021	69	[redacted]	179-131 Upstream Transportation Optimization
Mar-21	Chicago to Dawn	EGD	817,668	10/27/20	Nov 1, 2020 - Mar 31,2021	172	[redacted]	EGD Transactional Services Deferral Account
Mar-21	Chicago to Dawn	EGD	1,308,269	10/19/20	Nov 1, 2020-Oct 31, 2021	275	[redacted]	EGD Transactional Services Deferral Account
Mar-21	Empress to Dawn (Great Lakes)	Union	654,135	10/23/20	Nov 1, 2020 - Mar 31, 2021	468	[redacted]	179-131 Upstream Transportation Optimization
Mar-21	Kensington to Dawn	EGD	873,957	10/20/20	Nov 1, 2020 - Mar 31, 2021	979	[redacted]	EGD Transactional Services Deferral Account
Mar 21 (1)	Kensington to Dawn	EGD	654,135	07/16/18	Nov 1, 2018 - Oct 31, 2021	732	[redacted]	N/A
Mar 21 (1)	Kensington to Dawn	EGD	490,601	10/01/18	Nov 1, 2018 - Oct 31, 2021	549	[redacted]	N/A
Mar-21	PEPL FZ to Dawn	Union	1,144,736	02/01/21	Feb 1, 2021 - Mar 31, 2021	908	[redacted]	179-131 Upstream Transportation Optimization
Mar-21	PEPL FZ to Dawn	Union	719,548	11/30/20	Dec 1, 2020 - Mar 31, 2021	571	[redacted]	179-131 Upstream Transportation Optimization
Apr-21	Chicago to Dawn	Union	949,550	10/19/20	Nov 1, 2020 - Oct 31, 2022	205	[redacted]	179-131 Upstream Transportation Optimization
Apr-21	Chicago to Dawn	Union	949,550	03/24/21	Apr 1, 2021 - Oct 31, 2021	205	[redacted]	179-131 Upstream Transportation Optimization
Apr-21	Chicago to Dawn	EGD	1,266,067	10/19/20	Nov 1, 2020-Oct 31, 2021	274	[redacted]	EGD Transactional Services Deferral Account
Apr 21 (1)	Kensington to Dawn	EGD	633,034	07/16/18	Nov 1, 2018 - Oct 31, 2021	728	[redacted]	N/A
Apr 21 (1)	Kensington to Dawn	EGD	474,775	10/01/18	Nov 1, 2018 - Oct 31, 2021	546	[redacted]	N/A
Apr-21	PEPL FZ to Dawn	Union	1,107,809	03/29/21	Apr 1, 2021 - Mar 31, 2022	903	[redacted]	179-131 Upstream Transportation Optimization
Apr-21	PEPL FZ to Dawn	Union	696,337	03/30/21	Apr 1, 2021 - Mar 31, 2022	567	[redacted]	179-131 Upstream Transportation Optimization
May-21	Chicago to Dawn	Union	981,202	10/19/20	Nov 1, 2020 - Oct 31, 2022	199	[redacted]	179-131 Upstream Transportation Optimization
May-21	Chicago to Dawn	Union	981,202	03/24/21	Apr 1, 2021 - Oct 31, 2021	199	[redacted]	179-131 Upstream Transportation Optimization
May-21	Chicago to Dawn	EGD	1,308,269	10/19/20	Nov 1, 2020-Oct 31, 2021	266	[redacted]	EGD Transactional Services Deferral Account
May 21 (1)	Kensington to Dawn	EGD	654,135	07/16/18	Nov 1, 2018 - Oct 31, 2021	706	[redacted]	N/A
May 21 (1)	Kensington to Dawn	EGD	490,601	10/01/18	Nov 1, 2018 - Oct 31, 2021	530	[redacted]	N/A
May-21	PEPL FZ to Dawn	Union	1,144,736	03/29/21	Apr 1, 2021 - Mar 31, 2022	876	[redacted]	179-131 Upstream Transportation Optimization
May-21	PEPL FZ to Dawn	Union	719,548	03/30/21	Apr 1, 2021 - Mar 31, 2022	551	[redacted]	179-131 Upstream Transportation Optimization
Jun-21	Chicago to Dawn	Union	949,550	10/19/20	Nov 1, 2020 - Oct 31, 2022	201	[redacted]	179-131 Upstream Transportation Optimization
Jun-21	Chicago to Dawn	Union	949,550	03/24/21	Apr 1, 2021 - Oct 31, 2021	201	[redacted]	179-131 Upstream Transportation Optimization
Jun-21	Chicago to Dawn	EGD	1,266,067	10/19/20	Nov 1, 2020-Oct 31, 2021	268	[redacted]	EGD Transactional Services Deferral Account
Jun 21 (1)	Kensington to Dawn	EGD	633,034	07/16/18	Nov 1, 2018 - Oct 31, 2021	712	[redacted]	N/A
Jun 21 (1)	Kensington to Dawn	EGD	474,775	10/01/18	Nov 1, 2018 - Oct 31, 2021	534	[redacted]	N/A
Jun-21	PEPL FZ to Dawn	Union	1,107,809	03/29/21	Apr 1, 2021 - Mar 31, 2022	883	[redacted]	179-131 Upstream Transportation Optimization
Jun-21	PEPL FZ to Dawn	Union	696,337	03/30/21	Apr 1, 2021 - Mar 31, 2022	555	[redacted]	179-131 Upstream Transportation Optimization
Jul-21	Chicago to Dawn	Union	981,202	10/19/20	Nov 1, 2020 - Oct 31, 2022	206	[redacted]	179-131 Upstream Transportation Optimization
Jul-21	Chicago to Dawn	Union	981,202	03/24/21	Apr 1, 2021 - Oct 31, 2021	206	[redacted]	179-131 Upstream Transportation Optimization
Jul-21	Chicago to Dawn	EGD	1,308,269	10/19/20	Nov 1, 2020-Oct 31, 2021	275	[redacted]	EGD Transactional Services Deferral Account
Jul 21 (1)	Kensington to Dawn	EGD	654,135	07/16/18	Nov 1, 2018 - Oct 31, 2021	730	[redacted]	N/A
Jul 21 (1)	Kensington to Dawn	EGD	490,601	10/01/18	Nov 1, 2018 - Oct 31, 2021	548	[redacted]	N/A
Jul-21	PEPL FZ to Dawn	Union	1,144,736	03/29/21	Apr 1, 2021 - Mar 31, 2022	906	[redacted]	179-131 Upstream Transportation Optimization
Jul-21	PEPL FZ to Dawn	Union	719,548	03/30/21	Apr 1, 2021 - Mar 31, 2022	569	[redacted]	179-131 Upstream Transportation Optimization
Aug-21	Chicago to Dawn	Union	981,202	10/19/20	Nov 1, 2020 - Oct 31, 2022	207	[redacted]	179-131 Upstream Transportation Optimization
Aug-21	Chicago to Dawn	Union	981,202	03/24/21	Apr 1, 2021 - Oct 31, 2021	207	[redacted]	179-131 Upstream Transportation Optimization
Aug-21	Chicago to Dawn	EGD	1,308,269	10/19/20	Nov 1, 2020-Oct 31, 2021	276	[redacted]	EGD Transactional Services Deferral Account
Aug 21 (1)	Kensington to Dawn	EGD	654,135	07/16/18	Nov 1, 2018 - Oct 31, 2021	734	[redacted]	N/A
Aug 21 (1)	Kensington to Dawn	EGD	490,601	10/01/18	Nov 1, 2018 - Oct 31, 2021	551	[redacted]	N/A
Aug-21	PEPL FZ to Dawn	Union	1,144,736	03/29/21	Apr 1, 2021 - Mar 31, 2022	911	[redacted]	179-131 Upstream Transportation Optimization
Aug-21	PEPL FZ to Dawn	Union	719,548	03/30/21	Apr 1, 2021 - Mar 31, 2022	572	[redacted]	179-131 Upstream Transportation Optimization
Sep-21	Chicago to Dawn	Union	949,550	10/19/20	Nov 1, 2020 - Oct 31, 2022	208	[redacted]	179-131 Upstream Transportation Optimization
Sep-21	Chicago to Dawn	Union	949,550	03/24/21	Apr 1, 2021 - Oct 31, 2021	208	[redacted]	179-131 Upstream Transportation Optimization
Sep-21	Chicago to Dawn	EGD	1,266,067	10/19/20	Nov 1, 2020-Oct 31, 2021	278	[redacted]	EGD Transactional Services Deferral Account
Sep 21 (1)	Kensington to Dawn	EGD	633,034	07/16/18	Nov 1, 2018 - Oct 31, 2021	739	[redacted]	N/A
Sep 21 (1)	Kensington to Dawn	EGD	474,775	10/01/18	Nov 1, 2018 - Oct 31, 2021	554	[redacted]	N/A
Sep-21	PEPL FZ to Dawn	Union	1,107,809	03/29/21	Apr 1, 2021 - Mar 31, 2022	916	[redacted]	179-131 Upstream Transportation Optimization
Sep-21	PEPL FZ to Dawn	Union	696,337	03/30/21	Apr 1, 2021 - Mar 31, 2022	576	[redacted]	179-131 Upstream Transportation Optimization
Oct-21	Chicago to Dawn	Union	981,202	10/19/20	Nov 1, 2020 - Oct 31, 2022	204	[redacted]	179-131 Upstream Transportation Optimization
Oct-21	Chicago to Dawn	Union	981,202	03/24/21	Apr 1, 2021 - Oct 31, 2021	204	[redacted]	179-131 Upstream Transportation Optimization
Oct-21	Chicago to Dawn	EGD	1,308,269	10/19/20	Nov 1, 2020-Oct 31, 2021	272	[redacted]	EGD Transactional Services Deferral Account
Oct 21 (1)	Kensington to Dawn	EGD	654,135	07/16/18	Nov 1, 2018 - Oct 31, 2021	724	[redacted]	N/A
Oct 21 (1)	Kensington to Dawn	EGD	490,601	10/01/18	Nov 1, 2018 - Oct 31, 2021	543	[redacted]	N/A
Oct-21	PEPL FZ to Dawn	Union	1,144,736	03/29/21	Apr 1, 2021 - Mar 31, 2022	898	[redacted]	179-131 Upstream Transportation Optimization
Oct-21	PEPL FZ to Dawn	Union	719,548	03/30/21	Apr 1, 2021 - Mar 31, 2022	565	[redacted]	179-131 Upstream Transportation Optimization
Nov-21	Chicago to Dawn	Union	949,550	10/19/20	Nov 1, 2020 - Oct 31, 2022	202	[redacted]	179-131 Upstream Transportation Optimization
Nov-21	Chicago to Dawn	Union	1,266,067	10/07/21	Nov 1, 2021 - Mar 31, 2022	269	[redacted]	179-131 Upstream Transportation Optimization
Nov-21	Chicago to Dawn	Union	316,485	09/08/21	Nov 1, 2021 - Mar 31, 2022	67	[redacted]	179-131 Upstream Transportation Optimization
Nov-21	Chicago to Dawn	Union	633,034	09/14/21	Nov 1, 2021 - Oct 31, 2022	135	[redacted]	179-131 Upstream Transportation Optimization
Nov-21	Chicago to Dawn	EGD	316,485	08/24/21	Nov 1, 2021 - Oct 31, 2023	67	[redacted]	EGD Transactional Services Deferral Account
Nov-21	Chicago to Dawn	EGD	316,517	10/26/21	Nov 1, 2021 - Oct 31, 2023	67	[redacted]	EGD Transactional Services Deferral Account
Nov-21	Chicago to Dawn	EGD	633,034	07/08/21	Nov 1, 2021 - Oct 31, 2023	134	[redacted]	EGD Transactional Services Deferral Account
Nov-21	Chicago to Dawn	EGD	791,292	07/26/21	Nov 1, 2021 - Oct 31, 2023	168	[redacted]	EGD Transactional Services Deferral Account
Nov-21	Chicago to Dawn	EGD	633,034	07/26/21	Nov 1, 2021 - Oct 31, 2023	134	[redacted]	EGD Transactional Services Deferral Account
Nov-21	Empress to Dawn (Great Lakes)	Union	633,034	07/15/21	Nov 1, 2021 - Mar 31, 2022	468	[redacted]	179-131 Upstream Transportation Optimization
Nov-21	Kensington to Dawn	Union	949,550	10/06/21	Nov 1, 2021 - Mar 31, 2022	1,099	[redacted]	179-131 Upstream Transportation Optimization
Nov-21	PEPL FZ to Dawn	Union	1,107,809	03/29/21	Apr 1, 2021 - Mar 31, 2022	909	[redacted]	179-131 Upstream Transportation Optimization
Nov-21	PEPL FZ to Dawn	Union	696,337	03/30/21	Apr 1, 2021 - Mar 31, 2022	571	[redacted]	179-131 Upstream Transportation Optimization
Dec-21	Chicago to Dawn	Union	981,202	10/19/20	Nov 1, 2020 - Oct 31, 2022	205	[redacted]	179-131 Upstream Transportation Optimization
Dec-21	Chicago to Dawn	Union	1,308,269	10/07/21	Nov 1, 2021 - Mar 31, 2022	274	[redacted]	179-131 Upstream Transportation Optimization
Dec-21	Chicago to Dawn	Union	327,035	09/08/21	Nov 1, 2021 - Mar 31, 2022	68	[redacted]	179-131 Upstream Transportation Optimization
Dec-21	Chicago to Dawn	Union	654,135	09/14/21	Nov 1, 2021 - Oct 31, 2022	137	[redacted]	179-131 Upstream Transportation Optimization
Dec-21	Chicago to Dawn	EGD	327,035	08/24/21	Nov 1, 2021 - Oct 31, 2023	68	[redacted]	EGD Transactional Services Deferral Account
Dec-21	Chicago to Dawn	EGD	327,067	10/26/21	Nov 1, 2021 - Oct 31, 2023	68	[redacted]	EGD Transactional Services Deferral Account
Dec-21	Chicago to Dawn	EGD	654,135	07/08/21	Nov 1, 2021 - Oct 31, 2023	136	[redacted]	EGD Transactional Services Deferral Account
Dec-21	Chicago to Dawn	EGD	817,668	07/26/21	Nov 1, 2021 - Oct 31, 2023	171	[redacted]	EGD Transactional Services Deferral Account
Dec-21	Chicago to Dawn	EGD	654,135	07/26/21	Nov 1, 2021 - Oct 31, 2023	136	[redacted]	EGD Transactional Services Deferral Account
Dec-21	Empress to Dawn (Great Lakes)	Union	654,135	07/15/21	Nov 1, 2021 - Mar 31, 2022	468	[redacted]	179-131 Upstream Transportation Optimization
Dec-21	Kensington to Dawn	Union	981,202	10/06/21	Nov 1, 2021 - Mar 31, 2022	1,118	[redacted]	179-131 Upstream Transportation Optimization
Dec-21	PEPL FZ to Dawn	Union	1,144,736	03/29/21	Apr 1, 2021 - Mar 31, 2022	924	[redacted]	179-131 Upstream Transportation Optimization
Dec-21	PEPL FZ to Dawn	Union	719,548	03/30/21	Apr 1, 2021 - Mar 31, 2022	581	[redacted]	179-131 Upstream Transportation Optimization
						48,261	6,995	

Notes:

(1) EGD Kensington to Dawn capacity released to third-party as part of a supply purchase AMA. No value was attributable to the pipe release. Instead, gas supply commodity was purchased at a favourable rate compared to a transaction without an AMA. The cost of the supply was booked to the EGD PGVA.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit E, Tab 1, Page 35-39 including Table 1

Preamble:

EGI evidence states:

A similar decrease and offsetting increase in UFG volumes has been observed between the 2020 and 2021 calendar years. The average UFG % for 2020 and 2021 is 0.440%, which is approximately 163.5 103m3/year average for the two years. The Company has identified that the true-up of estimated consumption based on the calendarization of UFG volumes has contributed to volatility between 2020 and 2021, but has not resulted in a material increase to the historical average of UFG over the course of two years. Typical estimation true-ups are outlined below.

At the end of each reporting period, Enbridge Gas records an estimate of gas delivered but not yet billed. The true-up between the December 2020 estimate and the actual billed volumes resulted in a decrease to the delivery volumes recorded in January 2021. This true-up reflects that, when billings related to December 2020 were completed over the following month, it was determined there was an overestimate of gas deliveries for December 2020.

We would like to understand better the impact of the year-end true-up as it pertains to the period of calendar 2021.

Question(s):

Please provide the before and after true-up volumes for December 2020 and January 2021.

a) Please provide the determination of the before and after UFG volumes for 2020 and any impacts on 2021.

Response:

Please see response to Exhibit I.STAFF.11 d).

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit E, Tab 1, Page 35-39 including Table 1

Preamble:

EGI evidence states:

A similar decrease and offsetting increase in UFG volumes has been observed between the 2020 and 2021 calendar years. The average UFG % for 2020 and 2021 is 0.440%, which is approximately 163.5 103m3/year average for the two years. The Company has identified that the true-up of estimated consumption based on the calendarization of UFG volumes has contributed to volatility between 2020 and 2021, but has not resulted in a material increase to the historical average of UFG over the course of two years. Typical estimation true-ups are outlined below.

At the end of each reporting period, Enbridge Gas records an estimate of gas delivered but not yet billed. The true-up between the December 2020 estimate and the actual billed volumes resulted in a decrease to the delivery volumes recorded in January 2021. This true-up reflects that, when billings related to December 2020 were completed over the following month, it was determined there was an overestimate of gas deliveries for December 2020.

We would like to understand better the impact of the year-end true-up as it pertains to the period of calendar 2021.

Question(s):

Did EGI perform a similar true-up for December 2021 using actuals for January 2022.

a) If not, why not?

b) If so, please provide the before and after volumes for December 2021 and the resulting UFG.

Response:

a) Yes, a similar true-up for December 2021 was performed.

b) December 2021 estimated volumes were approximately (4,000) 10^3m^3 lower than December 2021 actual billed volumes, which resulted in a true-up in January 2022 for that amount. The true-up resulted in an increase to the delivery volumes recorded in January 2022. The impact to UFG was an increase in UFG in 2021 and a decrease in UFG in 2022.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit E, Tab 1, Page 35-39 including Table 1

Preamble:

EGI evidence states:

A similar decrease and offsetting increase in UFG volumes has been observed between the 2020 and 2021 calendar years. The average UFG % for 2020 and 2021 is 0.440%, which is approximately 163.5 103m3/year average for the two years. The Company has identified that the true-up of estimated consumption based on the calendarization of UFG volumes has contributed to volatility between 2020 and 2021, but has not resulted in a material increase to the historical average of UFG over the course of two years. Typical estimation true-ups are outlined below.

At the end of each reporting period, Enbridge Gas records an estimate of gas delivered but not yet billed. The true-up between the December 2020 estimate and the actual billed volumes resulted in a decrease to the delivery volumes recorded in January 2021. This true-up reflects that, when billings related to December 2020 were completed over the following month, it was determined there was an overestimate of gas deliveries for December 2020.

We would like to understand better the impact of the year-end true-up as it pertains to the period of calendar 2021.

Question(s):

As noted later in the performance metrics, EGI has had a very high level of meters that go without actual reads over several months. We would like to understand the potential for this to be a contributing factor.

If a customer goes without a bill for a number of months due to incorrect account numbers resulting in a billing gap that the company does not collect:

a) Does the company write-off the gas cost to bad debt?
b) Given that there is no collection of funds, does the quantity of commodity still find its way to billed consumption or would it contribute to UFG?

Response:

a) No, if a customer goes without a bill for a number of months, the gas cost is not written off to bad debt, given that the customer has not been billed.

b) UFG is broadly defined as the difference between gas receipts and gas deliveries. Gas deliveries to customers are comprised of both billed and unbilled volumes. Billed volumes are based on both estimated and actual meter reads. Unbilled volumes are recorded at the end of each reporting period to quantify the amount of gas delivered but not yet billed. This ensures that both billed and unbilled volumes are incorporated into the formulaic determination of UFG.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit E, Tab 1, Page 35-39 including Table 1

Preamble:

EGI evidence states:

A similar decrease and offsetting increase in UFG volumes has been observed between the 2020 and 2021 calendar years. The average UFG % for 2020 and 2021 is 0.440%, which is approximately 163.5 103m3/year average for the two years. The Company has identified that the true-up of estimated consumption based on the calendarization of UFG volumes has contributed to volatility between 2020 and 2021, but has not resulted in a material increase to the historical average of UFG over the course of two years. Typical estimation true-ups are outlined below.

At the end of each reporting period, Enbridge Gas records an estimate of gas delivered but not yet billed. The true-up between the December 2020 estimate and the actual billed volumes resulted in a decrease to the delivery volumes recorded in January 2021. This true-up reflects that, when billings related to December 2020 were completed over the following month, it was determined there was an overestimate of gas deliveries for December 2020.

We would like to understand better the impact of the year-end true-up as it pertains to the period of calendar 2021.

Question(s):

As noted later in the performance metrics, EGI has had a very high level of meters that go without actual reads over several months. We would like to understand the potential for this to be a contributing factor.

As of December 31, 2021, for each Legacy utility, what percentage of customer had not had an actual meter read generated bill in at least two months.

a) Please provide EGI's views on the potential for this lack of actual data on consumption at year-end can contribute to UFG.

Response:

As of December 31, 2021, 11% of LEGD and 24% of LUG customers had not had an actual meter read generated bill in at least two months.

In a given reporting period, it is normal billing practice that a portion of all customer accounts are billed based on estimated reads. These billed volumes based on estimated reads are included into the formulaic determination of UFG. When an actual read is received, the customer account is adjusted accordingly, and the adjustment is subsequently also included in the formulaic determination of UFG. Therefore, Enbridge Gas does not believe that estimated reads contribute to higher levels of UFG when considered over time, though estimated reads may contribute to variations in UFG levels in the short-term.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit E, Tab 1, Page 35-39 including Table 1

Preamble:

EGI evidence states:

A similar decrease and offsetting increase in UFG volumes has been observed between the 2020 and 2021 calendar years. The average UFG % for 2020 and 2021 is 0.440%, which is approximately 163.5 103m3/year average for the two years. The Company has identified that the true-up of estimated consumption based on the calendarization of UFG volumes has contributed to volatility between 2020 and 2021, but has not resulted in a material increase to the historical average of UFG over the course of two years. Typical estimation true-ups are outlined below.

At the end of each reporting period, Enbridge Gas records an estimate of gas delivered but not yet billed. The true-up between the December 2020 estimate and the actual billed volumes resulted in a decrease to the delivery volumes recorded in January 2021. This true-up reflects that, when billings related to December 2020 were completed over the following month, it was determined there was an overestimate of gas deliveries for December 2020.

We would like to understand better the impact of the year-end true-up as it pertains to the period of calendar 2021.

Question(s):

Footnote 2 of Table 1 states: *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*

Please provide EGI's reconciliation of CSF (customer supplied fuel) by showing the activity based UFG for those customers and the amount provided by those customers for 2021

Response:

Exhibit E, Tab 1 pages 38 and 39 have been updated as a result of an error in the calculation of the UFG Price Variance account.

The response below is based on the updated evidence.

Table 1 provides a reconciliation of the UFG Price Deferral Account balance broken down by Utility Supplied Fuel vs Customer Supplied Fuel.

Table 1
Allocation 2021 UFG Price Deferral Account Balance

Line No.	Particulars	Utility Supplied Fuel	Customer Supplied Fuel	Total (1)
1	Experienced Utility UFG (10^3m^3) (2)	63,372	160,265	223,637
2	Collected UFG in Kind (10^3m^3)	-	68,416	68,416
3	Total (10^3m^3)	63,372	91,849	155,221
4	2021 UFG Price Deferral Account Balance ($ Millions)	3.33	4.82	8.15

Note:
(1) EB-2022-0110, Exhibit E, Schedule 1, Tab 9, Table 1
(2) Portion of actual UFG volumes related to utility and customer supplied fuel based on total throughput volumes.
(3) Line 3 applied to the UFG price variance of $52.52 that is listed in EB-2022-0110, Exhibit E, Schedule 1, Tab 9, Table 1

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 1, Page 2

Preamble:

EGI evidence states:

The MRPM represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the metric is 0.5% and Enbridge Gas achieved a level of 5.0% in 2021. The result for 2019 was 0.7% and 4.4% in 2020. Enbridge Gas has faced challenges meeting the target since 2019 for several reasons, including the decision of a key meter reading vendor to no longer provide meter reading service resulting in the need to onboard a new vendor.

Question(s):

For each of Legacy UG and EGD in 2021, please provide the percentage of meters with no read for:

a) 4 months
b) 6 months
c) 9 months
d) 12 months

Response:

Meter Reading Performance Measurement (MRPM) is a cumulative metric whereby the total number of unread meters fluctuates as some meters are read and are removed from the totals, while other meters remain as unread from the previous month, and new meters reach their four-month timeline and are added to the current consecutive estimate results. This means that even though a percentage of meters have successfully been read, Enbridge Gas will continue to have meters that have consecutive estimates. The following results are as of December 31st.

Table 1

% of meters with consecutive estimates

% of meters with consecutive estimates	UG Rate Zone 2021	EGD Rate Zone 2021
a) 4 months	3.02%	0.66%
b) 6 months	3.96%	0.83%
c) 9 months	2.77%	0.57%
d) 12 months	0.69%	1.29%

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 1, Page 2

Preamble:

EGI evidence states:

The MRPM represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the metric is 0.5% and Enbridge Gas achieved a level of 5.0% in 2021. The result for 2019 was 0.7% and 4.4% in 2020. Enbridge Gas has faced challenges meeting the target since 2019 for several reasons, including the decision of a key meter reading vendor to no longer provide meter reading service resulting in the need to onboard a new vendor.

Question(s):

For each of Legacy UG and EGD in 2021, what percent of accounts received a zero consumption bill:

a) From January to June
b) From July to November

Response:

a - b)

Zero consumption on a gas bill would be based on a customer's consumption behaviour, such as seasonal gas use, or in the case where the meter is temporarily locked. Enbridge Gas' billing practice whenever gas consumption is expected and an actual read is not present, is to use an estimated reading for billing.

Due to system integration in the Legacy UG rate zones, this level of information is not available prior to July 2021.

Table 1

% of accounts that received a zero consumption bill

% of accounts that received a zero consumption bill	Legacy UG rate zones	Legacy EGD rate zone
From January to June	N/A	1.20%
From July to November	3.90%	4.60%

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 1, Page 2

Preamble:

EGI evidence states:

The MRPM represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the metric is 0.5% and Enbridge Gas achieved a level of 5.0% in 2021. The result for 2019 was 0.7% and 4.4% in 2020. Enbridge Gas has faced challenges meeting the target since 2019 for several reasons, including the decision of a key meter reading vendor to no longer provide meter reading service resulting in the need to onboard a new vendor.

Question(s):

For each of Legacy UG and EGD in 2021, what percent of accounts received an estimated consumption bill:

a) From January to June
b) From July to November

Response:

a - b)

In each billing month, it is normal billing practice that 50% of all customer accounts are billed based on estimated reads. Also, whenever an actual read is not present, an estimated reading will be used for billing purposes.

Due to system integration in the Legacy UG rate zones, this level of information is not available prior to July 2021.

Table 1

Average # of Monthly Accounts with an Estimated Consumption Bill

Average # of monthly accounts with an estimated consumption bill	Legacy UG rate zones	Legacy EGD rate zones
From January to June	N/A	55.3%
From July to November	67.4%	54.9%

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 1, Page 2

Preamble:

EGI evidence states:

The MRPM represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the metric is 0.5% and Enbridge Gas achieved a level of 5.0% in 2021. The result for 2019 was 0.7% and 4.4% in 2020. Enbridge Gas has faced challenges meeting the target since 2019 for several reasons, including the decision of a key meter reading vendor to no longer provide meter reading service resulting in the need to onboard a new vendor.

Question(s):

What criteria is used to determine if a customer is billed an estimate or billed for zero consumption for a month for which the meter is not read.

a) If the bill is estimated, does classification (actual vs. estimate) appear in the consumption data (e.g., the Invoice Rate Ready data) for direct purchase pools.

b) If not, what would be the cost to add this field to the data provided?

Response:

Enbridge Gas reads customer meters every other month. On months when the meter is not scheduled to be read or when a meter read was not attained, an estimated reading is used. Zero consumption on a gas bill would be based on a customer's consumption behaviour, such as seasonal gas use, or in the case where the meter is temporarily locked.

a) Current defined fields (Est. vs. Actual) are not included in the direct purchase consumption data as this is not defined in the Electronic Business Transactions (EBT) Standards Document of the Gas Distribution Access Rule (GDAR) that all gas distributors are required to follow.

b) The estimate for Enbridge Gas to add a field to the two current business systems supporting Enbridge and Union rate zone direct purchase general service markets is estimated at $120,000. This estimate does not include large volume contract market.

   It should be noted to make these changes to the EBT standards would require the OEB to assemble the GDAR working group to discuss and agree to add the field (Est. vs. Actual) to the schema for all participants and the needed timeline on implementing the changes.

   All market participants would be required to be committed to updating their own systems to accommodate the new field or fields to use the new schema at the same time. Implementation timelines would need to be coordinated with all market participants. The ability to adapt to the technical change will likely vary greatly based the vendor’s own resources and level of controls.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 1, Page 2

Preamble:

EGI evidence states:

The MRPM represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the metric is 0.5% and Enbridge Gas achieved a level of 5.0% in 2021. The result for 2019 was 0.7% and 4.4% in 2020. Enbridge Gas has faced challenges meeting the target since 2019 for several reasons, including the decision of a key meter reading vendor to no longer provide meter reading service resulting in the need to onboard a new vendor.

Question(s):

If a direct purchase customer whose year-end contract balance or two-point balancing limits were impacted by estimated or zero consumption readings, did EGI reverse any charges to the customer caused by the estimated or zero consumption billings.

a) Please provide examples of communications that were sent to the affected customers.

b) If a direct purchase customer was affected by 3 or more zero or estimated reads, please describe how EGI approached any costs associated with balancing (i.e., annual renewal, two-point balancing, etc.).

Response:

a - b)

Enbridge Gas has, and continues to, accommodate request to mitigate billing impacts to customers by providing balancing flexibility when operationally available and by waiving fees for surplus gas stored or for short gas loaned.

Below is an example of the communications sent out to affected customers.

Communication to Direct Purchase Market in the Union Gas Rate Zones:

We are reaching out to provide an update on billing issues you may have experienced since Enbridge Gas Inc.'s (EGI) integration of our customer account system for general service customers in July 2021. This may have impacted the direct purchase accounts you have or manage.

The following issues have been experienced for some customers which may have impacted the Banked Gas Account:

- *Estimated meter reads spanning several months that may be higher than usual.*
- *End use accounts may not be receiving regular monthly bills resulting in unreported consumption for the same period*

EGI's billing operations team have identified the root causes of the issue and have been working to address impacted accounts. The issue was due to data migration between the customer account systems resulting in delays in billing to a subset of customers. Each impacted account requires a detailed manual review to analyse and resolve, resulting in significant time required to address all impacted bills. Over the last several months, EGI has treated this issue with high priority and has dedicated additional resources to address it. It is our current expectation that the resolution of all known impacted accounts will be completed by the end of Q1, 2022.

We appreciate your patience as we complete this detailed review and recognize it has taken longer than we initially expected. As a result, Enbridge will take this issue into consideration when evaluating requests for South and North balancing requirements directly impacted by this issue. Please let your Direct Purchase Customer Service Representative know if you are experiencing any issues and provide a list of your impacted accounts/contracts. The CSRs will assess each request to determine where additional flexibility can be accommodated.

If you have any questions about this communication, please contact authorizations@enbridge.com

Thank you.

Direct Purchase Contracting and Compliance

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 1, Page 2

Preamble:

EGI evidence states:

The MRPM represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the metric is 0.5% and Enbridge Gas achieved a level of 5.0% in 2021. The result for 2019 was 0.7% and 4.4% in 2020. Enbridge Gas has faced challenges meeting the target since 2019 for several reasons, including the decision of a key meter reading vendor to no longer provide meter reading service resulting in the need to onboard a new vendor.

Question(s):

What was EGI's approach to handling direct purchase customers whose accounts were closed in error with respect to returning that customer to their Direct Purchase Account?

Response:

End use customer accounts identified as having been finalized in error and dropped from a Direct Purchase gas pool are returned to the pool with a new billing account number. Pools are then updated with the associated consumption volumes, price points and remittances through back-dating adjustment where applicable.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 1, Page 2

Preamble:

EGI evidence states:

The MRPM represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the metric is 0.5% and Enbridge Gas achieved a level of 5.0% in 2021. The result for 2019 was 0.7% and 4.4% in 2020. Enbridge Gas has faced challenges meeting the target since 2019 for several reasons, including the decision of a key meter reading vendor to no longer provide meter reading service resulting in the need to onboard a new vendor.

Question(s):

If a group of general service rate customers are aggregated into a direct purchase group, what avenues do these customers have to seek adjustments to their accounts?

a) Is there an Account Executive or similar type role?

Response:

Individual customers that are part of an aggregated direct purchase gas pool can call the Call Centre to inquire about their own end use account. Typically, general service customers that are part of a direct purchase gas pool are represented by their Energy Marketer.

Energy Marketers can contact Enbridge Gas's dedicated direct purchase support team with specific direct purchase inquiries across all Enbridge and Union rate zones.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 1, Page 2

Preamble:

EGI evidence states:

The MRPM represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the metric is 0.5% and Enbridge Gas achieved a level of 5.0% in 2021. The result for 2019 was 0.7% and 4.4% in 2020. Enbridge Gas has faced challenges meeting the target since 2019 for several reasons, including the decision of a key meter reading vendor to no longer provide meter reading service resulting in the need to onboard a new vendor.

Question(s):

What was the average wait time to get to a live account representative using the customer billing enquiry number 1-877-362-7434 and what is the abandonment rate:

a) From January to June of 2021?
b) From July to November of 2021?

Response:

a) For the period January to June of 2021, the average wait time to get a live account representative was 164 seconds (2 minutes 44 seconds); the abandonment rate was 8.6%.

b) For the period July to November 2021, the average wait time to get a live account representative was 629 seconds (10 minutes 29 seconds); the abandonment rate was 22.7%.

Please see Exhibit G, Tab 1, pages 3 to 4, paragraphs 6 to 7 for information pertaining to the increase in abandonment rates in 2021.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 1, Page 2

Preamble:

EGI evidence states:

The MRPM represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the metric is 0.5% and Enbridge Gas achieved a level of 5.0% in 2021. The result for 2019 was 0.7% and 4.4% in 2020. Enbridge Gas has faced challenges meeting the target since 2019 for several reasons, including the decision of a key meter reading vendor to no longer provide meter reading service resulting in the need to onboard a new vendor.

Question(s):

Please provide the respective amounts invested in the meter read, billing and customer accounting for EGI:

a) Using 2020 actual costs
b) Using 2021 actual costs

Response:

a) The O&M costs in 2020 to support meter reads, billing and customer accounting was $47.6 million.

b) The O&M costs in 2021 to support meter reads, billing and customer accounting was $51.8 million.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit A, Tab 3, Appendix A

Question:

a) Please indicate the prescribed interest rate(s) used for each quarter of 2022 in calculating the interest costs shown in the table.

b) If required, please update the table to reflect the use of the most current OEB approved prescribed interest rates for each quarter, assuming that the prescribed rate for the fourth quarter of 2022 is equal to that of the third quarter of 2022.

Response

a) The prescribed interest rates used in calculating the interest costs in Exhibit A, Tab 3, Appendix A were 0.57% in Q1 and 1.02% in Q2. Enbridge Gas used the OEB prescribed Q2 2022 interest rate of 1.02% as a forecast when calculating the interest costs shown in Exhibit A, Tab 3, Appendix A as that was the rate that was available at the time of filing.

b) Please see Attachment 1 updated with forecast interest costs calculated at the OEB prescribed Q3 2022 interest rate of 2.20% for the remainder of the year.

ENBRIDGE GAS
DEFERRAL & VARIANCE ACCOUNT
ACTUAL & FORECAST BALANCES

Line No.	Account Description	Account Acronym		Col. 1 Forecast for clearance at January 1, 2023 Principal ($000's)	Col. 2 Interest ($000's)	Col. 3 Total ($000's)	Col.4 Reference to Evidence
	EGD Rate Zone Commodity Related Accounts						
1.	Storage and Transportation D/A	2021 S&TDA		7,942.5	145.5	8,088.0	D-1, Page 2
2.	Transactional Services D/A	2021 TSDA		(3,904.1)	(58.5)	(3,962.6)	D-1, Page 4
3.	Unaccounted for Gas V/A	2021 UAFVA		753.9	9.0	762.9	D-1, Page 6
4.	Total commodity related accounts			4,792.2	96.0	4,888.2	
	EGD Rate Zone Non Commodity Related Accounts						
5.	Average Use True-Up V/A	2021 AUTUVA		14,934.3	223.6	15,157.9	D-1, Page 10
6.	Gas Distribution Access Rule Impact D/A	2021 GDARIDA		-	-	-	D-1, Page 23
7.	Deferred Rebate Account	2021 DRA		4,359.4	79.2	4,438.6	D-1, Page 12
8.	Transition Impact of Accounting Changes D/A	2021 TIACDA		4,435.8	-	4,435.8	D-1, Page 1
9.	Electric Program Earnings Sharing D/A	2021 EPESDA		-	-	-	D-1, Page 23
10.	Open Bill Revenue V/A	2021 OBRVA		-	-	-	D-1, Page 23
11.	Ex-Franchise Third Party Billing Services V/A	2021 EXFTPBSVA		-	-	-	D-1, Page 23
12.	RNG Injection Service V/A	2021 RNGISVA		-	-	-	D-1, Page 23
13.	OEB Cost Assessment V/A	2021 OEBCAVA		2,550.3	46.6	2,596.9	D-1, Page 13
14.	Dawn Access Costs D/A	2021 DACDA		1,968.0	29.5	1,997.5	D-1, Page 16
15.	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Dif	2021 P&OPEBFAVACPDVA		-	-	-	D-1, Page 23
16.	Total EGD Rate Zone (for clearance)			33,040.0	474.8	33,514.9	
	Union Rate Zones Gas Supply Accounts	OEB Account Number					
17.	Upstream Transportation Optimization	179-131	2021	8,616.3	129.0	8,745.3	E-1, Page 6
18.	Spot Gas Variance Account	179-107	2021	-	-	-	E-1, Page 58
19.	Unabsorbed Demand Costs Variance Account	179-108	2021	(1,665.6)	(38.1)	(1,703.7)	E-1, Page 1
20.	Base Service North T-Service TransCanada Capacity	179-153	2021	83.5	1.5	85.0	E-1, Page 52
21.	Total Gas Supply Accounts			7,034.2	92.4	7,126.6	
	Union Rate Zones Storage Accounts						
22.	Short-Term Storage and Other Balancing Services	179-70	2021	3,576.9	53.6	3,630.5	E-1, Page 8
	Union Rate Zones Other Accounts						
23.	Normalized Average Consumption	179-133	2021	18,997.4	351.4	19,348.8	E-1, Page 13
24.	Deferral Clearing Variance Account	179-132	2021	(3,120.4)	(63.7)	(3,184.1)	E-1, Page 21
25.	OEB Cost Assessment Variance Account	179-151	2021	907.1	16.8	923.9	E-1, Page 49
26.	Unbundled Services Unauthorized Storage Overrun	179-103	2021	-	-	-	E-1, Page 58
27.	Gas Distribution Access Rule Costs	179-112	2021	-	-	-	E-1, Page 58
28.	Conservation Demand Management	179-123	2021	-	-	-	E-1, Page 58
29.	Parkway West Project Costs	179-136	2021	(603.3)	(10.0)	(613.3)	E-1, Page 25
30.	Brantford-Kirkwall/Parkway D Project Costs	179-137	2021	(45.0)	(0.7)	(45.7)	E-1, Page 29
31.	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	179-142	2021	24.0	0.6	24.6	E-1, Page 41
32.	Lobo D/Bright C/Dawn H Compressor Project Costs	179-144	2021	(112.1)	(4.2)	(116.3)	E-1, Page 44
33.	Burlington-Oakville Project Costs	179-149	2021	(51.0)	(0.8)	(51.8)	E-1, Page 47
34.	Panhandle Reinforcement Project Costs	179-156	2021	(3,162.0)	(54.6)	(3,216.6)	E-1, Page 53
35.	Sudbury Replacement Project	179-162	2021	-	-	-	E-1, Page 58
36.	Parkway Obligation Rate Variance	179-138	2021	-	-	-	E-1, Page 58
37.	Unauthorized Overrun Non-Compliance Account	179-143	2021	-	-	-	E-1, Page 58
38.	Pension and OPEB Forecast Accrual vs. Actual Cash Payment Dif	179-157	2021	-	(1,345.6)	(1,345.6)	E-1, Page 56
39.	Unaccounted for Gas Volume Variance Account	179-135	2021	20,501.3	287.0	20,788.3	E-1, Page 31
40.	Unaccounted for Gas Price Variance Account	179-141	2021	8,151.4	123.3	8,274.8	E-1, Page 38
41.	Total Other Accounts			41,487.4	(700.4)	40,787.1	
42.	Total Union Rate Zones (for clearance)			52,098.5	(554.4)	51,544.1	
	EGI Accounts						
43.	Earnings Sharing D/A	179-382	2021	-	-	-	C-1, Page 1
44.	Tax Variance - Accelerated CCA - EGI	179-383	2021	(19,162.6)	(339.1)	(19,501.7)	C-1, Page 12
45.	IRP Operating Costs Deferral Account	179-385	2021	57.7	0.9	58.6	C-1, Page 15
46.	IRP Capital Costs Deferral Account	179-386	2021	-	-	-	C-1, Page 1
47.	Expansion of Natural Gas Distribution Systems V/A	179-380	2021	-	-	-	C-1, Page 1
48.	Total EGI Accounts (for clearance)			(19,104.9)	(338.2)	(19,443.1)	
49.	Total Deferral and Variance Accounts (for clearance)			66,033.7	(417.8)	65,615.8	
	Not Being Requested for Clearance						
50.	Accounting Policy Changes D/A - Pension - EGI	179-120	2021	169,431.8	-	169,431.8	C-1, Page 2
51.	Accounting Policy Changes D/A - Other - EGI	179-120	2019	(1,749.5)	(63.1)	(1,812.6)	C-1, Page 2
52.	Accounting Policy Changes D/A - Other - EGI	179-120	2020	(14,789.5)	(336.7)	(15,126.2)	C-1, Page 2
53.	Accounting Policy Changes D/A - Other - EGI	179-120	2021	(13,864.6)	(250.5)	(14,115.1)	C-1, Page 2
54.	Tax Variance - Integration Capital Additions - EGI	179-383	2020	(3,736.3)	(41.1)	(3,777.4)	C-1, Page 12
55.	Tax Variance - Integration Capital Additions - EGI	179-383	2021	(10,462.6)	(115.1)	(10,577.7)	C-1, Page 12
56.	Incremental Capital Module Deferral Account - EGD	2020 ICMDA	2020	(254.0)	(4.7)	(258.7)	C-1, Page 1
57.	Incremental Capital Module Deferral Account - EGD	2021 ICMDA	2021	175.5	3.1	178.6	C-1, Page 1
58.	Incremental Capital Module Deferral Account - UGL	179-159	2019	(6,869.6)	(236.6)	(7,106.2)	C-1, Page 1
59.	Incremental Capital Module Deferral Account - UGL	179-159	2020	(5,615.4)	(125.0)	(5,740.4)	C-1, Page 1
60.	Incremental Capital Module Deferral Account - UGL	179-159	2021	(14,353.4)	(231.9)	(14,585.3)	C-1, Page 1
61.	Impacts Arising from the COVID-19 Emergency D/A - EGI	2020 IACEDA	2020	1,377.5	28.5	1,406.0	C-1, Page 1
62.	Impacts Arising from the COVID-19 Emergency D/A - EGI	2021 IACEDA	2021	34.3	0.5	34.8	C-1, Page 1
63.	Total of Accounts not being requested for clearance			99,324.2	(1,372.7)	97,951.5	

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit B, Tab 1, Page 3

Question:

a) What is the gross revenue sufficiency for 2021 based on the OEB approved formula return on equity of 8.34%?

b) What is the magnitude of the net and gross revenue deficiency of a 100-basis point difference in the return on equity for 2021?

Response

The responses below are provided in reference to Exhibit B, Tab 1 Updated September 2, 2022:

a) Removing the OEB-approved deadband of 150 basis points above the Board formula return on equity (ROE) for 2021, the gross earnings sufficiency would be $57.7 million as compared to the Board formula ROE of 8.34%. This is reflective of a $104.5 million change as compared to the $46.8 million deficiency inclusive of the 150 basis point deadband.

b) A 100 basis point increase (or decrease) in ROE would result in a gross sufficiency/deficiency change of $69.7 million or a net change of $51.2 million for 2021.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit B, Tab 1, Pages 4 & 5

Question:

Has EGI made and changes to the process related to the calculation of the return on equity from that used for 2020 and 2019? If there are any changes, please explain fully the change and the reason for the change.

Response

No, Enbridge Gas has not made any process changes related to the calculation of the return on equity from that used in 2020 and 2019, and as described in Exhibit B, Tab 1, pages 4 and 5.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 4

Question:

a) Please explain the meaning of a negative number under additions to gross plant. For example, line 53 on page 4 shows (23.6) for additions to measuring and regulating equipment for Union rate zones underground storage plant.

b) Please explain why the average of monthly averages shown on line 102, sub-total Union rate zones general plant of $437.6 is higher than both the opening balance of $418.6 and the closing balance of $419.5. Is this related to the timing of the retirements compared to the timing of the additions?

c) Please explain the timing associated with the retirement of an asset such as computers shown on line 95 of $69.1 relative to the additions shown of $53.0.

d) Please explain how adjustments to accumulated depreciation are impacted for each of (a), (b) and (c) above.

Response

Responses below are provided in relation to Exhibit B, Tab 1, Schedule 4 updated September 2, 2022:

a) The resulting negative $23.6 million in Line 53 additions primarily pertains to a reclassification in 2021 of assets from asset class 457 - Underground Storage to asset class 467 - Transmission Plant. The negative amount in line 53 is offset in Line 62 additions. This reclassification also included an associated reclassification of accumulated depreciation included on page 5, in Line 48, and offset in Line 55. There was no impact to rate base as a result of the reclassification.

Other negative additions presented in 2021 gross plant would have also resulted from similar reclassifications between asset classes with associated reclassifications of accumulated depreciation, resulting in no overall rate base impact.

b) Yes, the average of monthly averages balance of $437.5 million is impacted by the timing of the associated additions and retirements of assets during the year. In particular, the balances for Union Rate Zones - General Plant were impacted by asset class 483 – Office Equipment additions which primarily went into service between June and September, and retirements which occurred primarily in September and December.

c) The additions in Union Rate Zones - General Plant for asset class 483 – Office Equipment shown on Line 95 primarily went into service between June and September whereas retirements occurred primarily in September and December. The asset additions and retirements are independent of each other.

d) As noted above in response a), the reclassifications of gross plant between asset classes that occurred were offset by associated reclassifications of accumulated depreciation, resulting in no impact to rate base in 2021.

   As for the impacts to accumulated depreciation of the timing of additions and retirements noted above in responses b) and c), depreciation begins the month after assets go into service and ceases the month following retirement.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit B, Tab 2 Schedule 2, page 2 & Exhibit B, Tab 1, Schedules 1 & 2

Question:

Please provide versions of Schedules 1 & 2 in Exhibit B, Tab 1 that reflect the normalized total utility revenue of $4,640.1 shown on page 2 of Exhibit B, Tab 2, Schedule 2 and show the resulting normalized actual return on equity for 2021.

Response

Please refer to Attachment 1 of this response, which addresses the request above in relation to Exhibit B, Tab 1, Schedules 1 & 2 updated September 2, 2022.

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

FOR THE YEAR ENDED DECEMBER 31, 2021

Line No.	Col. 1 Description	Col. 2 Reference	Col. 3 Actual
1.	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
			($Millions) & (%'s
2.	Utility Income before Income Tax	(Ex. B, Tab 1, Sch. 2)	938.9
3.	Less: Income Taxes	(Ex. B, Tab 1, Sch. 3)	56.2
4.	Utility Income		882.6
5.	Utility Rate Base	(Ex. B, Tab 1, Sch. 4)	14,221.6
6.	Indicated Return on Rate Base %	(line 4 / line 5)	6.206%
7.	Less: Required Rate of Return %	(Ex. B, Tab 1, Sch. 5)	6.166%
8.	(Deficiency) / Sufficiency %		0.040%
9.	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	5.7
10.	Provision for Income Taxes		2.1
11.	Gross Earnings (Deficiency) / Sufficiency	(line 9 / 73.5%)	7.7
12.	50% Earnings sharing to ratepayers	(if line 11 > 1, line 11 x 50%)	3.9
13.	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
14.	Utility Income before Income Tax	(Ex. B, Tab 1, Sch. 2)	938.9
15.	Less: Long Term Debt Costs	(Ex. B, Tab 1, Sch. 5)	371.3
16.	Less: Short Term Debt Costs	(Ex. B, Tab 1, Sch. 5)	1.9
17.	Less: Cost of Preferred Capital	(Ex. B, Tab 1, Sch. 5)	0.0
18.	Net Income before Income Taxes		565.7
19.	Less: Income Taxes	(Ex. B, Tab 1, Sch. 3)	56.2
20.	Net Income Applicable to Common Equity	(line 18 - line 19)	509.5
21.	Common Equity	(Ex. B, Tab 1, Sch. 5)	5,119.8
22.	Approved ROE (including deadband before earning sharing) %	(Board-approved + 150bp)	9.840%
23.	Achieved Rate of Return on Equity %	(line 20 / line 21)	9.951%
24.	Resulting (Deficiency) / Sufficiency in Return on Equity %		0.111%
25.	Net Earnings (Deficiency) / Sufficiency	(line 21 x line 24)	5.7
26.	Provision for Income Taxes		2.1
27.	Gross Earnings (Deficiency) / Sufficiency	(line 25 / 73.5%)	7.7
28.	50% Earnings sharing to ratepayers	(if line 27 > 1, line 27 x 50%)	3.9

EGI UTILITY INCOME - WEATHER NORMALIZED
2021 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)	4,513.2	-	126.9	(i)	4,640.1
2.	Transportation	(Ex. B, Tab 2, Sch. 3)	143.1	0.4	(0.8)	(ii)	141.9
3.	Storage	(Ex. B, Tab 2, Sch. 3)	159.7	153.6	(0.1)	(iii)	6.0
4.	Other operating revenue	(Ex. B, Tab 2, Sch. 4)	64.3	1.8	(13.4)	(iv)	49.1
5.	Other income	(Ex. B, Tab 2, Sch. 4)	7.2	-	(6.3)	(viii)	0.9
6.	Total operating revenue		4,887.5	155.8	106.3		4,838.0
7.	Gas costs		2,146.2	20.2	89.5	(i)	2,215.4
8.	Operation and maintenance	(Ex. B, Tab 3, Sch. 1)	938.7	14.1	(4.0)	(v)	920.6
9.	Depreciation and amortization expense		676.8	14.1	(22.6)	(vi)	640.1
10.	Fixed financing costs		6.3	0.0	0.5	(vii)	6.8
11.	Municipal and other taxes		117.9	1.7	-		116.2
12.	Cost of service		3,885.9	50.2	63.4		3,899.1
13.	Utility income before income taxes						938.9
14.	Income tax expense	(Ex. B, Tab 1, Sch. 3)					56.2
15.	Utility income						882.6

Notes on Adjustments:

(i)	Weather normalization (remove revenue impact warmer than normal weather)	159.5
	Reclassification of Union rate zone optimization revenue as a cost of gas reduction	(15.4)
	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues	(17.2)
		126.9
(i.1)	Weather normalization (remove gas cost impact warmer than normal weather)	104.9
	Reclassification of Union rate zone optimization revenue as a cost of gas reduction	(15.4)
		89.5
(ii)	Elimination of the Union rate zone shareholder portion of net optimization activity (before tax)	(0.8)
(iii)	Elimination of the Union rate zone shareholder portion of net short-term storage revenue (before tax)	(0.1)
(iv)	Adjust EGD rate zone OBA costs to reflect EB-2013-0099 approved unit costs agreed to be used for determining net revenu	(4.3)
	Elimination of EGD rate zone Open Bill shareholder incentive	0.3
	Elimination of EGD rate zone shareholder portion of transactional service revenues	(1.8)
	Elimination of demand-side management incentive	(6.9)
	Elimination of EGD rate zone net revenue from ABC T-service, considered to be non-utility	(0.8)
		(13.4)
(v)	Elimination of donations	(3.6)
	Elimination of OEB Penalty assessed in EB-2021-0204 (Assurance of Voluntary Compliance and Administrative Penalty)	(0.1)
	Elimination of non-utility costs and expenses relating to support of the EGD rate zone ABC T-service program	(0.3)
		(4.0)
(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	0.5
(viii)	Elimination of interest income from investments not included in utility rate base	(0.1)
	Eiliminate loss on sale of SLG assets	-
	Elimination of interest income from affiliates	(1.6)
	Elimination of Part VI.1 tax	(4.6)
		(6.3)

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1

Question:

Paragraph 10 notes that one of the drivers of the increase in outside services in 2021 is related to increases in regulatory consulting costs related to rebasing preparations. Please quantify these costs and confirm that these costs will not be recoverable in the upcoming rebasing application.

Response

Regulatory consulting costs were $1.3 million higher in 2021 compared to 2020. Rebasing consulting activities accounted for $0.9 million and higher OEB and intervenor costs amounted to $0.4 million.

These costs were included in 2021 utility earnings and as a result will not form part of the rebasing application.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit F, Tab 1

Question:

Paragraph 8 states that consistent with the TVDA, EGI has split the debit balance of $0.058 million in the 2021 IRP Operating Cost Deferral Account balance between the EGD and Union rate zones in proportion to the 2018 actual rate base for each rate zone. Footnote 3 then references page 16 of the EB-2020-0134 Decision and Order dated May 6, 2021.

a) Please indicate the specific reference in the EB-2020-014 Decision and Order that deals with the allocation of the IRP Operating Cost Deferral Account.

b) Is this the first year that the balance in the account is being allocated and disposed of?

c) Did EGI consider any method of allocating these operating costs other than based on historical rate base? If not, why not?

Response

a) Clearance of the IRP Operating Cost Deferral Account is being requested for the first time with the current application. The footnote reference to the EB-2020-0134 Decision and Order was included in the evidence as a reference to the OEB's approval of the methodology for the Tax Variance Deferral Account (TVDA).

b) Please see part a).

c) Please see the response at Exhibit I.STAFF.12.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit F, Tab 3, Schedule 1 & 5

Question:

a) Please explain the difference in the M1 unit rate of 0.7547 for sales/system gas and 0.4169 for bundled t-service shown in line 11 of Exhibit F, Tab 3, Schedule 1 and the figures shown on lines 1 through 3 (0.0870 delivery, 0.3378 commodity, 0.4248 sales service impact) on page 1 of Exhibit F, Tab 3, Schedule 5.

b) Please explain the difference in the M2 unit rate of 1.5045 for sales/system gas and 1.1667 for bundled t-service shown in line 12 of Exhibit F, Tab 3, Schedule 1 and the figures shown on lines 15 through 17 (0.5105 delivery, 0.3378 commodity, 0.8483 sales service impact) on page 1 of Exhibit F, Tab 3, Schedule 5.

Response

a) Exhibit F, Tab 3, Schedule 1 has been corrected in evidence.

b) Please see the response to part a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit F, Tab 1 & Exhibit F, Tab 3, Schedule 3 & Exhibit E, Tab 1

Preamble:

Paragraph 14 in Exhibit F, Tab 1 states that the allocation of account balances to customer classes use the same methodologies approved by the OEB in previous years with the exception of the Deferral Clearing Variances Account (179-132) ("DCVA") in the Union rate zone.

Paragraph 15 in Exhibit F, Tab 1 states that EGI proposes to split the DCVA balance between general service and contract customers and that the allocation of general service and contract customer balances to rate classes is based on respective volumes. The evidence then refers to Exhibit F, Tab 3, Schedule 3 for the proposed allocation.

Line 8 of Exhibit F, Tab 3, Schedule 3 shows credits for general service classes for the DCVA and debits for the contract rate classes, but does not explain how this is arrived at.

Question:

a) Please provide a table that shows the calculations and allocation factors used to arrive at the allocation of the DCVA balance to the rate classes.

b) Please explain fully, how the composition of the DCVA balance discussed in Exhibit E, Tab 1, page 21, impacts the allocation of the amounts to the various rate classes, if at all

Response

a) Please see Attachment 1 for the allocation of the DCVA by account disposition balance. The DCVA account balance for each disposition is split between general service and in-franchise contract customers based on information provided by

Enbridge Gas's billing systems. The general service and in-franchise contract account balances are allocated to the respective rate classes in proportion to 2021 actual volumes.

The credit balances accruing to general service rate classes are a result of the prospective disposition methodology that was used by Union for disposition of balances from the 2017/18 DSM Deferrals Disposition, 2019 Earnings Sharing and Deferrals Disposition, and 2020 FCPP proceedings.

b) The proposed allocation approach for the 2021 DCVA balance by splitting it into general service and in-franchise contract and allocating each to the respective rate classes is in response to the change in disposition methodology from prospective disposition to a one-time adjustment disposition for general service rate classes. Enbridge Gas's customer information system (CIS) is no longer able to identify the balance at a rate class level that was possible when the prospective disposition methodology was used. As a result, a harmonized allocation approach was proposed for all DCVA account disposition balances in 2021. That is, the Union rate zones' DCVA allocation approach to use actual volumes is consistent with the EGD rate zone's Deferral Rebate Account allocation which uses actual volumes.

   The composition of the DCVA balances discussed at Exhibit E, Tab 1, page 21 was used to identify general service and contract split but was not used in the allocation to rate classes because the rate class level of detail was not available for all account disposition balances.

ENBRIDGE GAS INC.
Allocation of Deferral Clearing Variance Account (DCVA) Balance by Account Disposition

Line No.	Particulars ($000's)	General Service Total	In-Franchise Contract Total	Account Total	General Service Allocation (1)					In-Franchise Contract Allocation (2)											
					Rate 01	Rate 10	M1	M2	Total	Rate 20	Rate 100	Rate 25	M4	M5A	M7	M9	M10	T1	T2	T3	Total
		(a)	(b)	(c) = (a)+(b)	(d)	(e)	(f)	(g)	(h)=sum(d:g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)=sum(h:r)
1	2021 Actual Volumes	5,252,686	8,585,841	13,838,527	929,941	311,794	2,897,087	1,113,864	5,252,686	637,600	958,587	143,898	610,808	63,511	686,353	90,096	320	453,007	4,700,474	241,187	8,585,841
	Account Disposition																				
2	2017/18 DSM Deferrals	(1,990)	-	(1,990)	(352)	(118)	(1,097)	(422)	(1,990)	-	-	-	-	-	-	-	-	-	-	-	-
3	2019 Earning Sharing and Deferrals	(2,071)	89	(1,982)	(367)	(123)	(1,142)	(439)	(2,071)	7	10	1	6	1	7	1	0	5	49	3	89
4	2019 FCPP	(291)	-	(291)	(52)	(17)	(160)	(62)	(291)	-	-	-	-	-	-	-	-	-	-	-	-
5	2019 DSM Deferrals	1,154	(33)	1,122	204	69	637	245	1,154	(2)	(4)	(1)	(2)	(0)	(3)	(0)	(0)	(2)	(18)	(1)	(33)
6	Subtotal	(3,197)	57	(3,140)	(566)	(190)	(1,763)	(678)	(3,197)	4	6	1	4	0	5	1	0	3	31	2	57
7	Interest	(26)	0	(25)	(5)	(2)	(14)	(5)	(26)	0	0	0	0	0	0	0	0	0	0	0	0
8	Total	(3,223)	57	(3,166)	(571)	(191)	(1,777)	(683)	(3,223)	4	6	1	4	0	5	1	0	3	31	2	57

Notes:
(1) The allocation of DCVA general service account balances (column (a)) to rate classes is in proportion 2021 actual general service volumes (line 1).
(2) The allocation of DCVA in-franchise contract account balances (column (b)) to rate classes is in proportion 2021 actual in-franchise contract volumes (line 1).

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit G, Tab 1

Question:

a) Please provide the number of customers for each of 2019, 2020 and 2021 that were contacted to reschedule work used in the calculation of the TRMA as noted in paragraph 4.

b) Please provide the number of meters for each of 2019, 2020 and 2021 with no reads for four consecutive months used in the calculation of the MRPM as noted in paragraph 5. Please also provide the number of active meters to be read for the same years.

c) Please provide the number of calls received for each of 2019, 2020 and 2021, along with a monthly breakdown of the number of calls received for each year used in the calculation of the CASL as noted in paragraph 6.

d) Please provide the number of callers that hung up while waiting for a live operation in each of 2019, 2020 and 2019 used in the calculation of the abandon rate as noted in paragraph 7.

Response

a) The number of appointments where reschedules were required and met, plus the total number of reschedules required are listed below. In addition, the reschedules not met as a percentage of total appointments is included.

Table 1

Number of Appointments Rescheduled Within Two Hours

	Reschedules Met	Total Reschedules	Percentage Met
2019	2,624	2,706	97.0%
2020	2,554	2,626	97.3%
2021	1,729	1,783	97.0%

b) The number of meters with no reads for four consecutive months and the number of active meters for 2019, 2020, and 2021 are listed below.

Table 2

Number of Meters With No Read for Four Consecutive Months or More

	Meters with No Read for Four Consecutive Months or More	Total Number of Active Meters to be Read	Percentage of Meters with No Read for Four Consecutive Months or More
2019	306,722	44,719,845	0.69%
2020	1,969,224	45,208,820	4.36%
2021	2,290,800	45,822,429	5.00%

c) The number of calls received and answered within 30 seconds for 2019, 2020, and 2021 and the monthly breakdown are listed below.

Table 3

2019 - Number of Calls Received and Answered Within 30 Seconds

2019			
	Calls Answered Within 30 Seconds	Total Calls	Percentage Met
January	232,403	283,997	81.83%
February	196,653	245,257	80.18%
March	231,276	298,723	77.42%
April	227,720	286,859	79.38%
May	247,727	321,043	77.16%
June	249,341	309,449	80.58%
July	253,764	330,705	76.73%
August	256,891	332,505	77.26%
September	234,440	297,662	78.76%
October	251,562	320,873	78.40%
November	259,192	317,003	81.76%
December	192,226	244,247	78.70%
	2,833,195	3,588,323	78.96%

Table 4

2020 - Number of Calls Received and Answered Within 30 Seconds

2020			
	Calls Answered Within 30 seconds	Total Calls	Percentage Met
January	221,754	281,267	78.84%
February	213,378	270,585	78.86%
March	195,392	241,523	80.90%
April	157,373	192,346	81.82%
May	179,823	213,299	84.31%
June	177,965	213,213	83.47%
July	171,791	243,629	70.51%
August	169,393	275,884	61.40%
September	190,803	268,775	70.99%
October	202,124	289,408	69.84%
November	200,041	282,688	70.76%
December	176,598	228,804	77.18%
	2,256,435	3,001,421	75.18%

Table 5

2021 - Number of Calls Received and Answered Within 30 Seconds

2021			
	Calls Answered within 30 seconds	Total Calls	Percentage Met
January	198,563	275,958	71.95%
February	192,847	250,236	77.07%
March	227,309	281,746	80.68%
April	178,109	256,173	69.53%
May	169,450	254,034	66.70%
June	180,983	289,307	62.56%
July	242,498	379,354	63.92%
August	252,044	351,924	71.62%
September	194,825	337,022	57.81%
October	175,423	330,994	53.00%
November	168,935	333,919	50.59%
December	138,050	268,664	51.38%
	2,319,036	3,609,331	64.25%

d) The number of callers that hung up while waiting for a live operator compared with the number of calls requesting a live agent are listed below.

Table 6

Number of Calls Abandoned While Waiting for a Live Agent

	Calls Abandoned While Waiting for a Live Agent	Total Calls Requesting a Live Agent	Abandon Rate (%)
2019	58,423	2,326,628	2.51%
2020	97,556	1,810,867	5.39%
2021	309,476	1,928,841	16.04%

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers (OGVG)

Interrogatory

Reference:

Exhibit C / Tab 1 / pp. 4, 8, 9, 10, 11
EB-2021-0149 Exhibit C Tab 1 Page 4
EB-2020-0134 Exhibit C Tab 1 Page 5

Preamble:

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

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. (emphasis added)

Approximately $39 million of Actuarial Losses were amortized between February 27, 2017 and December 31, 2018, resulting in a balance of $211 million remaining in Union's AOCI at amalgamation (the Amalgamation) (January 1, 2019).
As noted in the EB-2020-0134 Interrogatory Response to LPMA, the amortization of actuarial gains/losses and past service costs is a component of accrual-based pension expense. Base rates for both the EGD and Union rate zones include a provision for accrual-based pension expenses as part of O&M. (emphasis added)

The Pension Expense drawdown against the APCDA for 2021 has been calculated by EGI to be $12,033,400.

The Pension Expense drawdown for 2019 and 2020 were calculated by EGI to be $17,509,000 and $12,288,000 respectively

<u>Question(s):</u>

a) Please explain how EGI calculates the amount to be drawn down against the APCDA as annual pension related amortization expense included in rates.

b) Please explain why the amount drawn down against the APCDA as annual pension related amortization expense included in rates appears to be declining (i.e. from $17.509M in 2019 to $12.033M in 2021).

<u>Response:</u>

a- b)

In determining the amount to be drawn down against the APCDA balance representing pre-2017 unamortized actuarial losses, Enbridge Gas relies on information provided by its external pension expert, Mercer. Mercer provides details on annual pension accrual costs prepared in accordance with the United States Generally Accepted Accounting Principles (US GAAP) (ASC 715 – Compensation – Retirement Benefits).

Under US GAAP, a corridor approach to the recognition of actuarial gains and losses, such that only actuarial gains and losses exceeding 10% of the greater of plan assets or obligations is recognized in the income statement and spread over the maximum period of the employees' remaining service period. The corridor amount is recalculated annually by Mercer on behalf of Enbridge Gas, as well as the resulting accrual-based amortization of those gains and losses. Therefore, the amortization of losses is not on a straight-line basis and will vary annually.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers (OGVG)

Interrogatory

Reference:

Exhibit E / Tab 1 / p. 58

Preamble:

Accounts with A Zero Balance-Union Rate Zones

Unauthorized Overrun Non-Compliance Account

Question(s):

a) Is there no balance in the Unauthorized Overrun Non-Compliance Account for 2021 because there were no interruptions in 2021, or because there were no unauthorized overruns during interruptions in 2021? If the latter, please provide a summary of the interruptions (location and duration) experienced by EGI in the Union Rate Zone in 2021.

Response:

There is no balance in the Unauthorized Overrun Non-Compliance Account for 2021 because all customers complied with the distribution interruptions in that year. Table 1 provides a summary of the distribution interruptions in the Union rates zones for 2021.

Table 1
2021 Distribution Interruption Summary

Line No.	Rate Zone	Start Date/Time	Location	Calendar Days
1	Union North	August 9, 2021	Kirkland Lake	50
2	Union North	October 23, 2021	Napanee	2
3	Union South	January 19, 2021	Cambridge	13
4	Union South	January 28, 2021	Dunnville	3
5	Union South	February 4, 2021	Cambridge	2
6	Union South	February 4, 2021	Dunnville	1
7	Union South	February 7, 2021	Dunnville	11
8	Union South	February 16, 2021	Cambridge	1
9	Union South	February 20, 2021	Dunnville	2
10	Union South	August 9, 2021	Sarnia	2

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, p. 2, 3

Question(s):

Corporate Shared Services have increased by 16.1% from 2020 to 2021. With respect to CSS, please provide:

a) A complete breakdown of CSS charges, by category, for each of 2019 through 2021, with explanations of all variances in excess of 5% from year to year.

b) The most recent breakdown of all CSS charges in the Enbridge Inc. group of companies, with explanations of how those charges have been allocated between affiliates (e.g. based on FTEs, rate base, etc.).

c) A full list of all OM&A and capital costs in 2021 in categories other than CSS that have been reduced due to increases in CSS charges, with a comparison of the reduction and the related CSS increase and an explanation of any anomalies (such as changes in service levels).

d) The current agreement between Enbridge Inc. (or any other affiliate providing CSS) and the Applicant with respect to CSS charges.

e) The full calculation of all stock-based compensation charges allocated to the Applicant for each of 2019, 2020, and 2021.

Response:

a) Please see the restatement of CSS as explained in FRPO #5. While it does not change total O&M for 2020 and 2021, it lowers the allocation of benefits costs for CSS in 2020 and results in a 24% increase in CSS costs between 2020 and 2021.

CSS charges are allocated by the functional service provided, not by expense categories. As a result, variance analyses on CSS are carried out at the functional service level and supports the restatement of CSS costs.

And with the restatement noted please refer to Attachment 1 for the breakdown of CSS charges with variance explanations as requested from year to year.

b) Costs are assigned and allocated to Enbridge business segments using the Central Functions Cost Allocation Methodology (CFCAM) which groups costs into (1) Directly Attributable Costs, (2) Indirect Costs, and (3) Direct Charges. Only the first two are allocated; the third is a direct cost to the segment. Directly Attributable Costs are allocated based on specific drivers that reflect causality and materiality. Indirect Costs apply to the whole enterprise and are allocated based on a three-factor formula (3FF) comprised of payroll for permanent and contract employees, gross book value for PP&E, and revenue. The costs received for each Central Function listed in part a) of this response can be a combination of directly attributed and indirect costs and direct charges. Examples of cost drivers used to allocate costs include direct attribution, time estimates and headcount.

c) CFCAM has been in place since 2018 although refinements have been made in 2019 and 2020 that shifted costs from business segments to reflect greater centralization. There are no material reductions in O&M and capital costs in 2021 associated with the increase in CSS costs which is predominantly due to external cost pressures as originally described in Exhibit B, Tab 3, Schedule 1, page 3.

d) The Intercorporate Services Agreement between Enbridge Inc. and Enbridge Gas effective January 1, 2019 is included at Attachment 2.

e) The calculation of all stock-based compensation (SBC) charges is performed in accordance with USGAAP and policies and assumptions as described in Enbridge Inc.'s audited financial statements for 2021 (pages 22, 54-56)[1].

SBC was allocated to EGI using a combination of direct attribution and indirect allocation of the general cost pool. SBC amounts for central function employees are inherent within CSS (Line 13).

$ Millions	2019	2020	2021
SBC	23.8	23.1	28.8

[1]Enbridge Inc. Quarterly and Annual Reports. https://www.enbridge.com/investment-center/reports-and-sec-filings/investor-documents-and-filings, 2021 Q4 MDA and Financials

Central Functions (CSS) O&M

Line No	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2019-2020 Variance	2020-2021 Variance	2019-2020 Variance (%)	2020-2021 Variance (%)	2019 - 2020 Variance	2020 - 2021 Variance
1	Finance & Insurance	EGI	35.7	36.6	43.8	0.9	7.1	2%	20%		As noted in EB-2022-0110 Exhibit B, Tab 3, Schedule 1, Page 3, paragraph 7, increase is primarily related to higher insurance costs from market conditions brought about by heightened pandemic risk. Changing dynamics in the global insurance market have made it difficult for energy companies, including Enbridge, to maintain similar levels of coverage at historically comparable premiums.
2	HR & Benefits, Real Estate & Workplace Services	EGI	76.2	81.6	105.8	5.4	24.1	7%	30%	Increase in 2020 is primarily related to higher employee benefits costs, higher incentive payments related to stronger performance than 2019, and higher facilities costs.	As noted in EB-2022-0110, Exhibit B, Tab 3, Schedule 1, Page 3, paragraph 7, increase is primarily related to higher pension and benefits costs resulting from a higher actuarial valuation for 2021 as well as continued escalation of health care costs. As well as higher incentive payments related to stronger performance occurred in 2021 versus 2020.
3	Legal	EGI	13.8	11.0	11.0	(2.7)	(0.0)	-20%	0%	Decrease in 2020 reflects the benefits achieved from implementing enterprise contracting for services.	
4	Technology & Information Systems (TIS)	EGI	70.2	66.1	75.0	(4.2)	9.0	-6%	14%	Decrease in 2020 primarily due to the transition to an outsourced contractor services model which matches resourcing based on the Company's technological needs at a given point in time.	As noted in EB-2022-0110 Exhibit B, Tab 3, Schedule 1, Page 3, paragraph 7, increase is primarily related to higher information technology costs driven by cybersecurity investments resulting from government mandates in response to heightened threats to energy companies, deployment and sustainment costs of new technology to support business requirements. The increased costs were incurred in order to mitigate hightened cybersecurity threats beginning in 2021.
5	Depreciation	EGI	20.9	21.2	22.0	0.3	0.8	2%	4%		
6	Other	EGI	21.9	24.9	22.2	3.0	(2.7)	14%	-11%	Various drivers partially offsetting, less than 5% individually.	Various drivers partially offsetting, less than 5% individually.
7	CF Cost Allocations (Gross)	EGI	238.7	241.5	279.7	2.7	38.2	1%	16%		
8	Capitalization		(63.7)	(65.9)	(61.6)	(2.2)	4.3	3%	-7%		
9	CSS (Net)		175.1	175.6	218.1	0.5	42.6	0%	24%		

INTERCORPORATE SERVICES AGREEMENT

ENBRIDGE INC.

– and –

ENBRIDGE GAS INC.

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INTERCORPORATE SERVICES AGREEMENT

THIS AGREEMENT made as of the 1st day of January, 2019 (the "**Effective Date**")

B E T W E E N:

ENBRIDGE INC., a corporation incorporated under the laws of Canada ("**EI**")

- and -

ENBRIDGE GAS INC., a corporation incorporated under the laws of the Province of Ontario ("**EGI**")

WHEREAS EI and Enbridge Gas Distribution Inc. entered into a prior intercorporate services agreement made as of January 1, 2016 (the "**Prior Agreement**");

AND WHEREAS Enbridge Gas Distribution Inc. and Union Gas Limited amalgamated, effective January 1, 2019, to form EGI;

AND WHEREAS EI and EGI intend to terminate the Prior Agreement and replace it, effective from January 1, 2019 (pursuant to Section 2), with this Agreement which reflects an updated cost allocation methodology;

AND WHEREAS EGI wishes to provide to EI and its Affiliates and EGI wishes to receive from EI and its Affiliates certain services, resources and products set forth in Schedule 1 (the "**Services**");

AND WHEREAS the Parties wish to allocate the costs of the Services in accordance with the terms and conditions of this Agreement;

NOW THEREFORE THIS AGREEMENT WITNESSES that in consideration of the premises and mutual covenants hereinafter contained, the Parties agree:

1. Definitions

"Accounting for Intercompany Transactions Policy" means Enbridge's Accounting for Intercompany Transaction Policy, version 1.0, as may be amended from time to time.

"Affiliate" has the meaning set forth in the Code, provided however that:

(a) in respect of a Service Recipient, "Affiliate" shall not include the Service Provider in respect of the applicable Services and any Affiliate of the Service Provider to whom the Service Provider assigns or delegates the performance of such Services; and

(b) in respect of a Service Provider, "Affiliate" shall not include the Service Recipient in respect of the applicable Services.

"Agreement" means this Intercorporate Services Agreement, including its recitals and schedules annexed hereto or otherwise incorporated herein, as may be amended from time to time.

"Business Day" means a day on which banks are open for normal commercial business and which is not a Saturday or a Sunday or statutory holiday.

"CCAM" has the meaning set forth in Article 4.

"CCAM Report" has the meaning set forth in Section 5.2.

"Code" means the OEB's *Affiliate Relationships Code for Gas Utilities*, as amended from time to time.

"Confidential Customer Information" has the meaning set forth in Section 12.4.

"Disclosing Party" has the meaning set forth in Section 12.1.

"Effective Date" has the meaning set forth in the Preamble.

"EGI" has the meaning set forth in the Preamble.

"EI" has the meaning set forth in the Preamble.

"Indemnified Party" has the meaning set forth in Section 11.3(a).

"Indemnifying Party" has the meaning set forth in Section 11.3(a).

"Insolvency Event" means, in the case of a person, that it: (a) files a voluntary application in or for liquidation, receivership or bankruptcy; (b) is subject to the filing of an involuntary petition for bankruptcy if such petition is not discharged or dismissed within sixty (60) days after such petition was filed; (c) is finally and validly declared and adjudged to be liquidated, bankrupt or insolvent; (d) is subject to a resolution passed by its members for the purposes of placing it in voluntary administration; (e) is subject to an order by any court of competent jurisdiction for its winding up; (f) is the subject of an appointment of a receiver or receiver and manager or like officer of all or substantially all of its assets; (g) has a secured party take possession of all or substantially all its assets or has a distress, execution, attachment, sequestration or other legal process levied or enforced on it or against all or substantially all of its assets; and such secured party maintains possession, or any such process is not dismissed, discharged, stayed or restrained, in each case within fifteen (15) Business Days thereafter; (h) is the subject of an appointment of an administrator, official manager or like officer in circumstances where it is or is likely to become insolvent; or (i) enters into a scheme or plan of arrangement with its creditors or any of them or declares a moratorium on the payment of its creditors, but does not include any voluntary proceeding for the purpose of amalgamation, reconstruction or reorganization not taken at the request of or to meet the requirements of the creditors of such person.

"OEB" means the Ontario Energy Board, including any successors or permitted assigns.

"Parties" means EI and EGI, and "Party" means any one of EI or EGI.

"Personal Information" has the meaning set forth in Section 12.3.

"Prior Agreement" has the meaning set forth in the Recitals.

"Receiving Party" has the meaning set forth in Section 12.1.

"Representative" means any Service Provider Representative and any Service Recipient Representative.

"Senior Supervisory Personnel" means, with respect to a Party, any director or officer of such Party, and any individual who functions for such Party (or one of its Affiliates with responsibility for such Party or any of its business or operating functions) at a management level equivalent or superior to any individual functioning as Vice-President.

"Services" has the meaning set forth in the Recitals.

"Services Charge" means the amount allocated by EI to EGI pursuant to the CCAM. For greater certainty, the Services Charge shall be the aggregate direct and allocated costs of Services received by EGI less the aggregate cost of Services provided by EGI, as further described in Schedule 2.

"Service Provider" means either Party, when providing Services to the other Party.

"Service Provider Representatives" means a Service Provider, such Service Provider's Affiliates, and its and their respective directors, officers, employees, agents and contractors.

"Service Recipient" means either Party, when receiving Services from the other Party.

"Service Recipient Representatives" means a Service Recipient, such Service Recipient's Affiliates, and its and their respective directors, officers, employees, agents and contractors.

"Term" has the meaning set forth in Section 8.1.

"Third Party Claim" has the meaning set forth in Section 11.3.

2. Other Agreements

Effective as of 11:59 pm EST on December 31, 2018, the Prior Agreement is terminated. Effective as of 12:00 am EST on January 1, 2019, this Agreement shall be in full force and effect.

3. Regulatory Considerations

The Parties acknowledge that this Agreement is subject to any rule or order applicable to EGI made by the OEB pursuant to the *Ontario Energy Board Act*, S.O. 1998, c. 15, Sch. B., including without limitation, the Code. EI agrees to do and to cause its Affiliates to do such things as are reasonably necessary to assist EGI in complying with these rules, including without limitation, promptly complying with all requests either made or authorized by the OEB for information with respect to: (a) the Services; and (b) the cost of providing the Services.

4. Central Services Cost Allocation Methodology

EI, in consultation with EGI, has developed a central services cost allocation methodology attached hereto as Schedule 2 (the "**CCAM**"). The CCAM sets out the purpose, objectives, principles, and procedures for identifying and allocating the costs of the Services received and provided by EI and its Affiliates, including EGI. EGI will use the CCAM to determine the amounts which it will request to be recovered in rates from time to time. For clarity, where a section of this Agreement is inconsistent with the CCAM, the CCAM shall prevail.

5. Allocation Procedures

5.1 Cost allocations shall be made in accordance with the processes and procedures set out in the CCAM, which describes how EI will assign direct costs and calculate the allocable portion of pooled allocable costs of the Services to its Affiliates, including EGI.

5.2 EI, in consultation with its Affiliates, including EGI, shall set the projected CCAM cost allocations for the Services prior to December 31st of the year prior to the year to which the cost allocations apply, or as soon thereafter that such budgeting and cost allocation processes are concluded. As soon as practicable following such process, EI shall provide an annual CCAM report to each Affiliate, including EGI, that is either a Service Provider and/or a Service Recipient, setting out the final projected CCAM cost allocations for the year and the Services Charge to be paid by each Service Recipient (the "**CCAM Report**").

5.3 Upon request by EGI, the Parties shall work together to prepare and execute a confirmation notice substantially in the form set out in Schedule 3 to evidence their agreement with the projected CCAM cost allocations for any year during the Term.

5.4 For clarity, as described further in the CCAM, EI shall true-up the Service Charges, from time to time, if there is a material difference between the projected CCAM cost allocation set out in the CCAM Report for a Service Recipient and the actual costs incurred by the applicable Service Providers in any year during the Term.

6. Payment Procedures

The Parties agree that all Service Charges shall be documented and paid in accordance with the Accounting for Intercompany Transaction Policy, as may be amended from time to time.

7. Service Agreement Review and Amendment Process

This Agreement may be amended from time to time upon the approval in writing of the Parties. Version control and archival storage of all amendments shall be the responsibility of EGI.

8. Term and Termination

8.1 This Agreement shall be effective January 1, 2019 and, subject to Section 8.4 below, shall remain in effect until December 31, 2020 (the "**Term**"). The Term shall be automatically renewed for successive one (1) year periods unless EI or EGI delivers written notice of its intention to terminate this Agreement to the other Parties no later than six (6) months prior to the expiration of the then applicable Term. Notwithstanding the foregoing, the Term shall not extend beyond December 31, 2023 unless otherwise approved by the OEB.

8.2 Upon the occurrence of any of the following events, a Party may terminate this Agreement by giving notice of such termination to the other Party:

(a) the other Party becomes subject to an Insolvency Event;

(b) the other Party becomes subject to proceedings for the dissolution, liquidation or winding-up of such Party; or

(c) the other Party materially breaches any provision of this Agreement (other than the failure to pay) or any Senior Supervisory Personnel of the other Party engages in fraud or gross negligence in the performance of its obligations pursuant to this Agreement and, within sixty (60) days after the giving of notice by the Party wishing to terminate this Agreement specifying the nature of such event or default, the Party responsible for such event or default fails to cure such event or default if such event or default is reasonably remediable within such cure period, or if such event or default is not reasonably remediable within such cure period, the Party responsible for such event or default fails to commence to take, within the sixty (60) day cure period, steps to remedy such event or default and to thereafter proceed diligently and as expeditiously as reasonably possible to cure or remedy such default;

8.3 Any termination under Section 8.2 shall become effective upon the date specified in the notice first described in Section 8.2, which date shall not be earlier than: (a) in the case of any of the termination events in subsection 8.2(a) or 8.2(b), the date of delivery of such notice; or (b) in the case of the termination event in subsection 8.2(c), six (6) months after the date of delivery of such notice, unless otherwise agreed to by the Parties; provided, however, that in the event a Party in good faith disputes the occurrence of the event giving rise to the termination right hereunder, such termination shall not become effective until such dispute is finally determined in accordance with Article 16.

8.4 EI may terminate this Agreement for convenience upon six (6) months prior written notice. EGI may terminate this Agreement for convenience immediately in the event that it ceases to be a direct or indirect wholly owned subsidiary of EI.

8.5 Upon termination or expiration of this Agreement:

(a) all rights and obligations under this Agreement shall cease except for:

(i) liabilities and obligations that have accrued prior to such termination, including the obligation to pay any amounts that have become due and payable prior to such termination; and

(ii) those rights and obligations described in accordance with Section 17.3; and

(b) upon written request, the Parties shall comply with the obligation to return or destroy Confidential Information and Personal Information in accordance with Section 12.6.

8.6 During the period between delivery of a termination notice and the date of termination, the Service Provider shall use commercially reasonable efforts to effect an orderly and seamless transition of the Services to the Service Recipient or a new service provider selected by the Service Recipient. Such commercially reasonable efforts shall include but not be limited to the Service Provider: (a) transferring of all books, logs, documents, reports, records, manuals, policies, programs, data or other records related to the Services, whether in written or electronic form, that may be reasonably required by the Service Recipient or a new service provider to perform the Services; and (b) attending meetings with the Service Recipient and/or a new service provider regarding the transition of the Services.

9. <u>Representations and Warranties</u>

Each Party represents and warrants, as to itself, to the other Party that:

(a) it is duly incorporated or formed, validly existing and in good standing under the laws of the jurisdiction of its incorporation or formation. It has all requisite power and authority to enter into and perform its obligations under this Agreement and to carry out the transactions contemplated herein. The execution and delivery of this Agreement and the consummation of the transactions contemplated herein and the performance of its obligations hereunder have been duly and validly authorized by all necessary action by such Party, and this Agreement has been duly executed and delivered;

(b) this Agreement constitutes a valid and binding obligation, enforceable against in accordance with its terms, subject to applicable bankruptcy, insolvency, reorganization, moratorium and other similar laws affecting creditor's rights generally and general principles of equity;

(c) the execution, delivery and performance of this Agreement, the consummation of the transactions contemplated hereby, and the compliance with the provisions hereof, will not, with or without the passage of time or the giving of notice or both:

(i) conflict with, constitute a breach, violation or termination of, give rise to any right of termination, cancellation or acceleration of or result in the loss of any right or benefit under, any agreement to which it is a party that would have a material adverse effect on the transactions contemplated hereby or on its ability to perform its material obligations contemplated hereunder;

(ii) conflict with or violate its organizational documents; or

(iii) violate any laws applicable to it or its properties or assets that would have a material adverse effect on the transactions contemplated hereby or on its ability to perform its material obligations contemplated hereunder.

(d) there is no injunction or restraining order, arbitration or claim pending against it which restrains or prohibits the consummation of the transactions and the performance of its obligations contemplated by this Agreement.

10. Limits of Liability

10.1 Liability of the Service Provider

Notwithstanding anything contained in this Agreement, no Service Provider or Service Provider Representative shall, either directly or indirectly, be liable, answerable or accountable to a Service Recipient or Service Recipient Representative to which it provides Services, under this Agreement or otherwise at law or in equity, for:

(a) any loss resulting from, incidental to or relating to a breach by any Service Provider Representative of any of the terms of this Agreement, the performance or non-performance of the Services by any Service Provider Representative (irrespective of whether such Services have been provided before the Effective Date, including any exercise or refusal to exercise a discretion, any mistake or error of judgement or any act or omission believed by the Service Provider Representative to be within the scope of authority conferred thereon by this Agreement, unless the proximate cause of such loss resulted from the fraud or gross negligence of any Senior Supervisory Personnel of the Service Provider Representative, in performing the Services, in which case the benefit of this Section 10.1(a) shall not apply to the Service Provider Representative.

(b) any loss resulting from, incidental to or relating to a breach by any Service Provider Representative of any of the terms of this Agreement, the performance or non-performance of the Services by any Service Provider Representative (irrespective of whether such Services have been provided before the Effective Date), where the proximate cause of such loss is attributable to: (i) a Service Provider Representative acting in accordance with the instructions of the Service Recipient (ii) any action or omission that occurred with the Service Recipient's advance consent; or (iii) if applicable, the Service Recipient's failure to approve an item in any budget that was proposed by the Service Provider where the omission of the Service, activity or operation proposed was the cause of the claim asserted against or loss suffered by the Service Recipient; or

(c) any loss resulting from, incidental to, or relating to any act or omission by any Service Provider Representative (irrespective of whether such act or omission occurred prior to the Effective Date), provided that such act or omission is based upon the Service Provider Representative's reliance on: (i) statements of fact of other persons (excluding any Service

Provider Affiliates) who are considered by the Service Provider to be knowledgeable of such facts; or (ii) the opinion or advice of or information obtained from any expert.

Each Party acknowledges and agrees that the limits of liability provided for in this Section 10.1 shall not only be enforceable by the Service Provider and the Service Provider's Affiliates, but shall also be enforceable directly by each of the Service Provider Representatives.

10.2 No Liability for Certain Losses

Notwithstanding anything to the contrary in this Agreement, in no event shall a Service Provider (or any Service Provider Representatives) or a Service Recipient (or any Service Recipient Representatives) be liable to the other for any exemplary, punitive, remote, speculative, consequential, indirect, special or incidental damages or loss of profits; provided that, if any Service Recipient Representative or Service Provider Representative is subject to a Third Party Claim for any such damages and the Indemnifying Party is obligated to indemnify such Service Recipient Representative or Service Provider Representative, as applicable, for the matter that gave rise to such damages, the Indemnifying Party shall be liable for, and obligated to reimburse such Service Recipient Representative or Service Provider Representative, as applicable, for, such damages.

10.3 Exclusive Remedy

As between any Service Provider Representatives and any Service Recipient Representatives pursuant to this Agreement, the indemnification provisions set forth in Article 11 and the termination provisions set forth in Article 8 will be the sole and exclusive remedies of the Parties. Neither Party nor any of its respective successors or assigns shall have any rights against the other Party or its Affiliates with respect to the subject matter of this Agreement other than as expressly contemplated. The remedies contained in Article 8 and Article 11 are given and accepted in lieu of (a) any express or implied warranties by any Service Provider, including warranties of merchantability, fitness for a particular purpose, or good and workmanlike performance, and (b) any obligation, liability, right, claim or remedy at law or in equity arising out of any defect in the Services whether such claim arises under contract, negligence, intentional misconduct, other tort, breach of warranty, deceptive trade practice, other statutory cause of action, strict liability, product liability, or other theory of liability. Except as expressly set forth herein, no Service Provider makes any representations or warranties (expressed, implied, oral or otherwise) regarding any aspect of its performance of (or failure to perform) the Services including warranties of merchantability, fitness for a particular purpose, or good and workmanlike performance or its other duties and obligations under this Agreement.

11. Indemnification

11.1 Indemnification by a Service Recipient

Subject to Section 10.2, a Service Recipient shall be liable to and, as a separate covenant, shall indemnify, protect, defend, release and hold harmless each Service Provider Representative from and against any claims asserted by or on behalf of any person, and for any losses, incurred by, borne by or asserted against any Service Provider Representative and which in any way arise from or relate in any manner to this Agreement or the performance or non-performance of Services (irrespective of whether such Services have been provided before the Effective Date), except to the extent the proximate cause of such claim or loss resulted from the fraud or gross negligence of any Senior Supervisory Personnel of the Service Provider Representative, in performing the Services.

11.2 Indemnification by a Service Provider

Subject to the limits and restrictions on the liability of a Service Provider set forth in Sections 10.1 and 10.2, a Service Provider shall be liable to and, as a separate covenant, shall indemnify, protect, defend, release and hold harmless each Service Recipient Representative from and against any claims asserted by or on behalf of any person, and for any losses, incurred by, borne by or asserted against any Service Recipient Representative to the extent the proximate cause of such claim or loss resulted from the fraud or gross negligence of any Senior Supervisory Personnel of the Service Provider, in performing the Services.

11.3 Method of Asserting Claims

(a) If a Party entitled to indemnification (the "**Indemnified Party**") intends to seek indemnification under this Article 11 from the other Party (the "**Indemnifying Party**") for any claim by a third party (including a governmental authority) (a "**Third Party Claim**"), the Indemnified Party shall give the Indemnifying Party notice of such Third Party Claim for indemnification promptly following the receipt or determination by the Indemnified Party of actual knowledge or information as to the factual and legal basis of any Third Party Claim which is subject to indemnification and, promptly following receipt of notice of such Third Party Claim. The failure of or delay by an Indemnified Party to so notify the Indemnifying Party (as set forth above) shall not relieve the Indemnifying Party of its indemnification obligations to the Indemnified Party, however the liability which the Indemnifying Party has to the Indemnified Party pursuant to the terms of this Article 11 (and for which the Indemnifying Party will be obligated to indemnify the Indemnified Party in respect of) shall be reduced to the extent that any such delay in or failure to give notice as required in this Agreement prejudices the defence of any such Third Party Claim, or otherwise results in any increase in the liability which the Indemnifying Party has under its indemnity provided for therein.

(b) The Indemnifying Party, at its sole cost and expense, shall have the right to assume the defense of any Third Party Claim brought against the Indemnified Party with counsel designated by the Indemnifying Party and reasonably satisfactory to the Indemnified Party; provided that the Indemnifying Party will not, without the Indemnified Party's prior written consent (such consent not to be unreasonably withheld, conditioned, or delayed), settle, compromise, consent to the entry of any judgement in or otherwise seek to terminate any Third Party Claim in respect of which indemnification may be sought unless such settlement, compromise, consent or termination includes a release of the Indemnified Party from all liabilities arising out of such Third Party Claim. The Indemnified Party will give to the Indemnifying Party and its counsel reasonable access to all business records and other documents relevant to such defence or settlement and shall permit them to consult with the employees and counsel (if any) of the Indemnified Party.

(c) Notwithstanding the foregoing:

(i) If the defendants in any Third Party Claim include both the Indemnified Party and the Indemnifying Party, and the Indemnified Party is advised by counsel that there are legal defences available to the Indemnified Party that are additional to those available to the Indemnifying Party and that in such circumstances representation by the same counsel would be inappropriate; or

(ii) If the Indemnified Party shall have reasonably concluded that the Indemnifying Party is not taking or has not taken, all necessary steps to diligently defend such Third Party Claim, the Indemnified Party has provided written notice of same to the Indemnifying Party, and the Indemnifying Party has not rectified the situation within a reasonable time,

then the Indemnified Party shall have the right to retain separate counsel, the reasonable costs of which shall be at the Indemnifying Party's expense, to represent the Indemnified Party and to otherwise participate in the defense of such claim on behalf of such Indemnified Party. For further certainty, only one legal firm for all indemnified parties may be engaged at the expense of the Indemnifying Party.

(d) Notwithstanding anything contained in this Agreement, an Indemnified Party shall have the right, at its sole cost and expense, to retain counsel to separately represent it in connection with the negotiation, settlement or defence of any Third Party Claim provided, for further certainty, that such counsel shall not, unless agreed by the Indemnifying Party, assume control of the negotiation, settlement or defence on behalf of the Indemnifying Party.

(e) Except to the extent expressly provided in this Agreement, no Indemnified Party shall settle any Third Party Claim with respect to which it has sought or intends to seek indemnification pursuant to this Article 11 without the prior written consent of the Indemnifying Party, which consent shall not be unreasonably withheld, conditioned, or delayed.

(f) If the Indemnifying Party does not assume the defence of any Third Party Claim brought against the Indemnified Party, then the Indemnified Party shall have the right to do so on its own behalf and all such expense in so doing shall be added to the amount of the claim for indemnification by such Indemnified Party as against the Indemnifying Party.

11.4 Net Amount

If an Indemnifying Party is obligated to indemnify and hold any Indemnified Party harmless under this Article 11, the amount owing to the Indemnified Party shall be the amount of such Indemnified Party's out-of-pocket losses (whether paid or payable), net of any such out-of-pocket losses recovered by the Indemnified Party from any other person; provided that the foregoing shall not be construed so as to obligate an Indemnified Party to pursue or seek recovery of any of its out-of-pocket losses from any other person whomsoever, including insurers.

11.5 Third Party Beneficiaries

Each Party acknowledges and agrees that the rights of indemnification provided for in this Article 11 shall not only be enforceable by the Parties but shall be enforceable directly by each of the Service Provider Representatives and the Service Recipient Representatives, and in this respect:

(a) the Service Recipient appoints the Service Provider to act as agent and trustee for the Service Provider Representatives as regards the covenants of indemnification by the Service Recipient given in favour of the Service Provider Representatives pursuant to Section 11.1, and the Service Provider accepts such appointment; and

(b) the Service Provider appoints the Service Recipient to act as agent and trustee for the Service Recipient Representatives as regards the covenants of indemnification by the Service Provider given in favour of the Service Recipient Representatives pursuant to Section 11.2, and the Service Recipient accepts such appointment.

11.6 Subrogation Rights

If an Indemnified Party has a right against a person (other than as against the other Party to be indemnified by the Indemnifying Party) with respect to any damages or other amounts paid by the Indemnifying Party, then the Indemnifying Party shall, to the extent of such payment and to the extent permitted by applicable law, be subrogated to the rights of such Indemnified Party as against such person. Notwithstanding the foregoing, no Indemnifying Party shall be subrogated to any insurance rights of any Indemnified Party.

12. Confidential Information and Personal Information

12.1 Each of the Parties hereto agrees to keep all information provided by the other Party (the "**Disclosing Party**") to it (the "**Receiving Party**") that the Disclosing Party designates as confidential or which ought to be considered as confidential from its nature or from the circumstances surrounding its disclosure ("**Confidential Information**") confidential, and a Receiving Party shall not, without the prior consent of an authorized senior officer of the Disclosing Party, disclose any part of such Confidential Information which is not available in the public domain from public or published information or sources except:

(a) to those of its employees who require access to the Confidential Information in connection with performance of Services hereunder;

(b) as in the Receiving Party's judgement may be appropriate to be disclosed in connection with the provision by the Receiving Party of Services hereunder;

(c) as the Receiving Party may be required to disclose in connection with the preparation by the Receiving Party or any of its direct or indirect holding companies, Affiliates or subsidiaries of reporting documents including, but not limited to, annual financial statements, annual reports and any filings or disclosure required by statute, regulation or order of a regulatory authority; and

(d) to such legal and accounting advisors, valuators and other experts as in the Receiving Party's judgement may be appropriate or necessary in order to permit the Receiving Party to rely on the services of such persons in carrying out the Receiving Party's duties under this Agreement.

12.2 The covenants and agreements of the Parties relating to Confidential Information shall not apply to any information:

(a) which is lawfully in the Receiving Party's possession or the possession of its professional advisors or its personnel, as the case may be, at the time of disclosure and which was not acquired directly or indirectly from the Disclosing Party;

(b) which is at the time of disclosure in, or after disclosure falls into, the public domain through no fault of the Receiving Party or its personnel;

(c) which, subsequent to disclosure by the Disclosing Party, is received by the Receiving Party from a third party who, insofar as is known to the Receiving Party, is lawfully in possession of such information and not in breach of any contractual, legal or fiduciary obligation to the Disclosing Party and who has not required the Receiving Party to refrain from disclosing such information to others; or

(d) disclosure of which the Receiving Party reasonably deems necessary to comply with any legal or regulatory obligation which the Receiving Party believes in good faith it has.

12.3 If in the course of performing the Services, the Receiving Party obtains or accesses personal information about an individual, including without limitation, a customer, potential customer or employee or contractor of the Disclosing Party ("**Personal Information**"), the Receiving Party agrees to treat such Personal Information in compliance with all applicable federal or provincial privacy or protection of personal information laws and to use such Personal Information only for purposes of providing the Services. Furthermore, the Receiving Party acknowledges and agrees that it will:

(a) not otherwise copy, retain, use, modify, manipulate, disclose or make available any Personal Information, except as permitted by applicable law;

(b) establish or maintain in place appropriate policies and procedures to protect Personal Information from unauthorized collection, use or disclosure; and

(c) implement such policies and procedures thoroughly and effectively.

12.4 EI acknowledges that EGI may not release to EI or its Affiliates, and EI and its Affiliates shall not have access to, any confidential information relating to an EGI consumer, marketer or other service customer (“**Confidential Customer Information**”), unless aggregated such that individual Confidential Customer Information cannot be reasonably identified, without consent in writing from the applicable consumer, marketer or other EGI service customer, except where required for purposes of billing or market operation, law enforcement, complying with legal requirements or processing past due accounts of the consumer that have been passed to a debt collection agency. EI acknowledges and shall ensure that its employees and its Service Provider Representatives and Service Recipient Representatives that are involved in providing or receiving Services will, upon request of EGI, receive Code training and, in the event they inadvertently receive or gain unauthorized access to any Confidential Customer Information, will (a) promptly advise EGI and (b) at EGI’s request, immediately destroy all copies of such Confidential Customer Information.

12.5 Each Party shall be entitled to periodically conduct reviews of the procedures implemented by the other Party in relation to the obligations described in this Article 12.

12.6 Upon the termination of this Agreement and written request by a Party, the other Party shall immediately return all Confidential Information and Personal Information provided by such Party, and all copies thereof in its possession or control (other than such Confidential Information or Personal Information which continues to be used or relevant to the provision of the Services), or destroy such information and copies and certify in writing to such Party that such destruction has been carried out; provided that, to the extent Confidential Information is electronically stored, the other Party shall destroy such electronically stored Confidential Information only to the extent that it is reasonably practical to do so and that doing so is consistent with applicable law. The confidentiality of any copies retained by any Party pursuant to this paragraph shall be maintained in accordance with the terms of this agreement and access to any such copies shall be restricted to persons whose primary functions are legal, compliance or information technology services.

13. <u>Audit Rights</u>

13.1 Each Party shall have the right, at its own cost and by notice to the other Party at reasonable hours to, or to direct a third party to, examine and make copies of the books, records and charts of the other Party to the extent necessary to verify the accuracy of any statement, charge or computation made pursuant to any of the provisions of this Agreement and to comply with any government filing requirements. Such books, records and charts shall be preserved in accordance with the records retention policies of such Party, provided the books, records or charts related to any matter disputed between the Parties or which is the subject of an outstanding application or proceeding before a governmental authority shall be preserved until such dispute is settled or such application or proceeding has been finally resolved, whichever is later. The Parties’ rights under this Article 13 to view books, records and charts to make copies:

(a) for internal purposes, shall subsist for a period of two (2) years from the end of the calendar year to which such books, records and charts relate, during the Term and for a period of two (2) years after expiration or termination of this Agreement, and

(b) for the purposes of complying with the requirements of governmental authorities, including tax authorities, shall subsist for a period of seven (7) years from the end of the calendar year to which such books, records and charts relate, during the Term and for a period of two (2) years after expiration or termination of this Agreement.

13.2 If this Agreement has been terminated or has expired, each Party's obligations to preserve such books, records and charts in accordance with its records retention policy shall continue. A Party may fulfill such obligations by continuing to preserve such books, records, and charts or by delivering them to EGI.

14. Force Majeure

If either Party is rendered unable by force majeure to carry out its obligations under this Agreement, other than a Party's obligation to make payments to the other Party, that Party shall give the other Party prompt written notice of the event giving rise to force majeure with reasonably full particulars concerning it. Thereupon, the obligations of the Party giving the notice, so far as they are affected by the force majeure, shall be suspended during, but no longer than the continuance of, the force majeure. The affected Party shall use all reasonable diligence to remove or remedy the force majeure situation as quickly as practicable.

15. Services

15.1 Each Service Provider shall, and shall cause its Service Provider Representatives to, perform the Services exercising the care, diligence and skill of an experienced and prudent service provider performing similar services in similar circumstances and in accordance with the highest generally accepted industry standards. Each Service Provider shall, and shall cause its Service Provider Representatives to, use commercially reasonable efforts to perform the Services in accordance with any additional instructions received from the Service Recipient; provided, however, that the Service Provider and its Service Provider Representatives shall not be required to incur any additional costs related to such request.

15.2 For clarity, the Parties acknowledge and agree that each Party may, as it deems necessary, use its Affiliates to perform any of the Services.

16. Dispute Resolution Process

16.1 In the event that the applicable managers of the Parties cannot resolve an issue related to the nature or performance of the Services, the amount of the cost allocations, or the interpretation of this Agreement within ten (10) Business Days of the date that written notice of the disputed issue is received by the non-disputing Party from the disputing Party, then either Party may send a written notice of the dispute to the responsible executives to be escalated upward through the respective organizations of the Parties, to Director, Vice-President and/or President, for resolution within twenty-one (21) Business Days after the receipt by the applicable executive of the notice. If required, the President of EGI shall make a final determination which shall be binding on the Parties. The Director of each of the Parties' Accounting Operations groups, or equivalent level of Finance personnel, shall facilitate this dispute resolution process.

16.2 Upon mutual agreement of the Parties, any dispute or issue of interpretation arising hereunder may be jointly referred for non-binding guidance or arbitration to an external facilitator with recognized expertise in the subject matter of the dispute or issue of interpretation.

17. General

17.1 This Agreement is an agreement made under and shall be governed by and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada, without regard to principles of conflicts of laws that, if applied, might require the application of the laws of another jurisdiction. Subject to the terms of this Agreement and of applicable laws, the Parties agree to attorn to the jurisdiction of the Ontario Superior Court for the purpose of resolving any disputes that may arise out of this Agreement that are not to be dealt with in accordance with Article 16.

17.2 Without limiting Section 17.1, each Party hereby waives any and all rights to demand a trial by jury in any legal proceeding arising out of or related to this Agreement.

17.3 The provisions of this Agreement requiring performance or fulfilment after the termination of this Agreement, including Sections 3, 6, 9, 10, 11, 12, 13, 16, 17.1, 17.2, 17.3 and 17.6, and such other provisions as are necessary for the interpretation thereof and any other provisions hereof, the nature and intent of which is to survive termination of this Agreement, will survive the termination of this Agreement.

17.4 Each Party shall, from time to time, and at all times, do such further acts and execute and deliver all such further deeds and documents as shall be reasonably requested by each other Party in order to fully perform and carry out the terms of this Agreement.

17.5 The relationship among the Parties under this Agreement is limited to the purpose herein. Nothing in this Agreement shall be deemed to constitute, create or give effect to or otherwise recognize any partnership, joint venture, or formal business entity among the Parties under this Agreement.

17.6 Any notice, request, demand, direction or other communication required or permitted to be given or made under this Agreement to a Party shall be in writing and may be given by hand delivery to the Party to whom it is addressed or sent by electronic mail to such party at its address noted below or at such other address of which notice may have been given by such Party.

(a) **EI**:

Enbridge Inc.

Address:	Fifth Avenue Place, 200, 425 – 1st Street S.W. Calgary, AB T2P 3L8
Attention:	Vice President, Corporate Law Department
Email:	legalnotices@enbridge.com

(b) **EGI:**

Enbridge Gas Inc.

Address:	500 Consumers Road North York, ON M2J 1P8
Attention:	Law Department
Email:	EGILawContracts@enbridge.com

Any such electronic mail shall be deemed to have been received at the opening of business at the premises of such addressee on the first Business Day following the transmission of such notice.

17.7 This Agreement may be executed in counterparts, no one of which needs to be executed by the Parties. Each counterpart, including an electronic transmission of this Agreement, shall be deemed to be an original and shall have the same force and effect as an original. All counterparts together shall constitute one and the same instrument.

17.8 This Agreement will enure to the benefit of and be binding upon the Parties and their respective successors. This Agreement may not be assigned by either Party without the prior written consent of the other Party.

17.9 The division of this Agreement into articles and sections and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms "this Agreement", "hereof", "hereunder", and similar expressions refer to this Agreement and not to any particular section or other portion hereof. Unless something in the subject matter or context is inconsistent therewith, references herein to articles and sections are to articles and sections of this Agreement. Words importing the singular number shall include the plural and vice versa, words importing the masculine gender shall include the feminine and neuter genders and vice versa, and words importing persons shall include individuals, partnerships, associations, trusts, unincorporated organizations and corporations and vice versa.

17.10 In the event that one or more of the provisions contained in this Agreement shall be invalid, illegal or unenforceable in any respect under any applicable law, the validity, legality or enforceability of the remaining provisions hereof shall not be affected or impaired thereby. Each of the provisions of this Agreement is hereby declared to be separate and distinct.

17.11 No waiver of any of the provisions of this Agreement shall be deemed or shall constitute a waiver of any other provision (whether or not similar) nor shall any waiver constitute a continuing waiver unless otherwise expressed or provided.

17.12 This Agreement constitutes the whole and entire agreement between the Parties respecting the subject matter of the Agreement and supersedes any prior agreement, undertaking, declarations, commitments, representations, verbal or oral, in respect thereof.

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Dated as of the date first written.

ENBRIDGE INC.

Per: Patrick Murray
Patrick Murray (Sep 28, 2020 11:41 MDT)

Patrick R. Murray

Senior Vice President & Chief Accounting Officer

ENBRIDGE GAS INC.

Per:

Cynthia L. Hansen

President

SCHEDULE 1
SERVICES

Finance	
Purpose	Trusted advisors driving value through disciplined financial management, insightful analysis and rigorous compliance.
Service Description	1. Provide timely and accurate information on actual performance through monthly financial reports and quarterly external reporting. 2. Provide timely and accurate information of future financial performance. 3. Partner in decision making by supporting the development of business unit strategy and deep technical expertise as needed. 4. Reliably manage finance operations executing transactional accounting and execution of effective capital, tax and risk programs, maintaining strong control environment and improving processes and systems. 5. Investor Relations: Communicate corporate financial and operational information publicly.

Technology and Information Systems (TIS)	
Purpose	Drive competitive advantage for the businesses of the Service Provider by optimizing information and technology.
Service Description	1. Core infrastructure and operations: Information Technology (IT) Support services, backup and storage. IT operations and monitoring etc. 2. Enterprise Business Applications: Multiple ERP Platforms and applications for corporate functions. 3. Enterprise Architecture & Data: Advanced Analytics, Data Governance, Enterprise Business Intelligence, IT Architecture. 4. Cyber Security Governance, Risk and Compliance, Security Operations, Network Security and Identity and Access Management. 5. TIS Office of the Chief Information Officer: Enterprise Records Management, Technology Direction and Compliance, Vendor Management, TIS Project Management Office.

Human Resources (HR) & Benefits Pool	
Purpose	Enable Strategy through inspired and capable people.
Service Description	1. Attract and source diverse talent in an inclusive environment. 2. Train and develop our people. 3. Support people & workforce management activities. 4. Effective execution of talent management programs. 5. Effective organizational culture reflective of our values to deliver superior results. 6 HR advice and consultation services.

Real Estate and Workplace Services	
Purpose	Provide a consistent cost-effective workplace that enables the business to achieve its strategic objectives in an efficient and collaborative environment.
Service Description	1. Full life cycle of demand analysis 2 Feasibility 3. Planning 4. Execution 5. Procurement 6. Operations 7. Asset management 8. System assessment 9. Development of enterprise wide policies

Supply Chain Management (SCM)	
Purpose	Create value for the business by optimizing the enterprise spend for the acquisition and logistics of goods and services at competitive costs.
Service Description	1. Business Partners a) Business Unit Facing: Primary point of contact for internal customers with the responsibility to advise customers and SCM on the best ways to translate Business Unit needs into concrete steps that enable our customer's success. b) SCM Facing: Improve supplier delivery and performance, leveraging/driving SCM processes such as Supplier Performance

	Management, Contract Conformance, Suppliers Relationship Management, etc. c) Sourcing: Regional sourcing of services and materials. 2. Supply Chain Service Centre a) Customer Support Centre: Centrally manage inbound purchase requisitions for goods and services across the enterprise. b) Procurement Centre: Centrally manage tactical sourcing, transactional order processing, and logistics transactions activities for good and services across the enterprise. c) Enterprise Procurement Support: Collaborate with SCM Stakeholders, TIS and customers to enable Service Supply Chain infrastructure for efficient and compliant processing (e.g., tools, process improvements, data, etc.).

Legal	
Purpose	To provide comprehensive legal services to support corporate, commercial, litigation, regulatory and other business needs of Service Recipient, working with external counsel as necessary.
Service Description	1. Corporate Law Governance 2. Commercial Support 3. Litigation and Human Resources Support 4. Regulatory Support 5. Ethics & Compliance 6. Legal Services Operations

Corporate Development Office	
Purpose	Develop, refine, communicate and execute Strategic (business) plan.
Service Description	1. Corporate Strategy: Develop and disseminate a strategic plan to position the company for sustainable growth and value creation over the near, medium and long-term. 2. Investment Review: Guide capital allocation (investment) process and decisions.

	3. Assess and create investment opportunities for inorganic growth (outside existing platforms) at the enterprise level. Geographical / community expansion services are not included under this corporate function.

Public Affairs and Communications	
Purpose	Serve Service Recipient as a valued partner, providing differentiated and meaningful stakeholder communication and engagement that manages risks and builds trust and confidence.
Service Description	1. Engagement strategies that support the business objectives including Enterprise Communications, Corporate Social Responsibility, community investment guidance and industry relations. 2. Project and operational advancement including public and agency participation plans, community engagement, indigenous engagement, external affairs, conflict resolution and regional communications. 3. Enabling leadership and advocacy.

Executive	
Purpose and Service Description	1. Chief Executive Officer department provides senior leadership, overall management guidance and advice regarding the financial and operational affairs. 2. Approval and communication of policies and controls (capital spending, operating spending, Authorized Spending Limits Policy, Risk management policies, etc.). 3. Provides ultimate responsibility for all personnel, safety & environmental, and regulatory policy issues. 4. Provides ultimate responsibility for governance of the organization with respect to ensuring the proper procedures, policies, processes, people and culture to be successful.

Safety and Reliability (S&R)	
Purpose	Provide programs and field support to enable Industry Leading performance in Safety, Environmental and Lands & Right of Way (ROW).
Service Description	1. Effective Management System: Structure and processes to reveal and manage operational risk.

	2. Effective safety and reliability performance in the operation and construction of the pipeline system. 3. One Enbridge: Safety Program; Environmental Program; ROW Program. 4. Standardized performance reporting and data systems. 5. Standards and assurance processes to achieve industry leading performance.

Aviation	
Purpose	To provide safe, efficient and convenient air transportation to assist in achieving the mission and goals of the company.
Service Description	1. Safe air service in response to company needs including pipeline patrol operations, monitoring right-of-way for adverse conditions impacting persons, property and environment. 2. Provide surveillance for activities around the pipeline over large, inaccessible areas and satisfy requirement of CSA Z662. 3. 24/7 Emergency Response to any pipeline mishap or emergency.

SCHEDULE 2
CENTRAL SERVICES COST ALLOCATION METHODOLOGY

1. Background

Centralized services groups ("**Central Services**")[1] of Enbridge Inc. ("**Enbridge**") perform various functions for the benefit of Enbridge and many of its subsidiary legal entities (the "**Enterprise**"). Costs of Central Services are recorded in centralized cost pools and charged or allocated to individual entities or lines of business ("**LOBs**") on a reasonable basis, as described below, with the intent to match cost causation as closely as possible. The approach documented herein is meant to bring alignment, simplicity and standardization across the Enterprise in respect of the allocation methods for 2019 onward.

This document describes the allocation methodology used to allocate costs from Central Services to LOBs within the Enterprise that meet certain criteria. Any other cost allocations performed by individual LOBs or Business Units ("**BUs**") are outside the scope of this document.

2. Guiding Principles

In arriving at the allocation methodology discussed in this document, the following guiding principles were considered:

i. Corporate costs will be allocated based on a reasonable estimate of the benefit derived by various operating assets; Certain Corporate Business Development and Special Projects costs will be retained at the Corporate office.

ii. Approach should be supported by Regulatory and Tax Services groups.

iii. Reasonable rules of thumb shall be used in developing basis for allocating costs to ensure allocations are formula driven, consistently applied, materially correct and defensible.

iv. Corporate costs will not be allocated back to Corporate by the operating assets, unless material.

v. Corporate allocations will be excluded for purposes of determination of the financial metric of the BU, as part of incentive compensation calculations.

vi. Allocations shall be trued-up at conclusion of each year, or earlier, if material.

3. Businesses Requiring Allocation of the Central Services Costs

Consistent with Enbridge's past practice, the Central Services costs will be allocated on a normalized basis to individual LOBs. The following criteria are used for identifying a LOB that requires allocation.

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[1] Central Services are: Finance, Technology and Information Systems, Human Resources & Benefits Pool, Real Estate and Workplace Services, Supply Chain Management, Law, Corporate Development Office, Public Affairs and Communications, Executive, Safety & Reliability (S&R) and Aviation.

A LOB is:

- 50% or more owned, directly or indirectly, by Enbridge
- Operated by Enbridge
- In operation or expected to be in operation in the first half of the year to which the allocations apply. For clarity, for 2019 allocations, Enbridge will ignore a LOB which is expected to be in operation in the second half of 2019.
- An asset/entity not meeting the parameters listed above, but which has contractual arrangements for being charged allocations of Central Services costs from Enbridge (e.g. Joint Ventures operated by Enbridge).
- Not an equity investment, financing or holding company within the Enterprise.

For greater certainty, it is intended that Central Services costs will be allocated to individual operating LOBs directly, and that allocations to groups of businesses or employee services companies (as was done by legacy companies prior to the Enbridge-Spectra merger) will be minimized to the extent practicable. The allocation process at employee services companies, for costs other than those which are now related to Central Services, would remain the responsibility of such companies.

Utilizing the above criteria, and in consultation with BUs, a list of LOBs requiring allocations of Central Services Costs is prepared and documented and updated annually or as required.

4. Central Services Cost Pool

A Central Services "Cost Pool", comprising the costs of all Central Services, has been determined utilizing the cost centre ("**CC**") mappings under the Central Services cost allocation methodology. Each CC is ultimately assigned to a VP in charge of that area. Generally, all CCs linked to VPs who are part of one of the Central Services will be included in the Central Services Cost Pool. CCs in the Central Services Cost Pool are divided into two buckets: (1) **Allocable Costs**, which are allocated to individual operating entities using the methodology prescribed by this document; and (2) **Direct Charged Costs**, which represent costs that are booked directly in LOBs where they belong and hence excluded from the allocations process.

A. Direct Charged Costs

- All costs residing in the "Direct Charged" category of CCs under Law, Finance and S&R are excluded from the cost allocation pool and directly charged to the LOB they roll up to. Following are examples of Direct Charged Costs:
  - S&R – Some of the CCs belonging to S&R have costs belonging to specific LOBs. These costs are recorded as Direct Charged Costs in CCs which are dedicated for specific LOBs. This allows for the tracking of such costs by LOBs and facilitates the recovery of these costs from insurance providers and/or shippers.
  - External Legal Fees – From 2019 onward, external legal fees are centralized. Law is responsible for budgeting Enterprise external legal fees, maintaining all such

relationships with external counsels and approving all invoices. As a result, specific Direct Charged CCs have been created where Law has budgeted such costs under specific LOBs.

- External Audit Fees – To the extent audit fees are billed directly to individual operating entities, such fees are budgeted to the appropriate LOBs as Direct Charges and excluded from the pool of allocable costs.

5. Allocable Costs - Directly Attributable (including those attributable to Capital Projects)

BUs/Departments will be asked to provide input as to whether a portion of a CC is directly attributable to Capital Projects, or to other LOBs. For a majority of cases, it is expected that the direct attribution will be based on time estimates. Any amount remaining after the direct attribution will form part of the Central Services Cost Pool for allocation and thereby be an "Allocable Cost". BUs/Departments are contacted in or around the second week of July to seek their input.

6. Allocation Method

To the extent a cost is directly attributable to a LOB (see section 5 above); such component of the cost will be assigned directly to that LOB (Directly Attributable Costs), with any residual balance being included in the Central Services Cost Pool for allocation.

Costs in the general cost pool will be allocated using an allocation formula. In a majority of cases, it is expected that the extent of utilization of a shared service is driven by the size of and contribution by an operating LOB. Therefore, a Modified 3-Factor Formula ("**3FF**") is utilized to allocate such costs to LOBs.

The three factors used in the Modified 3FF are: Revenues; Gross Book Value of Property, Plant and Equipment ("**PP&E**"); and Payroll. These terms are explained further as follows:

i. The term "revenues" means gross revenues for each LOB, with the exception of Energy Marketing businesses (Tidal US and Tidal Canada), Gas Distribution businesses and Gas Pipelines and Processing businesses for which net revenues (gross revenues minus commodity cost or gas distribution cost) will be used. Energy Marketing businesses operate on a margin bases, but recognize revenues on a gross basis; therefore, net revenue is recognized as a more reasonable basis of allocation. Likewise, for Gas Distribution businesses, gas distribution cost is a flow-through cost; therefore, net revenue is considered to be a more reasonable basis. Revenues from Gas Pipelines and Processing ("**GPP**") businesses also inflate due to commodity prices; therefore, net revenue will also be a reasonable basis for GPP. In cases where unrealized derivative gains or losses on non-qualifying economic hedges are recorded within revenues, such gains or losses will also be excluded for the purpose of the Modified 3FF.

ii. The term "payroll" comprises base pay and overtime for both permanent and contract employees.

iii. Any material impairments are excluded from PP&E gross amounts used for this calculation.

The term "Modified" is used for the 3FF to distinguish it from the Massachusetts 3-Factor Formula, which requires the use of "gross revenues". The 3-Factor Formula apportions a centralized cost to LOBs based on a LOB's "revenues", "assets" and "payroll" in relation to the "revenues", "assets" and "payroll" of all LOBs requiring allocation. Following is a simple example of the application of the Modified 3FF:

Assumptions:

The Company has 3 LOBs that require allocation of a corporate cost of $100,000. Revenues, assets and payroll of these LOBs are provided below, along with the allocation calculation.

	Input Amounts			Stand Alone Percentage			Weighted Percentage				
	Revenues	NBV PP&E	Payroll	Revenues	NBV PP&E	Payroll	Revenues	NBV PP&E	Payroll	Total Weight	Cost Allocation
				(a)	(b)	(c)	(A)=(a)x0.33	(B)=(b)x0.34	(C)=(c)x0.33	(A)+(B)+(C)	
LOB 1	100	800	80	16.67%	16.00%	22.86%	5.50%	5.44%	7.54%	18.48%	18,480
LOB 2	200	1300	100	33.33%	26.00%	28.57%	11.00%	8.84%	9.43%	29.27%	29,270
LOB 3	300	2900	170	50.00%	58.00%	48.57%	16.50%	19.72%	16.03%	52.25%	52,250
Total	600	5000	350	100.00%	100.00%	100.00%	33.00%	34.00%	33.00%	100.00%	100,000

7. Recoveries for Cost Centres in LOBs outside of Corporate

A number of CCs relating to Central Services groups still reside in LOBs outside of the Corporate legal entity. As a result, from the perspective of individual LOBs, such CCs, if unadjusted, will impact the LOB's bottom line. Where a CC is added to the centralized cost pool and gets allocated to businesses other than its parent LOB, the parent LOB will receive a credit from Corporate for such allocations.

As an example, if a CC in EPI contains costs of an IT team that is serving various other LOBs, then the cost in that CC will first be brought into the Central Services Cost Pool by way of providing a credit to EPI, and then such costs will be allocated out to those receiving services from the IT team. The Corporate Finance team has developed and implemented a mechanism to track and adjust such credits.

8. Documentation

A Central Services manager is responsible to:

i. Provide a service description that outlines the services provided and the basis of allocation of any directly attributable service to specific LOBs receiving the Central Services and cost allocation;

ii. Complete the Central Services budget (and subsequent forecasts) and provide any changes in the previously provided direct cost allocation input;

iii. Ensure all cost allocations are reflective of the economic benefit received by the LOBs;

iv. Provide communication and support during any resolution process in the case of allocations being questioned by the receiving LOB;

v. Keep documentation of the foundation for the budget including time estimates used for any direct charge to capital projects or to specific LOBs;

vi. Review monthly actual costs versus budget to ensure their costs and recoveries are tracking to expected levels, explain any material variances and work with the Corporate Finance team to ensure any true-up of cost allocations are appropriate and reasonable;

9. Contacts

Inquiries relating to allocation of Central Services costs can be sent to Corporate.Allocations@enbridge.com.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Ex. B/3/2, p. 13, 14

Question(s):

Please provide the internal capital plan on which the capital spending in 2021 was based, including all narrative materials and explanations, and all presentations to executive management or the board of directors dealing with the increases in capital spending from 2020 to 2021.

Response:

The 2021 Budget (capital plan) is underpinned by the Asset Management Plan as filed in EB-2020-0181, Schedule C, Tab 2, Exhibit 1. The 2021 Budget was presented to the Asset Management Steering Committee on June 8th, 2020. The presentation materials supporting the 2021 Budget were filed in EB-2020-0182, Exhibit 1.SEC.1, Attachment 1. To assist in understanding the increase in capital spending, a summary of variances between the 2020 Budget and 2021 Budget as presented in the AMP by rate zone and Asset Class is presented below:

Table 1

EGD Rate Zone – 2020 vs 2021 Budget Comparison in $millions

Asset Class	2020 Budget	2021 Budget	Variance	Comments
Utilization	34.3	55.3	21.0	- Increase in meter purchases $11M - Overheads $10M
Transmission Pipe and Underground Storage	7.8	12.5	4.7	- Increase in Integrity $3M - Overheads $2M
Technology Information Services	15.1	28.2	13.1	- Reprioritization of spend including Meter Reading Handheld Replacements $2M and other $6M - Overheads $5M
Real Estate & Workplace Services	23.1	59.6	36.5	- Increase due to Station B new building and Ottawa facility consolidation $26M - Overheads $11M
Growth	133.1	160.1	27.0	- primarily due to overheads $27M
Fleet & Equipment	8.6	10.9	2.3	- primarily due to overheads $2M
EA Fixed OH	14.0	15.4	1.4	- no significant variance
Distribution Stations	24.6	42.1	17.5	- Increase in station rebuilds $4M and gate & feeder $6M - Overheads $8M
Distribution Pipe	80.3	202.0	121.7	- Increase in main replacements including St. Laurent $11M and Cherry to Bathurst $64M, increased in service relays $6M and other $4.2M - Overheads $36.5M
Compression Stations	11.8	46.1	34.3	- Increase due to Meter Area Upgrade project $19M and Replacements $7M - Overheads $8M
Overheads	133.8	-	(133.8)	- Overheads allocated to asset classes starting in 2021
Total	486.5	632.2	145.7	

Table 2

UG Rate Zone – 2020 vs 2021 Budget Comparison in $millions

Asset Class	2020 Budget	2021 Budget	Variance	Comments
Utilization	48.2	55.2	7.0	- decrease in meter purchases $3M - Overheads $10M
Transmission Pipe and Underground Storage	8.6	53.1	44.5	- Increase due to Sarnia Industrial Reinforcement $23M and Class Locations $11M - Overheads $10M
Technology Information Services	31.0	11.3	(19.7)	- Reduction in spend of $18M due to removal of integration projects included in the 2020 AMP including CARE Application Replacement and CARS Application Replacement - Overheads $2M
Real Estate & Workplace Services	11.7	44.9	33.2	- Increase due to London new building $10M, Keil Dr renovations $8M and other facility renovations $7M - Overheads $8M
LNG	0.3	0.3	-	- no significant variance
Growth	127.9	116.9	(11.0)	- Lower reinforcements due to completion of Owen Sound ($54M) offset by higher Customer Connections $16M and other reinforcements $6M - Overheads $21M
Fleet & Equipment	8.9	11.7	2.3	- primarily due to overheads $2M
EA Fixed OH	2.4	2.8	0.4	- no significant variance
Distribution Stations	26.6	52.3	25.7	- Increase in station rebuilds $7M and gate & feeder $7M and other $2M - Overheads $10M
Distribution Pipe	199.6	280.4	80.8	- Increase in main replacements including London Lines Replacement $95M offset by reduced spend on Windsor Line ($70M) and other $5M - Overheads $51M
Compression Stations	5.3	9.3	4.0	- Increase in Improvements $1M and Land/Structures $1M - Overheads $2M
Overheads	74.0	-	(74.0)	- Overheads allocated to asset classes starting in 2021
Total	544.5	638.2	93.7	

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Ex. C/1, p. 4

Question(s):

In July 2021 a class action lawsuit #CV-21-00658687-00CP was filed in the Ontario Superior Court of Justice seeking a range of relief over a period of more than 30 years for under-calculations of pensions. With respect to this issue, please:

a) Confirm that no amounts have been included in any deferral or variance accounts related to this lawsuit.

b) Provide the amount that is included in the OM&A calculation for 2021 relating to this lawsuit.

c) Provide the Applicant's most recent estimate of the amount potentially at risk if the lawsuit is successful, and confirm that the Applicant expects to include any eventual cost associated with this lawsuit in rates in the future.

d) Confirm that the practices alleged in the lawsuit to be wrongful (failure to include maternity and parental leave periods in credited service for pension calculation purposes) have, to the extent that they were in fact in place prior to amalgamation, continued since the amalgamation or, if not confirmed, describe what changes have been made to those practices since amalgamation. This question does not seek an admission of fact or interpretation, but only information on whether what was happening before amalgamation continued after amalgamation.

e) Confirm that the practices alleged in the lawsuit to be wrongful were the same practices that were in place at Union Gas for the period 1990 to 2018 or, if not confirmed, describe how those practices were different at Union Gas. Again, not admission is requested, only a comparison of practices between the two utilities.

f) If similar practices were in place at Union Gas, provide the Applicant's most recent estimate of the amount potentially at risk if a similar lawsuit against Union Gas were to be successful, and confirm that the Applicant expects to include any eventual cost associated with any such lawsuit in rates in the future

Response:

a) Confirmed.

b) Other than for external legal costs, there is no amount included in the 2021 OM&A calculation for this lawsuit.

c) The amount of any potential loss is not determinable at this stage of the litigation.

d) The alleged practices are under investigation and are the subject of ongoing discussions with the plaintiffs.

e) The practices at Union Gas for the period 1990 to 2018 are not named and therefore are not relevant to the lawsuit.

f) See response to e).

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Ex. E/1, p. 15

Question(s):

Please provide any internal reports, analyses, memoranda, or other documents disaggregating the changes in normalized average consumption in Rates 01 and/or M1 between residential and non-residential customers.

Response:

The Company does not have any internal reports, analyses, memoranda, or other documents that deal with disaggregating the changes in normalized average consumption between residential and non-residential similar to what was provided in Table 2 of Exhibit E, Tab 1, page 15.

Tables below provide the actual NAC for Rate 01 residential and non-residential customers and for Rate M1 residential and non-residential, for the period of 2019-2021 and shows the year over year change in normalized average consumption. The figures below are weather normalized at each year's respective OEB-approved weather normal.

Rate 01:

Relative to 2020, the 2021 normalized average consumption shows a decrease of approximately 3.8% across the residential and non-residential sectors as well as the overall Rate 01 class. In the prior year, relative to 2019, the non-residential sector incurred a decline in normalized average consumption whereas the residential sector remained relatively flat.

Table1:

Rate 01 Normalized Average Consumption Residential & Non-residential

Year	Rate 01 Residential Actual NAC	Rate 01 Residential Year over Year Change	Rate 01 Non-Residential Actual NAC	Rate 01 Non-Residential Year over Year Change	Rate 01 Actual NAC	Rate 01 Year over Year Change
	(m^3)	(%)	(m^3)	(%)	(m^3)	(%)
2019	2,322		9,174		2,880	
2020	2,332	0.4%	9,059	-1.3%	2,875	-0.2%
2021	2,244	-3.76%	8,715	-3.80%	2,766	-3.80%

Rate M1:

In relation to 2020, the normalized average consumption of 2021 shows a decrease of 2.85% for the rate class, mainly concentrated in the non-residential market with a decrease of 5.80% while the residential segment registered a reduction of 1 .8%. In the previous year, in relation to 2019, the average consumption of the rate class decreased by 1.24%, this time again the non-residential sector was the main contributor in the reduction of the consumption of the rate class with a decrease of 2.24 % while the residential segment experienced a decrease of 0.79%.

Table 2:

Rate M1 Normalized Average Consumption Residential & Non-residential

Year	Rate M1 Residential Actual NAC	Rate M1 Residential Year over Year Change	Rate M1 Non-Residential Actual NAC	Rate M1 Non-Residential Year over Year Change	Rate M1 Actual NAC	Rate M1 Year over Year Change
	(m^3)	(%)	(m^3)	(%)	(m^3)	(%)
2019	2,284		8,985		2,780	
2020	2,266	-0.79%	8,783	-2.24%	2,746	-1.24%
2021	2,225	-1.80%	8,274	-5.80%	2,668	-2.85%

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Ex. E/1, p. 24

Question(s):

Please provide more detail on the "billing systems' inability to locate all intended customers" and describe how that problem results in the ratepayers being responsible for the shortfall in collection.

Response:

As was described at Exhibit I.STAFF.12 in the 2020 Earnings Sharing and Deferrals Disposition proceeding[1], the "billing systems' inability to locate all intended customers" means that at the time the deferral clearance was billed to customers, some customers, because of moves and other account changes were no longer active. As a result of this "inability to locate the intended customers", the deferral clearance unit rates, which were derived utilizing historical customers and volumes, were not able to be assessed against all the historical customers and or volumes. Therefore, the full deferral balance was not able to be billed, and the differences reside in the Deferred Rebates Account and the Deferral Clearing Variance Account (clearing accounts) which are requested for disposition at the following earnings sharing and deferrals disposition proceeding.

The recovery of residual amounts from ratepayers is in accordance with the OEB approved purpose of the clearing accounts, which is to record any amounts payable to, or receivable from, customers of the Company resulting from clearing deferral and variance accounts authorized by the OEB which remain outstanding due to the Company's inability to locate such customers and due to variances between actual and forecast volumes under prospective recovery. The Company also notes that residual balances are treated consistently, regardless of whether they are amounts to be recovered from or payable to ratepayers.

[1] EB-2021-0149.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Ex. E/1, p. 31

Question(s):

Please provide a detailed explanation of the steps taken by the Applicant to identify the specific causes of the large, $35.9 million UFG charges. Please provide any internal reports, analyses, memoranda, or other documents dealing with those steps, and/or reporting on the results.

Response:

A UFG Dashboard is used to communicate results to management relating to UFG volumes and costs. A copy of the 2021 UFG Dashboard is included as Attachment 1[1].

In Q3 of 2021, the data captured in the UFG Dashboard indicated that it was likely that UFG volumes and costs would exceed 2013 OEB approved amounts as well as exceeding the $5 million dead-band in the UFG Volume Deferral account.

In Q4 of 2021 through Q1 2022, work was undertaken to validate the inputs and the calculations utilized in the formulaic determination of UFG volumes. The work to validate the appropriateness and completeness of the inputs and calculations used in the formulaic determination of UFG included the following:

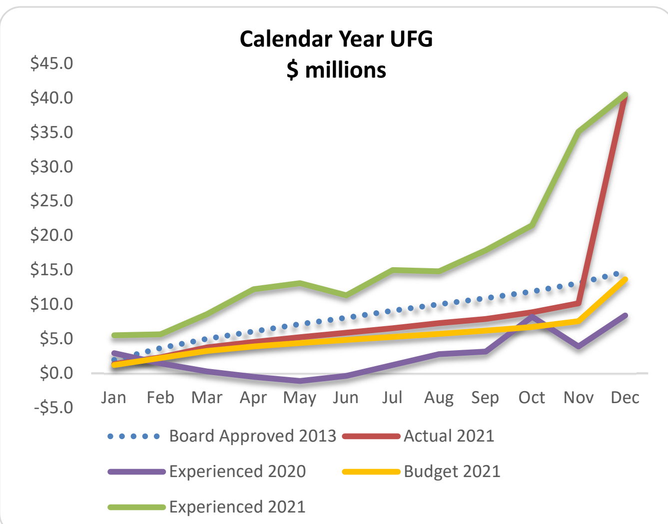
1) Calculation of true-up relating to the monthly accounting estimates for gas delivered but not yet billed
2) Analysis of prior period adjustments
3) Assessment of impacts relating to the transition of customers within the Union Rate Zones to the SAP CIS Customer Billing System in July 2021.
4) Validation of the appropriateness and completeness of line-pack volumes recorded
5) Review of meter reads between custody and check meters to identify inconsistencies

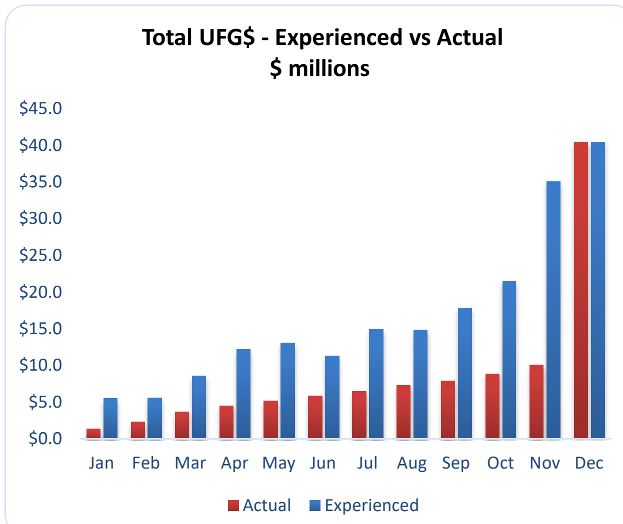
[1] The UFG Dashboard includes the terms “Board Approved”, “Budget”, “Actual”, and “Experienced”. For the purposes of the UFG Dashboard, “Actual” reflects UFG recorded based on the Board Approved throughput percentage of 0.219%, with a true-up to the actual throughput percentage in December. “Experienced” reflects UFG recorded based on the actual throughput percentage each month.

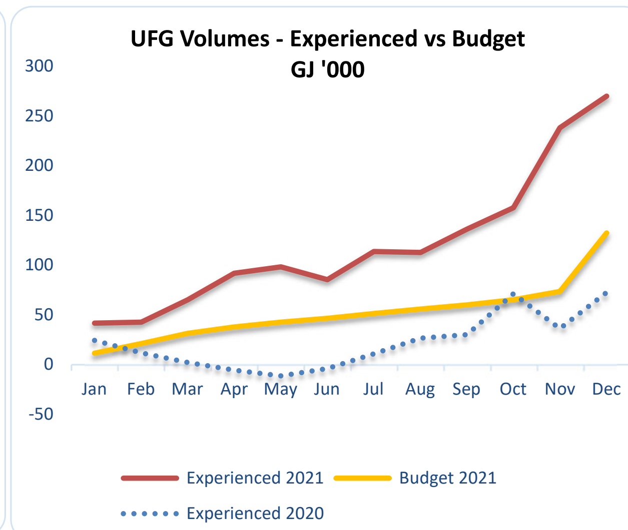
6) Review of Send-out data to assess consistency and reasonableness with prior periods, adjusted for weather
7) Review of heat values used and the appropriateness of the calculations of the conversions of volumes as it relates to the calculation of UFG
8) Review of storage inventory adjustments recorded and appropriateness of inclusion in the calculation of UFG

UFG Dashboard
Actual 2021 vs. Board Approved 2013

	Actual 2021				Board Approved 2013				Financial Variances ($000's) Favourable / (Unfavourable)						
	a	b	c	d	e	f	g	h	i = e - a	k	l	m	n	o	p
	$000's	103m3	PJ's	%	$000's	103m3	PJ's	%	Variance	Variance Allocated to		Variance to $5M Deadband		Variance Offset by Revenue	
	Total Company UFG - $	Total UFG Volume		UFG Throughput %	Total Company UFG - $	Total UFG Volume		UFG Throughput %	Total Company UFG - $	Regulated ST Storage	Unregulated Storage	Regulated Utility UFG	UFG Volume Deferral	Regulated Utility Price	Regulated Utility Throughput
Jan	1,360	10,350	0.4	0.219%	1,953	9,278	0.4	0.219%	593	30	(0)	3	-	664	(104)
Feb	948	7,210	0.3	0.219%	1,685	8,005	0.3	0.219%	738	29	23	2	-	573	111
Mar	1,427	10,856	0.4	0.219%	1,365	6,484	0.2	0.219%	(62)	15	(48)	3	-	464	(495)
Apr	804	5,929	0.2	0.219%	1,086	5,157	0.2	0.219%	281	16	(5)	2	-	349	(81)
May	679	5,005	0.2	0.219%	1,040	4,941	0.2	0.219%	361	17	4	1	-	335	4
Jun	676	4,987	0.2	0.219%	933	4,432	0.2	0.219%	257	14	(3)	1	-	300	(56)
Jul	630	4,876	0.2	0.219%	1,042	4,948	0.2	0.219%	412	17	10	1	-	364	20
Aug	757	5,865	0.2	0.219%	917	4,355	0.2	0.219%	159	13	(12)	1	-	321	(163)
Sep	619	4,793	0.2	0.219%	892	4,238	0.2	0.219%	273	14	0	1	-	312	(54)
Oct	941	5,561	0.2	0.219%	969	4,604	0.2	0.219%	28	11	(27)	2	-	172	(130)
Nov	1,307	7,723	0.3	0.219%	1,213	5,762	0.2	0.219%	(94)	13	(47)	3	-	215	(277)
Dec	30,365	179,427	7.1	4.264%	1,694	8,048	0.3	0.219%	(28,671)	(362)	(2,957)	(5,019)	(20,482)	301	(151)
YTD	**40,513**	**252,582**	**9.93**	**0.672%**	**14,789**	**70,253**	**2.66**	**0.219%**	**(25,724)**	**(174)**	**(3,063)**	**(5,000)**	**(20,482)**	**4,370**	**(1,376)**







ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Ex. E/1, p. 46

Question(s):

Please provide any internal reports, analyses, memoranda, or other documents dealing with the 52% increase in OM&A costs set out in Table 2, and provide an explanation of what steps were taken by the Applicant to minimize those cost overruns.

Response:

The Company does not have any internal reports, analyses, memoranda, or other documents that deal with the increase in OM&A costs attributable to the Dawn H/LOBO D/Bright C Compressor Project.

Management recognizes the increased cost of operating the noted assets/project, however, Enbridge Gas does note that the costs incurred were necessary to address the needs and demands of the overall Dawn to Parkway system. The costs are reflective of operational decisions made in order to meet those demands in a safe and reliable manner, including at times limited options of various available units. The parameters of how the system is operated today was unknown at the time the original estimates were made based on assumptions at that time.

Overall, the 52% increase noted is primarily related to higher salaries and wages including overtime and benefits of the employees required to operate these assets based on a higher level of operating hours. Also, as a result, utility costs associated with operating these assets has increased because of higher operating hours and a significantly higher cost per kwH than initially estimated. And finally, the costs of maintenance on these assets have escalated, based on parts and labour being OEM specific and reflective of higher vendor invoicing.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Ex. F/1, p. 3

Question(s):

Please explain why the spending on IRP in 2021 was so low, and reconcile that low spending with the criticisms of the members of the IRP Working Group about the slow start of the Applicant to meeting its IRP obligations.

Response:

IRP spending in 2021 was low due to the timing of the OEB's IRP Framework Decision, which was received in July 2021[1]. Prior to the OEB's IRP Framework Decision being issued, existing IRP resources continued to work with team members from across the organization to identify what would be required to implement the decisions that were anticipated to be included within the OEB's IRP Framework Decision. However, Enbridge Gas did not hire the resources identified as being required, begin work with a consultant on enhancements to the DCF+ test or work with an agency to create new stakeholder engagement web site materials until the OEB's IRP Framework Decision was received and there was certainty with regards to cost-recovery of these activities.

Following the OEB's IRP Framework decision Enbridge Gas initiated:

- Hiring for the roles identified as being required. The hiring process is time intensive, taking place between September 2021 and early 2022,
- Engagement with a consultant, Guidehouse, on the DCF+ enhancement study, and
- Engagement with a marketing agency to develop an IRP Stakeholder engagement web site.

The costs associated with these activities, due to timing, will mostly be reflected in the costs included in the 2022 deferral account.

[1] EB-2020-0091, OEB Decision and Order, July 22, 2021.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Ex. H/1, p. 27-37

Question(s):

Please confirm that the Applicant does not believe the role of the IRP Working Group includes providing input to the Applicant on load and demand forecasting as it relates to the energy transition, nor input on asset management planning activities other than those relating to specific IRP projects.

Response:

Confirmed. As outlined in the IRP Decision and Order issued on July 22, 2021 the OEB indicated that:

> Despite concern raised by some parties about the demand forecast, the OEB has determined that a more comprehensive review of Enbridge Gas's demand forecasting methodology is not needed at this time. Detailed examination of the ten-year demand forecast methodology is appropriately done at Enbridge Gas's next rebasing application, at which time the AMP will be filed as evidence.[1]

[1] EB-2020-0091, OEB Decision and Order, July 12, 2021. page 42