EB-2022-0200

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Enbridge Gas Inc., pursuant to section 36(1) of the *Ontario Energy Board Act, 1998,* for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2024

COMPENDIUM OF THE SCHOOL ENERGY COALITION
(EGI – Deferral & Variance Accounts Panel)

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Counsel for the School Energy Coalition

Forecast. The account name is also changing from a deferral to a variance account to reflect the inclusion of the administrative costs associated with current federal and provincial regulations related to greenhouse gas emissions requirements in 2024 base rates.

3.10. Volume Variance Account (Account No. 179-310)

83. Enbridge Gas is proposing to update the purpose of the following existing variance accounts and replace the existing accounts with one Enbridge Gas account.
    - EGD – Average Use True-up Variance Account (AUTUVA) (Account No. 179-66_)
    - Union – Normalized Average Consumption (NAC) Account (Account No. 179-133)

84. For the EGD rate zone, the AUTUVA was established to record the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer, for general service rate classes, embedded in the volume forecast that underpins the general service rate classes and the actual weather normalized average use experienced during the year.

85. For the Union rate zones, the NAC Account was established to record the impact to delivery and storage revenue and costs resulting from the difference between the target NAC included in OEB-approved rates and the actual NAC experienced during the year for general service rate classes.

86. Enbridge Gas is proposing to establish one variance account for Enbridge Gas to record the revenue impact, exclusive of gas costs, of the volumetric forecast variance resulting from actual average use per customer and weather experienced during the year for the general service rate classes.

87. Neither the AUTUVA nor the NAC Account included the revenue variance due to weather. Including this revenue variance in the proposed Volume Variance Account reduces volumetric risk in a symmetric and revenue-neutral manner for both customers and Enbridge Gas. In a year where actual weather occurs colder than the OEB-approved normal, customers receive the benefit of being refunded higher delivery charges paid during the winter months in the proposed account. In a year where actual weather is reported warmer than the OEB-approved normal, the Company is able to recover the majority of its delivery costs, including recovery of fixed costs that do not vary with the level of customers' volumetric consumption.

88. The revenue impact of forecast variances related to changes in the customer forecast are not included in the proposed account.

89. The proposed Volume Variance Account provides a similar de-risking of fixed cost recovery to that resulting from the proposed Straight Fixed Variable and Demand (SFVD) rate design for general service customers. Please see Exhibit 8, Tab 2, Schedule 3 for the rate design proposal for general service customers.

90. The Volume Variance Account will remain in effect until the implementation of the SFVD rate design, if approved by the OEB in this Application. If, alternatively, the OEB approves another rate design approach, the proposed Volume Variance Account will continue to be required to capture average use and weather variances.

3.11. Earnings Sharing Mechanism Deferral Account (ESMDA) (Account No. 179-311)

91. Enbridge Gas is proposing to update the ESMDA account description but is not proposing a change to the purpose of the account. The Company is proposing to remove wording from the existing accounting order that references the MAADs Decision. Additionally, the Company proposes to add that the ESMDA will not apply

Guidehouse

Natural Gas Volume Forecasting Benchmarking Study

A Comparative Review

Prepared for:

ENBRIDGE

Enbridge Gas Inc.

Submitted by:

Guidehouse Inc.
100 King Street West
Suite 4950
Toronto, ON M5X 1B1
416.777.2440

Reference No.: 217640
September 2022

Resulting Targeted Comparator Group
The 10 comparators targeted for the study, based on the prioritization assessment, included the following (listed in alphabetical order):

- Ameren Illinois Company
- Boston Gas Company (National Grid)
- CenterPoint Minnesota
- Consolidated Edison Company of NY, Inc.
- DTE Gas Company
- Fortis BC Energy Inc.
- Niagara Mohawk Power Corporation (National Grid)
- National Fuel Gas Distribution Corporation
- Public Service Electric and Gas Company
- Wisconsin Power and Light Co.

Although these comparators are identified above, the benchmarking report below has anonymized them when reporting on specific elements of the forecasts, referring to them as Utility A, Utility B, etc. This is a result of the needs of the interview process. Interviewees were provided with anonymity to motivate participation in the process and to avoid imposing any onerous administrative or legal hurdles to participation. As interview anonymity can be provided effectively in this case only through complete anonymization of utilities reviewed, no utility in the report below is referred to by its name.

This is consistent with the approach used by others for similar benchmarking reports, for example a 2020 benchmarking report developed for FortisBC Energy Inc.[10]

[10] Energitix, presented to FortisBC Energy Inc. *Long Term Demand Forecasting Benchmarking Study on End-Use Methods Industry Practices Review*, November 2020

Table 3-12. Contract Market Volume Forecast

Utility	Contract Market Volume Forecast
Utility A	Not in literature review
Utility B	Large volume account volumes are modeled in the same way as other customer groups, as a product of AU and customer count forecasts (both based on regression analysis).
Utility C	Large volume customer counts and volumes are forecast by applying “known changes” to base year observed volumes. Known changes are determined by marketing and sales staff through enquiries to customer staff.
Utility D	For large volume customers (both those contracted for firm and non-firm service) the utility’s forecasters assume that forecast period volumes will stay consistent with volumes in the base period (most recent complete calendar year).
Utility E	Each end user transportation customer’s volume is forecast on the basis its historical consumption, considerations of weather sensitivity, and the expert opinion of the customers’ corresponding dedicated account representative.
Utility F	Forecast volumes are developed using information obtained through communication with the customers
Utility G	Not in literature review
Utility H	Forecasters collaborate with key account managers to identify upcoming significant changes affecting gas consumption. This information is applied to historical sales volumes using forecaster expert judgement to deliver the forecast volumes for the largest volume customers.
Utility I	5-year forecast is informed through a survey where the utility’s largest customers project their monthly volumes for the next calendar year and annual volumes for the following 4 years.
Utility J	Large Volume account volumes are modeled in the same way as other customer groups product of use-per-customer forecasts, both based on regression analysis).

3.7 Revenue Stability & Deferral Accounts

Revenue stability mechanisms are common in all regulated utilities. The scope of such mechanisms varies but these are generally applied to better align utility incentives with societal benefits (e.g., by protecting utilities from revenue short-falls due to DSM), and to provide bilateral protection to customers and utilities for random shocks and deviations from trend (e.g., volatility in weather and macro-economic drivers of volume demand). Both EGD and Union rate zones are equipped with deferral accounts intended to stabilize revenues to fluctuations in weather-normalized AU.

Additional details regarding the deferral and variance accounts used in each rate zone may be found in Table 3-13 below.

Table 3-13. EGI General Service Customer Forecast

Modelling Category	Enbridge Gas Distribution	Union Gas
Revenue Stability Mechanism	Average Use True-Up Variance Account (AUTUVA)	Normalized Average Consumption (NAC) deferral account.
Approach	Historical weather-normalized AU is compared to OEB approved weather-normalized AU. The difference between these values is multiplied by the OEB approved number of customers in the given class and then by the OEB approved delivery rates. Where differences between forecast and observed AU result in over-collection, customers receive bill credits, where the opposite is the case, a surcharge is applied.	Historical weather-normalized AU is compared to the target forecast approved by the OEB in the approved delivery and storage rates case. The difference between these values is multiplied by the OEB-approved number of customers in the given class and then by the OEB approved delivery and storage rates. Where differences between approved and observed weather-normalized AU result in over-collection, customers receive bill credits, where the opposite is the case, a surcharge is applied.

All of the comparators reviewed in this report employ some form of revenue stabilization. One of the utilities examined employs an approach very similar to that of the EGD and UG rate zones: variances are recovered (or refunded) on the basis of weather normalized revenue. For many of the utilities, however, some stabilization mechanism exists to provide consumers and the utility with bilateral protection from weather volatility. In some cases, this is explicit in the mechanism (e.g., the weather normalization adjustments of utilities D, F, G, and J), in other cases it appears to be implicit (e.g., utilities A, B, C, E, and I). In most of the instances in which an explicit weather-related revenue stabilization mechanism exists, there also exists a revenue decoupling mechanism which includes revenues collected (or credits disbursed) as part of intra-season weather normalization adjustments.

Although bilateral in nature, the protection offered by these mechanisms is not always symmetric: under-collection variance recovery is capped for utilities B, C, E, and G. In some cases, the cap is set as an absolute value, but in others it is determined in relation to the utility's overall approved rate of return or projected DSM achievement.

A summary of Guidehouse's findings for all the comparators may be found in Table 3-14, below.

Table 3-14. Revenue Stability Mechanisms

Utility	Revenue Stability Mechanism	Approach	Mechanism Addresses Weather-Based Revenue Volatility
Utility A	Volume Balancing Adjustment (VBA) Rider	The VBA rider applies to all residential and small general service customers and is calculated annually, by class. The adjustment amount per therm is calculated as the difference between actual revenues and rate-case approved revenues divided by forecast therms.	Implicitly

Utility	Revenue Stability Mechanism	Approach	Mechanism Addresses Weather-Based Revenue Volatility
Utility B	Revenue Decoupling Mechanism	The RDM provides for the semi-annual (seasonal) calculation of a variable ($/therm) adjustment factor applied to customer bills, by class. The aggregate pool (by class) is calculated by taking the difference between benchmark revenue per customer and the average observed revenue per customer and scaling this by the observed customer count. Benchmark revenue per customer is the allowed average revenue per customer, per season, by class, reflective of base distribution revenue determined in the most recent distribution rate case. Where revenue under-collection compared to the benchmark exceeds 3%[23] of total revenue from firm sales (for the given customer class) in the prior year (for the same season), funds in excess of the 3% threshold are carried over to the next year.	Implicitly
Utility C	Revenue Decoupling Rider	The rider allows the utility to recover its authorized revenues regardless of the causes of in variation up to an approved revenue cap. Every 12 months, actual utility revenues reflecting customer fixed and variable charges (net of charges for funding utility energy efficiency and affordability programs) is compared to the authorized number of customers and authorized sales volumes. Where there is over-collection, customers are refunded the difference between actual and authorized revenue in the subsequent 12 months. Where there is under-collection, a surcharge is applied to customers in the subsequent 12 months. The aggregate surcharge may not exceed 10% of authorized revenues. Adjustments are applied by rate class.	Implicitly
Utility D	Revenue Decoupling Mechanism and Weather Normalization Adjustment	The weather normalization adjustment is a $/therm surcharge or credit that is calculated and applied on a billing cycle basis by calculating the difference between that cycle's normal HDD and actual (observed) HDD, times the average therms per HDD and the base rate and then dividing that value by total therm consumption in that billing cycle. This is calculated by cycle and class. The RDM reconciliation process occurs annually. This reconciliation calculates the difference between actual and allowed delivery revenue from base rates (inclusive of any weather normalization surcharges and credits). This variance is then applied as a $/therm surcharge or credit to customers (by class) in the following year.	Yes
Utility E	Revenue Decoupling Mechanism	This utility's revenue decoupling mechanism applies to residential and small to medium sized general service (non-residential customers) and is applied as part of an annual reconciliation process. The mechanism compares rate-case approved total revenue by class with actual weather normalized revenue by class, with differences being recovered from, or returned to,	Implicitly

[23] The 3% threshold is asymmetric and applies only to cases of under-collection. Where average observed revenue per customer is less than benchmark revenue per customer, there appears to be no similar rule in place imposing a ceiling on customer credits.

Utility	Revenue Stability Mechanism	Approach	Mechanism Addresses Weather-Based Revenue Volatility
		customers as a surcharge or credit. Under-collection recovered by the utility is capped, with the cap determined as a function of the utility's legislated DSM targets.	
Utility F	Revenue Decoupling Mechanism and Weather Normalization Adjustment	The weather normalization adjustment is a $/Mcf surcharge or credit that is calculated and applied on revenue month basis for the months of October through May. This is calculated by taking the difference between that month's normal HDD and actual (observed) HDD, multiplied by a month-specific degree day factor (capturing the incremental Mcf gas consumption per HDD) times the relevant charge, divided by total consumption. This is calculated by month and class. The RDM reconciliation process occurs annually at the end of March. Reconciliation is determined through a comparison of weather-normalized actual AU with imputed weather-normal AU.	Yes
Utility G	Weather Normalization Charge	A weather normalization charge applies to residential, commercial and large volume consumers from October through May of each year. Charges for the subsequent period are set at the end of each winter by comparing each winter month's HDD to the weather-normal HDD for the given month. If the sum of these differences fall within a dead-band of 0.5% of normal winter HDD, no charge or refund is applied. When the total difference is outside the dead-band, the revenue deficiency (or surplus) is calculated by applying a margin revenue factor, and recovered (or refunded) in the subsequent period. Revenue deficiency recovery amounts are capped such that any recovery charges cannot result in the utility earn a rate of return on common equity in excess of its approved percentage.	Yes
Utility H	Gas Cost Recovery Mechanism	Under this mechanism, gas costs which exceed an established monthly benchmark commodity price may be approved for recovery by the utility's regulator.	No
Utility I	Revenue Stabilization Adjustment Mechanism	Variances between the forecast and actual delivery margin are captured in a deferral account and refunded or collected from customers in subsequent year through an annual reconciliation process.	Implicitly
Utility J	Revenue Decoupling Mechanism and Weather Normalization Adjustment	The weather normalization adjustment is a $/therm surcharge or credit that is calculated and applied on a billing cycle basis by calculating the difference between that cycle's normal HDD and actual (observed) HDD, scaling this using an average annual degree day factor (capturing incremental therm consumption per degree day, by class) and the margin/non-gas rate. This value is then divided by total therm consumption in that billing cycle. This is calculated by cycle and class. This utility's RDM is reconciled on an annual basis in July of each year. This reconciliation calculates the difference between actual and allowed delivery revenue from delivery rates (inclusive of any weather normalization surcharges and credits). This variance is then applied as a $/therm surcharge or credit to customers (by class) in a 12-month period that begins in October of the following year.	Yes

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Ex. 3, Tab 2, Schedule 2, page 29

Preamble:

EGI's Guidehouse Report states: *In addition to this a majority of the comparator utilities (unlike EGI) are also subject to some mechanism that provides bilateral protection to customers and utilities from the natural volatility of weather (HDD) around its projected mean value. Such mechanisms are not always symmetric: under-collection variance recovery is capped for half of the utilities where the mechanism exists. No such mechanism is in place for EGI.*

Question(s):

Please summarize the mechanisms for the half of the utilities where the variance recovery is capped exists including:

a) Parameters

b) Off-setting or mitigating attributes of their respective rate construct

Response:

The following response was provided by Guidehouse:

a) Under-collection variance recovery is capped for utilities B, C, E, and G. The parameters for the mechanisms used for these comparators are:

   i. Utility B: Where revenue under-collection compared to the benchmark exceeds 3% of total revenue from firm sales (for the given customer class) in the prior year (for the same season), funds in excess of the 3% threshold are carried over to the next year. The 3% threshold is asymmetric and applies only to cases of under-collection. Where average observed revenue per customer is less than benchmark revenue per customer, there appears to be no similar rule in place imposing a ceiling on customer credits.

ii. Utility C: Where there is under-collection, a surcharge is applied to customers in the subsequent 12 months. The aggregate surcharge may not exceed 10% of authorized revenues.
iii. Utility E: Under-collection recovered by the utility is capped, with the cap determined as a function of the utility's legislated DSM targets.
iv. Utility G: Revenue deficiency recovery amounts are capped such that any recovery charges cannot result in the utility earning a rate of return on common equity in excess of its approved percentage.

b) In its analysis, Guidehouse reviewed only revenue stability mechanisms within the context of forecast uncertainty. A review of the utility rate constructs was not in scope for the volume forecasting benchmarking study and so was not conducted. Consequently, Guidehouse cannot provide a description of off-setting or mitigating attributes of these rate constructs.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 173

To explain what is meant by the positive and negative numbers shown on Table 1 and how the total volume variance amounts are calculated using 2021 as an example.

Response:

The signs and summation provided in response at Exhibit I.9.1-SEC-225, Table 1, which was intended to illustrate what historically would have been captured in the proposed Volume Variance Account, were incorrect. Please see Table 1 for the correct calculation. Enbridge Gas will provide an updated response to Exhibit I.9.1-SEC-225 with the package of interrogatory response updates, currently expected on April 11, 2023.

Using 2021 as an example, Enbridge Gas under-collected $73.1 million cumulatively (AUTUVA/NAC in combination with the weather-related impact). The under-collection of $73.1 million is attributable to $40.8 million in the Union rate zones and $32.4 million in the EGD rate zone, which are comprised of the following two drivers:

a) NAC/AUTUVA Deferral Amount:

   Overall, the 2021 actual weather normalized average use was lower than the budget/target average use embedded in rates. The company under-collected due to actual lower weather normalized average use by approximately $19.2 million in the Union rate zones and approximately $14.9 million in the EGD rate zone.

b) Weather Impact:

   Actual weather in 2021 was warmer than normal, and as a result Enbridge Gas under-collected approximately $21.5 million in the Union rate zones and-under collected approximately $17.4 million in the EGD rate zone.

Proposed for Clearance
Accounting Policy Changes Deferral Account
Summary of Cumulative 2023 Revenue Requirement Impact

Line No.	Particulars ($ millions)	Rate Zone	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	Cumulative Total
			(a)	(b)	(c)	(d)	(e)	(f)
1	Change from Capital to O&M (1)	EGD	5.8	0.6	0.4	0.8	0.3	7.9
2	Change from O&M to Capital (2)	Union	(1.4)	(5.8)	(4.0)	(2.6)	(5.7)	(19.6)
3	Total Capitalization vs. Expense		4.4	(5.2)	(3.6)	(1.9)	(5.4)	(11.7)
4	Change in IDC Rate from WACD to CWIP (3) (4)	EGD	0.5	1.0	0.8	-	0.0	2.4
5	Removal of IDC Threshold (5)	Union	(0.6)	(0.1)	(0.3)	-	0.2	(0.8)
6	Total IDC		(0.1)	1.0	0.5	-	0.2	1.5
7	Depreciation Expense (change from half-year rule) (6)	Union	(6.1)	(4.1)	(5.8)	(4.4)	(10.8)	(31.2)
8	Overhead Capitalization Changes (7)	EGD	-	3.4	5.1	5.6	8.5	22.6
9	Overhead Capitalization Changes (8)	Union	-	(9.9)	(10.0)	(13.4)	(25.9)	(59.1)
10	Total Overhead Capitalization Changes		-	(6.4)	(4.9)	(7.8)	(17.4)	(36.5)
11	Amortized Gas Supply Storage and Transportation Costs	EGD	-	-	-	64.9	-	64.9
12	Total of APCDA - Other (non-pension related balances)		(1.7)	(14.8)	(13.9)	50.8	(33.4)	(13.0)
13	Opening Balance of Pre-17 Pension Actuarial Losses		211.3	193.8	181.5	169.4	157.4	155.2
14	Continued Amortization of Pre-17 Pension Actuarial Losses		(17.5)	(12.3)	(12.0)	(12.0)	(2.2)	-
15	Ending Pension & OPEB (Unamortized Pre-17 Pension Actuarial Losses) (9)	Union	193.8	181.5	169.4	157.4	155.2	155.2
16	Total Cumulative Revenue Requirement Impact		192.0	164.9	139.0	177.8	142.2	142.2
17	Annual Interest (10)		(0.1)	(0.7)	(0.6)	1.7	(0.4)	(0.0)
18	Total Cumulative Interest		(0.1)	(0.8)	(1.3)	0.3	(0.0)	(0.0)
19	Total APCDA Impact with Interest		191.9	164.3	138.5	179.5	141.8	142.2

Notes:
(1) Exhibit 9, Tab 2, Schedule 1, Attachment 4, page 1.
(2) Exhibit 9, Tab 2, Schedule 1, Attachment 4, page 2.
(3) 2020 revenue requirement includes a true-up of $0.249 booked in the 2021 APCDA. There was a change in the weighted average cost of debt (WACD) rate that wasn't captured until after 2020 results had already been filed with the OEB in the 2020 Earnings Sharing and Deferrals Disposition proceeding (EB-2021-0149).
(4) Exhibit 9, Tab 2, Schedule 1, Attachment 4, page 3.
(5) Exhibit 9, Tab 2, Schedule 1, Attachment 4, page 4.
(6) Exhibit 9, Tab 2, Schedule 1, Attachment 4, page 5.
(7) Exhibit 9, Tab 2, Schedule 1, Attachment 4, page 6.
(8) Exhibit 9, Tab 2, Schedule 1, Attachment 4, page 7.
(9) Exhibit 9, Tab 2, Schedule 1, Attachment 4, page 8.
(10) Interest is not calculated on unamortized pre-17 pension actuarial losses.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

For the APCDA category of *Amortized Gas Supply Storage and Transportation Costs,* please provide any evidentiary references on the calculation of the proposed deferral account amount.

Whether provided or not, please provide the calculation of the proposed balance by including actuals for 2022 and 2023 as much as available and forecast for the rest of the 2023 year

Response:

Please see Attachment 1 for the calculation of the Amortized Gas Supply Storage and Transportation Costs balance in the APCDA:

- Table 1 provides the calculation of the 2022 Forecast balance of $64.9 million recorded in the APCDA per Exhibit 9, Table 2, Schedule 1, Attachment 2.
- Table 2 provides the calculation 2022 Actual balance of $62.1 million recorded in the APCDA.
- Table 3 provides the calculation of the 2023 Forecast balance of $62.1 million. The 2023 ending balance is equivalent to the 2022 Actual balance because no additional amounts are proposed to be recorded in the APCDA in 2023. See Exhibit 9, Tab 2, Schedule 1 pages 14 to 16 for additional details.

Table 1: Amortized Gas Supply Storage and Transportation Costs in APCDA - 2022 Forecast

Line No.	Particulars ($ millions)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec (2)	Total
1	Opening Balance - Gas Supply Storage and Transportation Costs Balance Sheet Account	61.4	31.4	8.4	0.0	11.9	23.9	36.1	48.4	60.7	72.9	84.7	82.0	
2	Gas Supply Storage and Transportation Costs	12.7	12.7	12.7	12.8	12.9	13.1	13.2	13.1	13.1	12.8	12.7	12.7	154.6
3	Gas Supply Storage and Transportation Costs Variance Recorded in S&TDA	(0.9)	(0.8)	(0.9)	(1.0)	(0.9)	(0.9)	(0.8)	(0.9)	(0.9)	(0.9)	(1.1)	(1.1)	(11.1)
4	Net Gas Supply Storage and Transportation Costs Recorded in Balance Sheet Account	11.8	11.9	11.8	11.9	12.0	12.2	12.3	12.3	12.2	11.8	11.6	11.6	143.4
5	Amortized Gas Supply Storage and Transportation Costs Expensed	(41.9)	(34.9)	(20.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(14.3)	(28.7)	(139.9)
6	Closing Balance - Gas Supply Storage and Transportation Balance Sheet Account (1)	31.4	8.4	0.0	11.9	23.9	36.1	48.4	60.7	72.9	84.7	82.0	0.0	
7	Closing Balance - APCDA (2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	64.9	

Notes:
(1) Line 1 + Line 4 + Line 5
(2) Forecast December 2022 closing balance transferred to APCDA (Exhibit 9, Table 2, Schedule 1, Attachment 2)

Table 2: Amortized Gas Supply Storage and Transportation Costs in APCDA - 2022 Actual

Line No.	Particulars ($ millons)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec (2)	Total
1	Opening Balance - Gas Supply Storage and Transportation Costs Balance Sheet Account	61.4	31.0	7.6	(2.0)	11.2	22.7	34.5	46.1	57.9	69.1	80.3	78.6	
2	Gas Supply Storage and Transportation Costs	12.3	12.7	12.3	10.5	12.8	12.7	11.0	12.6	12.3	11.6	13.1	12.1	145.9
3	Gas Supply Storage and Transportation Costs Variance Recorded in S&TDA	(0.8)	(1.3)	(1.0)	0.7	(1.3)	(0.9)	0.6	(0.9)	(1.1)	(0.4)	(0.9)	(0.9)	(8.1)
4	Net Gas Supply Storage and Transportation Costs Recorded in Balance Sheet Account	11.4	11.4	11.3	11.2	11.5	11.8	11.6	11.8	11.2	11.2	12.2	11.2	137.9
5	Amortized Gas Supply Storage and Transportation Costs Expensed	(41.9)	(34.9)	(20.9)	2.0	0.0	0.0	0.0	0.0	0.0	0.0	(13.8)	(27.7)	(137.1)
6	Closing Balance - Gas Supply Storage and Transportation Balance Sheet Account (1)	31.0	7.6	(2.0)	11.2	22.7	34.5	46.1	57.9	69.1	80.3	78.6	0.0	
7	Closing Balance - APCDA (2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	62.1	

Notes:
(1) Line 1 + Line 4 + Line 5
(2) December 2022 closing balance transferred to APCDA

Table 3: Amortized Gas Supply Storage and Transportation Costs in APCDA - 2023 Forecast

Line No.	Particulars ($ millons)	Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Forecast	Jun Forecast	Jul Forecast	Aug Forecast	Sep Forecast	Oct Forecast	Nov Forecast	Dec Forecast	Total
1	Opening Balance - APCDA	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	
2	Gas Supply Storage and Transportation Costs	12.3	12.4	12.3	12.8	12.0	12.1	12.2	12.2	12.3	12.2	12.1	12.0	146.9
3	Gas Supply Storage and Transportation Costs Variance Recorded in S&TDA	(0.9)	(1.0)	(0.9)	(1.4)	(0.6)	(0.7)	(0.8)	(0.8)	(0.8)	(0.9)	(0.9)	(0.9)	(10.5)
4	Net Gas Supply Storage and Transportation Costs Expensed (1)	11.4	11.4	11.4	11.4	11.4	11.4	11.5	11.4	11.4	11.3	11.2	11.2	136.4
5	Closing Balance - APCDA	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	

Notes:
(1) Amounts expensed as incurred starting 2023. No additional amounts recorded in APCDA in 2023. Please see Exhibit 9, Tab 2, Schedule 1, pages 14 to 16 for additional details.

Enbridge and Spectra Energy to Combine to Create North America's Premier Energy Infrastructure Company with

C$165 Billion Enterprise Value

September 6, 2016

CALGARY, ALBERTA and HOUSTON, TEXAS--(Marketwired - Sept. 6, 2016) -

Highlights:

- Creates largest energy infrastructure company in North America with C$165[1] billion (US$127 billion) enterprise value
- Anticipated 15 percent annualized dividend increase in 2017 and annual 10-12 percent dividend growth thereafter through 2024. Industry leading secured project and risked development inventory of C$74 billion (US$57 billion) with C$26 billion (US$20 billion) currently in execution
- Complementary and diversified asset base to increase customer service offerings and optionality
- Enhanced ability to pursue projects that will improve customer access and service
- Strengthens investment grade balance sheet
- 96 percent of cash flow generated by cost-of-service, take-or-pay, or fee-based contracts
- Industry-leading total return potential

Enbridge Inc. (TSX:ENB) (NYSE:ENB) (Enbridge) and Spectra Energy Corp (NYSE:SE) (Spectra Energy) today announced that they have entered into a definitive merger agreement under which Enbridge and Spectra Energy will combine in a stock-for-stock merger transaction (the "Transaction"), which values Spectra Energy common stock at approximately C$37 billion (US$28 billion), based on the closing price of Enbridge's common shares on September 2, 2016. The combination will create the largest energy infrastructure company in North America and one of the largest globally based on a pro-forma enterprise value of approximately C$165 billion (US$127 billion). The Transaction was unanimously approved by the Boards of Directors of both companies and is expected to close in the first quarter of 2017, subject to shareholder and certain regulatory approvals, and other customary conditions.

Under the terms of the Transaction, Spectra Energy shareholders will receive 0.984 shares of the combined company for each share of Spectra Energy common stock they own. The consideration to be received by Spectra Energy shareholders is valued at US$40.33 per Spectra Energy share, based on the closing price of Enbridge common shares on September 2, 2016, representing an approximate 11.5 percent premium to the closing price of Spectra Energy common stock on September 2, 2016. Upon completion of the Transaction, Enbridge shareholders are expected to own approximately 57 percent of the combined company and Spectra Energy shareholders are expected to own approximately 43 percent. The combined company will be called Enbridge Inc.

This combination brings together two highly complementary platforms to create North America's largest energy infrastructure company and meaningfully enhances customer optionality. With an asset base that includes a diverse set of best-in-class assets comprised of crude oil, liquids and natural gas pipelines, terminal and midstream operations, a regulated utility portfolio and renewable power generation, the combined company will be positioned to provide integrated services and first and last mile connectivity to key supply basins and demand markets. On a combined basis for the 12 months ended June 30, 2016, the company would have generated combined revenues in excess of C$40 billion (US$31 billion) and combined Earnings before Interest and Taxes (EBIT) of C$5.8 billion (US$4.4 billion), and will have the scale, balance sheet strength, financial flexibility and free cash flow to comfortably fund future growth.

"Over the last two years, we've been focused on identifying opportunities that would extend and diversify our asset base and sources of growth beyond 2019," said Al Monaco, President and Chief Executive Officer, Enbridge Inc. "We are accomplishing that goal by combining with the premier natural gas infrastructure company to create a true North American and global energy infrastructure leader. This Transaction is transformational for both companies and results in unmatched scale, diversity and financial flexibility with multiple platforms for organic growth."

Greg Ebel, President and Chief Executive Officer of Spectra Energy, who will become chairman of Enbridge following the closing of the Transaction, said, "The combination of Enbridge and Spectra Energy creates what we believe will be the best, most diversified energy infrastructure company in North America, if not the world. This is an incredible opportunity for both companies and we at Spectra Energy could not be more excited about what it means going forward. Together, the merged company will have what we believe is the finest platform for serving customers in every region of North America and providing investors with the opportunity for superior shareholder returns."

Mr. Monaco added, "Bringing Enbridge and Spectra Energy together makes strong strategic and financial sense, and the all-stock nature of the Transaction provides shareholders of both companies with the opportunity to participate in the significant upside potential of the combined company. With combined secured projects in execution of C$26 billion (US$20 billion) and another C$48 billion (US$37 billion) of projects under development, the Transaction allows us to extend our anticipated 10-12 percent annual dividend growth through 2024. We believe our combination of best-in-class assets, superior growth and strong commercial underpinning of our business will be unrivaled in our sector. Importantly, we will preserve and enhance our shareholder value proposition, which centers on delivering consistent growth with a low-risk business model.

"This is also a combination of two companies, management and staff that have a shared vision and talented teams that are dedicated to serving customers and providing the energy that people want and need, safely and reliably every day. We look forward to welcoming Spectra Energy employees to Enbridge as we move forward as one company. In building on our existing strengths by joining with Spectra Energy, Enbridge will be very well positioned for future growth and continued value creation."

Mr. Ebel added, "The strength of the combined company will support a large capital program to fund the continued development of Spectra Energy's existing, preeminent project inventory in addition to allowing the combined company to compete for and win the most attractive new growth projects - all while maintaining expected strong dividend growth with exceptional coverage. The transaction premium recognizes the strength of Spectra Energy's world-class natural gas pipeline system and significant expansion program, while providing shareholders the opportunity to participate in the unparalleled value creation potential of the combined company. While our assets are largely complementary, our values are shared, and together we will create a best-in-class company for shareholders, employees, customers, and communities alike."

Compelling Value Proposition

- **Six leading strategic growth platforms:** The combined company brings together many of the highest quality energy infrastructure assets in North America: liquids and gas pipelines; US and Canadian midstream businesses; a top tier regulated utility portfolio; and a growing renewable power generation business. A map of the assets of the combined entity is available at www.enbridge.com and www.spectraenergy.com.
- **Secure, low-risk commercial structure with stable long-term cash flow visibility:** 96 percent of pro-forma free cash flow is underpinned by long-term commercial agreements (cost-of-service, take-or-pay, of fixed fee); 93 percent of customers are strong, investment grade or equivalent counterparties; less than 5 percent of combined pro-forma cash flow will have direct exposure to commodity price risk.
- **Largest and most secure program of diversified organic growth projects in the industry:** Together, Enbridge and Spectra Energy bring C$26 billion (US$20 billion) in secured capital and a C$48 billion (US$37 billion) inventory of probability weighted projects in development.
- **Strong balance sheet, growing cash flow and access to capital markets to fund large capital program:** The combination is expected to result in sufficient internally generated cash flow to fund growth and improve balance sheet strength. Enbridge will have multiple, cost-effective funding sources and be even more competitive in capturing opportunities.
- **Attractive dividend yield with visible organic dividend growth:** The combined company's C$74 billion (US$57 billion) organic growth platform is expected to support a highly visible dividend growth rate of 10-12 percent through 2024, including an anticipated aggregate increase of 15 percent in 2017 post closing, while maintaining a conservative payout of 50-60 percent of available cash flow from operations (ACFFO). This provides an industry leading total return driven by a strong, low-risk dividend yield.
- **Achievable cost synergies:** The combination is expected to achieve annual run-rate synergies of C$540 million (US$415 million), the majority of which should be achieved in the latter part of 2018. In addition, approximately C$260 million (US$200 million) of tax savings can be achieved through utilization of tax losses commencing in 2019.
- **Complementary businesses, shared culture and values support smooth integration:** Enbridge and Spectra Energy have similar business and operational models, talented teams, common cultures and values, including shared commitment to safety, stewardship of the environment, meaningful stakeholder engagement and investing in communities.

Leadership, Governance and Structure

Upon closing of the Transaction, Al Monaco will continue to serve as President and Chief Executive Officer of the combined company. Greg Ebel will serve as non-executive Chairman of Enbridge's Board of Directors.

Enbridge's Board of Directors is expected to have a total of 13 directors consisting of 8 members designated by Enbridge, including Mr. Monaco, and 5 members designated by Spectra Energy, including Mr. Ebel.

The senior management team of the combined entity will be communicated in due course. On closing, the following appointments will take effect:

Guy Jarvis, President, Liquids Pipelines & Major Projects

Bill Yardley, President, Gas Transmission & Midstream

John Whelen, Executive Vice President & Chief Financial Officer

The headquarters of the combined company will be in Calgary, Alberta. Houston, Texas will be the combined company's gas pipelines business unit center; Edmonton, Alberta will remain the business unit center for liquids pipelines, with gas distribution continuing to be based in Ontario.

Enbridge and Spectra Energy will immediately establish an integration planning team composed of leaders from both management teams to prepare for and oversee the effective and timely integration of the businesses. The approach to integration planning will be collaborative, drawing on strong participation from both companies, and ensuring continuity for customers and other stakeholders.

On closing the Enbridge common shares to be issued in connection with the Transaction will be listed on the TSX and NYSE. Spectra Energy common stock will be delisted from the NYSE.

Financial Considerations

Enbridge expects the Transaction to be neutral to its 12 percent to 14 percent secured ACFFO per share CAGR guidance through the 2014-2019 time period, and strongly additive to its growth beyond that timeframe. Enbridge is committed to maintaining the financial strength of the combined company. The funding program is designed to ensure strengthening of the balance sheet with the objective of maintaining strong investment grade credit ratings. Enbridge expects it will divest of approximately $2 billion of non-core assets over the next 12 months to provide additional financial flexibility.

At closing, Enbridge Energy Partners, LP and Spectra Energy Partners, LP are expected to continue to be publicly traded partnerships headquartered in Houston, Texas. Enbridge Income Fund Holdings will remain a publicly traded corporation headquartered in Calgary, Alberta.

Timing and Approvals

The Transaction is expected to close in the first quarter of 2017 subject to the receipt of both companies' shareholder approvals, along with certain regulatory and government approvals, including compliance with the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and approval under Canada Competition Act, and the satisfaction of other customary closing conditions.

Advisors

Credit Suisse Securities (Canada), Inc. acted as Lead Financial Advisor and delivered an opinion to Enbridge's Board of Directors. RBC Capital Markets also acted as financial advisor to Enbridge and delivered an opinion to Enbridge's Board of Directors. Sullivan & Cromwell LLP and McCarthy Tétrault LLP were legal advisors to Enbridge.

BMO Capital Markets and Citi acted as Joint Lead Financial Advisors to Spectra Energy's Board of Directors. Wachtell, Lipton, Rosen & Katz and Goodmans LLP acted as legal advisors to Spectra Energy and Skadden, Arps, Slate, Meagher & Flom LLP acted as tax counsel.

CONFERENCE CALL DETAILS

Enbridge and Spectra Energy will hold a joint conference call on September 6, 2016 at 8:00 a.m. Eastern Time (6:00 a.m. Mountain Time) to discuss the Transaction.

The conference call will begin with presentations by Enbridge's President and Chief Executive Officer and Spectra Energy's Chairman, President and Chief Executive Officer, followed by a question and answer period for investment analysts.

Analysts, members of the media and other interested parties can access the call toll-free at 1-866-610-1072 or within and outside North America at 1-973-935-2840 using the access code of 77468882. **The call will be audio webcast live here.** A webcast replay and podcast will be available approximately two hours after the conclusion of the event and a transcript will be posted to the website within 24 hours. The replay will be available at toll-free 1-800-585-8367 or within and outside North America at 1-404-537-3406 (access code 77468882) for seven days after the call.

ABOUT ENBRIDGE INC.

Enbridge Inc., a Canadian company, exists to fuel people's quality of life, and has done so for more than 65 years. A North American leader in delivering energy, Enbridge has been ranked on the Global 100 Most Sustainable Corporations index for the past seven years. Enbridge operates the world's longest crude oil and liquids transportation system across Canada and the U.S., and has a significant and growing involvement in natural gas gathering, transmission and midstream business, as well as an increasing involvement in power transmission. Enbridge owns and operates Canada's largest natural gas distribution company, serving residential, commercial, and industrial customers in Ontario, Quebec, New Brunswick and New York State. Enbridge has interests in nearly 2,000 megawatts of net renewable and alternative generating capacity, and continues to expand into wind, solar and geothermal power. Enbridge employs nearly 11,000 people, primarily in Canada and the U.S., and is ranked as one of Canada's Top Employers for 2016.

Enbridge's common shares trade on the Toronto and New York stock exchanges under the symbol ENB. For more information, visit www.enbridge.com.

ABOUT SPECTRA ENERGY CORP

Spectra Energy Corp (NYSE:SE), a FORTUNE 500 company, is one of North America's leading pipeline and midstream companies. Based in Houston, Texas, the company's operations in the United States and Canada include approximately 21,000 miles of natural gas and crude oil pipelines; approximately 300 billion cubic feet of natural gas storage; 4.8 million barrels of crude oil storage; as *well as natural gas gathering, processing, and local distribution operations. Spectra Energy is the general partner of Spectra Energy Partners (NYSE:SEP), one of the largest pipeline master limited partnerships in the United States and owner of the natural gas and crude oil assets in Spectra Energy's U.S. portfolio. Spectra Energy also has a 50 percent ownership in DCP Midstream, the largest producer of natural gas liquids and the largest natural gas processor in the United States. Spectra Energy has served North American customers and communities for more than a century. For more information, visit www.spectraenergy.com.*

FORWARD-LOOKING INFORMATION

This news release includes certain forward looking statements and information (FLI) to provide Enbridge and Spectra Energy shareholders and potential investors with information about Enbridge, Spectra Energy and their respective subsidiaries and affiliates, including each company's management's respective assessment of Enbridge, Spectra Energy and their respective subsidiaries' future plans and operations, which FLI may not be appropriate for other purposes. FLI is typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe", "likely" and similar words suggesting future outcomes or statements regarding an outlook. All statements other than statements of historical fact may be FLI. In particular, this news release contains FLI pertaining to, but not limited to, information with respect to the following: the Transaction; the combined company's scale, financial flexibility and growth program; future business prospects and performance; annual cost, revenue and financing benefits; the expected ACFFO per share growth; future shareholder returns; annual dividend growth and anticipated dividend increases; payout of distributable cash flow; financial strength and ability to fund capital program and compete for growth projects; run-rate and tax synergies; potential asset dispositions; leadership and governance structure; and head office and business center locations.

Although we believe that the FLI is reasonable based on the information available today and processes used to prepare it, such statements are not guarantees of future performance and you are cautioned against placing undue reliance on FLI. By its nature, FLI involves a variety of assumptions, which are based upon factors that may be difficult to predict and that may involve known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by these FLI, including, but not limited to, the following: the timing and completion of the Transaction, including receipt of regulatory and shareholder approvals and the satisfaction of other conditions precedent; interloper risk; the realization of anticipated benefits and synergies of the Transaction and the timing thereof; the success of integration plans; the focus of management time and attention on the Transaction and other disruptions arising from the Transaction; expected future ACFFO; estimated future dividends; financial strength and flexibility; debt and equity market conditions, including the ability to access capital markets on favourable terms or at all; cost of debt and equity capital; potential changes in the Enbridge share price which may negatively impact the value of consideration offered to Spectra Energy shareholders; expected supply and demand for crude oil, natural gas, natural gas liquids and renewable energy; prices of crude oil, natural gas, natural gas liquids and renewable energy; economic and competitive conditions; expected exchange rates; inflation; interest rates; tax rates and changes; completion of growth projects; anticipated in-service dates; capital project funding; success of hedging activities; the ability of management of Enbridge, its subsidiaries and affiliates to execute key priorities, including those in connection with the Transaction; availability and price of labour and construction materials; operational performance and reliability; customer, shareholder, regulatory and other stakeholder approvals and support; regulatory and legislative decisions and actions; public opinion; and weather. We caution that the foregoing list of factors is not exhaustive. Additional information about these and other assumptions, risks and uncertainties can be found in applicable filings with Canadian and U.S. securities regulators, including any proxy statement, prospectus or registration statement to be filed in connection with the Transaction. Due to the interdependencies and correlation of these factors, as well as other factors, the impact of any one assumption, risk or uncertainty on FLI cannot be determined with certainty.

Except to the extent required by law, we assume no obligation to publicly update or revise any FLI, whether as a result of new information, future events or otherwise. All FLI in this news release is expressly qualified in its entirety by these cautionary statements.

NON-GAAP MEASURES

This news release makes reference to non-GAAP measures, including ACFFO and ACFFO per share. ACFFO is defined as cash flow provided by operating activities before changes in operating assets and liabilities (including changes in environmental liabilities) less distributions to non-controlling interests and redeemable non-controlling interests, preference share dividends and maintenance capital expenditures, and further adjusted for unusual, non-recurring or non-operating factors. Management of Enbridge believes the presentation of these measures gives useful information to investors and shareholders as they provide increased transparency and insight into the performance of Enbridge. Management of Enbridge uses ACFFO to assess performance and to set its dividend payout target. These measures are not measures that have a standardized meaning prescribed by generally accepted accounting principles in the United States of America (U.S. GAAP) and may not be comparable with similar measures presented by other issuers. Additional information on Enbridge's use of non-GAAP measures can be found in Enbridge's Management's Discussion and Analysis (MD&A) available on Enbridge's website and www.sedar.com.

ADDITIONAL INFORMATION ABOUT THE TRANSACTION AND WHERE TO FIND IT

Enbridge will file with the U.S. Securities and Exchange Commission (SEC) a registration statement on Form F-4, which will include a proxy statement of Spectra Energy that also constitutes a prospectus of Enbridge, and any other documents in connection with the Transaction. The definitive proxy statement/prospectus will be sent to the shareholders of Spectra Energy. INVESTORS AND SHAREHOLDERS OF SPECTRA ENERGY ARE URGED TO READ THE PROXY STATEMENT/PROSPECTUS, AND ANY OTHER DOCUMENTS FILED OR TO BE FILED WITH THE SEC IN CONNECTION WITH THE TRANSACTION WHEN THEY BECOME AVAILABLE, AS THEY WILL CONTAIN IMPORTANT INFORMATION ABOUT ENBRIDGE, SPECTRA ENERGY, THE TRANSACTION AND RELATED MATTERS. The registration statement and proxy statement/prospectus and other documents filed by Enbridge and Spectra Energy with the SEC, when filed, will be available free of charge at the SEC's website at www.sec.gov. In addition, investors and shareholders will be able to obtain free copies of the proxy statement/prospectus and other documents which will be filed with the SEC by Enbridge on Enbridge's website at www.Enbridge.com or upon written request to Enbridge's Investor Relations department, 200, 425 First St. SW, Calgary, AB T2P 3L8 or by calling 800.481.2804 within North America and 403.231.5957 from outside North America, and will be able to obtain free copies of the proxy statement/prospectus and other documents filed with the SEC by Spectra Energy upon written request to Spectra Energy, Investor Relations, 5400 Westheimer Ct. Houston, TX 77056 or by calling 713.627.4610. You may also read and copy any reports, statements and other information filed by Spectra Energy and Enbridge with the SEC at the SEC public reference room at 100 F Street N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at 800.732.0330 or visit the SEC's website for further information on its public reference room. This communication shall not constitute an offer to sell or the solicitation of an offer to buy any securities, nor shall there be any sale of securities in any jurisdiction in which such offer, solicitation or sale would be unlawful prior to appropriate registration or qualification under the securities laws of such jurisdiction. No offering of securities shall be made except by means of a prospectus meeting the requirements of Section 10 of the U.S. Securities Act of 1933, as amended.

PARTICIPANTS IN THE SOLICITATION OF PROXIES

This communication is not a solicitation of proxies in connection with the Transaction. However, Enbridge, Spectra Energy, certain of their respective directors and executive officers and certain other members of management and employees, under SEC rules, may be deemed to be participants in the solicitation of proxies in connection with the Transaction. Information about Enbridge's directors and executive officers may be found in its Management Information Circular dated March 8, 2016 available on its website at www.Enbridge.com and at www.sedar.com. Information about Spectra Energy's directors, executive officers and other members of management and employees may be found in its 2015 Annual Report on Form 10-K filed with the SEC on February 25, 2016, and definitive proxy statement relating to its 2016 Annual Meeting of Shareholders filed with the SEC on March 16, 2016. These documents can be obtained free of charge from the sources indicated above. Additional information regarding the interests of such potential participants in the solicitation of proxies in connection with the Transaction will be included in the proxy statement/prospectus and other relevant materials filed with the SEC when they become available.

(1) Translated at spot FX rate on September 2 at close of trading.

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Ontario Energy Board | Commission de l'énergie de l'Ontario

RATE ORDER

EB-2018-0305

ENBRIDGE GAS INC.

Application for 2019 Rates

BEFORE: **Lynne Anderson**
Presiding Member

Susan Frank
Member

October 24, 2019

INTRODUCTION

On September 12, 2019, the Ontario Energy Board (OEB) issued its decision with respect to an incentive rate-setting application filed by Enbridge Gas Inc. (Enbridge Gas) for 2019 rates effective January 1, 2019 (Decision and Order). In its Decision and Order, the OEB ordered Enbridge Gas to file a draft rate order with the proposed tariff of rates and charges, and draft accounting orders reflecting the OEB's findings in its decision. The OEB also invited parties including OEB staff to file submissions on what should be the effective date for base rates and for Enbridge Gas to file a reply.

The OEB in a decision dated September 23, 2019 determined that the effective date for base rates shall be April 1, 2019. In its September 12, 2019 Decision and Order, the OEB required Enbridge Gas to provide options with respect to the duration of the recovery of the forgone revenue. The forgone revenue represented recoveries from the effective date to the implementation date of rates which was November 1, 2019.

Enbridge Gas filed its draft rate order on September 30, 2019. Only OEB staff filed comments on the draft rate order. OEB staff supported Enbridge Gas' proposed approach of recovering the forgone revenue for the period April 1, 2019 to October 31, 2019 over a two-month period. Enbridge Gas filed its reply to OEB staff comments on the draft rate order on October 10, 2019, amending the wording of the accounting orders as suggested by OEB staff.

The OEB has reviewed the rate schedules and draft accounting orders. The OEB approves the tariffs of rates and charges and the accounting orders as filed and amended in response to OEB staff's comments. Enbridge Gas has proposed rate riders to recover the forgone revenue over a two-month period. The OEB approves the proposed two-month recovery period for the forgone revenue.

DRAFT RATE ORDER

Enbridge Gas filed its draft rate order on September 30, 2019 with the proposed tariffs of rates and charges, and draft accounting orders reflecting the OEB's decision in the proceeding. The draft rate order also included customer notices and bill impacts.

The annual bill impact for a typical residential system sales customer consuming 2,400 cubic metres annually is $4.35 in the Enbridge Gas Distribution (EGD) rate zone. The rate impact for a Union Gas South residential system sales customer consuming 2,200 cubic metres annually is $9.38 while for the Union Gas North zone, the rate impact for a typical residential customer ranges from approximately $2.00 to $3.15 annually. The rate impacts are annual and do not reflect the specific impact for the nine months, from April 1, 2019 to December 31, 2019.

The OEB provided the other parties an opportunity to file comments on the draft rate order. Only OEB staff filed comments.

Forgone Revenue
In its draft rate order, Enbridge Gas proposed a two-month recovery period for the forgone revenues (revenue recovery for the period April 1, 2019 to October 31, 2019). Enbridge Gas submitted that since the total amount (forgone revenue) to be recovered from a typical residential customer in the EGD rate zone is $1.68 and between $1.00 and $2.00 in the Union Gas rate zones, the proposed amount should be recovered over a two-month period. OEB staff in its comments supported the two-month recovery period. Although Enbridge Gas provided calculations for alternative recovery periods as directed by the OEB in its Decision and Order, OEB staff believed that a longer recovery period was not necessary due to the minimal bill impact.

Deferral and Variance Accounts
In its comments, OEB staff questioned the update to the Open Bill Revenue Variance Account (EGD rate zone) and existing capital pass-through deferral accounts (Union Gas rate zones) as no changes were made to these accounts in the Decision and Order. Enbridge Gas in reply confirmed that no changes were made to the above mentioned deferral and variance accounts and Enbridge Gas only updated the respective rate zone within the title of each accounting order.

With respect to the draft accounting order for the Tax Variance Deferral Account, OEB staff submitted that a separate draft accounting order should be filed for the Tax Variance Deferral Account sub-account that is specific for accelerated capital cost allowance (CCA). In response, Enbridge Gas provided an updated accounting order to provide further clarity with regards to the accounting treatment of revenue requirement impacts attributable to CCA rule changes, as ordered by the OEB in its Decision and Order in this proceeding, and its letter dated July 25, 2019.[1]

For the 2019 Gas Supply Cost Consequences Deferral account, OEB staff submitted that the description of the account should identify the major cost components of the gas supply to be tracked separately within the account (e.g. commodity, transportation, storage, renewable natural gas, etc.) as per the OEB's direction in Procedural Order No. 3. In reply, Enbridge Gas provided an updated accounting order with the suggested revisions.

OEB staff in its comments noted that the Earnings Sharing Mechanism Deferral Account should clearly state that the earnings sharing calculation will be on an actual basis and not normalized for weather. Enbridge Gas filed an updated accounting order with the requested clarification.

In addition, Enbridge Gas made certain corrections to rate schedules that were included with the draft rate order. Minor corrections were made to Rate C1 and M12 rate schedules.

FINDINGS

The OEB has already determined that the effective date for base rates will be April 1, 2019 and the implementation date for the new rates will be November 1, 2019. In its Decision and Order, the OEB directed Enbridge Gas to provide alternate recovery periods for the forgone revenue (from April 1, 2019 to October 31, 2019) so that the OEB can consider different rate recovery durations in order to minimize bill impacts. Enbridge Gas in its draft rate order suggested recovery of the forgone revenue over a two-month period. Given the magnitude of the bill impact associated with the forgone revenue, the OEB approves recovery of the forgone revenue over a two-month period.

OEB staff in its comments suggested revisions and sought clarifications to certain deferral and variance accounts. Enbridge Gas in reply has made the suggested revisions and filed updated accounting orders. The OEB is satisfied with the revisions and notes that although Enbridge Gas has not requested a separate accounting order for the Tax Variance Deferral sub-account to record the impact of accelerated CCA, the updated description of the Tax Variance Deferral Account does state that Enbridge Gas

[1] OEB letter to all rate regulated electric and natural gas utilities regarding Bill C-97 (Accelerated Investment Incentive program).

will record 100% of the revenue requirement impact of any changes in CCA rules (including Bill C-97) that are not reflected in base rates.

The OEB approves the rate schedules and accounting orders as detailed in the subsequent Order section.

ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

For the Enbridge Gas Distribution rate zone

1. The rate changes set out in Appendix A1 and the rate handbook in Appendix B1 for the EGD rate zone are approved effective April 1, 2019. Enbridge Gas shall implement these rates on the first billing cycle on or after November 1, 2019.
2. For customers served in the EGD rate zone, Enbridge Gas shall dispose of the adjustment amount for forgone revenues through a temporary volumetric rate rider charge (credit) in rates from November 1, 2019 to December 31, 2019 as set out in the temporary price adjustments identified at Appendix D1.
3. The customer notices in Appendix C1 shall be given to all EGD rate zone customers with the first bill or invoice reflecting the new rate.
4. The deferral and variance accounts in Appendix E1 shall continue. These accounts are specific to the EGD rate zone and are identified accordingly.

For the Union Gas North and Union Gas South rate zones

5. The rate changes set out in Appendix A2 and Rate Schedules in Appendix B2 for the Union Gas North and Union Gas South rate zones are approved effective April 1, 2019. Enbridge Gas shall implement these rates on the first billing cycle on or after November 1, 2019.
6. The rates pursuant to all contracts for interruptible service under Rates M4, M5A, M7, T1, T2 and 25 shall be adjusted effective April 1, 2019 by the amounts set out in Appendix C2. Enbridge Gas shall implement the changes in rates on the first billing cycle on or after November 1, 2019.
7. For customers in the Union Gas North and Union Gas South rate zones, Enbridge Gas shall dispose of the adjustment amount for forgone revenues through a temporary volumetric rate rider charge (credit) in rates from November 1, 2019 to December 31, 2019 as set out in the temporary price adjustments identified at Appendix F2.

8. The customer notices in Appendix D2 shall be given to all customers in the Union Gas North and Union Gas South rate zones as applicable with the first bill or invoice reflecting the new rate.
9. Enbridge Gas shall charge the fees as set out in Appendix E2 for non-energy charges in the Union Gas North and Union Gas South rate zones.
10. The deferral and variance accounts in Appendix G2 shall continue. These accounts are specific to the Union Gas rate zones and are identified accordingly.

Enbridge Gas Inc. Deferral and Variance Accounts

11. The deferral and variance accounts in Appendix H shall continue. These accounts are Enbridge Gas accounts and are identified accordingly.

New Enbridge Gas Deferral and Variance Accounts

12. Enbridge Gas shall establish the following deferral and variance accounts as described in Appendix I:
    a. Accounting Policy Changes Deferral Account
    b. Earnings Sharing Mechanism Deferral Account
    c. Tax Variance Deferral Account
    d. Incremental Capital Module Deferral Account (separate for EGD and Union Gas rate zones)
    e. 2019 Gas Supply Plan Cost Consequences Deferral Account (EGD rate zone)
    f. Sudbury Replacement Project Costs Deferral Account (Union Gas rate zone)

DATED at Toronto, October 24, 2019

ONTARIO ENERGY BOARD

Original signed by

Christine E. Long
Registrar and Board Secretary

ENBRIDGE GAS INC.

Accounting Entries for
Accounting Policy Changes Deferral Account
Deferral Account No. 179-381

The purpose of the Accounting Policy Changes deferral account, as established in the Board's EB-2017-0306/EB-2017-0307 Decision and Order, is to record the impact of any accounting changes that affect revenue requirement, which are required as a result of the amalgamation of Enbridge Gas Distribution and Union Gas Limited into Enbridge Gas Inc.

Simple interest is to be calculated on the opening monthly balance of this account using the Board-approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179-381 Accounting Policy Changes Deferral Account
Credit	-	Account No. 300 Operating Revenues

To record, as a debit (credit) in Deferral Account No. 179-381, the impact of any accounting changes required as a result of the amalgamation that affect revenue requirement.

Debit	-	Account No.179-381 Accounting Policy Changes Deferral Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-381, interest on the balance in Deferral Account No. 179-381. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 177

To confirm where in the 2018 financial statements that amount resided; whether there is a note in the financial statements; to provide the 2017 union financial statements. To confirm where the balances resided between the Enbridge Spectra merger and the Enbridge Union. To provide the statements for 2017 and to 2018.

Response:

Please see response at Exhibit I.1.8-STAFF-14, Attachment 8 for the 2017 Union Gas Limited Financial Statements and Exhibit I.1.8-STAFF-14, Attachment 1 for the 2018 Enbridge Gas Inc. Combined Financial Statements.

In the 2017 Union Gas Limited Financial Statements, the unamortized actuarial gains/losses and past service costs were included in Accumulated Other Comprehensive Income (AOCI)[1]. An excerpt from Union's 2017 Financial Statements is provided below for reference.

FINANCIAL STATEMENTS | **UNION GAS LIMITED 2017**

Amounts Recognized in Accumulated Other Comprehensive Income (AOCI)

The amounts of pre-tax AOCI relating to the Company's pension and OPEB plans are as follows:

	Pension		**OPEB**	
($millions)	**2017**	2016	**2017**	2016
Net actuarial loss (gain)	**269**	257	**(4)**	(6)
Prior service cost	**1**	2	**(1)**	—
Total amounts recognized in AOCI, pre-tax	**270**	259	**(5)**	(6)

The $265 million[2] Union AOCI balance at December 31, 2017 consisted of the following:

- $231 million – pre-February 27, 2017, net pension and OPEB AOCI amounts

[1] Note 15 Pension and Other Postretirement Benefits in the 2017 Union Gas Financial Statements.
[2] $270 million pension minus $5 million OPEB

- $34 million – net pension and OPEB OCI amounts between February 27, 2017, to December 31, 2017

In the 2018 Enbridge Gas Inc. Combined Financial Statements, Union's pre-February 27, 2017, balance of unamortized actuarial losses and past service costs was segregated from AOCI and reclassified to Deferred Amounts and Other Assets[3]. An excerpt from Enbridge Gas's 2018 Financial Statements is provided below for reference. The net pension and OPEB OCI amount post February 27, 2017, continued to remain in AOCI.

10. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2018**	2017
(millions of Canadian dollars)		
Regulatory assets *(Note 6)*	**1,636**	1,538
Pension and OPEB assets	**29**	35
Other	**266**	289
	1,931	1,862

[3] $210 million included in $266 million of Other at December 31, 2018, and $231 million included in $289 million of Other at December 31, 2017, as provided at Note 10 Deferred Amounts and Other Assets of the 2018 Enbridge Gas Inc. Combined Financial Statements.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 180

After the merger, if there had been no accounting policy changes deferral account, what would have occurred to the balance, both on the financial and regulatory purposes, the amortized external gains and losses and past service costs remaining balance.

Response:

In the absence of the Accounting Policy Changes Deferral Account (APCDA), Enbridge Gas would have brought Union's pre-February 2017 net actuarial losses and prior service costs (the balance) forward in an applicable proceeding to establish a deferral account and dispose of the balance, subject to approval by the OEB.

The balance is representative of unamortized net actuarial pension losses and prior service costs that have been incurred but not yet expensed. The balance is amortized as part of pension expense, typically over the expected average remaining service lifetime (EARSL) of the relevant employees. These are prudently incurred costs that both EGD and Union have historically recovered in rates as part of pension expense.

Upon the merger of Spectra and Enbridge Inc., Enbridge Inc. recognized the balance within its acquisition accounting adjustments[1]. Upon the amalgamation of EGD and Union, US GAAP required the newly amalgamated Enbridge Gas to reflect the same adjustment (i.e. pushdown accounting), resulting in the pre-February 2017 balance being reclassified from Accumulated Other Comprehensive Income (AOCI) to the

[1] The initial acquisition accounting adjustments recorded at Enbridge Inc. on February 27, 2017, which impacted Enbridge Inc.'s goodwill, failed to recognize the regulatory and recoverable nature of Union's incurred pension costs. Upon receiving OEB approval for EGD and Union to amalgamate, Enbridge Inc.'s accounting treatment for the balance was re-assessed with a new understanding of the nature of the balance. As a result, Enbridge Inc. re-measured its goodwill balance to recognize the regulatory and recoverable nature of Union's pre-February 2017 unamortized actuarial losses and prior service costs. US GAAP required the pushdown of accounting adjustments made by Enbridge Inc. upon amalgamation. The pushed down accounting of goodwill did not impact utility results and goodwill is not recovered in rates.

APCDA. During the deferred rebasing term, Enbridge Gas continued to amortize the balance based on estimates provided by Mercer in accordance with US GAAP.

The continued recovery of these amounts is appropriate regardless of the merger of Spectra and Enbridge Inc. or the amalgamation of EGD and Union. The accounting to reflect the amalgamation does not change the underlying substance of the balance.

As of January 1, 2024, the amortization of the balance is not included in the 2024 Test Year Forecast due to the proposal to dispose of the balance in the APCDA.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 181

To see what exists and produce whatever is responsive to the question.

Response:

Neither the merger of Spectra and Enbridge Inc. (Merger), nor the amalgamation of EGD and Union (Amalgamation) changed the substance of Union's pre-February 2017 unamortized actuarial losses and past service costs that were recorded in Accumulated Other Comprehensive Income (AOCI) (the balance). As such, there was no specific consideration given to the balance (and therefore no accounting papers, internal memos or third-party accounting opinions) between the time of the Merger and the approval by the OEB of the Amalgamation.

Please see Attachment 1 for a memo dated May 2019 (post Amalgamation) which discusses the balance. The purpose of the memo was to support Enbridge Gas's accounting position for the balance as at December 31, 2018 and 2017 (i.e. at particular points in time) as reflected in Enbridge Gas's 2018 Combined Financial Statements[1]. Given the complexities involved, including the technical nature of the transactions discussed in the memo, response at Exhibit JT3.30 should be referenced as a more concise and transparent summary of the analysis undertaken to support the accounting and regulatory position of the Company. The memo does not address or contemplate Enbridge Gas's position in the absence of an APCDA or its proposal for recovery after December 31, 2023.

[1] The memo was also used to support Enbridge Inc.'s accounting for the balance. See Footnote 1 in response at Exhibit JT3.30.

Enbridge Gas Distribution Inc.
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Union Gas Limited
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memo

Date: May 16, 2019

To: Utility Financial Alignment (UFA) Project – Accounting Files

From: Jason Vinagre – Manager UPO Special Projects / Robert Rutitis – Supervisor Reporting & Research

Cc: Refer to Appendix A for Stakeholder Listing

Re: **Enbridge Gas Incorporated (EGI) – Accounting Treatment for Pension Related Costs & Regulatory Balances**

I. Executive Summary:

Background

The pension related costs accounting treatments for Enbridge Gas Distribution (EGD) and Union Gas Limited (UGL) followed accrual accounting in accordance with ASC 715.

However, the previous accounting policies of EGD and UGL differ with regard to whether or not a regulatory asset is recognized for pension actuarial gains/losses and prior service costs that are generally recorded as other comprehensive income in the absence of rate regulated accounting. At amalgamation, the two legacy entities held balances in assets and liabilities with certain offsets in regulatory assets and liabilities. These items are noted below.

Recognition of Regulatory Assets

Before an incurred cost can be recognized as a regulatory asset, it should be probable that the incurred cost will be recovered in future rates. The criterion for 'probable' is judgmental.

Enbridge Gas Distribution (EGD)

EGD has been under a Custom Incentive Regulation (IR) term since 2014 which has included an annual update to rates for pension cost forecast determined in accordance with ASC 715. EGD also has a Post-Retirement True-up Variance Account (PTUVA) which accounts for variances between pension cost forecasts in rates and actual pension costs incurred.

Based on the above, EGD has concluded that a cause and effect relationship exists between costs incurred and costs recovered in rates and that recoverability of actuarial losses incurred through future rates is probable and therefore recognition of the accumulated amounts as regulatory assets is appropriate.

Actuarial Losses and Past Service Costs

EGD recorded an offsetting regulatory asset/liability in lieu of accumulated other comprehensive income (AOCI). This accounting treatment is currently permissible under U.S. GAAP, and supported by the guidance within ASC 980 – Regulated Operations, if probable recoverability/refund of the regulatory asset/liability can be demonstrated by the regulated entity.

As at December 31, 2018, EGD had accumulated a pension regulatory offset asset balance of approximately $309 million, representing unamortized actuarial gain/losses and prior service costs (reclassified from AOCI). In the absence of rate regulation, the regulatory balance would be recognized in accumulated other comprehensive income/loss. These balances continue to be amortized into pension expense over the expected average remaining service life (EARSL).

Pension transition cumulative difference

Beginning January 1, 2013, Enbridge Gas Distribution Inc. (EGD) began recovering pension and other post-employment benefit (OPEB) costs on an accrual basis, as approved by the Ontario Energy Board (OEB) in EGD's 2013 rate application (EB-2011-0354). Until this point in time EGD recovered annual pension costs on a cash basis and accounted for its pension and OPEB costs using the accrual method of accounting. As a result, since rates included the recovery of pension costs on a cash basis, a pension regulatory asset/liability was recorded to account for the difference between cash and accrual pension expense. In the absence of rate regulation, the regulatory balance would not be recorded and pension costs would have been charged to earnings based on the accrual method of accounting for pension.

As at December 31, 2012, the cumulative impact of accumulated contributions in excess of net periodic benefit costs recorded to the pension regulatory offset asset/liability was $255 million. This balance represents the cumulative liability to ratepayers that resulted from recovering pension costs from customer in rates on a cash basis through December 31, 2012, compared to what would have been collected in rates, cumulative to December 31, 2012 had these amounts been recovered under the accrual method. Under the cash method EGD accumulated this liability because it experienced a negative accrual based pension expense and cash funding holidays for a period of time prior to December 31, 2012. Ratepayers did not receive the benefit of a negative accrual pension expense (or credit in rates) because pension costs were recovered on a cash basis (cash contributions were nil during the funding holiday).

Union Gas Limited (UGL)

UGL has been under a Price Cap Incentive Regulation (IR) term since 2014 which has mainly provided only for annual price escalations relative to inflation and other factors. Pension costs were forecast at this time and have not been updated since the IR term began. UGL has not had a deferral account during this IR term to account for any variances between pension costs forecasts in rates and actual pension costs incurred.

Based on the above, UGL took a more conservative approach than EGD and concluded that because of the disconnect between the forecast pension costs in rates and further incurred pension costs during an IR period that would span 5 years, probable recovery could not be assured for a portion of incurred costs in the absence of a variance deferral account. UGL could not reasonably determine if the unrecovered costs could be material, therefore recognition of the accumulated amounts as regulatory assets was deemed not appropriate and recognition through other comprehensive income was the appropriate treatment.

It should be noted that the UGL approach was a very conservative approach. In reality, UGL has incurred material actuarial losses during the each of the 5 year IR periods beginning January 1, 2007 & 2014 however the forecast costs ultimately included in rates each year more than compensated for actuarial losses amortized to expense annually. Each IR period the pension expense included recovery of the unamortized actuarial losses in rates. On average during the 5 year IR period ending December 31, 2018 UGL recovered in rates more than $40M of pension costs including amortization, offset by average annual pension expense of approx. $30M. Never was it a question of whether these costs should be recovered. The company was however, at risk of any variance between any actual loss and the amount included in rates until the next rebasing. A more aggressive approach to regulatory asset treatment of the losses would not have been unreasonable after seeing the results of the recovery as noted.

Actuarial Losses and Past Service Costs

As at December 31, 2018, UGL had $210 million in accumulated unamortized actuarial gain/losses and prior service costs recognized in accumulated other comprehensive income/loss. These balances continue to be amortized into pension expense over the expected average remaining service life (EARSL).

Proposal for EGI Treatment/Policy

The OEB in its MAADs decision ordered that EGI would adopt a Price Cap IR rate setting mechanism over a 5 year deferred rebasing period effective January 1, 2019. This generally allows for inflation and productivity adjustments to base amounts during the deferred rebasing period. EGI, in its January 1, 2019 rates application included pension costs based on previously approved forecasts where legacy UGL retains its cost forecast from the 2013 proceeding and legacy EGD will retain its 2018 pension forecast in rates.

Fundamentally, the OEB's mandate for rate setting mechanisms, whether cost of service or price-cap or incentive regulation, is consistent with regard to *the rate-setting mechanism [being] designed to support the legal requirement for a regulated utility to recover prudently incurred costs and earn a reasonable rate of return.* Therefore, EGI will apply ASC 980 treatment with regard to recognizing actuarial losses and past service costs as regulatory assets (incurred previously or in the future) and drawn down annually through recovery through rates.

Impact of Common Control and Push Down Accounting at February 27, 2017

Upon the Enbridge Inc. (EI) acquisition of UGL through the Spectra merger, EI eliminated the previously incurred losses of UGL ($250M gross / $185M net of deferred taxes) that resided in other comprehensive income. As part of the purchase price adjustment the amount written off was ultimately included in the goodwill balance recognized. This is because EI did not recognize an identifiable asset to allocate purchase price to since UGL did not recognize as a regulatory asset.

In accordance with ASC 805 *Business Combinations "any previously unrecognized prior service cost, gains or losses and transition amounts of the acquired company related to the assumed plan, including amounts previously recognized in other comprehensive income, are eliminated for financial reporting purposes."* As a result, and in accordance with ASC 715, *"subsequent to the acquisition, the eliminated items in accumulated other comprehensive income will have no effect on the acquiring company's net periodic pension cost."*

EI established common control over both EGD and UGL on February 27, 2017. This is the date that retrospective treatment is required under US GAAP to present combined financials for EGI in its December 31, 2018 financial statements. This results in the EI book values for pension assets & liabilities and annual pension expense being "pushed down" to EGI. EGI will reflect the book values as well as annual pension expense for 2017 & 2018 in accordance with EI.

EGI eliminates/writes off the legacy UGL OCI amount of $250M gross/$185M net at February 27, 2017 and reflects the amount as a deferred asset that is amortized throughout 2017 & 2018. The reason that EGI is now allowed to reflect it as a deferred asset is because there is a regulatory requirement to capture all impacts to revenue requirement resulting from accounting changes from the merger. The placement as a deferred asset is temporary until January 1, 2019 when the deferral account becomes effective. At that point the amount is reclassified to a regulatory asset (see discussion below on the Accounting Changes Deferral Account). Both assets are included on the same Balance Sheet line item, therefore the difference is minimal. Residual net amount at December 31, 2018 is $154M after amortization in 2017 & 2018.

The December 31, 2018 legacy EGD balances pertaining to actuarial losses and past service costs, as well as and pension transition cumulative differences, will remain on EGI's balance sheet netted against each other. This net balance was $54 million at December 31, 2018.

EI reclassifies the $154M net from goodwill to deferred assets at December 31, 2018 to align with EGI. The balance will be a regulatory asset on January 1, 2019.

January 1, 2019 – Accounting Changes Deferral Account (ACDA)

In the MAADs Decision and Order[1] the OEB established a deferral account "*to record the impact of any accounting changes required as a result of the amalgamation that affect revenue requirement*." In addition, the OEB also stated that "*EGI should propose an approach to disposition of any balances in its application for 2020 Rates*."

[1] EB-2017-0306 and EB2017-0307, Enbridge Gas Distribution Inc. and Union Gas Limited Application for Amalgamation and Rate-Setting Mechanism, Decision and Order, page 47.

The OEB has directed EGI to establish a deferral account and as a result, the OEB is not intending for EGI to impact annual earnings through accounting changes implemented as a result of the amalgamation; therefore, it is appropriate to recognize as a regulatory asset, amounts previously subject to recovery including the actuarial losses incurred which represent previously incurred costs that continue to be included in rates.

Therefore, on January 1, 2019 EGI will record the deferred regulatory asset noted above as part of the ACDA.

Summary of Conclusions

- EGI will apply push down accounting from EI effective February 27, 2017
    - Recognize previous AOCI amounts crystalized at Feb 27, 2017 in the amount of $250M as goodwill with reallocation to deferred assets (included in Regulatory and other assets)
    - Amortize this asset from Feb 27, 2017 through Dec 31, 2018 as UGL local records did, resulting in residual December 31, 2018 balance of $210M
    - EI will reclassify from goodwill to deferred assets at December 31, 2018 equivalent to the EGI residual of $250M million gross; EI will then record on January 1, 2019 a retained earnings adjustment to recognize a $31M amortization (net of tax) of the asset
    - EGI will record a regulatory asset at 1/1/2019 in accordance with the Accounting Change Deferral account
        - The asset will be equal to the amount of the Regulatory and other asset recorded on UGL's books at 12/31/2018 (as noted $210M gross). This will crystallize the balance for disposition, impacted only by amortization during the deferred rebasing term;
        - This regulatory asset will be amortized annually against the regulatory asset/deferral account and will be classified as "other expense";
        - After the balance is approved for disposition the balance will be drawn down by collections and will not impact P&L;
        - Unamortized actuarial gains and losses incurred annually from February 27, 2017 onward will be recognized in accordance with ASC 715 and amortized annually, with a Regulatory offset to the actuarial losses and past service costs initially recognized in OCI.

II. Accounting Guidance:

ASC 715-30-35-21:

Gains and losses that are not recognized immediately as a component of net periodic pension cost shall be recognized as increases or decreases in other comprehensive income as they arise. *Accounting for plan terminations and curtailments and other circumstances in which recognition of gains and losses as a component of net periodic pension cost might not be delayed is addressed in the Settlements, Curtailments, and Certain Termination Benefits Subsection of this section.*

ASC 715-30-35-23:

In other words, the expected return on plan assets generally will be different from the actual return on plan assets for the year. This Subtopic provides for recognition of that difference (a net gain or loss) in other comprehensive income in the period it arises. The amount recognized in other comprehensive income is also a component of net periodic pension cost for the current period. Thus, the amount recognized in other comprehensive income and the actual return on plan assets, when aggregated, equal the expected return on plan assets. ***The amount recognized in accumulated other comprehensive income affects future net periodic pension cost through subsequent amortization, if any, of the net gain or loss.***

Scope of ASC 980:

As outlined in ASC 980-10-15-2, a reporting entity is ***required to apply ASC 980*** *if it meets three specified criteria.*

□ *Rates are established by an independent third-party regulator or the entity's own governing board*

□ *Rates are designed to recover costs of service*

□ *Rates designed to recover costs can be charged to and collected from customers*

Regulatory Assets [PwC Utilities and Power Guide 2016 – Figure 17-3]:

Initial recognition and measurement

□ *Incurred costs may be capitalized as a regulatory asset if the amounts are probable of recovery through rates.*

□ *Regulatory assets are initially measured as the amount of the incurred cost.*

□ *If a cost does not meet the criteria for deferral as a regulatory asset at the date incurred, it should be expensed; a regulatory asset may subsequently be recorded if and when the criteria for recognition are met.*

Subsequent measurement

□ *Regulatory assets are typically amortized over future periods consistent with the period of recovery through rates.*

□ *If all or part of an incurred cost recorded as a regulatory asset is no longer probable of being recovered, the amount that will not be recovered should be written off to earnings.*

□ *If a regulator subsequently allows recovery of costs that were previously disallowed, a new asset is recorded; classification of the new asset depends on how the asset would have been classified had it been previously allowed.*

ASC 980-715-25-3 through 25-7 specify additional criteria for recognition of a regulatory asset for OPEB costs, including a satisfactory rate order that allows for recovery of those costs within 20 years, and no backloading of cost recovery on a percentage basis. That guidance also specifically precludes recognition of a regulatory asset if costs are recovered on a pay-as-you-go basis, even if other factors indicate that future recovery of OPEB costs is probable.

KPMG Report to the Ontario Energy Board[2]:

ASC 980 defines an 'incurred cost' as a cost arising from cash paid out or obligation to pay for an acquired asset or service, a loss from any cause that has been sustained and has been or must be paid for. As such, 'incurred cost' includes costs that have been paid already as well as those for which an obligation to make a payment in the future exists as at the reporting date. This is consistent with the accrual accounting principles used in preparing general purpose financial statements.

Under the general provisions of ASC 980-340, Other Assets and Deferred Costs, an incurred cost that would otherwise be charged to expense is capitalized as a regulatory asset if:

a) It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes; and

b) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the

[2] KPMG Report to the Ontario Energy Board Report on Pension and Other Post-Employment Benefit Costs May 2, 2016

revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost.

Based on this requirement, a regulatory asset is only recognized if it is probable that the incurred cost will be recovered in future rates. ASC 450 states that an event is probable if it is "likely to occur". As such, in order for incurred costs to be capitalized as regulatory assets, there needs to be suitable evidence to support the judgmental criteria that recovery in future periods is reasonably assured. In assessing that probability, reporting entities consider (1) how the costs are being recovered in rates and on what basis they are being recovered; (2) any specific actions by the regulator with respect to similar deferred costs; (3) the regulator's historical approach to inclusion of such costs in rates; and, (4) whether there is significant uncertainty indicated by the regulator regarding the future rate recovery approach.

Recovery of costs on a US GAAP accrual basis as well as the implementation of a tracker mechanism by the regulator (which allows the entity to track the actual costs as compared to the amount being recovered and to currently recover those actual costs from customers) are strong indicators that recovery from future rates is probable.

Incentive Rate Regulation [PwC – Letter to International Accounting Standards Board Date May 30, 2013 – Request for Information: Rate Regulation – pg 9]:

Some regulators in Canada have introduced incentive- or performance-based regulatory mechanisms to encourage efficiency in utility operations or achieve certain targets. These mechanisms might include the sharing of cost savings above a prescribed level between utilities and customers, or rate caps. During the period covered by these performance-based rates, the relationship between cost incurred and rates might temporarily diverge; so, at the end of the period, there is a re-basing of rates based on actual cost incurred. Furthermore, where rates become materially different from actual cost incurred, there are usually provisions to adjust the formula or adjust rates for the costs that differed materially. Consequently, despite a temporary disconnect between actual costs incurred and rates charged, the basis for the rates continues to reflect cost and the legal requirement for rates to be set in such a way that allows the utility to recover its incurred costs.

III. Analysis – Actuarial Losses and Past Service Costs:

Application of ASC 715

Both EGD and UGL, since 2012 have been applying US GAAP and consequently account for retirement benefits in accordance with ASC 715. With regard to the treatment of actuarial gains/losses and past service costs, both entities recognize these amounts annually in Other Comprehensive Income (OCI). It is the interpretation and application of ASC 980 that results in the recognition of regulatory assets/liabilities offsetting the OCI amounts at EGD and not at UGL.

Application of ASC 980

As noted above an entity is required to apply ASC 980 if it meets the specified criteria. Both EGD and UGL have supported that each entity meets the specified criteria and has therefore been subject to application of ASC 980 with regard to the effects of rate regulation. It has also been concluded that

EGI will also continue to meet the specified criteria and will apply ASC 980 for the effects of rate regulation on a go forward basis subsequent to amalgamation. Please refer to the paper *"Continued Application of Rate Regulated Accounting Under a 10 Year Rate Term."*

- UGL Post February 27, 2017 (pre-January 1, 2019)
  UGL, since January 1, 2014, has been under a 5 year price cap incentive regulation (IR) term, and as a result has a rate order in effect from 2013 to 2018. Included in this rate order is the recovery of pension costs based on the forecast as submitted in the 2013 rate case, which includes the forecast amortization of ASC 715 related pension charges which are accumulated in OCI, and amortized accordingly. These amounts are forecasted as part of O&M. Any difference between the forecasted and actual expense during the IR period is not recoverable and consequently it was management's conservative interpretation that a regulatory asset would not be recognized for these variances. As at February 27, 2017 UGL had accumulated unamortized actuarial losses of $185 million net of deferred tax that were being amortized annually and recovered in rates during the IR term. UGL amortized through pension expense with an offsetting draw down of OCI by approximately $15-$20 million in each of 2017 and 2018 subsequent to the February 27, 2017 merger.

  In accordance with ASC 805 *Business Combinations "any previously unrecognized prior service cost, gains or losses and transition amounts of the acquired company related to the assumed plan, including amounts previously recognized in other comprehensive income, are eliminated for financial reporting purposes."* As a result Enbridge Inc. (EI) recognized the fair value of identifiable assets and liabilities of Union Gas as part of its Purchase Price Adjustment. AOCI that was recognized by UGL as at February 27, 2017 was eliminated as the amount ($185 million) was not recognized as regulatory assets at the time by UGL and the value of the unamortized actuarial losses in AOCI was recognized as a debit to goodwill.

- EGD Post February 27, 2017 (pre-January 1, 2019)
  EGD has been under a Custom Incentive Regulation (CIR) methodology since 2014, and as such submits annual updated pension forecasts for approval to the OEB. Through the CIR period EGD is permitted to recover these costs in full, in addition to any annual variances between actual and forecast in rates, and therefore management chose to recognize regulatory assets/liabilities in applying ASC 980 and amortize accordingly. At February 27, 2017, EGD had accumulated unamortized actuarial losses/gains of $32 million recognized as regulatory assets and $5 million recognized as regulatory liabilities. These amounts have been amortized annually and recovered through annual updates to rates and deferral dispositions.

- EGI Post January 1, 2019
  The OEB has decided that EGI will be subject to a 5 year deferred rebasing period and adopt a Price Cap IR rate setting mechanism during this period. As such, rates will be set annually based on each utility's previous cost of service (2013 and 2018 for UGL and EGD respectively) with annual adjustments for only inflation, a productivity factor of 0%, and a stretch factor of 0.3%.

As a result of the amalgamation of EGD and UGL, there is a requirement to develop a uniform accounting policy as there will be a single regulated entity going forward (with one combined rate case). Management has reviewed the legacy policies of each of EGD and UGL, as well as the implications of a new Price Cap IR rate-setting framework and concluded that it with respect to actuarial losses incurred and accumulated in AOCI the criteria of ASC 980 to record an offsetting regulatory asset are met.

The amalgamation of EGD and UGL triggered a re-evaluation of communications issued by accounting advisors and regulators, as well as a review of industry practices for the accounting for unamortized actuarial gains and losses. As a result of this review, management has re-evaluated the manner in which the recovery of pension costs should be considered (i.e. at an aggregate level of considering the reasonableness of the pension plan as a whole vs. amounts recognized from period to period). Management appreciates that there is some risk related to the recoverability of amounts accumulated in OCI, however it is able to support a clear and transparent cause and effect relationship between actuarial losses incurred and amounts collected in rates in a Price Cap term.

Any RPP/Supplemental actuarial losses incurred post January 1, 2019 for either legacy EGD or UGL will be accumulated in AOCI and reclassified from AOCI to a pension regulatory offset asset/liability to be amortized. OPEB related costs that are recovered on a pay-as-you go basis will continue to be recorded in OCI, as the guidance specifically precludes recognition of a regulatory asset if costs are recovered on a pay-as-you-go basis, even if other factors indicate that future recovery of OPEB costs is probable.

IV. Analysis – Pension Transition Cumulative Difference:

As mentioned in PwC's accounting guide for utilities and power companies (2018), regulated utilities should evaluate potential regulatory liabilities associated with refunds to customers of previously-collected amounts in accordance with the guidance for loss contingencies in ASC 450-20-25-2[3]. They should recognize a liability if it is probable that the loss was incurred at the balance sheet date and the loss is reasonably estimable.

Furthermore, the OEB's report for the Regulatory Treatment of Pension and OPEB Costs (EB-2015-0040) incurred by rate-regulated Ontario energy utilities contains the following provisions:

- "For some utilities, the OEB approved the recovery of their pension and OPEB costs on a cash basis as an interim measure pending the outcome of this pension and OPEB consultation. Variance accounts were used to capture the difference between the cash and accrual methods in order to keep the period open for final adjustments once the outcome of the consultation was known. These utilities are required to continue to record amounts into the previously approved account(s) until the effective date of a utility's next cost-based rate order. Utilities will be expected to dispose of the account(s) at their next cost-based rates application.

[3] **ASC 450-20-25-2:** An estimated loss from a loss contingency shall be accrued by a charge to income if both the following conditions are met:

a) Information available before the financial statements are issued or available to be issued indicates that it is probable that an asset has been impaired or a liability has been incurred at the date of the financial statements. Date of the financial statements means the end of the most recent accounting period for which financial statements are being presented. It is implicit in this condition that it must be probably that one or more future events will occur confirming the fact of the loss.
b) The amount of loss can be reasonably estimated.

- "The OEB is of the view that if a particular case demonstrates that a transition is necessary to set just and reasonable rates and the transition issues are manageable for that particular utility, it is open to a panel to require a transition to a recovery mechanism suitable for that utility's particular circumstances. In such case, the OEB could require the utility to calculate the cumulative difference to date for disposition."

Probability of loss:

Establishing probability is a matter of judgment and management should evaluate all available evidence. In accordance the OEB's report for the Regulatory Treatment of Pension and OPEB Costs, the OEB expects utilities with cumulative differences or variances between cash and accrual methods of accounting to dispose of the balances at their next cost-based rate application. Although EGD does not have an approved variance account for pension balances, it has received approval to recover the cumulative differences for EGD's OPEB plan through the Transition Impact Accounting Change Deferral Account (EB-2011-0354). Furthermore, Union Gas Limited's deferred tax drawdown represented a similar accumulated transitional difference which was refunded to ratepayers until the end of 2018. It is also management's intent to dispose of this balance at a point in time in the future. Furthermore, the OEB's report suggests that utilities, like EGD will be required to propose disposition of such balances within the next available cost of service rates application. Therefore it is probable that EGD will be required to refund the cumulative differences as at December 31, 2012 between cash and accrual methods of accounting for its pension plans.

Loss is reasonably estimable:

Supported by Mercer's final pension accounting report for the year ended December 31, 2012, EGD is able to specifically identify the accumulated contributions in excess of net periodic benefit costs under the cash method of pension accounting. The cumulative difference is approximately $255 million.

Balance Sheet Presentation

The presentation of a regulatory asset and liability on the balance sheet is primarily dependent on the regulatory jurisdiction for which rates are being collected from or refunded to, as well as the method and timing of recovery.

According to ASC 210-20-45-1, a right to setoff exists when all of the following conditions are met:

a) Each of the two parties owes the other determinable amounts.
b) The reporting party has the right to set off the amount owed with the amount owed by the other party.
c) The reporting party intends to set off.
d) The right of setoff is enforceable by law.

Therefore, EGD will continue to offset its pension regulatory asset related to accumulated unamortized actuarial gains/losses and prior service costs of $309 million, with the $255 million regulatory liability for the transition cumulative difference, as at December 31, 2012 for the following reasons:

- Although the two pension related balances are looked at as two separate components both are a result of pension costs recovered from ratepayers.
- The OEB's report for the Regulatory Treatment of Pension and OPEB Costs, clarifies that the recovery/repayment of transition balances should be applied against pension costs recovered in

rates for the purpose of calculating forecasted overall accrual costs recovered in rates. Therefore both balances should be viewed as part of overall pension costs.
- EGD intends to recover the $309 million from ratepayers and repay the $255 million to ratepayers in future rates over a long-term period. The method of disposal/collection of these balances will be done so through customer billings which are billed on a net basis. Overall pension costs built into rates will be comprised forecasted pension costs and a credit for the transition balance.
- The OEB permits regulated utilities to bill customers on a net basis.

V. Application of Push Down Accounting from EI to UGL/EGI:

In accordance with ASC 805 *Business Combinations "any previously unrecognized prior service cost, gains or losses and transition amounts of the acquired company related to the assumed plan, including amounts previously recognized in other comprehensive income, are eliminated for financial reporting purposes."*

Therefore, for the purposes of the acquisition all AOCI balances relating to UGL that had accumulated prior to February 27, 2017 were eliminated at EI and will be pushed down to EGI at February 27, 2017.

Pushdown accounting will also be applied for any EI adjustments related to UGL through December 31, 2018.

As a result, and in accordance with ASC 715, *"subsequent to the acquisition, the eliminated items in accumulated other comprehensive income will have no effect on the acquiring company's net periodic pension cost."*

VI. Regulatory Asset January 1, 2019:

As a result of applying push down accounting at EGI, Pension expense will no longer include amortization of historical AOCI balances that were eliminated. Pension assets and liabilities were revalued and the previously incurred actuarial losses and past service costs were written off out of AOCI and reallocated as a regulatory asset. Pension expense will include amortization of any losses and past service costs incurred post February 27, 2017.

The OEB's policy is that a rate regulated entity's pension costs will be recovered on an accrual basis, including amortization of actuarial losses. It is EGI's view that pension expense approved by the OEB, for recovery, would continue to include amortization of actuarial losses, had the acquisition (and push-down of EI's purchase price allocation for UGL to EGI) not occurred.

Applying pushdown accounting therefore has an impact on revenue requirement. Therefore EGI will record a Regulatory asset at January 1, 2019 to record the impact on revenue requirements, as outlined below.

The regulatory asset will equal the amount that is recorded in UGL's AOCI at December 31, 2018 ($154 million net of deferred tax). EGI will amortize this balance over the remaining EARSL until the net balance is proposed for disposition.

Regulatory Considerations and Conclusion

In the MAADs Decision and Order[4] the OEB established a deferral account "to record the impact of any accounting changes required as a result of the amalgamation that affect revenue requirement." In addition, the OEB also stated that "EGI should propose an approach to disposition of any balances in its application for 2020 Rates."

As noted above, the amounts that have accumulated in AOCI prior to February 27, 2017 were part of allowable costs for ratemaking purposes as per ASC 980. The accumulated losses were a previously incurred cost to EGD and UGL that continued to be recovered through rates as part of annual pension expense accrued as per ASC 715. As such:

- The OEB has allowed and continues to allow both EGD and UGL to collect pension costs recognized in accordance with ASC 715 through rates. This includes unamortized actuarial gains and losses.
- The OEB has directed EGI to establish a deferral account and as a result, the OEB expects there to be no impact to annual earnings caused by accounting changes implemented as a result of the amalgamation.
- The application of push down accounting eliminating AOCI amounts would impact revenue requirement. Therefore, it is appropriate to record the amounts as regulatory assets and propose for continued recovery.

The EGD rate zone will continue to recognize a $255 million regulatory liability for the transition cumulative difference, as at December 31, 2012. This regulatory liability balance will be disposed of and presented to the OEB as part of EGI's next cost of service rates application, after taking into consideration the overall deficiency/sufficiency, cost allocation and bill impacts, and approved by the OPEB accordingly.

Any RPP/Supplemental actuarial losses incurred post January 1, 2019 for either legacy EGD or UGL will be accumulated in AOCI and reclassified from AOCI to a pension regulatory offset asset/liability to be amortized. OPEB related costs that are recovered on a pay-as-you go basis will continue to be recorded in OCI, as the guidance specifically precludes recognition of a regulatory asset if costs are recovered on a pay-as-you-go basis, even if other factors indicate that future recovery of OPEB costs is probable.

[4] EB-2017-0306 and EB2017-0307, Enbridge Gas Distribution Inc. and Union Gas Limited Application for Amalgamation and Rate-Setting Mechanism, Decision and Order, page 47.

Appendix A – Stakeholder Listing

Stakeholder	Review Status
Chris Tuckwell – Director Accounting Operations (EGD/UGL)	Complete
Tanya Ferguson – Director FP&A	Complete
Ryan Small – Manager Revenue and Regulatory Acct (EGD)	Complete
Evgenia Vangelova – Manager Tax Reporting	Complete
Mark Kitchen – Director Regulatory Affairs (UGL)	Complete
Cassell Kincaid – Director Corporate Accounting	Complete
Monica Woodward – Director Financial Reporting	Complete
Jana Murdock – Director Financial Reporting	Complete
Andrew Alonzo – Manager Enterprise Accounting Research (EI)	Complete
Tammy Gillard – Manager Pension Reporting	Complete
Abbas Lahka – External (EY)	Complete
Phil Hagel / Rebecca Shaw – External Auditors (PwC)	Complete

Appendix B: Analysis of Pension Costs Incurred as Regulatory Assets – Post Jan 1, 2019

From *PwC Utilities and Power Guide 2016, section 17.3.3.2, pages 17-24 to 17-26:*

In accounting for pension and OPEB plans, a regulated utility should consider whether it is appropriate to record a regulatory asset to offset the liability recognized as a result of applying ASC 715 (in lieu of recognizing a charge to other comprehensive income). Examples of positive and negative factors are considered below for both EGD and UGL:

Positive Factors:	**Criteria Met - EGD?**	**Criteria Met - UGL?**	**Criteria Met - EGI?**
Current rate recovery of pension and OPEB costs that is consistent with expense recognition under ASC 715-30 and ASC 715-60 (i.e., ASC 715 costs under U.S. GAAP form the basis for pension and OPEB amounts recovered in rates)	**Yes** – for both EGD and UGL pension forecasted in accordance with ASC 715 accrual method forms the basis for pension amounts included in rates.	**Yes** – for both EGD and UGL pension forecasted in accordance with ASC 715 accrual method forms the basis for pension amounts included in rates.	**Yes** – EGI's pension will continue to be forecasted in accordance with ASC 715 accrual method and form the basis for pension amounts included in rates.
Existence of a regulatory tracker mechanism or reconciliation process specified in a rate order with comparison of actual annual ASC 715 cost to costs included in rates, with short-term recovery of the difference	**Yes** - EGD has an approved tracker mechanism for variances incurred through 2018 and can defer variances in costs forecast in rates versus costs incurred.	**No** – UGL does not have an approved tracker mechanism and must manage variances in costs forecast in rates versus costs incurred.	**No** – EGI not have an approved tracker mechanism and must manage variances in costs forecast in rates versus costs incurred.
Historical consistency and clarity in the regulator's approach to rate recovery	**Yes** – the OEB has been consistent in its approach to requiring utility's to include in rates costs incurred in accordance with accrual accounting for pension as per ASC 715	**Yes** – the OEB has been consistent in its approach to requiring utility's to include in rates costs incurred in accordance with accrual accounting for pension as per ASC 715	**Yes** – the OEB has been consistent in its approach to requiring utility's to include in rates costs incurred in accordance with accrual accounting for pension as per ASC 715
No indication of uncertainty or potential changes in the jurisdiction regarding the rate recovery approach to costs consistent with ASC 715-30 and ASC 715-60 combined with general stability in the jurisdiction's approach	**Yes** – there is no indication that the OEB intends to adjust its rate recovery approach or	**Yes** – there is no indication that the OEB intends to adjust its rate recovery approach or deregulate any	**Yes** – there is no indication that the OEB intends to adjust its rate recovery approach or deregulate any

to traditional cost of service (i.e., there is no existing legislation or substantive discussion to deregulate any aspect of a regulated utility's operations)	deregulate any aspect of either EGD's or UGL's utility operations	aspect of either EGD's or UGL's utility operations	aspect of either EGD's or UGL's utility operations
Existence or issuance of a rate order providing that regulatory asset treatment for the unfunded liability is appropriate or required and that recovery of the unfunded costs will be provided in future rates (A rate order provides the best evidence, but consideration may also be given to staff accounting orders and policy statements)	**No** – EGD did not have an approved rate order.	**No** – UGL did not have an approved rate order.	**No** – the OEB has not approved a rate order to capture any variances.

Negative Factors:	**Criteria Met - EGD?**	**Criteria Met - UGL?**	**Criteria Met - EGI?**
Current rate recovery of pension or OPEB costs on a "pay-as-you-go," cash funding, Employee Retirement Income Security Act (ERISA) minimum funding, or some other basis	**No** – for pension amounts other than OPEB, rate recovery is based off of accrual method as per ASC 715; OPEB costs are recovered on a pay as you go basis, however these amounts are immaterial in relation to total pension costs	**No** – for pension amounts other than OPEB, rate recovery is based off of accrual method as per ASC 715; OPEB costs are recovered on a pay as you go basis, however these amounts are immaterial in relation to total pension costs	**No** – for pension amounts other than OPEB, rate recovery is based off of accrual method as per ASC 715; OPEB costs are recovered on a pay as you go basis, however these amounts are immaterial in relation to total pension costs
Previous specific disallowance of either pension or OPEB costs	**No** – neither EGD or UGL has any history of the recovery of actuarial losses incurred as per ASC 715 being disallowed	**No** – neither EGD or UGL has any history of the recovery of actuarial losses incurred as per ASC 715 being disallowed	**No** – neither EGD or UGL has any history of the recovery of actuarial losses incurred as per ASC 715 being disallowed
Substantive historical inconsistency in the regulator's approach to rate recovery for pension and OPEB costs	**No** – the OEB has been consistent in its approach to rate recovery for pension since it directed all utilities applying US GAAP to recognize in accordance with ASC 715	**No** – the OEB has been consistent in its approach to rate recovery for pension since it directed all utilities applying US GAAP to recognize in accordance with ASC 715	**No** – the OEB has been consistent in its approach to rate recovery for pension since it directed all utilities applying US GAAP to recognize in accordance with ASC 715

Appendix C: Analysis of Pension Costs Recognized in OCI, Eliminated on Pushdown – Feb 27, 2017

With regard to the February 27, 2017 amounts recognized as unamortized losses in AOCI at UGL, written off as a result of the EI pushdown, the following provides analysis of whether the amounts crystallized and recognized in goodwill should be re-classified as a regulatory asset:

Positive Factors:	**Criteria Met - EGI?**
Current rate recovery of pension and OPEB costs that is consistent with expense recognition under ASC 715-30 and ASC 715-60 (i.e., ASC 715 costs under U.S. GAAP form the basis for pension and OPEB amounts recovered in rates)	**Yes** – EGI's pension will continue to be forecasted in accordance with ASC 715 accrual method and form the basis for pension amounts included in rates.
Existence of a regulatory tracker mechanism or reconciliation process specified in a rate order with comparison of actual annual ASC 715 cost to costs included in rates, with short-term recovery of the difference	**Yes** – the OEB, in its MAADs decision, ordered the creation of the Accounting Changes Deferral Account, to account for the impacts to revenue requirement as a result of the amalgamation. EGI will propose inclusion of the net residual amount at Jan 1, 2019 that was eliminated from OCI as a result of the pushdown of EIs values; this amount continues to be collected in rates and should continue to be amortized to expense during the deferred rebasing period.
Historical consistency and clarity in the regulator's approach to rate recovery	**Yes** – the OEB has been consistent in its approach to requiring utility's to include in rates costs incurred in accordance with accrual accounting for pension as per ASC 715
No indication of uncertainty or potential changes in the jurisdiction regarding the rate recovery approach to costs consistent with ASC 715-30 and ASC 715-60 combined with general stability in the jurisdiction's approach to traditional cost of service (i.e., there is no existing legislation or substantive discussion to deregulate any aspect of a regulated utility's operations)	**Yes** – there is no indication that the OEB intends to adjust its rate recovery approach or deregulate any aspect of either EGD's or UGL's utility operations
Existence or issuance of a rate order providing that regulatory asset treatment for the unfunded liability is appropriate or required and that recovery of the unfunded costs will be provided in future rates (A rate order provides the best evidence, but consideration may also be given to staff accounting orders and policy statements)	**Yes** – the OEB did not issue a specific rate order, however, as noted above established a deferral account "to record the impact of any accounting changes required as a result of the amalgamation that affect revenue requirement."
Negative Factors:	**Criteria Met - EGI?**
Current rate recovery of pension or OPEB costs on a "pay-as-you-go," cash funding, Employee Retirement	**No** – for pension amounts other than OPEB, rate recovery is based off of

Income Security Act (ERISA) minimum funding, or some other basis	accrual method as per ASC 715; OPEB costs are recovered on a pay as you go basis, however these amounts are immaterial in relation to total pension costs
Previous specific disallowance of either pension or OPEB costs	**No** – neither EGD or UGL has any history of the recovery of actuarial losses incurred as per ASC 715 being disallowed
Substantive historical inconsistency in the regulator's approach to rate recovery for pension and OPEB costs	**No** – the OEB has been consistent in its approach to rate recovery for pension since it directed all utilities applying US GAAP to recognize in accordance with ASC 715

Appendix D: Pushdown Accounting Transactions and Details

Required transactions for legacy UGL in the 2018 Combined Financial Statements and EGI Day 1 Balance Sheet:

Timing	Description	Amount	Journal Entries – Financial Statement Line Items
Pushdown: 2/27/2017	To write-off AOCI and recognize goodwill as recorded by EI	$251 million ($67 million) ($185 million)	DR Goodwill Cr Deferred Tax CR AOCI
Reallocate: 2/27/2017	To reallocate the amount in goodwill to Regulatory and other assets	$251 million ($251 million)	Dr. Reg assets and other Cr. Goodwill
Pushdown: 2/28/2017 – 12/31/2017	To recognize the amortization of previous amounts in AOCI at UGL	$19 million ($5 million) ($14 million)	Dr Other expense Cr Deferred income taxes Cr Reg assets and other
Pushdown: 1/1/2018 – 12/31/2018	To recognize the amortization of previous amounts in AOCI at UGL	$22 million ($6 million) ($16 million)	Dr Pension expense Cr Deferred income taxes Cr Reg assets and other

Required transactions for Enbridge Inc. on December 31, 2018 & January 1, 2019:

Timing	Description	Amount	Journal Entries – Financial Statement Line Items
Record regulatory asset: 12/31/2018	To recognize regulatory asset for residual balance of losses to be amortized and recovered through Accounting Change deferral account; reallocate from goodwill	$154 million ($154 million)	DR Reg assets and other CR Goodwill
Adjust retained earnings: 1/1/2019	To adjust goodwill and retained earnings for amounts amortized prior to Jan 1, 2019 (after EGI pushes $189M of goodwill adjustment to EI through Jan 2019 consolidation)	$31 million ($31 million)	DR Retained earnings CR Goodwill

Appendix E: Continuity of Actuarial Losses Crystallized on Push Down – Legacy UGL

	Balance - Feb 27, 2017	2017 Amortization	Balance - December 31, 2017	2018 Amortization	Balance – December 31, 2018
Gross	$250,949,979	$19,494,967	$231,455,012	$21,857,400	$209,597,612
Deferred Tax	(66,501,743)	(5,166,166)	(61,335,577)	(5,749,811)	(55,585,766)
Net	$184,448,235	$14,328,800	$170,119,435	$16,107,589	$154,011,846

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 183

To provide details of the $28 million forecast amortization accumulated actuarial gains and losses and past service costs that are embedded in the 47. [audio dropout] million dollar [audio dropout]

Response:

Please see Attachment 1 for the extract from the Willis Towers Watson 2013 Pension and OPEB Forecast. The $28 million forecast amortization forecast is comprised of:

Amortization of actuarial gains and losses	$26.6 million
Amortization of prior service cost	$1.5 million
Total 2013 forecast pension amortization	$28.1 million

Please note the reconciliation of Attachment 1 to total approved 2013 pension forecast of $47.4 million provided below:

Forecast net benefit cost (per Attachment 1)	$41.5 million
Direct contribution costs	$5.6 million
Forecast filing fees	$0.3 million
Total approved pension forecast	$47.4 million

UNION GAS LIMITED
ESTIMATED NET BENEFIT COSTS
US GAAP FOR CANADIAN REPORTING ("NEW GAAP")

	Registered Pension Plans	Supplemental Pension Arrangements	Post-Retirement Benefits Other Than Pensions	
2012				
Employer current service cost	$ 15,280	$ 487	$ 2,627	$ 18,394
Interest cost	30,368	1,421	3,497	35,286
Expected return on assets	(40,481)	0	0	(40,481)
Amortization:				
- Net actuarial (gain) loss	25,312	691	1,022	27,025
- Prior service (credit) cost	1,536	0	0	1,536
- Transitional (asset) obligation	0	0	0	0
Net benefit cost (income)	$ 32,015	$ 2,599	$ 7,146	$ 41,760
2013				
Employer current service cost	$ 16,204	$ 510	$ 2,846	$ 19,560
Interest cost	32,081	1,472	3,717	37,270
Expected return on assets	(43,433)	0	0	(43,433)
Amortization:				
- Net actuarial (gain) loss	24,875	675	1,031	26,581
- Prior service (credit) cost	1,536	0	0	1,536
- Transitional (asset) obligation	0	0	0	
Net benefit cost (income)	$ 31,263	$ 2,657	$ 7,594	$ 41,514

Notes:
All amounts are shown in thousands of Canadian dollars

Key Assumptions:

2012 net benefit cost
Discount rate:
- Pensions = 4.30% per year
- Post-retirement benefits other than pensions = 4.33% per year

Expected rate of return on assets = 6.75% per year
Rate of salary increases = 3.25% per year
Mortality = 90% of UP94 projected generationally using Scale AA
Health care cost trend rate = 7.5% in 2012, grading to 5% per year in 2017 and thereafter
All actuarial valuations as at January 1, 2012 will be filed
Excess contribution remitted in 2011 treated as a plan asset at January 1, 2012 (i.e., not a pre-payment)

2013 net benefit cost

Discount rate:
- Pensions = 4.30% per year
- Post-retirement benefits other than pensions = 4.33% per year

Expected rate of return on assets = 6.50% per year
Rate of salary increases = 3.25% per year
Mortality = 80% of UP94 projected generationally using Scale AA
Health care cost trend rate = 7.0% in 2013, grading to 5% per year in 2017 and thereafter
There are no other changes in assumptions
There are no experience gains or losses

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 184

To describe the specific requirements needed from the board to allow a DVA or the recovery of $155 million

Response:

Enbridge Gas requires an OEB decision and rate order approving a deferral account and specifying the manner and timing of recovery of Union's pre-February 2017 unamortized actuarial losses and prior service costs in order for Enbridge Gas to:

- Continue recognizing the balance as a regulatory asset effective January 1, 2024; and

- Recover the balance over an extended period of time in rates.

The current Transition Impact of Accounting Change Deferral Account (TIACDA) for the EGD rate zone, established in EGD's 2013 Cost of Service Application[1], represents a comparable example. In the OEB Decision[2], the OEB approved the establishment of a deferral account in order to drawdown and clear another post-employment benefits (OPEB) related balance over a specified period of time.

[1] EB-2011-0354.
[2] EB-2011-0354, OEB Decision and Order.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Greenhouse Vegetable Growers (OGVG)

Undertaking

Tr: 202

With reference to I.4.4-STAFF-133, page 3 of the Attachment, to add a column for board approved.

Response:

Please see Attachment 1 for the inclusion of 2013 OEB-approved Pension and OPEB actuarial gains/losses and prior service costs. In addition, the 2018 Pension and OPEB actuarial gains/losses and prior service costs were separated between EGD and Union.

Pension and OPEB Actuarial Gains/Losses - EGI

Line No.	Particulars ($ millions)	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Pension							
1	Opening Balance (Gain) Loss	564.0	383.1	471.1	595.1	279.1	24.1	19.6
2	Current Year Actuarial (Gain) Loss	73.0	104.0	144.0	(288.0)	(247.0)	(4.2)	-
3	Amortization of Actuarial (Gain) Loss	(36.0)	(16.0)	(20.0)	(28.0)	(8.0)	(0.2)	0.1
4	Amortization of Prior Service Cost	(1.0)	-	-	-	-	-	-
5	AOCI Amounts Crystalized	(216.9)	-	-	-	-	-	-
6	Subtotal	(180.9)	88.0	124.0	(316.0)	(255.0)	(4.5)	0.1
7	Closing Balance (Gain) Loss	383.1	471.1	595.1	279.1	24.1	19.6	19.8
	OPEB							
8	Opening Balance (Gain) Loss	8.0	(10.4)	4.6	18.6	(12.4)	(49.4)	(45.6)
9	Current Year Actuarial (Gain) Loss	(24.0)	14.0	13.0	(31.0)	(38.0)	0.1	-
10	Amortization of Actuarial (Gain) Loss	-	1.0	1.0	-	1.0	3.7	3.5
11	Amortization of Prior Service Cost	-	-	-	-	-	-	-
12	AOCI Amounts Crystalized	5.6	-	-	-	-	-	-
13	Subtotal	(18.4)	15.0	14.0	(31.0)	(37.0)	3.8	3.5
14	Closing Balance (Gain) Loss	(10.4)	4.6	18.6	(12.4)	(49.4)	(45.6)	(42.1)
	Union Pre-2017 Actuarial Losses and Past Service Costs							
	Opening Balance:							
15	AOCI Amounts Crystalized - Pension (Gain) Loss	-	216.9	198.8	186.2	173.8	164.3	-
16	AOCI Amounts Crystalized - Pension Past Service Costs (1)	-	-	-	-	-	-	-
17	AOCI Amounts Crystalized - OPEB (Gain) Loss	-	(5.6)	(5.0)	(4.7)	(4.4)	(4.1)	-
18	AOCI Amounts Crystalized - OPEB Past Service Costs (1)	-	-	-	-	-	-	-
19		-	211.3	193.8	181.5	169.4	160.2	-
20	AOCI Amounts Crystalized - Pension (Gain) Loss	216.9						
21	AOCI Amounts Crystalized - OPEB (Gain) Loss	(5.6)						
22	Amortization - Pension (Gain) Loss	-	(18.1)	(12.6)	(12.4)	(9.4)	(4.6)	
23	Amortization - Pension Past Service Costs	-	-	-	-	-	-	
24	Amortization - OPEB (Gain) Loss	-	0.6	0.3	0.3	0.3	0.3	
25	Amortization - OPEB Past Service Costs	-	-	-	-	-	-	
26		211.3	(17.5)	(12.3)	(12.1)	(9.1)	(4.3)	-
	Closing Balance:							
27	AOCI Amounts Crystalized - Pension (Gain) Loss	216.9	198.8	186.2	173.8	164.3	159.8	-
28	AOCI Amounts Crystalized - Pension Past Service Costs	-	-	-	-	-	-	-
29	AOCI Amounts Crystalized - OPEB (Gain) Loss	(5.6)	(5.0)	(4.7)	(4.4)	(4.1)	(3.8)	-
30	AOCI Amounts Crystalized - OPEB Past Service Costs	-	-	-	-	-	-	-
31		211.3	193.8	181.5	169.4	160.2	156.0	-

Note:
(1) At the time of crystallization, the Past Service Costs on a Corporate and Local basis were the same, therefore only Pension and OPEB (gains) losses were transferred to a Regulatory Asset in 2018 and then to the APCDA on January 1, 2019.

Pension and OPEB Actuarial Gains/Losses - EGD

Line No.	Particulars ($ millions)	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Pension							
1	Opening Balance (Gain) Loss	N/A	370.0	256.0	345.0	286.0	309.0	294.0
2	Current Year Actuarial (Gain) Loss	-	(85.0)	105.0	(40.0)	37.0	2.0	30.0
3	Amortization of Actuarial (Gain) Loss	(27.4)	(28.0)	(16.0)	(19.0)	(14.0)	(17.0)	(14.0)
4	Amortization of Prior Service Cost	(1.2)	(1.0)	-	-	-	-	-
5	Subtotal	(28.6)	(114.0)	89.0	(59.0)	23.0	(15.0)	16.0
6	Closing Balance (Gain) Loss		256.0	345.0	286.0	309.0	294.0	310.0
	OPEB							
7	Opening Balance (Gain) Loss	N/A	13.0	-	9.0	9.0	11.0	13.0
8	Current Year Actuarial (Gain) Loss	-	(13.0)	9.0	-	2.0	2.0	(19.0)
9	Amortization of Actuarial (Gain) Loss	-	-	-	-	-	-	-
10	Amortization of Prior Service Cost	-	-	-	-	-	-	-
11	Subtotal	-	(13.0)	9.0	-	2.0	2.0	(19.0)
12	Closing Balance (Gain) Loss		-	9.0	9.0	11.0	13.0	(6.0)

Note:
(1) Opening unamortized gain/loss and current year actuarial gain/loss amounts related to the 2013 OEB-approved forecast of pension and OPEB costs were not available.

Pension and OPEB Actuarial Gains/Losses - Union

Line No.	Particulars ($ millions)	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Pension							
1	Opening Balance (Gain) Loss	N/A	336.0	216.0	261.0	245.0	259.0	270.0
2	Current Year Actuarial (Gain) Loss	-	(93.0)	64.0	7.0	32.0	26.0	43.0
3	Amortization of Actuarial (Gain) Loss	(25.6)	(25.0)	(18.0)	(22.0)	(17.0)	(14.0)	(22.0)
4	Amortization of Prior Service Cost	(1.5)	(2.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)
5	AOCI Amounts Crystalized	-	-	-	-	-	-	(216.9)
6	Subtotal	(27.1)	(120.0)	45.0	(16.0)	14.0	11.0	(196.9)
7	Closing Balance (Gain) Loss		216.0	261.0	245.0	259.0	270.0	73.1
	OPEB							
8	Opening Balance (Gain) Loss	N/A	8.0	3.0	4.0	(2.0)	(6.0)	(5.0)
9	Current Year Actuarial (Gain) Loss	-	(5.0)	1.0	(6.0)	(4.0)	2.0	(5.0)
10	Amortization of Actuarial (Gain) Loss	(1.0)	-	-	-	-	-	-
11	Amortization of Prior Service Cost	-	-	-	-	-	(1.0)	-
12	AOCI Amounts Crystalized	-	-	-	-	-	-	5.6
13	Subtotal	(1.0)	(5.0)	1.0	(6.0)	(4.0)	1.0	0.6
14	Closing Balance (Gain) Loss		3.0	4.0	(2.0)	(6.0)	(5.0)	(4.4)

Note:
(1) Opening unamortized gain/loss and current year actuarial gain/loss amounts related to the 2013 OEB- approved forecast of pension and OPEB costs were not available.