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September 4, 2014

VIA COURIER AND RESS

Ms. Kirsten Walli
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 26th Floor
Toronto, ON M4P 1E4

Re: Enbridge Gas Distribution Inc.
EB-2014-0195 – 2013 Deferral and Variance Accounts
Interrogatory Responses

In accordance with Procedural Order No. 1 dated August 8, 2014, enclosed please find the interrogatory responses of Enbridge Gas Distribution Inc. (“Enbridge”).

This information will be filed through the Ontario Energy Board’s Regulatory Electronic Submission System.

The interrogatory response will also be available on Enbridge’s website at http://www.enbridgegas.com/ratecase under the Other Regulatory Proceedings tab.

If you require further information, please contact the undersigned.

Yours truly,

(Original Signed)

Stephanie Allman
Regulatory Coordinator

Enclosure

cc: EB-2014-0195 Intervenors (via email)

BOARD STAFF INTERROGATORY #1

INTERROGATORY

Ref: ExB/T3/S4/Table page 2

Please describe Enbridge's policy on booking amounts to the Ontario Hearing Cost variance account. Please address, for example:
Are the amounts booked based on the fiscal accounting year in which the costs are incurred?

Are the amounts booked based upon the relevant year for the Board proceeding? (e.g. 2013 cost of service rates application EB-2011-0354: all costs related to the 2013 COS application are booked into the 2013 hearing costs account, even if the invoices were paid in 2012 or 2014)

RESPONSE

The Company continues to follow the same methodology for budgeting and expensing of regulatory proceeding costs that has been utilized for many years. Costs relating to the annual rate application proceeding are budgeted and expensed in the year in which the corresponding rates are in place. As such, costs for a particular annual rate proceeding, incurred prior to the rate setting year, are deferred and then expensed during the applicable rate year, against the corresponding rate hearing cost budget included within that year's rates. In addition to costs related to the annual rate proceeding, each year's regulatory proceeding budget, and recognized actual costs, include charges for other miscellaneous applications, generic proceedings, and consultatives incurred during the year. Actual regulatory proceeding costs recorded in this manner are compared to the budgeted costs included in rates to determine if an amount needs to be recorded in the Ontario Hearing Cost Variance Account ("OHCVA"). As a result of this process, actual 2013 regulatory proceeding costs include 2013 Rate Application (EB-2011-0354) costs, incurred prior to or during 2013, as well as costs incurred during 2013 in relation to miscellaneous applications, generic proceedings and consultatives.

Witness: R. Small

BOARD STAFF INTERROGATORY #2

INTERROGATORY

Ref: ExB/T3/S4/Table page 2

With respect to the 2013 Ontario Hearing Cost variance account and the table of costs, please add a column to the table to show the actual regulatory costs balances, based on invoices actually paid in 2013, as of December 31, 2013.

RESPONSE

The following table summarizing 2013 regulatory costs, and the Ontario Hearing Cost Variance Account ("OHCVA") determination, has been updated to include a column showing amounts paid in 2013. The table also reflects corrections made in response to Energy Probe Interrogatory #3 found at Exhibit I, Tab 2, Schedule 3.

Witness: R. Small

Enbridge Gas Distribution Inc.
2013 Regulatory Proceeding Costs

Line No.	2013 Test Year Rate Proceeding Costs	Col. 1 2013 Approved / Budgeted Regulatory Costs ($000's)	Col. 2 Actual Regulatory Costs Incurred as at 31-May-14 ($000's)	Col. 3 Variance (over) / under ($000's)	Col. 4 Actual Regulatory Costs Paid in 2013
1.	Legal	900.0	1,316.7	(416.7)	407.7
2.	Intervenor Costs	900.0	884.1	15.9	867.2
3.	Ontario Energy Board	3,250.0	2,591.0	659.0	601.8
4.	Consultants (note 1)	1,100.0	1,114.5	(14.5)	224.9
5.	Transcripts, newspaper notices, printing, other	392.5	232.8	159.7	55.2
6.	Sub-total	6,542.5	6,139.1	403.4	2,156.8
7.	Other proceedings & consultatives (note 2)	800.0	950.5	(150.5)	118.3
8.	Actual versus OHCVA threshold variance	7,342.5	7,089.6	252.9	2,275.1

Notes:
1. Consultant costs can be broken down as follows:

	Col. 2	Col. 4
Concentric Energy Advisors Inc. - Benchmarking / Capital Structure	771.0	139.3
Mercer Ltd. - Compensation Study / Pension Estimates	153.6	62.0
Gannett Flemming Inc. - Depreciation Study	58.7	-
Other	131.2	23.6
	1,114.5	224.9

2. Other proceedings & consultatives:

	Col. 2	Col. 4
MNP LLP - RCAM Update Study	512.6	-
Elenchus - CAM/RCAM Consultatives and Process	153.8	5.9
KPMG LLP - IFRS/USGAAP Benchmarking Study	100.0	-
Black & Veatch - Storage Cost Allocations	71.7	-
Other	112.4	112.4
	950.5	118.3

BOARD STAFF INTERROGATORY #3

INTERROGATORY

Ref: ExB/T3/S4/Table page 2

What amount appears for 2013 regulatory costs in the 2013 audited financial statements?

RESPONSE

The 2013 audited financial statements include regulatory proceeding costs of $7,095.5 thousand. A variance of $5.9 thousand, as compared to the final total of $7,089.6 thousand used to determine the final Ontario Hearing Costs Variance Account ("OHCVA") amount of ($252.9) thousand, was due to variances between amounts accrued at year end for services rendered, and the final invoiced amounts.

Witness: R. Small

BOARD STAFF INTERROGATORY #4

INTERROGATORY

Ref: ExB/T3/S4/Table page 2

With respect to the 2013 Ontario Hearing Cost variance account, are there any costs relating to fiscal 2014 rates proceedings? If so, please identify them.

RESPONSE

No costs related to the 2014 rate proceeding were included in the regulatory proceeding costs expensed during 2013, and therefore do not impact the amount recorded in the 2013 Ontario Hearing Cost Variance Account. In accordance with the process identified in the response to Board Staff Interrogatory #1 found at Exhibit I, Tab 1, Schedule 1, 2014 Rate Hearing Costs incurred in 2013 were deferred and are being expensed in 2014.

BOARD STAFF INTERROGATORY #5

INTERROGATORY

Ref: ExB/T3/S6

With respect to the Post Retirement True-Up Variance Account, please provide the relevant pages from the 2013 audited financial statements that show the actual 2013 pension and OPEB expense of $46.1 million that is being claimed for the variance account.

RESPONSE

Please refer to the attachment for an extract from Enbridge's December 31, 2013 audited consolidated financial statements showing the 2013 accrual based pension and OPEB expense under the table labeled "Net Benefit Cost Recognized". The attachment shows actual 2013 pension and OPEB expense as $41 million and $6 million, respectively. However these include amounts relating to Enrbidge's wholly owned subsidiary, St. Lawrence Gas Company Inc. ("St. Lawrence"). Please refer to the table below for a breakdown of pension and OPEB costs between Enbridge and St. Lawrence.

Enbridge pension expense	$40.1 million
St. Lawrence pension expense	$ 1.3 million
Total consolidated pension expense	$41.4 million
Enbridge OPEB expense	$6.0 million
St. Lawrence OPEB expense	$0.2 million
Total consolidated OPEB expense	$6.2 million

The total pension and OPEB expense for Enbridge is $46.1 million.

Witnesses: J. Shem
R. Small

NET BENEFIT COSTS RECOGNIZED

	Pension			OPEB		
Year ended December 31,	**2013**	2012	2011	**2013**	2012	2011
(millions of Canadian dollars)						
Benefits earned during the year	**25**	21	16	**1**	2	1
Interest cost on projected benefit obligations	**38**	37	39	**4**	4	5
Actual return on plan assets	**(84)**	(59)	(15)	**(1)**	(1)	-
Actuarial loss	**(52)**	33	127	**(16)**	5	13
Difference between actual and expected return on plan assets						
Return on plan assets	**32**	10	(38)	**-**	-	-
Amortization of prior service costs	**1**	1	2	**-**	-	-
Amortization of actuarial loss	**80**	(3)	(110)	**18**	(4)	(13)
Net defined benefit costs on an accrual basis	**40**	40	21	**6**	6	6
Defined contribution benefit costs	**1**	1	1	**-**	-	-
Net benefit cost recognized on an accrual basis	**41**	41	22	**6**	6	6
Net amount recognized in OCI						
Net actuarial (gain)/loss[1]	**-**	-	-	**(14)**	4	13
Total amount recognized in OCI	**-**	-	-	**(14)**	4	13
Total net benefit cost on an accrual basis and amount recognized in OCI	**41**	41	22	**(8)**	10	19

1 *Unamortized actuarial losses included in AOCI, before tax, were nil relating to OPEB at December 31, 2013 (2012 - $14 million, 2011 - $10 million).*

The Company estimates that approximately $17 million related to pension plans and OPEB at December 31, 2013 will be reclassified into earnings in the next 12 months, as follows:

	Pension Benefits	OPEB	Total
(millions of Canadian dollars)			
Prior service costs	**-**	**-**	**-**
Actuarial Loss	**17**	**-**	**17**
	17	**-**	**17**

Regulatory adjustments were recorded in the Consolidated Statements of Earnings, the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension or OPEB costs or gains are expected to be collected from or refunded to customers in future rates *(Note 5)*. For the year ended December 31, 2013, an offsetting regulatory asset of $3 million (2012 - $22 million) has been recorded to the extent pension and OPEB costs are expected to be collected from customers in future rates.

Pension and OPEB costs related to the period on an accrual basis are presented above and were initially expensed. However, there was a partially offsetting adjustment for pension and OPEB costs due to the regulatory mechanism in place. As a result, the net pension and OPEB expense primarily consisted of OEB approved pension and OPEB costs.

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2013**	2012	2011	**2013**	2012	2011
Discount rate	**4.3%**	4.5%	5.7%	**4.3%**	4.5%	5.7%
Average rate of return on pension plan assets	**6.8%**	7.0%	7.3%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.5%**	3.5%	3.5%	**3.5%**	5.0%	5.0%

BOARD STAFF INTERROGATORY #6

INTERROGATORY

Ref: ExC/T1/S1/para 6 TIACDA

With respect to the change in the allocation of the TIACDA balance to the rate classes from a Distribution Revenue Requirement (DRR) allocator to a Rate Base allocator, what was the reason for the change? What is the impact on the rate classes of the DRR allocator versus the Rate Base allocator?

RESPONSE

Please see the response to Energy Probe Interrogatory #6, at Exhibit I, Tab 3, Schedule 6.

Witness: M. Kirk

CME INTERROGATORY #1

INTERROGATORY

Reference: Exhibit A, Tab 2, Schedule 1, page 4, lines 12 and 13
Exhibit B, Tab 1, Schedule 1, page 1, para.1

EGD proposes to carry forward the debit balances in these deferral accounts to a future proceeding. In connection with this proposal, please provide the following information:

(a) Please advise of the extent to which the debit balances in each of these accounts are likely to increase from their current levels between October 1, 2014 and the date on which EGD proposes to clear the accounts.

RESPONSE

The $279.3 thousand balance in the Manufactured Gas Plant Deferral Account ("MGPDA"), shown in Line 12 of Exhibit A, Tab 2, Schedule 1, page 4, represents costs incurred in managing and resolving issues related to the Company's manufactured gas plant legacy operations. The balance represents the accumulation of costs incurred since 2006, the year in which the account was first approved, which have been carried forward through to the current account balance. As per the EB-2013-0459 Final Accounting Order, the balance in the 2013 MGPDA will be rolled forward to the 2014 MGPDA.

Most of the amounts recorded within the 2013 MGPDA arise from Enbridge's defence of a lawsuit brought by Cityscape Residential Inc. against the Company in relation to alleged contamination at a site in Toronto. Very recently, after a prolonged period of inactivity, the plaintiff has indicated that it intends to move the lawsuit forward. Enbridge expects, therefore, that the current balance within the MGPDA will increase over the coming years. Enbridge is not able to predict the amount or timing of future costs at this time.

The Company does not have any current expectation about the specific date when it will seek to clear any balance within the MGPDA. Depending upon the magnitude of amounts recorded within the account over the next years, Enbridge may seek clearance of existing balances within its 2014 or 2015 Deferral and Variance Account proceedings. Alternately, Enbridge may not seek initial clearance until the completion of the Cityscape lawsuit. In any event, though, because the MGPDA relates to all of the

Company's former MGP sites, it is anticipated that the MGPDA will continue beyond the time of any initial clearance and beyond the time that the Cityscape lawsuit is completed.

The purpose of the Customer Care CIS Rate Smoothing Deferral Account ("CCCISRSDA") is to capture the difference between the forecast customer care and CIS costs versus the amount to be collected in revenues as approved by the Board in the EB-2011-0226 CIS Customer Care Settlement Agreement and proceeding. The amount to be debited or credited to the deferral account, for each of 2013 through 2018 years, will be calculated by multiplying the difference between the approved cost per customer and the smoothed cost per customer by the updated customer forecast for that year. The balances in the CCCISRSDA will not be cleared until the end of the IR term. The cumulative balance will build up during the years 2013 to 2015 when the approved cost per customer exceeds the smoothed cost per customer being collected in rates, and then will be drawn down during the years 2016 to 2018 when the approved cost per customer is lower than the smoothed cost per customer being collected in rates. After 2018, any remaining cumulative balance in the CCCISRSDA is to be cleared along with the clearance of other 2018 deferral and variance accounts

The $4.6 million balance in the 2013 CCCISRSDA, shown in line 13 of Exhibit A, Tab 2, Schedule 1, page 4, represents the variance between approved 2013 customer care and CIS costs and the smoothed amount recovered in 2013 rates, as approved by the Board in the 2013 Rate Application EB-2011-0354. Based on the updated customer forecast provided in the 2014 to 2018 Rate Application (Exhibit D1, Tab 10, Schedule 2), the approved 2014 variance to be recorded in the CCCISRSDA is $2.9 million, while the forecast 2015 to 2018 variances to be recorded are $1.1 million, ($0.8) million, ($2.9) million, and ($5.0) million. The 2015 to 2018 amounts to be recorded in the CCCISRSDA may change as the forecast customer numbers are updated in each of the respective rate applications for those years.

Witness: R. Small

CME INTERROGATORY #2

Reference: Exhibit A, Tab 2, Schedule 1, page 4, line 4
Exhibit B, Tab 2, Schedule 2, page 3, para.7

The evidence indicates that there were two (2) significant third party damages incidents that occurred in 2013 on high pressure lines — one in Ottawa and one in Markham. With respect to this evidence, please provide the following further information:

(a) Please provide details of each of the significant third party damages incidents in Ottawa and Markham.

(b) Identify the parties responsible for causing the damages.

(c) What claims, if any, did EGD make against the parties causing the damages.

(d) What insurance coverage, if any, did EGD have to respond to the damages caused in each incident?

(e) In each of the 2 major third party damages incidents, for what period of time was gas being lost from the system before the appropriate valves were closed?

(f) Provide EGD's estimates of the gas volume lost as a result of each incident

(g) Please explain why losses arising from third party damages incidents fall within the ambit of the deferral account. In particular, please explain why EGD's shareholder should not be at risk for the failure of EGD to recover from the responsible third parties all of the damages which they have caused, including the value of the gas which was lost as a result of the incidents.

RESPONSE

(a) through (f), except (d):

The incident in Ottawa occurred on November 10, 2013 and was due to third-party contractor error. OLRT Constructors drilled horizontally under Highway 417 and hit a 12” HP gas main. Although the gas blew for four days, losses were kept to a minimum as the drill tip remained embedded in the main. The bulk of the gas loss occurred during the shut-down and re-energization of the line. Total gas loss was estimated at 402,000 m^3. The damage invoices totaled $731,000, of which $69,000 related to lost gas.

Witness: C. Ho

The incident in Markham occurred on February 3, 2013. Powell Contracting had performed vertical augers for a new bridge rail guard and inadvertently punctured the 6” HP steel main with the auger. The damage was located twenty-three feet deep right next to a water course. Ultimately, the damage was ruled to be as a result of a poor gas locate completed by an Enbridge contractor. The gas blew for approximately eleven hours, with gas losses estimated at 26,000 m^3. The damage invoices totaled $617,000, of which $5,000 related to lost gas.

(d) Enbridge does not have insurance that would cover claims of this nature.

(g) As cited in pre-filed evidence (EB-2014-0195, Exhibit B, Tab 2, Schedule 2, page 1, paragraph 2) UAF is the difference between natural gas delivered into the distribution system as billed by third-party transmission entities and natural gas that is billed as consumption to customers. It arises from a number of factors which includes third-party damages. The UAF Variance Account (“UAFVA”) records the cost of gas that is associated with the volumetric variances between the actual volume of UAF and the Board-approved UAF volumetric forecast. It is this amount which is reflected in the interrogatory reference (Exhibit A, Tab 2, Schedule 1, page 4, Line 14).

In the course of investigating responses to this query, the Company determined that invoices sent to third parties for damages included amounts for an estimated volume of gas loss. Enbridge’s current financial record-keeping does not track these invoiced gas loss amounts as offsets to the UAF costs being recorded. As a result, they were not identified as amounts that should be removed from the UAFVA as they were rightly invoiced to identified, responsible parties.

Enbridge acknowledges that costs associated with gas losses that have been invoiced to third parties should not be included within UAF costs that are recoverable through the UAFVA. To rectify this, the Company is backing out the value of all 2013 gas losses that were invoiced to third parties from the UAFVA, reducing the total by $260,000. In 2013, there were approximately 1,100 third party damage incidents with gas losses for which the Company issued invoices to recover. The two incidents quoted in the evidence and explained above were the major gas losses. The balance of the incidents involved insignificant amounts of gas losses. The resulting new balance for the 2013 UAFVA, following the reduction of $260,000, is $1,947,333.68.

The Company will implement a process going forward that will identify the gas losses included in invoiced amounts for damages. The associated volumes will not reduce the UAF volumetric amount, but the invoiced amounts will be removed from the UAFVA balance.

Witness: C. Ho

CME INTERROGATORY #3

Reference: Exhibit A, Tab 2, Schedule 1, page 4, line 9
Exhibit B, Tab 3, Schedule 2, page 1, para.3

EGD seeks to recover a debit amount of about $5.6M for a short-fall in average uses which, according to EGD, is primarily attributable to a slower than expected economic recovery. EGD is seeking to recover this debit balance following actual 2013 consumption by ratepayers significantly greater than normal because of the extremely cold weather in the last quarter of 2013. This cold weather also led to very significant gas cost increases which the Board has already approved for recovery from ratepayers. In connection with the foregoing, please provide the following information:

(a) To what extent were volumes consumed by Rates 1 and 6 customers in 2013 greater because of colder than normal weather, particularly in the last quarter of the year?

(b) How much incremental margin did EGD realize from Rates 1 and 6 customers in 2013 as a result of actual use exceeding normal use because of the colder than normal weather?

(c) Why should EGD be entitled to recover any amounts attributable to a slower than expected economic recovery when the customers against whom such relief is sought have already been hard hit with the cost consequences of an extremely cold winter, including significant gas cost increases attributable to the colder than normal weather in 2013?

RESPONSE

(a) The following Table 1 and Table 2 illustrate the corresponding actual average use for both Rate 1 and Rate 6. These tables also show the comparison between the actual average uses and the normalized average uses and these differences, as illustrated by Line 1.5, in both Table 1 and Table 2, provide the impact to volumes due to colder than normal weather. The average consumption per customer was higher by 13.9 m^3 for Rate 1 customers. For Rate 6 customers, the average consumption per customer was higher by 186.0 m^3.

Witness: C. Ho
R. Small

TABLE 1
GENERAL SERVICE RATE 1
2013 ACTUAL - VOLUME, CUSTOMERS, AVERAGE USE

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Reference
Item.		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	
1.1	Actual Volumes (10^6m^3)	763.4	818.8	665.3	542.2	283.3	170.9	105.5	109.7	128.2	166.7	389.6	641.8	4,785.6	
1.2	Customer Meters	1,859,938	1,862,355	1,864,894	1,866,664	1,867,428	1,865,681	1,864,592	1,866,038	1,868,191	1,875,671	1,882,365	1,888,078	1,869,325	
1.3	Actual Average Use per Customer (m^3)	410.4	439.7	356.7	290.5	151.7	91.6	56.6	58.8	68.6	88.9	207.0	339.9	2,560.5	
1.4	Normalized Actual Average Use per Customer (m^3)	453.4	441.2	369.0	261.0	162.3	91.6	56.6	58.8	68.6	90.5	183.5	310.0	2,546.6	
1.5	Variance Actual Avg. Use vs Norm. Avg Use. (m^3)	(42.9)	(1.6)	(12.3)	29.4	(10.6)	(0.0)	(0.0)	0.0	(0.0)	(1.6)	23.4	30.0	13.9	(Item 1.3 - 1.4)
1.6	2014 Budget Average Use per Customer (m^3)	451.0	440.4	360.0	258.9	172.2	88.0	55.8	56.5	59.9	94.0	191.6	339.8	2,568.1	
1.7	Variance Actual Avg. Use vs Budget Avg Use. (m^3)	(40.6)	(0.7)	(3.2)	31.6	(20.5)	3.7	0.7	2.3	8.7	(5.1)	15.4	0.1	(7.6)	(Item 1.3 - 1.6)

Witness: C. Ho
R. Small

TABLE 2
GENERAL SERVICE RATE 6
2013 ACTUAL - VOLUME, CUSTOMERS, AVERAGE USE

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Reference
Item.		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	
1.1	Actual Volumes (10^6m^3)	700.4	791.1	680.4	560.8	303.1	159.9	104.0	104.5	124.0	170.8	380.3	660.5	4,739.9	
1.2	Customer Meters	161,291	161,867	162,037	161,857	161,131	159,533	158,267	157,601	157,212	158,762	161,079	162,438	160,256	
1.3	Actual Average Use per Customer (m^3)	4,342.7	4,887.6	4,199.3	3,465.0	1,881.0	1,002.2	656.9	662.9	788.9	1,075.8	2,361.2	4,065.9	29,389.3	
1.4	Normalized Actual Average Use per Customer (m^3)	4,746.0	4,910.2	4,328.9	3,143.0	2,010.2	1,002.2	656.9	662.9	788.9	1,093.5	2,118.4	3,742.3	29,203.4	
1.5	Variance Actual Avg. Use vs Norm. Avg Use. (m^3)	(403.3)	(22.6)	(129.6)	322.0	(129.1)	0.0	(0.0)	0.0	(0.0)	(17.7)	242.8	323.6	186.0	(Item 1.3 - 1.4)
1.6	2014 Budget Average Use per Customer (m^3)	4,752.0	5,046.3	4,446.7	2,939.1	1,900.1	989.5	707.1	656.3	770.6	1,111.8	2,247.0	4,312.0	29,878.2	
1.7	Variance Actual Avg. Use vs Budget Avg Use. (m^3)	(409.2)	(158.7)	(247.3)	525.9	(19.0)	12.7	(50.2)	6.6	18.3	(36.0)	114.2	(246.1)	(488.9)	(Item 1.3 - 1.6)

Witness: C. Ho
R. Small

(b) As illustrated by Line 1.7 in both Table 1 and Table 2, the actual average uses, even with colder than normal weather, were lower compared to 2013 Board Approved average uses in both Rate 1 and Rate 6. The actual average use for Rate 1 was lower by 7.6 m^3 and the actual average use for Rate 6 was lower by 488.9 m^3. The short-fall in average uses result a deficiency of margin of $3.3M. The following Table 3 illustrates the calculations of the margin impact.

TABLE 3
2013 ACTUAL AVERAGE USE

Reference		Table 1 & 2 - Item 1.3					
	Col. 1	Col. 2	Col. 3 =Col. 2-1	Col. 4	Col. 5 =Col. 3*4	Col. 6	Col. 7 =Col. 5*6
Rate Class	2013 Budget Annual Use (m^3)	2013 Actual Annual Use (m^3)	Actual Usage Variance (m^3)	Budget Customer Meters	Actual Volumetric Variance ($10^6 m^3$)	Unit Rate ($/$m^3$)	Margin Impact ($ millions)
1	2,568	2,560	(8)	1,866,534	(14.3)	0.0521	(0.74)
6	29,878	29,389	(489)	158,495	(77.5)	0.0329	(2.55)
Total					(91.8)		(3.30)

(c) In accordance with the 2013 Board approved EB-2011-0354 Settlement Agreement, the purpose of the AUTUVA is to record ("true-up") the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer and the actual weather normalized average use experienced during the year for general service (Rate 1 and Rate 6) customers. The amount of $5.6M that Enbridge seeks to recover does not include any gas costs impact as the unit rates used in calculating the AUTUVA amount exclude gas costs. Please refer to Enbridge's response to FRPO Interrogatory #1 found at Exhibit I, Tab 4, Schedule 1 for supporting calculations for the unit rates.

The parameters and operation of the AUTUVA, were defined and agreed upon in the EB-2011-0354 Settlement Agreement. The prefiled evidence that was adopted within the Settlement Agreement contemplated that Enbridge would continue to operate this true-up mechanism in the same manner as during the 1st Generation IR

Witness: C. Ho
R. Small

plan. This, along with the 2013 Final Rate Order (See Appendix D, Page 28), makes clear that the 2013 AUTUVA is to operate on the basis of actual weather normalized average use for general service customers. That is consistent with past practice. The use of the AUTUVA and derivation of amounts to be included within it should not be subject to further adjustments resulting from after the fact views of the amount of influence of external factors such as higher gas prices and colder weather. Doing so would be inconsistent with the 2013 Settlement Agreement, and the associated EB-2011-0354 Final Rate Order.

CME INTERROGATORY #4

Reference: Exhibit A, Tab 2, Schedule 1, page 4, line 8
Exhibit B, Tab 3, Schedule 4, page 2

Column 2 in the second reference above is headed "Actual Regulatory Costs Incurred as at 30-Apr-14". In connection with the amounts shown in lines 1 to 8 of that Exhibit and in Notes 1 and 2, please provide the following information:

(a) Do any of the amounts shown in lines 1 to 8 and Notes 1 and 2 relate to services provided after December 31, 2013? If so, then please provide details of the amounts which pertain to services provided in 2014?

RESPONSE

No. None of the actual regulatory proceeding costs shown in Exhibit B, Tab 3, Schedule 4, page 2, Column 2 are for services provided after December 31, 2013. The values in Column 2 have been corrected within the response to Energy Probe Interrogatory #3 found at Exhibit I, Tab 3, Schedule 3.

Witness: R. Small

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

Ref: Exhibit A, Tab 2, Schedule 1 & July 22, 2014 Letter

In its' July 22, 2014 letter, Enbridge indicates that it is proposing a January 1, 2015 implementation date due to the current timing of this proceeding.

Please update the figures in Appendix A to reflect a forecast clearance of January 1, 2015.

RESPONSE

The forecast balances for clearance shown in Appendix A of Exhibit A, Tab 2, Schedule 1, and at page 2 of Exhibit B, Tab 1, Schedule 1 have been updated in the table provided on the following page to reflect the proposed January 2015 clearance.

In addition to reflecting the impact of the revised proposed clearance timing on the forecast balances for clearance, the following table also includes revised 2013 Transactional Services Deferral Account ("TSDA") and 2013 Unaccounted for Gas Variance Account ("UAFVA") balances. The revision to the TSDA is required as a result of ($37.0) thousand which was inadvertently recorded in the 2014 TSDA. The forecast 2013 TSDA balance for clearance now agrees with the TSDA details provided in the Attachment to Exhibit B, Tab 2, Schedule 1. Details of the revision to the UAFVA, of ($260.0) thousand, are provided in the response to CME Interrogatory #2 found at Exhibit I, Tab 2, Schedule 2.

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNT
ACTUAL & FORECAST BALANCES

Line No.	Account Description	Account Acronym	Col. 1 Actual at May 31, 2014 Principal ($000's)	Col. 2 Actual at May 31, 2014 Interest ($000's)	Col. 3 Forecast for clearance at January 1, 2015 Principal ($000's)	Col. 4 Forecast for clearance at January 1, 2015 Interest ($000's)	
	Non Commodity Related Accounts						
1.	Demand Side Management V/A	2012 DSMVA	2,506.5	(3.9)	2,506.5	17.7	1
2.	Demand Side Management V/A	2013 DSMVA	(3,601.8)	(155.9)	-	-	1
3.	Lost Revenue Adjustment Mechanism	2012 LRAM	(40.7)	(0.1)	(40.7)	(0.4)	1
4.	Demand Side Management Incentive D/A	2012 DSMIDA	8,817.5	54.0	8,160.3	124.8	1
5.	Deferred Rebate Account	2013 DRA	(2,083.0)	(2.5)	(2,083.0)	(20.6)	2
6.	Gas Distribution Access Rule Costs D/A	2012 GDARCDA	208.6	4.5	-	-	3
7.	Gas Distribution Access Rule Costs D/A	2013 GDARCDA	654.1	5.0	(75.0)	-	3
8.	Ontario Hearing Costs V/A	2013 OHCVA	(252.9)	(1.5)	(252.9)	(3.6)	4
9.	Average Use True-Up V/A	2013 AUTUVA	5,616.9	34.4	5,616.9	82.7	5
10.	Post-Retirement True-Up V/A	2013 PTUVA	3,253.4	19.9	3,253.4	47.9	6
11.	Transition Impact of Accounting Change D/A	2014 TIACDA	84,280.2	-	4,435.8	-	7
12.	Manufactured Gas Plant D/A	2013 MGPDA	279.3	25.8	-	-	8
13.	Customer Care CIS Rate Smoothing D/A	2013 CCCISRSDA	4,634.9	59.6	-	-	9
12.	Total non commodity related accounts		104,273.0	39.3	21,521.3	248.5	
	Commodity Related Accounts						
13.	Transactional Services D/A	2013 TSDA	(24,028.2)	(270.0)	(24,065.2)	(476.6)	10
14.	Unaccounted for Gas V/A	2013 UAFVA	2,207.3	37.5	1,947.3	55.2	11
15.	Storage and Transportation D/A	2013 S&TDA	(2,109.5)	(24.2)	(2,109.5)	(42.4)	12
16.	Total commodity related accounts		(23,930.4)	(256.7)	(24,227.4)	(463.8)	
17.	Total Deferral and Variance Accounts		80,342.6	(217.4)	(2,706.1)	(215.3)	

Notes:

1. The 2012 DSMVA, LRAM, and DSMIDA balances forecast for clearance are those which were approved in the EB-2013-0352 proceeding. 2012 DSMVA, LRAM, and DSMIDA evidence is found at Exhibit B, Tab 3, Schedules 7, 8, and 9. Clearance of the 2013 DSMVA will be requested at a later date.
2. DRA evidence is found at Exhibit B, Tab 3, Schedule 1.
3. The forecast clearance amount, associated with the 2012 and 2013 GDARCDA balances, is the result of a revenue requirement calculation found in evidence at Exhibit B, Tab 3, Schedule 3.
4. OHCVA evidence is found at Exhibit B, Tab 3, Schedule 4.
5. AUTUVA evidence is found at Exhibit B, Tab 3, Schedule 2.
6. PTUVA evidence is found at Exhibit B, Tab 3, Schedule 6.
7. TIACDA evidence is found at Exhibit B, Tab 3, Schedule 5.
8. Clearance of the MGPDA is not being requested at this time. As indicated in the EB-2012-0459 proceeding, the balance will be transferred to the 2014 MGPDA.
9. Clearance of the CCCISRSDA is not being requested at this time. As approved in the EB-2011-0226 proceeding, any net balance of amounts recorded in the 2013 through 2018 CCCISRSDA's will be requested for clearance in conjunction with 2018 deferral and variance accounts.
10. TSDA evidence is found at Exhibit B, Tab 2, Schedule 1.
11. UAFVA evidence is found at Exhibit B, Tab 2, Schedule 2.
12. S&TDA evidence is found at Exhibit B, Tab 2, Schedule 3.

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

Ref: Exhibit B, Tab 3, Schedule 3

a) Please explain the difference in the depreciation ($47.3) and the accumulated depreciation ($21.7).

b) Please confirm that the rate base has been calculated as the average of the monthly averages. If this cannot be confirmed, please indicate how the rate base figure has been calculated.

RESPONSE

a) The depreciation amount of $47.3 thousand, shown at Exhibit B, Tab 3, Schedule 3, page 5, Line 9, is the 2013 depreciation expense calculated on the Low Income Customer Service Rule capital put into service in 2013. The accumulated depreciation amount of ($21.7) thousand, shown at Exhibit B, Tab 3, Schedule 3, page 4, Line 2, is the 2013 average of monthly averages rate base impact of the 2013 depreciation expense of $47.3 thousand.

b) Confirmed. Rate base has been calculated on an average of monthly averages basis.

Witness: R. Small

ENERGY PROBE INTERROGATORY #3

INTERROGATORY

Ref: Exhibit B, Tab 3, Schedule 4

Please reconcile the figure of $252,900 shown on page 1 with the calculated figure of $246.9 in the table on page 2.

RESPONSE

The $252,900 referenced on page 1 of Exhibit B, Tab 3, Schedule 4 is the correct Ontario Hearing Costs Variance Account ("OHCVA") balance. The amount of $246.9 thousand, shown in Column 3 of page 2 of that exhibit, was incorrect. A review of the table resulted in the discovery of a small input error, a small categorization update, and the correction of the Column 2 title, which should have referenced May 31, 2014 as opposed to April 30, 2014. The table on the following page reflects these changes.

Witness: R. Small

Enbridge Gas Distribution Inc.
2013 Regulatory Proceeding Costs

Line No.	2013 Test Year Rate Proceeding Costs	Col. 1 2013 Approved / Budgeted Regulatory Costs ($000's)	Col. 2 Actual Regulatory Costs Incurred as at 31-May-14 ($000's)	Col. 3 Variance (over) / under ($000's)
1.	Legal	900.0	1,316.7	(416.7)
2.	Intervenor Costs	900.0	884.1	15.9
3.	Ontario Energy Board	3,250.0	2,591.0	659.0
4.	Consultants (note 1)	1,100.0	1,114.5	(14.5)
5.	Transcripts, newspaper notices, printing, other	392.5	232.8	159.7
6.	Sub-total	6,542.5	6,139.1	403.4
7.	Other proceedings & consultatives (note 2)	800.0	950.5	(150.5)
8.	Actual versus OHCVA threshold variance	7,342.5	7,089.6	252.9

Notes:

1. Consultant costs can be broken down as follows:

Concentric Energy Advisors Inc. - Benchmarking / Capital Structure	771.0
Mercer Ltd. - Compensation Study / Pension Estimates	153.6
Gannett Flemming Inc. - Depreciation Study	58.7
Other	131.2
	1,114.5

2. Other proceedings & consultatives:

MNP LLP - RCAM Update Study	512.6
Elenchus - CAM/RCAM Consultatives and Process	153.8
KPMG LLP - IFRS/USGAAP Benchmarking Study	100.0
Black & Veatch - Storage Cost Allocations	71.7
Other	112.4
	950.5

Witness: R. Small

ENERGY PROBE INTERROGATORY #4

INTERROGATORY

Ref: Exhibit C, Tab 1, Schedule 1

a) With the delay with a January 1, 2015 implementation date, will the unit rates still be applied to each customer's actual consumption over the January 1, 2013 through December 31, 2013 period?

b) Please confirm that the references to Exhibit C, Tab 2, Schedule 2 should be to Exhibit C, Tab 1, Schedule 2. If this cannot be confirmed, please provide Exhibit C, Tab 2, Schedule 2.

RESPONSE

a) Yes, the updated unit rates will be applied to each customer's actual consumption over the January 1, 2013 through December 31, 2013 period.

b) Confirmed.

Witness: M. Kirk

ENERGY PROBE INTERROGATORY #5

INTERROGATORY

Ref: Exhibit C, Tab 1, Schedule 2

Please update the schedules to reflect the change in balances as a result of not clearing the balances until January 1, 2015.

RESPONSE

The attached schedules have been updated to reflect the proposed January 2015 clearance.

Details on the account balances to be cleared can be found in the response to Energy Probe Interrogatory #1 found at Exhibit I, Tab 3, Schedule 1.

Witness: M. Kirk

UNIT RATE AND TYPE OF SERVICE: CLEARING IN JANUARY 2015

		COL.1
		TOTAL (¢/m³)
Bundled Services:		
RATE 1	- SYSTEM SALES	(0.0073)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.2649
	- WESTERN T-SERVICE	(0.0073)
RATE 6	- SYSTEM SALES	(0.1347)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.1375
	- WESTERN T-SERVICE	(0.1347)
RATE 9	- SYSTEM SALES	0.2207
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.4929
	- WESTERN T-SERVICE	0.0000
RATE 100	- SYSTEM SALES	(0.2552)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0170
	- WESTERN T-SERVICE	(0.2552)
RATE 110	- SYSTEM SALES	(0.3588)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.0866)
	- WESTERN T-SERVICE	(0.3588)
RATE 115	- SYSTEM SALES	(0.0920)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.1802
	- WESTERN T-SERVICE	(0.0920)
RATE 135	- SYSTEM SALES	0.3618
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.6340
	- WESTERN T-SERVICE	0.3618
RATE 145	- SYSTEM SALES	(0.4243)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.1522)
	- WESTERN T-SERVICE	(0.4243)
RATE 170	- SYSTEM SALES	(0.3234)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.0513)
	- WESTERN T-SERVICE	(0.3234)
RATE 200	- SYSTEM SALES	(0.2877)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.0156)
	- WESTERN T-SERVICE	0.0000
Unbundled Services:		
RATE 125	- All	0.8988
	- Customer-specific ($)	$0
RATE 300	- All	23.2026

Determination of Balances to be Cleared from the 2013 Deferral and Variance Accounts

ITEM NO.		COL. 1 PRINCIPAL For CLEARING ($000)	COL. 2 INTEREST ($000)	COL. 3 TOTAL For CLEARING ($000)
1.	**TRANSACTIONAL SERVICES D/A**	(24,065.2)	(476.6)	(24,541.8)
2.	**UNACCOUNTED FOR GAS V/A**	1,947.3	55.2	2,002.5
3.	**STORAGE AND TRANSPORTATION D/A**	(2,109.5)	(42.4)	(2,151.9)
4.	**DEFERRED REBATE ACCOUNT**	(2,083.0)	(20.6)	(2,103.6)
5.	**DEMAND SIDE MANAGEMENT 2012**	2,506.5	17.7	2,524.2
6.	**LOST REVENUE ADJ MECHANISM 2012**	(40.7)	(0.4)	(41.1)
7.	**DEMAND SIDE MANAGEMENT INCENTIVE 2012**	8,160.3	124.8	8,285.1
9.	**ONTARIO HEARING COSTS V/A**	(252.9)	(3.6)	(256.5)
10.	**GAS DISTRIBUTION ACCESS RULE D/A 2012**	(75.0)	0.0	(75.0)
11.	**AVERAGE USE TRUE-UP V/A**	5,616.9	82.7	5,699.6
12.	**POST-RETIREMENT TRUE-UP V/A**	3,253.4	47.9	3,301.3
13.	**UNBUNDLED RATE IMPLEMENTATION COST D/A**	0.0	0.0	0.0
14.	**MUNICIPAL PERMIT FEES D/A**			0.0
15.	**OPEN BILL SERVICE D/A**			0.0
16.	**OPEN BILL ACCESS V/A**			0.0
17.	**EX-FRANCHISE THIRD PARTY BILLING SERVICES D/A**	0.0	0.0	0.0
18.	**TAX RATE & RULE CHANGE V/A**	0.0	0.0	0.0
19.	**TRANSITION IMPACT OF ACCT CHANGE D/A**	4,435.8		4,435.8
20.	**EARNINGS SHARING MECHANISM**	0.0	0.0	0.0
21.	**TOTAL**	(2,706.1)	(215.3)	(2,921.4)

Classification and Allocation of Deferral and Variance Account Balances

ITEM NO.		COL.1 TOTAL ($000)	COL. 2 SALES AND WBT ($000)	COL. 3 TOTAL SALES ($000)	COL. 4 TOTAL DELIVERIES ($000)	COL. 5 SPACE ($000)	COL. 6 DELIVE-RABILITY ($000)	COL. 7 DISTRIBUTION REV REQ (DRR) ($000)	COL. 8 DIRECT ($000)	COL. 9 NUMBER OF CUSTOMERS ($000)	COL. 10 RATE BASE ($000)
	CLASSIFICATION										
	PGVA:										
1.1	COMMODITY	0.0		0.0							
1.2	SEASONAL PEAKING-LOAD BALANCING	0.0					0.0				
1.3	SEASONAL DISCRETIONARY-LOAD BALANCING	0.0				0.0					
1.4	TRANSPORTATION TOLLS	0.0	0.0								
1.5	CURTAILMENT REVENUE	0.0					0.0		0.0		
1.6	RIDER C 2009 DIRECT ALLOCATION	0.0							0.0		
1.7	INVENTORY ADJUSTMENT	0.0									
1.		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.	**TRANSACTIONAL SERVICES D/A**	(24,541.8)	(22,597.3)			(758.2)	(1,186.3)				
2.	**UNACCOUNTED FOR GAS V/A**	2,002.5			2,002.5						
3.	**STORAGE AND TRANSPORTATION D/A**	(2,151.9)				(839.1)	(1,312.8)				
4.	**DEFERRED REBATE ACCOUNT**	(2,103.6)			(2,103.6)						
5.	**DEMAND SIDE MANAGEMENT 2012**	2,524.2							2,524.2		
6.	**LOST REVENUE ADJ MECHANISM 2012**	(41.1)							(41.1)		
7.	**DEMAND SIDE MANAGEMENT INCENTIVE 2012**	8,285.1							8,285.1		
9.	**ONTARIO HEARING COSTS V/A**	(256.5)									(256.5)
10.	**GAS DISTRIBUTION ACCESS RULE D/A 2012**	(75.0)								(75.0)	
11.	**AVERAGE USE TRUE-UP V/A**	5,699.6							5,699.6		
12.	**POST-RETIREMENT TRUE-UP V/A**	3,301.3									3,301.3
13.	**UNBUNDLED RATE IMPLEMENTATION COST D/A**	0.0								0.0	
14.	**MUNICIPAL PERMIT FEES D/A**	0.0									0.0
15.	**OPEN BILL SERVICE D/A**	0.0								0.0	
16.	**OPEN BILL ACCESS V/A**	0.0								0.0	
17.	**EX-FRANCHISE THIRD PARTY BILLING SERVICES D/A**	0.0								0.0	
18.	**TAX RATE & RULE CHANGE V/A**	0.0									0.0
19.	**TRANSITION IMPACT OF ACCT CHANGE D/A**	4,435.8						0.0			4,435.8
20.	**EARNINGS SHARING MECHANISM**	0.0						0.0			
21.	**TOTAL**	(2,921.4)	(22,597.3)	0.0	(101.1)	(1,597.3)	(2,499.1)	0.0	16,467.8	(75.0)	7,480.6
	ALLOCATION										
1.1	RATE 1	722.2	(11,955.2)	0.0	(42.0)	(760.9)	(1,417.7)	0.0	9,778.8	(69.1)	5,188.3
1.2	RATE 6	(2,839.9)	(9,355.2)	0.0	(41.6)	(733.2)	(1,029.3)	0.0	6,256.1	(5.9)	2,069.2
1.3	RATE 9	1.8	(1.7)	0.0	(0.0)	(0.0)	0.0	0.0	0.6	(0.0)	2.9
1.4	RATE 100	(7.3)	(7.8)	0.0	(0.0)	(0.1)	(0.7)	0.0	0.0	(0.0)	1.4
1.5	RATE 110	(887.8)	(435.4)	0.0	(4.6)	(16.5)	(20.1)	0.0	(474.8)	(0.0)	63.6
1.6	RATE 115	981.4	(43.1)	0.0	(5.0)	(0.0)	(7.8)	0.0	1,004.6	(0.0)	32.7
1.7	RATE 125	88.0	0.0	0.0	0.0	0.0	0.0	0.0	21.2	0.0	66.8
1.8	RATE 135	288.7	(62.9)	0.0	(0.5)	0.0	0.0	0.0	348.6	(0.0)	3.5
1.9	RATE 145	(373.7)	(120.4)	0.0	(1.5)	(16.6)	0.0	0.0	(252.8)	(0.0)	17.5
1.10	RATE 170	(483.0)	(228.2)	0.0	(4.4)	(44.6)	0.0	0.0	(223.3)	(0.0)	17.5
1.11	RATE 200	(416.0)	(387.3)	0.0	(1.6)	(25.3)	(23.5)	0.0	7.4	(0.0)	14.4
1.12	RATE 300	4.2	0.0	0.0	0.0	0.0	0.0	0.0	1.4	0.0	2.8
1.		(2,921.4)	(22,597.3)	0.0	(101.1)	(1,597.3)	(2,499.1)	0.0	16,467.8	(75.0)	7,480.6
		(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0

ALLOCATION BY TYPE OF SERVICE

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DISTRIBUTION REV REQ (DRR)	DIRECT	NUMBER OF CUSTOMERS	RATE BASE
		($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Bundled Services:											
RATE 1	- SYSTEM SALES	(301.2)	(11,298.0)	0.0	(36.4)	(660.0)	(1,229.8)	0.0	8,482.5	(59.9)	4,500.5
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	1,040.9			(3.4)	(62.5)	(116.4)	0.0	802.9	(5.7)	426.0
	- WBT	(17.5)	(657.2)		(2.1)	(38.4)	(71.5)	0.0	493.4	(3.5)	261.8
RATE 6	- SYSTEM SALES	(3,630.1)	(7,334.2)	0.0	(23.6)	(416.9)	(585.2)	0.0	3,556.8	(3.4)	1,176.4
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	1,790.4			(11.4)	(201.5)	(282.9)	0.0	1,719.2	(1.6)	568.6
	- WBT	(1,000.3)	(2,021.0)		(6.5)	(114.9)	(161.3)	0.0	980.1	(0.9)	324.2
RATE 9	- SYSTEM SALES	1.4	(1.7)	0.0	(0.0)	(0.0)	0.0	0.0	0.5	(0.0)	2.7
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	0.3			(0.0)	(0.0)	0.0	0.0	0.1	(0.0)	0.3
	- WBT	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0
RATE 100	- SYSTEM SALES	(6.8)	(7.2)	0.0	(0.0)	(0.1)	(0.6)	0.0	0.0	(0.0)	1.2
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	0.1			(0.0)	(0.0)	(0.1)	0.0	0.0	(0.0)	0.1
	- WBT	(0.5)	(0.6)		(0.0)	(0.0)	(0.0)	0.0	0.0	(0.0)	0.1
RATE 110	- SYSTEM SALES	(321.4)	(243.9)	0.0	(0.8)	(2.8)	(3.4)	0.0	(81.4)	(0.0)	10.9
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(313.8)			(3.2)	(11.5)	(13.9)	0.0	(329.4)	(0.0)	44.1
	- WBT	(252.6)	(191.6)		(0.6)	(2.2)	(2.7)	0.0	(64.0)	(0.0)	8.6
RATE 115	- SYSTEM SALES	(1.0)	(2.8)	0.0	(0.0)	(0.0)	(0.0)	0.0	1.8	(0.0)	0.1
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	996.0			(4.9)	(0.0)	(7.6)	0.0	976.6	(0.0)	31.8
	- WBT	(13.6)	(40.3)		(0.1)	(0.0)	(0.2)	0.0	26.1	(0.0)	0.9
RATE 135	- SYSTEM SALES	8.1	(6.1)	0.0	(0.0)	0.0	0.0	0.0	14.0	(0.0)	0.1
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	205.0			(0.3)	0.0	0.0	0.0	203.3	(0.0)	2.0
	- WBT	75.6	(56.9)		(0.2)	0.0	0.0	0.0	131.3	(0.0)	1.3
RATE 145	- SYSTEM SALES	(93.4)	(59.9)	0.0	(0.2)	(2.2)	0.0	0.0	(33.4)	(0.0)	2.3
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(186.0)			(1.1)	(12.2)	0.0	0.0	(185.6)	(0.0)	12.9
	- WBT	(94.3)	(60.5)		(0.2)	(2.2)	0.0	0.0	(33.8)	(0.0)	2.3
RATE 170	- SYSTEM SALES	(150.9)	(127.0)	0.0	(0.4)	(4.2)	0.0	0.0	(21.0)	(0.0)	1.6
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(211.8)			(3.6)	(37.1)	0.0	0.0	(185.6)	(0.0)	14.6
	- WBT	(120.3)	(101.2)		(0.3)	(3.3)	0.0	0.0	(16.7)	(0.0)	1.3
RATE 200	- SYSTEM SALES	(409.4)	(387.3)	0.0	(1.2)	(19.5)	(18.1)	0.0	5.7	(0.0)	11.1
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(6.5)			(0.4)	(5.8)	(5.4)	0.0	1.7	(0.0)	3.3
	- WBT	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbundled Services:											
RATE 125		88.0	0.0	0.0	0.0	0.0	0.0	0.0	21.2	0.0	66.8
RATE 300		4.2	0.0	0.0	0.0	0.0	0.0	0.0	1.4	0.0	2.8
		(2,921.4)	(22,597.3)	0.0	(101.1)	(1,597.3)	(2,499.1)	0.0	16,467.8	(75.0)	7,480.6

UNIT RATE AND TYPE OF SERVICE

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10	COL. 11
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DISTRIBUTION REV REQ (DRR)	DIRECT	NUMBER OF CUSTOMERS	RATE BASE	NUMBER OF CUSTOMERS
		(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	($000/user)
Bundled Services:												
RATE 1	- SYSTEM SALES	(0.0073)	(0.2722)	0.0000	(0.0009)	(0.0159)	(0.0296)	0.0000	0.2043	(0.0014)	0.1084	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.2649			(0.0009)	(0.0159)	(0.0296)	0.0000	0.2043	(0.0014)	0.1084	0.0000
	- WESTERN T-SERVICE	(0.0073)	(0.2722)		(0.0009)	(0.0159)	(0.0296)	0.0000	0.2043	(0.0014)	0.1084	0.0000
RATE 6	- SYSTEM SALES	(0.1347)	(0.2722)	0.0000	(0.0009)	(0.0155)	(0.0217)	0.0000	0.1320	(0.0001)	0.0437	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.1375			(0.0009)	(0.0155)	(0.0217)	0.0000	0.1320	(0.0001)	0.0437	0.0000
	- WESTERN T-SERVICE	(0.1347)	(0.2722)		(0.0009)	(0.0155)	(0.0217)	0.0000	0.1320	(0.0001)	0.0437	0.0000
RATE 9	- SYSTEM SALES	0.2207	(0.2722)	0.0000	(0.0009)	(0.0000)	0.0000	0.0000	0.0796	(0.0000)	0.4142	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.4929			(0.0009)	(0.0000)	0.0000	0.0000	0.0796	(0.0000)	0.4142	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 100	- SYSTEM SALES	(0.2552)	(0.2722)	0.0000	(0.0009)	(0.0040)	(0.0217)	0.0000	0.0000	(0.0000)	0.0437	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0170			(0.0009)	(0.0040)	(0.0217)	0.0000	0.0000	(0.0000)	0.0437	0.0000
	- WESTERN T-SERVICE	(0.2552)	(0.2722)		(0.0009)	(0.0040)	(0.0217)	0.0000	0.0000	(0.0000)	0.0437	0.0000
RATE 110	- SYSTEM SALES	(0.3588)	(0.2722)	0.0000	(0.0009)	(0.0032)	(0.0038)	0.0000	(0.0909)	(0.0000)	0.0122	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0866)			(0.0009)	(0.0032)	(0.0038)	0.0000	(0.0909)	(0.0000)	0.0122	0.0000
	- WESTERN T-SERVICE	(0.3588)	(0.2722)		(0.0009)	(0.0032)	(0.0038)	0.0000	(0.0909)	(0.0000)	0.0122	0.0000
RATE 115	- SYSTEM SALES	(0.0920)	(0.2722)	0.0000	(0.0009)	(0.0000)	(0.0014)	0.0000	0.1767	(0.0000)	0.0058	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.1802			(0.0009)	(0.0000)	(0.0014)	0.0000	0.1767	(0.0000)	0.0058	0.0000
	- WESTERN T-SERVICE	(0.0920)	(0.2722)		(0.0009)	(0.0000)	(0.0014)	0.0000	0.1767	(0.0000)	0.0058	0.0000
RATE 135	- SYSTEM SALES	0.3618	(0.2722)	0.0000	(0.0009)	0.0000	0.0000	0.0000	0.6286	(0.0000)	0.0062	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.6340			(0.0009)	0.0000	0.0000	0.0000	0.6286	(0.0000)	0.0062	0.0000
	- WESTERN T-SERVICE	0.3618	(0.2722)		(0.0009)	0.0000	0.0000	0.0000	0.6286	(0.0000)	0.0062	0.0000
RATE 145	- SYSTEM SALES	(0.4243)	(0.2722)	0.0000	(0.0009)	(0.0099)	0.0000	0.0000	(0.1519)	(0.0000)	0.0105	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.1522)			(0.0009)	(0.0099)	0.0000	0.0000	(0.1519)	(0.0000)	0.0105	0.0000
	- WESTERN T-SERVICE	(0.4243)	(0.2722)		(0.0009)	(0.0099)	0.0000	0.0000	(0.1519)	(0.0000)	0.0105	0.0000
RATE 170	- SYSTEM SALES	(0.3234)	(0.2722)	0.0000	(0.0009)	(0.0090)	0.0000	0.0000	(0.0449)	(0.0000)	0.0035	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0513)			(0.0009)	(0.0090)	0.0000	0.0000	(0.0449)	(0.0000)	0.0035	0.0000
	- WESTERN T-SERVICE	(0.3234)	(0.2722)		(0.0009)	(0.0090)	0.0000	0.0000	(0.0449)	(0.0000)	0.0035	0.0000
RATE 200	- SYSTEM SALES	(0.2877)	(0.2722)	0.0000	(0.0009)	(0.0137)	(0.0128)	0.0000	0.0040	(0.0000)	0.0078	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0156)			(0.0009)	(0.0137)	(0.0128)	0.0000	0.0040	(0.0000)	0.0078	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unbundled Services:												
RATE 125	- All	0.8988	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2169	0.0000	0.6820	0.0000
	- Customer-specific **											0.0000
RATE 300	- All	23.2026	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	7.8739	0.0000	15.3287	0.0000
	- Customer-specific **											

Notes:
* Unit Rates derived based on 2013 actual volumes

Enbridge Gas Distribution Inc.
2013 Deferral and Variance Account Clearing
Bill Adjustment in January 2015 for Typical Customers

Item No.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Unit Rates			Bill Adjustment		
	GENERAL SERVICE	Annual Volume m3	Sales cents/m3	Ontario TS cents/m3	Western TS cents/m3	Sales Customers $	Ontario TS Customers $	Western TS Customers $
1.1	**RATE 1 RESIDENTIAL**							
1.2	Heating & Water Heating	3,064	(0.0073)	0.2649	(0.0073)	(0.2)	8.1	(0.2)
2.1	**RATE 6 COMMERCIAL**							
2.2	General Use	43,285	(0.1347)	0.1375	(0.1347)	(58)	59	(58)
	CONTRACT SERVICE							
3.1	**RATE 100**							
3.2	Industrial - small size	339,188	(0.2552)	0.0170	(0.2552)	(865)	58	(865)
4.1	**RATE 110**							
4.2	Industrial - small size, 50% LF	598,568	(0.3588)	(0.0866)	(0.3588)	(2,148)	(518)	(2,148)
4.5	Industrial - avg. size, 75% LF	9,976,120	(0.3588)	(0.0866)	(0.3588)	(35,792)	(8,640)	(35,792)
5.1	**RATE 115**							
5.2	Industrial - small size, 80% LF	4,471,609	(0.0920)	0.1802	(0.0920)	(4,114)	8,056	(4,114)
6.1	**RATE 135**							
6.2	Industrial - Seasonal Firm	598,567	0.3618	0.6340	0.3618	2,166	3,795	2,166
7.1	**RATE 145**							
7.2	Commercial - avg. size	598,568	(0.4243)	(0.1522)	(0.4243)	(2,540)	(911)	(2,540)
8.1	**RATE 170**							
8.2	Industrial - avg. size, 75% LF	9,976,120	(0.3234)	(0.0513)	(0.3234)	(32,268)	(5,116)	(32,268)

Notes:
Col. 6 = Col. 2 x Col. 3
Col. 7 = Col. 2 x Col. 4
Col. 8 = Col. 2 x Col. 5

ENERGY PROBE INTERROGATORY #6

INTERROGATORY

Ref: Exhibit C, Tab 1, Schedule 1

a) Please explain why a DRR allocator was not produced.

b) Are both the TIACDA and PTUVA related to labour costs with O&M costs?

c) How was the forecast amount included in rates ($42.8 million) for forecast pension and post-employment benefit expenses allocated to rate classes?

d) Please provide a table that shows, by rate class, the difference in the PTUVA amount allocated based on the proposed rate base methodology and the response to part (c) above.

e) What is the most comprehensive representation of the distribution of O&M costs to each rate class that is available for 2013?

f) Please provide a table that shows, by rate class, the difference in the TIACDA amount allocated based on the proposed rate base methodology and the response to part (e) above.

RESPONSE

a) A Distribution Revenue Requirement ("DRR") allocator was not produced as part of the 2013 evidence because it was a Cost of Service application rather than an Incentive Regulation ("IR") application.

During the IR period from 2008 to 2012, the Company's IR formula produced a DRR, which was then used in Cost Allocation and Rate Design. Under IR, the Company did not produce detailed schedules for forecast Rate Base and O&M.

In the 2013 Cost-of-Service filing, once again detailed forecasts were used to produce a revenue requirement as a starting point for Cost Allocation and Rate Design.

For comparison, the following chart shows the allocation percentages for the Rate Base allocator and DRR allocator for the last three years in which both factors were produced. Note that both sets of percentages are very similar given they are both a function of similar sets of cost drivers, such as the number of customers and peak demand.

	2012[1]		2011[2]		2010[3]	
	DRR	**RB**	**DRR**	**RB**	**DRR**	**RB**
Rate 1	67.8%	68.2%	68.0%	68.1%	67.8%	67.8%
Rate 6	28.7%	28.4%	28.1%	28.7%	28.2%	28.7%
Rate 9	0.0%	0.1%	0.0%	0.0%	0.1%	0.1%
Rate 100	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%
Rate 110	1.0%	0.9%	1.0%	0.8%	1.1%	1.0%
Rate 115	0.4%	0.5%	0.6%	0.4%	0.5%	0.4%
Rate 125	1.0%	0.9%	0.7%	0.7%	0.8%	0.7%
Rate 135	0.1%	0.1%	0.1%	0.0%	0.1%	0.0%
Rate 145	0.3%	0.3%	0.6%	0.5%	0.6%	0.5%
Rate 170	0.3%	0.4%	0.5%	0.4%	0.5%	0.4%
Rate 200	0.3%	0.3%	0.3%	0.2%	0.3%	0.3%
Rate 300	0.0%	0.1%	0.0%	0.1%	0.0%	0.1%

1. EB-2011-0277
2. EB-2010-0146
3. EB-2009-0172

b) Yes. Both accounts relate to post-employment benefits which are an element of labour costs.

c) In the Fully Allocated Cost Study, pension and post-employment benefit expenses are treated as a part of Fringe Benefits and are functionalized based on the proportion of O&M costs forecast to support each operating function. O&M costs for each function are then classified and allocated based on their respective drivers (such as the number of customers or peak demand), with pension and post-employment benefit expenses embedded within.

   Accordingly, there is no one specific allocator for O&M, given that O&M expenditures support all facets of the Company's operations.

d) The requested table cannot be produced. Since there is no one specific allocator for O&M, it is not possible to allocate the Post-Retirement True-Up Variance Account ("PTUVA") amount using the process described in the response to part (c) above.

Witness: M. Kirk

As described in the response to part (c), the pension and post-employment benefit expenses are embedded within O&M for all functions of the Company's operations. As a result, the pension and post-employment benefit expenses are not allocated on one specific allocation factor. In other words, the allocation of pension and post-employment benefit expenses follows the allocation of O&M, which supports all facets of the Company's operations. This is why the Rate Base allocator, which also supports all facets of the Company's operations and whose allocation drivers are very similar to allocate O&M expense, was chosen as the most comprehensive representation of the distribution of costs to each rate class for both PTUVA and Transition Impact of Accounting Change Deferral Account ("TIACDA").

e) See above.

f) The requested table cannot be produced. As is the case with the allocation of PTUVA (described in part (d)), the allocation of TIACDA can also not be reproduced using the process described in part (c).

FRPO INTERROGATORY #1

INTERROGATORY

Reference: Exhibit B, Tab 3, Schedule 2, Table 1

Please provide the supporting calculations for the unit rates in column 10 including the supporting assumptions.

RESPONSE

As explained in Exhibit B, Tab 3, Schedule 2, Page 1, paragraph 4, the purpose of the Average Use True-up Variance Account ("AUTUVA") is to record the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer, for general service rates classes (Rate 1 and 6) embedded in the volume forecast that underpins Rates 1 and 6, and the actual weather normalized average use experienced during the year. Impacts due to changes in the cost of gas are accounted for through the Company's gas cost related variance/deferral accounts (i.e., PGVA, UAF). Gas costs are removed so the Company and ratepayers are kept whole when determining the AUTVA balance and no double counting of gas costs occurs.

The unit rates depicted in Column 10 of Exhibit B, Tab 3, Schedule 2, Table 1 represent the variable delivery unit rate (exclusive of gas costs). The use of this rate is necessary to determine the revenue impact, exclusive of gas costs. These unit rates when applied to the volume variance form the AUTVA balance to be either collected or refunded to ratepayers. In order to develop the variable delivery unit rate, adjustments must be made to the Rate 1 and 6 Board approved delivery rates to remove the impact of gas costs. As explained in the rate design evidence in EB-2012-0459, Exhibit H1, Tab 1, Schedule 1, page 5, Paragraph 12, storage and unaccounted for gas costs are recovered through the Company's delivery rates. The distribution costs are recovered primarily through the Company's delivery rates, however, some distribution related costs are recovered from the commodity and load balancing rates.

The Rate 1 and 6 blocked delivery rates have some gas costs related expenses such as Lost and Unaccounted for Gas and Union Storage costs. Conversely, some of the Company's operating expenses such as Bad Debt commodity, system gas administration and return on gas in inventory are recovered through the gas supply and load balancing charges.

Witnesses: J. Collier
C. Ho
A. Kacicnik

To determine the variable delivery unit rate, the Company takes the Total delivery revenues (fixed and variable) for the rate class and subtracts the gas costs recovered in the delivery charge and then adds back the rate classes allocated cost of operating expenses recovered in the gas supply and load balancing charges. This yields a total delivery revenue exclusive of gas costs.

To determine the variable delivery unit rate, the amount of fixed customer charge revenue is subtracted which results in the remaining delivery revenue to be recovered from the variable delivery unit rate. The variable delivery unit rate is determined by taking the variable delivery revenues divided by the forecast delivery volumes. The derivation of the Rate 1 and 6 unit rates (based on the EB-2011-0354 Rate Order) are depicted below.

	Rate 1	Rate 6
Total Delivery Revenues ($ Million)	753.1	334.6
Less: allocated gas cost related expenses in delivery charge ($ Million)	-67.3	-55.6
Add: allocated EGD expenses recover in other charges ($ Million)	12.0	11.0
Total Rate Class Delivery Only Revenues ($ Million)	697.8	290
Less: Revenue recovered from fixed customer charges ($ Million)	-447.9	-133.1
Total Variable Delivery Only Revenue ($ Million)	249.9	156.9
Divide: Delivery Volumes 106m3	4792.028	4764.874
Variable Delivery Unit Rates ($/m3)	0.0521	0.0329
(i.e. Unit rate of the Revenue Impacts Exclusive of Gas Costs)		

Witnesses: J. Collier
C. Ho
A. Kacicnik

FRPO INTERROGATORY #2

INTERROGATORY

Reference: Exhibit B, Tab 3, Schedule 2, Table 1

Please file the interrogatory responses of EGD in EB-2014-0039 and the EGD reply submission of March 25, 2014 in that same proceeding.

RESPONSE

For the reasons stated in response to FRPO Interrogatory #3 found at Exhibit I, Tab 4, Schedule 3, Enbridge does not believe this is the appropriate proceeding to address questions related to future gas supply planning. Enbridge believes that more appropriate forums to discuss forward-looking issues related to gas supply planning parameters are either the 2014 Natural Gas Review or as part of the annual stakeholder meetings that Enbridge has committed to hold in conjunction with the filing of its gas supply plan.

Witness: D. Small

FRPO INTERROGATORY #3

INTERROGATORY

Reference: EGD Reply Submission, March 25th, 2014, page 11

Preamble: The above reference includes the following sentences:

"As discussed above, the main difference between average unit costs incurred by Enbridge and Union occurred in the month of February. In order for Enbridge to have "layered" on its purchases, Enbridge would have been required to purchase additional volumes in January in order to maintain higher-than-target deliverability in February. Such an action would have been a significant deviation from the gas supply plan developed by Enbridge and approved by the Board and any such deviation would have meant attendant risks for Enbridge."

Please provide the specific aspects of the Enbridge Gas Supply Plan that EGD believed could not be varied due to Board approval and a reference to those specific approvals.

RESPONSE

As a part of its EB-2014-0195 application the Company has requested the clearance of the following Commodity Related Deferral accounts:

- 2013 Transactional Services D/A,
- 2013 Unaccounted for Gas V/A, and the
- 2013 Storage and Transportation D/A.

Because the question above is not relevant to any of these deferral accounts, Enbridge declines to answer it.

The Company believes a more appropriate forum for a discussion of generic forward-looking matters relating to gas supply planning would be the 2014 Natural Gas Market Review.

The Board in its Decision and Order in EB-2014-0199 (the QRAM process review proceeding), has provided such an opportunity stating: "This review [the 2014 Natural Gas Market Review] would include an examination of the underlying drivers of the

Witness: D. Small

QRAM, including the cost and risk trade-offs of different gas supply planning parameters."

There will also be opportunity for parties to review and understand Enbridge's future year gas supply plans, as part of the annual stakeholder processes that Enbridge has committed to undertake during the current IR term. Enbridge explained this within its submission on the Review of the Quarterly Rate Adjustment Mechanism Process dated June 24, 2014, stating that:

> Enbridge's gas supply plan would be subject to review in general rate proceedings, as well as the annual stakeholder meetings proposed by Enbridge. During each annual stakeholder meeting, there would be a forward-looking discussion of the next year's gas supply plan. This forward-looking discussion would include the decision-making criteria that would be applied to execute the plan under different scenarios, such as the timing and type of arrangements to be made in response to weather, demand or supply issues. Thus, stakeholders would be made aware of the steps that would be taken to execute the plan in various circumstances, including extreme circumstances such as those that prevailed during the winter of 2013/2014. Stakeholders would gain a general understanding, going into a particular year, of the effect of extreme weather on the execution of the gas supply plan during that year.

These opportunities will allow for further discussion and hopefully greater understanding on how Enbridge develops and executes its gas supply plan. They are more appropriate forums for this item to be addressed, as compared to this current 2013 deferral and variance account proceeding, which seeks only the clearance of 2013 specific accounts.

FRPO INTERROGATORY #4

INTERROGATORY

Reference: EGD Reply Submission, March 25th, 2014, page 11

Preamble: The above reference includes the following sentences:

"As discussed above, the main difference between average unit costs incurred by Enbridge and Union occurred in the month of February. In order for Enbridge to have "layered" on its purchases, Enbridge would have been required to purchase additional volumes in January in order to maintain higher-than-target deliverability in February. Such an action would have been a significant deviation from the gas supply plan developed by Enbridge and approved by the Board and any such deviation would have meant attendant risks for Enbridge."

Please provide a description with specific numeric values the "higher-than-target deliverability" in February.

RESPONSE

For the reasons stated in response to FRPO Interrogatory #3 found at Exhibit I, Tab 4, Schedule 3, Enbridge does not believe this is the appropriate proceeding for this question. Enbridge believes that more appropriate forums to discuss forward-looking issues related to gas supply planning parameters are either the 2014 Natural Gas Review or as part of the annual stakeholder meetings that Enbridge has committed to hold in conjunction with the filing of its gas supply plan.

Witness: D. Small

FRPO INTERROGATORY #5

INTERROGATORY

Reference: EGD Reply Submission, March 25th, 2014, page 12

Preamble: EGD states that gas supply personnel met on a weekly basis.

Please provide all internal minutes from these meetings and all correspondence (emails, etc.) that include the analysis of alternatives reviewed and actions taken as a result of colder than normal temperatures from the meetings of December to February.

RESPONSE

For the reasons stated in response to FRPO Interrogatory #3 found at Exhibit I, Tab 4, Schedule 3, Enbridge does not believe this is the appropriate proceeding for this question. Enbridge believes that more appropriate forums to discuss issues related to gas supply planning parameters are either the 2014 Natural Gas Review or as part of the annual stakeholder meetings that Enbridge has committed to hold in conjunction with the filing of its gas supply plan. As a part of those forward looking discussions there will be an opportunity to discuss the decision making criteria under different scenarios such as the timing and type of arrangements to be made in response to weather, demand or supply issues.

Witness: D. Small

FRPO INTERROGATORY #6

INTERROGATORY

Reference: EGD Reply Submission, March 25th, 2014, page 12

Preamble: EGD states that gas supply personnel met on a weekly basis.

Please provide the specifics of the gas supply plan for December to February that showed gas supply to be received for each month by source including expectations of unutilized transport.

a) Please provide specific information that was used to draw the conclusion that the deficit in storage plan could be eliminated in the subsequent period by utilizing the full transport contracted.

b) Please provide the daily prices for the forward prompt month at Dawn throughout the months of December to February.

c) Please provide the daily price at Dawn from December to February.

d) For the gas brought in by peaking service, please provide the nature of the contract(s) including demand charges, notice, delivery point, etc.

RESPONSE

For the reasons stated in response to FRPO Interrogatory #3 found at Exhibit I, Tab 4, Schedule 3, Enbridge does not believe this is the appropriate proceeding for this question. Enbridge believes that more appropriate forums to discuss issues related to gas supply planning parameters are either the 2014 Natural Gas Review or as part of the annual stakeholder meetings that Enbridge has committed to hold in conjunction with the filing of its gas supply plan.

Witness: D. Small

FRPO INTERROGATORY #7

INTERROGATORY

Reference: Exhibit I, Tab 1, Schedule 1, Attachment 1 and EB-2012-0459 Exhibit K8.2

Preamble: In response to Board staff inquiry, Enbridge prepared Attachment 1 and stated in their response:

"The attached table provides a breakdown of the effect of higher prices for Enbridge's planned or budgeted purchases as well as the effect higher prices had on the incremental purchases required to meet the increased demand."

We would like to understand another view of last winter. In Exhibit K8.2, Enbridge provided the targeted and actual levels for storage at the end of each month starting with November. The Exhibit has been updated subsequently to include March.

For the entire period of November to March and using the format provided in Attachment 1, between columns 8 and 9, please add additional columns for Target Volume showing the Budget and Actual price consistent with the monthly actual price for delivered supply for that month in the table (column 7) and the resulting variance for those volumes. Target Volume would be defined as the volume needed to be purchased (or not purchased in later winter months as a result of earlier purchases) to meet the Targeted Volume in storage per Exhibit K8.2. For greater clarify, the intent is to show a hypothetical case of buying delivered supply throughout the winter to meet the targeted level of storage at month end throughout the winter.

a) Please ensure to include subtotals similar to rows 3.5 and 3.6 and a grand total for the winter.

RESPONSE

For the reasons stated in response to FRPO Interrogatory #3 found at Exhibit I, Tab 4, Schedule 3, Enbridge does not believe this is the appropriate proceeding for this question. Enbridge believes that more appropriate forums to discuss issues related to gas supply planning parameters are either the 2014 Natural Gas Review or as part of the annual stakeholder meetings that Enbridge has committed to hold in conjunction with the filing of its gas supply plan.

Witness: D. Small

VECC INTERROGATORY #1

INTERROGATORY

Reference: Exhibit B/T2/S1/Attachment/TSDA Details

Pre-amble: VECC notes that Energy Probe (interrogatory #1) has requested that Enbridge Gas Distribution (EGD) update the deferral and variance accounts to reflect the revised proposal for January 1st, 2015 clearance. The following question is based on current filing and a response is not be required if the revised filing/request shows no difference.

a) Please reconcile the TSDA balances shown at Exhibit B, Tab 2 ($24,065.2) with the amounts shown in Exhibit B, Tab 1 ($24,028.2).

RESPONSE

The balance shown at Exhibit B, Tab 2 ($24,065.2) is correct. Exhibit B, Tab 1 will be updated.

Witness: D. Small

VECC INTERROGATORY #2

INTERROGATORY

Reference: Exhibit B/T2/S2/pg.3

a) Were any damage claims collected from parties, or might be expected to be collected, with respect to the two significant damages in Ottawa and Markham? If yes please provide details and show any offset to UAF.

RESPONSE

Please refer to the response to CME Interrogatory #2 found at Exhibit I, Tab 2, Schedule 2.

Witness: C. Ho

VECC INTERROGATORY #3

INTERROGATORY

Reference: Exhibit B/T3/S3

a) Please explain the difference between the 2012 GDARCDA Cost/Redetermined Value of 253.9 ('000) shown in EB-2013-0046 (Exhibit C/T1/S2/pg.5) and the amount of 260.1 shown at Exhibit B/T3/S3/pg.4 of this filing. Are there expected to be further additional capital costs for this project?

RESPONSE

The Cost or redetermined value of $253.9 thousand shown at Exhibit C, Tab 1, Schedule 2, page 5, Line 1 within EB-2013-0046, represents the 2012 gross plant average of monthly averages balance related to capital incurred to implement Gas Distribution Access Rule ("GDAR") amendments for Customer Service Rule ("CSR") changes which became effective within 2012. By comparison, the Cost or redetermined value of $260.1 thousand shown at Exhibit B, Tab 3, Schedule 3, page 4, Line 1 within this filing, represents the 2013 gross plant average of monthly averages balance related to capital incurred to implement GDAR amendments for Low Income Customer Service Rule ("LICSR") changes which became effective within 2013. The 2013 Cost or redetermined value does not include the amounts incurred to implement the CSR changes.

The Company's 2013 revenue requirement, approved in EB-2011-0354, included forecast impacts (including rate base impacts) related to CSR changes, and as such no incremental 2013 revenue requirement needs to be recovered through the 2013 Gas Distribution Access Rule Costs Deferral Accounts ("GDARCDA"). In addition, with 2013 approved revenue requirement inputs serving as the base for the 2014 to 2018 customized incentive regulation ("CIR") allowed revenue forecasts, no incremental CSR impacts will be requested during the CIR term. However, as indicated in paragraphs 3 to 5 of Exhibit B, Tab 3, Schedule 3, in this proceeding, forecast impacts of LICSR changes, which became effective in 2013, were not able to be incorporated into the 2013 revenue requirement approved in EB-2011-0354, nor are they reflected in the forecast 2014 to 2018 CIR allowed revenues approved in EB-2012-0459. Therefore, revenue requirements resulting from LICSR capital spending will be requested for recovery within the 2013 GDARCDA, as well as the 2014 to 2018 GDARCDA's.

At this time, the Company is not expecting any further capital spending on this project, and is not aware of any further GDAR amendments.

Witness: R. Small