ENBRIDGE

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June 9, 2009

VIA RESS, COURIER and EMAIL

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. ("Enbridge")
2008 Earnings Sharing Mechanism and Other Deferral
And Variance Accounts Clearance Review
Ontario Energy Board ("Board") File No. EB-2009-0055

Further to Enbridge's letter of May 26, 2009 and as directed in Procedural Order No. 1 of May 20, 2009, enclosed please find Enbridge's interrogatory responses as follows:

Exhibit I, Tab 1, Schedules 1 to 5;
Exhibit I, Tab 3, Schedules 1 to 4;
Exhibit I, Tab 4, Schedules 1 and 2;
Exhibit I, Tab 5, Schedules 1 to 3;
Exhibit I, Tab 6, Schedules 1 to 9; and
Exhibit I, Tab 7, Schedules 1 to 3.

Two paper copies and one electronic copy via email and through the RESS are being filed with the Board today.

This evidence will be available on Enbridge's website @ www.enbridge.com/ratecase as of Wednesday, June 10, 2009.

Yours truly,

L. Chiasson

Lorraine Chiasson
Regulatory Coordinator

cc: Mr. F. Cass, Aird & Berlis LLP
All Interested Parties EB-2009-0055 (via email)

BOARD STAFF INTERROGATORY #1

INTERROGATORY

Clearance Balances – Implementation Plan

Ref: ExA/T2/S1/page 2

The original Application requested the clearances to coincide with the July 2009 QRAM (the update provided on May 26, 2009 cites the October 2009 QRAM). In relation to implementation with the October 2009 QRAM:

- Enbridge notes a "one-time" bill adjustment (A/3/1) but refers to two months of billing adjustments in July and August (C/2/2). Please clarify whether the billing adjustment is one month or two and to which months it would apply.

- How does Enbridge calculate the interest amounts for clearance? What date is assumed for interest amounts - e.g. October 31, 2009?

- Please identify any issues that the Board should be aware of in terms of the revised timing and rate implementation associated with this order.

RESPONSE

- Given the timeline of this proceeding and as shown in updated evidence Exhibit C, Tab 1, Schedule 1, Enbridge is now requesting clearance of the deferral accounts to coincide with the October 1, 2009 QRAM. As such, the Company now proposes to clear the balances to customers in two equal installments during the October and November 2009 billing cycles (the original evidence at Exhibit C-2-1 proposed to clear balances over July and August months in association with the originally proposed July 1, one time clearance). While the Company proposes to clear the balances in two equal installments, the term "one-time" bill adjustment was used to signify the fact that the clearance adjustment is a definitive one-time amount to be collected/refunded.

- Monthly interest amounts are calculated by multiplying opening monthly principal balances by the Board prescribed interest rate. The interest amounts shown in updated schedules Exhibit A, Tab 2, Schedule 1, Appendix A and Exhibit C, Tab 1, Schedule 1 includes interest calculated through September 30, 2009. If the Board

Witness: K. Culbert

approves Enbridge's proposal to clear the deferral and variance account balances in two installments, interest would need to be calculated for October 2009 as well. However, in this instance the Company would propose to calculate interest on half (50%) of the October 1, 2009 principal balances in recognition of the fact the 50% would be cleared during October 2009.

- A Board Decision or Order is required by approximately August 15, 2009 in order to achieve clearance commencing October 1, 2009. The Company is planning and requesting the clearance of the deferral and variance account balances within the Company's October 1, 2009 QRAM application, a request which is dependent upon the successful implementation of the new CIS system currently scheduled for August/September, 2009.

BOARD STAFF INTERROGATORY #2

INTERROGATORY

Earnings Sharing Amount

Ref: ExB/T1/S1/page 1

Please provide the calculation details underpinning the ROE established for 2008 for which the earnings sharing formula applies. Please provide the reference to the proceeding in which the Board approved the ROE for use in earnings sharing. Will the Board need to establish an updated ROE for use in 2010 earnings sharing? If so, when should the Board do this?

RESPONSE

In the EB-2007-0615 Revised Settlement Agreement (dated February 4, 2008 and approved by the Board on February 11, 2008), at issue 10.1(i), it was established that, the ROE calculated annually by the application of the Board's ROE formula, plus 100 basis points, would be the benchmark to which EGD's actual weather normalized ROE would be compared for the purposes of calculating earnings sharing in each year of the IR plan. The calculation details underpinning the 2008 ROE of 8.66%, established using the Board's ROE formula, were filed in EB-2008-0219 (EGD's 2009 rate proceeding) at Exhibit E, Tab 4, Schedule 1, page 1, and is reproduced below.

Table 1
Determination of ROE for 2008

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*
Yield on 10s 3 Months Out[a]	Yield 10s 12 Months Out[a]	Average 10s Yield	Average Spread (30s-10s)[b]	Long Bond Forecast	Difference in Long Bond Forecast	0.75xDifference (Rounded to 2 Decimal Places)	ROE (%)
		(Col. 1+Col. 2)/2		Col. 3+Col. 4	Col. 5-4.24	0.75xCol. 6	8.39+Col. 7
4.40	4.70	4.55	0.06	4.61	0.37	0.27	8.66

Notes:
2007 ROE: 8.39
2007 Long Canada Forecast: 4.24
[a] From Consensus Forecasts October 8, 2007
[b] From Financial Post

Witness: K. Culbert

The calculation details underpinning a 2009 ROE value of 8.31%, established using the Board's ROE formula, and to be used in 2009 earnings sharing calculations, were also filed in EB-2008-0219 at Exhibit E, Tab 4, Schedule 1, Appendix A.

An updated ROE will need to be established, using the Boards formula, for use in 2010 earnings sharing calculations. Data is not currently available for that calculation which will be filed in a future proceeding, such as EGD's 2010 rate proceeding.

Witness: K. Culbert

BOARD STAFF INTERROGATORY #3

INTERROGATORY

Transactional Services

Ref: ExB/T3/S1/ page 3 and 4

Please explain the composition of the TS and TSDA amounts and the basis for the adjustment to utility revenue. In terms of the treatment of TS revenues, please provide the reference for the Board proceeding where this was decided.

RESPONSE

The table below provides a breakdown of the Transactional Services Revenue for 2008 and also provides the calculation underpinning the amount in the 2008 TSDA.

As per the NGEIR Decision with Reasons (EB-2005-0551) net transportation related transactional services revenue would continue to be shared on a 75:25 percentage basis between the Company's ratepayers and shareholders and net storage related transactional services revenues would be shared 90:10 between ratepayer and shareholder.

In EGD's 2007 Test Year proceeding (EB-2006-0034) it was agreed that the purpose of the 2007 TSDA would be to record the ratepayer portion of the net transactional services revenue in excess of the $8.0 million guaranteed in rates. As a result, the residual amount contained in the TS revenue account is comprised of the ratepayer's $8.0 million guaranteed in rates and the Company's/shareholder's incentive. Therefore, the Company's incentive must be eliminated from utility results. This TS methodology was carried over into EGD's incentive regulation plan approved in EB-2007-0615. The description of the 2008 TSDA contained in Appendix E of the Decision and Rate Order confirms this treatment of TS revenues. The elimination of Company/shareholder incentives from utility results is consistent with past regulatory accounting practice. The approved settlement agreement in EB-2007-0615, at Issue 10.1 Earnings Sharing Mechanism, also confirms this practice by stating:

> The parties acknowledge that the following shareholder incentives and other amounts are outside the ambit of the ESM: (ii) amounts related to storage and transportation related deferral accounts; …

Witness: D. Small

	Storage Optimization	Transportation Optimization	Total Revenue
	$(000's)	$(000's)	$(000's)
Net Revenue	8,589.1	8,994.4	17,583.5
Rate Payer Share - %	90%	75%	
Rate Payer Share - $(000's)	7,730.2	6,745.8	14,476.0
Amount Included in Rates			(8,000.0)
Amount Transferred to TSDA			6,476.0
Utility Revenue (EB-2009-0055 Exhibit B, Tab 3, Schedule 1, page 3 of 4, Line11)			11,107.5
Transactional Services Elimination - EGD Incentive (EB-2009-0055 Exhibit B, Tab 3, Schedule 1, page 4 of 4)			3,107.5

BOARD STAFF INTERROGATORY #4

INTERROGATORY

Weather Normalization

Ref: ExB / T4 / S1 / page 2

Please provide a brief description of the methodology underpinning the weather normalization calculation.

RESPONSE

The weather normalization methodology embraced by the Company has been approved by the Board and utilized for more than ten years. A brief description of the methodology underpinning the weather normalization calculation is explained below.

Weather normalization is a process which isolates the impact of weather on volumes by segregating the actual volumes between heating sensitive and non-heating sensitive portions. Then, weather normalization adjustments are determined by adjusting the actual heating sensitive portion of volumes associated with actual degree days that would have been had the Company achieved the forecasted degree days that underpin the Company's test year volume budget. The degree days forecast is either based on the Board Approved methodology or Settlement Agreement number.

A detailed description of the methodology was also discussed at EB-2008-0219, Exhibit B, Tab 1, Schedule 5, pages 33 to 36 (attached).

Witness: I. Chan

48. This positive volumetric variance was attributable to favourable residential average use variances of 66.2 10^6m^3 in the presence of lower actual gas prices than forecast resulting from the lack of significant hurricane activity in the Gulf of Mexico during 2007 in contrast to previous years and favourable general service customer variance of 4.5 10^6m^3, partially offset by contract market customer losses relating to either plant closures or consolidation (i.e., relocation outside the franchise area) of 22.9 10^6m^3, unfavourable usage variances largely driven by two large auto customers of 25.8 10^6m^3 and large pulp and paper customers of 19.9 10^6m^3 for the same reasons explained in previous sections. Further rate class detail is provided at Appendix A, pages 22 to 24.

Weather Normalization Methodology

49. The weather normalization methodology embraced by the Company has been approved by the Board and utilized for more than ten years. Consistent with the previous rate case, this section explains the Board approved normalization methodology of normalizing actual consumption for each of the general service rate classes and uses an example to describe how the normalization is done.

50. General Service normalization is conducted on customers at a group level. The Company's General Service customers are grouped together into homogenous classes of gas usage within the six regions of the Company's franchise area. Only the heat sensitive portion of consumption is normalized for heat sensitive or balance point degree days. Further explanation of the balance point degree days is explained later. An example of the methodology is illustrated below.

51. Firstly, the total load per customer of a customer group is calculated by dividing the group's consumption by the total customers within this group. Then, baseload per

customer is calculated by taking an average of the two non-weather sensitive summer months' total load. Baseload represents non-weather sensitive load, such as, water heating, other non-heating uses. Thereafter, heatload per customer is calculated by subtracting the baseload per customer from the total load per customer. This heatload represents the heat sensitive portion of consumption. By dividing the heatload per customer by Actual Heating Degree Days, an Actual Use per Degree Day is generated. The Actual Use per Degree Day is then adjusted to reflect normal weather by multiplying the Budget Heating Degree Days. Consequently, total normalized average use per customer is defined as an aggregate sum of baseload use per customer and normalized heatload per customer.

52. In the EBRO 465 Decision with Reasons, paragraph 3.1.16 states that the Board accepted the Company's weather normalization methodology and directed the Company to further investigate methods to more effectively segregate its weather sensitive and non-weather sensitive loads. A more effective segregation of load and an enhanced weather normalization methodology that included changing summer base load definition to the average of July and August consumption, performing calculations using new base load/heating load split and include September as a heating load month, was proposed in EBRO 473 and the Board accepted this change in methodology.

53. In EBRO 487, the Company proposed to change from the traditional 18^{O}C balance point temperature assumption to a new temperature for purposes of normalizing average general service customer uses. The reason was that results from load research indicated that this 18^{O}C balance point assumption was not valid due to technological and building standard environment. The basic conclusion of the

research was that an average balance point value for Central, Niagara, and Eastern weather zones are 14.8^{O}C, 15.3^{O}C and 14.6^{O}C, respectively. That means the new normalization approach only normalizes heating load in the Central weather zone if the temperature falls below 14.8^{O}C.

54. In addition, this proposed new normalizing technique has been very beneficial in reducing the volatility in residential normalized average use for the shoulder months of November and April and, to a lesser extent, October and May. Shoulder months have been important in the overall consideration of average use trends. Unnormalized average uses in the months leading into the winter period and out of the winter period can fluctuate significantly depending on the length of a seasonably warm or cold cycle.

55. As stated in the Decision with Reasons, the Board found the Company's proposals to implement an improved model for heating load analysis when estimating volumetric forecasts was reasonable and acceptable. All intervenors accepted the Company's proposals during the settlement process. They all felt that the proposed changes were a significant improvement over the balance point traditionally used at 18^{o}C or 65 ^{o}F.

56. For contract market customers who consume more than 340,000 m^3 annually, a similar process is followed to determine the actual baseload for each contract. Actual heating load is obtained by removing the baseload and the process load from the total consumption, which is then adjusted to reflect normal weather. The actual volumes are also adjusted, where necessary, to the budgeted level of curtailment. For example, a large volume customer with interruptible contract may be required to

reduce or to completely eliminate or curtail the use of gas to balance the Company's gas supply and demand requirements under extreme or peak weathers. Therefore, the actual volumes used by customers would have been lower than budgeted and must be increased to the normal level assumed in the budget.

BOARD STAFF INTERROGATORY #5

INTERROGATORY

Purchased Gas Variance Account

Ref: ExC/T2/S2/page 2

This schedule shows the seven (7) elements that constitute the 2008 PGVA principle for clearance of $23.1354 million. Please provide a written explanation with supporting back-up, including working papers and schedules where appropriate, to provide additional detail as to the build-up of the elements which make up the amount proposed for clearance.

RESPONSE

With each QRAM application EGD provides a schedule setting out a forecast of the projected year-end PGVA balance. The projection includes actual purchase costs to date and a forecast of purchase costs for the remainder of the year versus the applicable Reference Price, the impact of the Reference Price change on the System Supply inventory volume, as well as, a forecast of any Rider C collections/refunds.

For the purposes of the QRAM applications the variances associated with EGD’s purchase costs are deemed to be all commodity related.

The projected year-end PGVA schedule provided as part of the QRAM application does not contemplate or include items such as the impact of TCPL toll changes on the delivery of Direct Purchase volumes, the impact of such toll changes on inventory relating to BGA balances, LBA Charges, Curtailment Non-Compliance Penalties, and Supply UOG penalties. These elements are typically cleared to system and direct purchase customers through the year end clearing of the PGVA administered as one time adjustment on customers’ bills.

At year-end once the final audited balance is known a detailed analysis of all the components of the PGVA is conducted. The year end balance includes the elements listed above which are not included in the QRAM forecasts of PGVA balance and the final balances for the elements which were included, but at a forecasted level in the QRAMs. The underlining principle is that any variances between actual and forecasted acquisition costs are captured in the PGVA and are then collected/refunded to customers. In recent history this process has resulted in both credits amounts; 2002 ($41.7 million), 2003 ($15.1 million), 2005 ($6.5 million) and debit amounts; 2004 $24.7 million, 2006 $17.6 million, 2007 $7.6 million.

Column 1 of Table A) provides a breakdown of the projected 2008 year-end PGVA balance used in the January 2009 QRAM application (EB-2008-0348 Exhibit Q1-3, Tab 1, Schedule 2, p. 3) which was prepared November 17, 2008. This amount was rolled over into the opening balance in the 2009 PGVA.

Column 2 shows the breakdown of the 2008 Final PGVA Balance. Column 3 shows the amount which EGD is required to clear as a one time adjustment to customers' bills.

Table A)
PGVA True Up Breakdown

	Col. 1	Col. 2	Col. 3
PGVA:	**Projected Principal**	**Final Balance**	**Variance to be Cleared**
COMMODITY	(175,602,847)	(207,036,147)	(31,433,300)
SEASONAL PEAKING-LOAD BALANCING	0	3,111,115	3,111,115
SEASONAL DISCRETIONARY-LOAD BALANCING	0	(3,498,044)	(3,498,044)
TRANSPORTATION TOLLS	0	34,618,775	34,618,775
CURTAILMENT REVENUE	0	(824,752)	(824,752)
RIDER C 2008 DIRECT ALLOCATION	72,747,971	54,879,930	(17,868,041)
INVENTORY ADJUSTMENT	(8,898,215)	30,131,415	39,029,630
TOTAL PGVA	$ (111,753,091)	$ (88,617,707)	$ 23,135,383

The 2008 Final clearance amount of $23.1M is primarily driven by the transportation tolls variance, partially offset by variances related to commodity, storage revaluation and Rider C. These items include differences between forecasted purchase volumes at forecasted prices versus actual volumes at actual prices and the derivation of Rider C unit rates based on forecast consumption versus the collection/refund of Rider C amounts on actual consumption.

As discussed at the March 30, 2008 stakeholder meeting TCPL toll changes, the primary driver of the true up, impact (among other elements) BGA inventory revaluation and Direct Purchase delivery volumes. The impact of toll changes relating to theses elements is provided in Tables B), C) and D) below. The total of tables C & D, in the amount of $32.9 million shows the majority of the make up of the transportation toll amount shown in Table A.

Table B)
Actual vs. Effective Transportation Costs

	Actual TCPL Tolls	Transportation Costs embedded in rates	Unit Rate Variance
	$/10*3 m*3	$/10*3 m*3	$/10*3 m*3
Dec-07		38.833	
Jan-08	41.082	36.049	5.033
Feb-08	41.082	36.049	5.033
Mar-08	41.082	36.049	5.033
Apr-08	49.374	37.627	11.747
May-08	49.374	37.627	11.747
Jun-08	52.766	37.627	15.139
Jul-08	52.766	46.675	6.091
Aug-08	52.766	46.675	6.091
Sep-08	52.766	46.675	6.091
Oct-08	52.766	49.187	3.579
Nov-08	52.766	49.187	3.579
Dec-08	52.766	49.187	3.579

Table C)
Inventory Revaluation

	Volume	Unit Rate Change	
	10*3 m*3	$/10*3 m*3	$(000's)
1-Jan-08	657,185.9	2.784	1,829.6
1-Apr-08	(492,572.3)	(1.578)	777.3
1-Jul-08	(255,301.9)	(9.048)	2,310.0
1-Oct-08	577,361.7	(2.512)	(1,450.3)
Sub-total			3,466.5

Table D)
Impact of Unit Rate Variance, Table B)
applied to Direct Purchase delivery volumes

	10*3 m*3	$/10*3 m*3	
January	381,207.8	5.033	1,918.7
February	356,131.9	5.033	1,792.4
March	380,949.4	5.033	1,917.4
April	363,624.2	11.747	4,271.5
May	364,851.1	11.747	4,285.9
June	352,471.6	15.139	5,335.9
July	353,179.6	6.091	2,151.1
August	338,950.8	6.091	2,064.4
September	337,858.8	6.091	2,057.8
October	341,643.2	3.579	1,222.6
November	330,467.1	3.579	1,182.6
December	352,256.1	3.579	1,260.6
Sub-total			29,460.8
Total Impact on PGVA Balance			32,927.3

The other elements within the PGVA are not as easily identifiable and require more detailed and extensive calculations. Throughout the year the actual purchase costs are referenced against the PGVA price thereby creating the dollar value to be booked to the PGVA. Under the current methodology for PGVA disposition, the Company disaggregates its PGVA entries by major type of purchase i.e., Empress Supplies, Nova Supplies, Alliance Supplies, Chicago Supplies, Ontario Discretionary Supplies, and Peaking Supplies at year end to determine the dollars associated with the commodity, transportation, and load balancing elements. The purpose of this disaggregation is so that dollars within the PGVA can be allocated to the various rate classes based on the Board approved methodology including average demand and load balancing needs.

As mentioned previously for purposes of developing Rider C the projected balance in the PGVA is assumed to be all commodity related. Therefore, the first step would be to prepare a detailed breakdown of the balance as shown in Column 1 of Table A) into the seven elements identified in Table A). The next step is to follow the same process for the Final Balance in the PGVA as shown in Column 2 of Table A). Table E) below provides that breakdown. The need for this breakdown is to ensure the clearance of the PGVA balance in accordance with the Board approved Cost Allocation and Rate Design.

Table E)	**Col. 1**	**Col. 2**	**Col. 3**
PGVA:	**Projected Principal**	**Final Balance**	**Principal to be Cleared**
2007 PGVA ROLLOVER	(137,658,997)	(137,658,997)	0
COMMODITY	(32,663,779)	(64,097,079)	(31,433,300)
SEASONAL PEAKING-LOAD BALANCING	79,470	3,190,585	3,111,115
SEASONAL DISCRETIONARY-LOAD BALANCING	(13,146,051)	(16,644,095)	(3,498,044)
TRANSPORTATION TOLLS	7,786,510	42,405,284	34,618,775
CURTAILMENT REVENUE	0	(824,752)	(824,752)
RIDER C 2008 DIRECT ALLOCATION	72,747,971	54,879,930	(17,868,041)
INVENTORY ADJUSTMENT	(8,898,215)	30,131,415	39,029,630
TOTAL PGVA	(111,753,091)	(88,617,708)	23,135,383

In order to determine this breakdown it is necessary to break the purchases down by quarter and then compare those costs versus the costs that were assumed for that same quarter in the applicable QRAM. For example, January to March actual purchase costs are compared with the January to March costs underpinning the January QRAM, April to June purchase costs with the April to June costs underpinning the April QRAM etc.

The next step is then to break the variance(s) down between volume variance(s) and rate variance(s). The rate variances are then broken down between Commodity and, if necessary, Load Balancing. As one can appreciate the amount of backup information for this level of calculations is extensive and would not lend itself to a concise interrogatory response. The two schedules attached are intended to provide an understanding to the calculations that would support one category from Table E above.

Schedules 1 and 2 provide the calculations that would underpin the Seasonal Discretionary – Load Balancing amounts as provided in Table E.

Witness: D. Small

Columns 1, 2, and 3 of Schedule 1 represent the forecasted amount of Ontario Discretionary supplies for the applicable quarter from the applicable QRAM forecast.

Columns 4, 5, and 6 of Schedule 1 represent the actual and estimated amount of Ontario Discretionary supplies for the applicable quarter from the total forecasted purchases as per the Column 1 of the January 1, 2009 QRAM EB-2008-0348, Exhibit Q1-3, Tab 1, Schedule 2, page 3.

Column 7 identifies the variance, and Columns 8 and 9 of Schedule 1 break that variance down into a volumetric and rate variance respectively.

Columns 11 and 12 of Schedule 1 break the rate variance down to a commodity component and a load balancing component. The total in Column 12 can be found in Column 1 of Table E above.

Columns 1, 2, and 3 of Schedule 2 represent the forecasted amount of Ontario Discretionary supplies for the applicable quarter from the applicable QRAM forecast.

Columns 4, 5, and 6 of Schedule 2 represent the actual Ontario Discretionary supplies for the 2008 Fiscal Year.

Column 7 identifies the variance, and Columns 8 and 9 of Schedule 2 break that variance down into a volumetric and rate variance respectively.

Columns 11 and 12 of Schedule 2 break the rate variance down to a commodity component and a load balancing component. The total in Column 12 can be found in Column 2 of Table E above.

As stated above the Company has attempted to provide an example of the calculations related to one source of supply. The information used for these calculations are an excerpt from more detailed monthly calculations such as back up material to the Company's QRAM applications and in the case of actual amounts gas supply invoices which are reviewed by our external auditors. The amount of information that would need to be filed to support all calculations would be too extensive to incorporate in a concise fashion into an interrogatory response.

As part of the QRAM Generic proceeding (EB-2008-0106) the Company proposed to adopt and harmonize with Union's methodology regarding to the determination of the PGVA amount to be cleared, the application of calculating the rider unit rates based upon the volumetric forecast for a 12 month rolling period and the removal of the need for the year end PGVA true up mechanism. For each QRAM, if EGD's proposal is approved by the Board, EGD will identify the elements of its PGVA attributable to commodity, transportation and load balancing costs. Based on this breakdown, individual riders would be determined and applied to sales service, western bundled T-service and Ontario T-service customers. Developing a rider to reflect the manner in which costs are accumulated in the PGVA as they relate to commodity, transportation and load balancing would eliminate the need for the one time PGVA true up mechanism at year end.

The Company would like to reiterate that the steps followed in 2008 are consistent with past practices of determining the one time true up which in the past have resulted in both credit and debit amounts. Therefore, in summary EGD is proposing that the amount of $23.1 million identified in Column 3 of Table A (including any amounts for interest) should be cleared as a one time adjustment in conjunction with the October 1, 2009 QRAM application.

Schedule 1

	Ontario Discretionary Purchases										Season Discretionary - Load Balancing		
	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
	QRAM			ACTUAL			Variance						
	($ 000's)	Volumes (103 M3)	Unit Rate $/10*3 m*3	($ 000's)	Volumes (103 M3)	Unit Rate $/10*3 m*3	($ 000's)	Volume Variance ($ 000's)	Rate Variance ($ 000's)	Total Variance ($ 000's)	Commodity ($ 000's)	Rate Variance Load Balancing ($ 000's)	Total ($ 000's)
January -March	88,529.0	298,609.9	296.470	177,108.1	540,663.4	327.576	88,579.1	71,761.7	16,817.4	88,579.1	17,092.8	(275.4)	16,817.4
April - June	16,815.6	53,064.5	316.891	33,206.3	80,810.8	410.914	16,390.6	8,792.6	7,598.1	16,390.6	6,933.6	664.5	7,598.1
July - September	162,365.5	373,664.1	434.523	100,803.0	296,820.4	339.609	(61,562.5)	(33,390.3)	(28,172.2)	(61,562.5)	(16,243.9)	(11,928.2)	(28,172.2)
October - December	64,803.1	177,011.2	366.096	74,211.1	247,106.3	300.320	9,408.0	25,661.5	(16,253.5)	9,408.0	(14,646.6)	(1,606.9)	(16,253.5)
	332,513.2	902,349.7	368.497	385,328.4	1,165,400.8	330.640	52,815.2	72,825.4	(20,010.2)	52,815.2	(6,864.1)	(13,146.1)	(20,010.2)

- monthly forecasted information as per applicable QRAM

- monthly actual and forecasted information as per projected 2008 PGVA as filed in January 2009 QRAM

- see note 1

Schedule 2

	Ontario Discretionary Purchases										Season Discretionary - Load Balancing		
	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
	QRAM			ACTUAL			Variance						
	($)	Volumes (103 M3)	Unit Rate	($)	Volumes (103 M3)	Unit Rate	($ 000's)	Volume Variance ($ 000's)	Rate Variance ($ 000's)	($ 000's)	Commodity ($ 000's)	Rate Variance Load Balancing ($ 000's)	Total ($ 000's)
January -March	88,529.0	298,609.9	296.470	177,592.5	541,903.5	327.720	89,063.5	72,129.3	16,934.1	89,063.5	17,131.6	(197.5)	16,934.1
April - June	16,815.6	53,064.5	316.891	32,805.1	79,571.2	412.273	15,989.4	8,399.8	7,589.7	15,989.4	6,827.3	762.4	7,589.7
July - September	162,365.5	373,664.1	434.523	100,803.0	296,820.4	339.609	(61,562.5)	(33,390.3)	(28,172.2)	(61,562.5)	(16,243.9)	(11,928.2)	(28,172.2)
October - December	64,803.1	177,011.2	366.096	149,520.4	509,062.3	293.717	84,717.3	121,562.5	(36,845.2)	84,717.3	(31,642.3)	(5,202.9)	(36,845.2)
	332,513.2	902,349.7	368.497	460,720.9	1,427,357.5	322.779	128,207.7	168,701.3	(40,493.6)	128,207.7	(23,927.3)	(16,566.3)	(40,493.6)

- monthly forecasted information as per applicable QRAM

- monthly actual information as per final 2008 PGVA balance

- see note 1

BOMA INTERROGATORY #1

INTERROGATORY

Ref: Ex. A, Tab 3, Schedule 1, page 1

Given that the Board Decision in this application will not be received by May 15, 2009, what is EGD's revised proposal as to the timing of the clearance of the account balances?

RESPONSE

As a Board Decision within this application is now not able to be received in time to permit clearance of the deferral and variance accounts commencing July 1, 2009, the next reasonable date for clearance proposed by EGD is in conjunction with the October 1, 2009 QRAM filing.

Witness: K. Culbert

BOMA INTERROGATORY #2

INTERROGATORY

Ref: Ex. A, Tab 2, Schedule 1, Appendix A

Based on the response to Interrogatory # 1, please update, if necessary, the forecast for clearance as at the revised proposed clearance date.

RESPONSE

The Company has filed an update to the required deferral and variance account balances and proposed timing of clearance at Exhibit A, Tab 2, Schedule 1, Appendix A, Updated: 2009-05-26 and Exhibit C, Tab 1, Schedule 1, pages 2 and 3, Updated: 2009-05-26.

Witness: K. Culbert

BOMA INTERROGATORY #3

INTERROGATORY

Ref: Ex. C, Tab 1, Schedule 4 & Exhibit B5.4 (EB-2009-0052 - Attached).

EGD states that the CCA rate changes were not passed into law in 2008 and as a result the ratepayer share of $1.83 million in tax reductions used in determining the 2008 Board Approved rates did not materialize.

a) Does EGD agree with Union's expectation that the CCA rate changes will be passed into law in May 2009 as stated in their response part (b) (i) to Exhibit B5.4 in EB-2009-0052? If not, please explain why not.

b) To the best of EGD's knowledge, has the CCA rate changes been passed into law as of the current time?

c) Please comment on the response provided by Union in part (b) (ii) of Exhibit B5.4 in EB-2009-0052.

d) Has EGD filed its 2008 tax return? If yes, did EGD use the new CCA rates? If EGD did not used the new CCA rates, please confirm that EGD can refile its tax return using the new proposed CCA rates if it so wishes.

e) Has any of EGD's affiliate companies filed tax returns for 2008 using the new CCA rates?

f) If EGD were to use the new CCA rates, would there be any impact on the earnings sharing for 2008? If yes, please provide the impact on earnings sharing by providing an update to Exhibit B, Tab 1, Schedule 2 that reflects the higher CCA rates.

RESPONSE

The CCA rate changes being referred to were passed into law in April of 2009. EGD has filed updated evidence, at Exhibit M1, Tab 1, Schedule 1, (the "Impact Statement") and Exhibit C, Tab 1, Schedule 1, which includes and explains the impact of these CCA rate changes within its 2008 results and deferral & variance accounts requested for clearance. As a result the answers to part a) through f) of this interrogatory are inherent within that updated evidence filed on May 26, 2009.

Witness: K. Culbert

BOMA INTERROGATORY #4

INTERROGATORY

Ref: Exhibit C, Tab 2, Schedule 3

a) Has EGD made any changes to the allocations of the various deferral and variance accounts to the rate classes from what has been approved by the Board in the past?

b) If the response to part (a) is yes, please explain the allocation change, the rationale for the change and the impact of the change on the various rate classes.

RESPONSE

a) No. Enbridge has made no changes to the allocation methodology previously approved by the Board for the clearance of existing deferral and variance accounts.

Note that for 2008, the Board approved the creation of four new accounts. Those are: the Average True-Up Variance Account (AUTUVA), Municipal Permit Fees Deferral Account (MPFDA), Tax Rate & Rule Change Variance Account (TRRCVA), and Earnings Sharing Mechanism Deferral Account (ESMDA).

The proposed classification and allocation of these accounts by rate class can be found at Exhibit C, Tab 2, Schedule 2, page 3 as well as at Schedule 3, page 1.

b) N/A

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

CME INTERROGATORY #1

INTERROGATORY

Ref: Utility Income Calculations Before and After-Taxes – Exhibit B, Tab 5, Schedule 2, lines 18 and 20

Deferral and Variance Account Actual and Forecast Balances – Exhibit C, Tab 1, Schedule 1, page 2

EGD Financial Statements and Regulatory Assets (Liabilities) at December 31, 2008, at Note 3 entitled "Financial Statement affects Rate Regulation" – Exhibit D, Tab 1, Schedule 1 (pages unnumbered)

Earnings Sharing Calculation – Exhibit B, Tab 1, Schedule 2

In Note 3 to the Consolidated Financial Statements at Exhibit D, Tab 1, Schedule 1, there is a list of Regulatory Assets (Liabilities) at December 31, 2008; the balances in each Regulatory
Assets (Liabilities) Account at December 31, 2008, and a calculation of the Earnings Impact (After-tax) of each of the items. CME is interested in verifying that the amounts shown for each of these Deferral Accounts in the December 31, 2008 Financial Statements reconciles with the
2008 amounts EGD proposes to clear to ratepayers shown in Exhibit C, Tab 1, Schedule 1 at page 2. As well, the Financial Statements show EGD's Return on Equity for the year ended December 31, 2008, at 11.4%. Whereas the return being used by EGD in the Earnings Sharing
Calculation at line 42 of Exhibit B1, Tab 1, Schedule 2 is 10.22%. We wish to verify that the utility income at line 19 of Exhibit B1, Tab 1, Schedule 2 and at line 33 thereof reconcile with the Financial Statements.

In the context of these concerns, please provide the following information:

(a) Are there any revenues or expenses recorded in the 2008 Regulatory Deferral Accounts shown in Exhibit C, Tab 1, Schedule 1, page 2 for the period ending December 31, 2008, which have not been fully reflected in the list of Regulatory Assets (Liabilities) at December 31, 2008, shown in Section 3 of the Notes to the

Witnesses: K. Culbert
N. Kishinchandani

Consolidated Financial Statements of EGD at Exhibit D, Tab 1, Schedule 1 (pages unnumbered)? If so, then please provide details of the variances.

(b) The 2008 "Class Action Lawsuit Settlement Deferral" shown in the list of Regulatory Assets (Liabilities) in the Financial Statements at December 31, 2008, at a value of $20.1M and, according to Footnote 9, recoverable over a 5 year period commencing in 2008, is shown to have an "Earnings Impact (After-tax)" of only ($1.2M). Exhibit C, Tab 1, Schedule 1, page 3 shows an amount charged to ratepayers in 2008 of $4,709,500 for principal and $740,300 for interest. Please explain how the recovery of these costs by way of a deferral account has an impact on 2008 net income which is only ($1.2M).

(c) For each of the other Regulatory Assets (Liabilities) at December 31, 2008, shown in the Notes to the Consolidated Financial Statements, please explain how the "Earnings Impact (After-tax)" is derived and include therein an explanation as to why there is no "Earnings Impact" for certain items such as the Shared Savings Mechanism, and the Deferred Rebate Deferral.

(d) Please describe how ratepayers can easily verify that the Costs and Expenses deducted from Total Operating Revenue to produce Utility Income before taxes of $396.4M and Utility Income after taxes of $305.7M, shown in lines 18 and 20 of Exhibit B, Tab 5, Schedule 2, page 1, do not include any cost and expenses recorded in 2008 Deferral Accounts.

(e) Please provide an exhibit which reconciles the 11.4% Return on Equity shown in the Financial Statements for Enbridge Gas Distribution Inc. and the 10.22% Achieved Return on Equity shown at line 42 of Exhibit B, Tab 1, Schedule 2 in the Earnings Sharing Determination.

RESPONSE

It is important to emphasize the qualifying explanation at the top of the page within Note 3 of the EGD Financial Statements entitled “Financial Statement Effects of Rate Regulation”. The explanation of the list of Regulatory Assets and Liabilities at December 31, 2008, is that it is a list that has been recognized solely as a result of the effects of rate regulation which complies with the requirements of accounting guidance 19, primarily a disclosure requirement prescribed under Canadian GAAP.

In paragraph two of the previous page in the financials under the heading “Impacts of Rate Regulation” it is explained that absent rate regulation, the recognition of regulatory

Witnesses: K. Culbert
N. Kishinchandani

assets and liabilities would not be permitted and the impacts of the revenue and or expense amounts and related after tax earnings impacts would be recognized in the period in which they occurred.

The identification of the after tax earnings impacts are purely a note within the financials indicating the notional earnings impacts on a year over year basis that would occur if Canadian Generally Accepted Accounting Principles ("CGAAP") did not recognize rate regulated accounting treatments for certain accounts. The schedule is not intended to be a reconciliation of deferral and variance account balances to be cleared but rather is an accounting disclosure requirement as referenced above.

In fact, the establishment and clearance of non capital, cost related deferral & variance or like accounts, do not have an impact on earnings over the life of the account. An example of this is the treatment and recovery of Ontario hearing cost amounts. Upon incurrence of costs which have exceeded the agreed upon regulatory cost threshold, the effective entries for such amounts in 2008 are a debit in the OHCVA account, creating a receivable on the balance sheet, and a credit or reduction to cash, also a balance sheet entry. As seen through these entries, there are no entries affecting the income statement or impacting earnings in 2008. Upon recovery of the variance account in the future, the entries in the fiscal year of clearance will be an increase or debit to cash (balance sheet) and a reduction or credit to receivables (balance sheet) to recognize recovery of the account. The schedule showing the after tax earnings impact in the financial statements, however, is showing what the earnings impact would have been, absent the ability of EGD to apply rate regulated accounting under CGAAP.

(a) The purpose of the regulatory assets and liabilities section in the notes to the consolidated financial statements is not to mirror or reconcile amounts to be cleared through deferral and variance accounts but rather is a CGAAP accounting disclosure requirement. Please see the explanation above.

(b) The purpose of the regulatory assets and liabilities section in the notes to the consolidated financial statements is not to mirror or reconcile amounts to be cleared through deferral and variance accounts but rather is a CGAAP accounting disclosure requirement. Please see the explanation above.

(c) The notional 2008 after tax earnings impacts are derived by subtracting the 2007 deferral account balances from the 2008 account balances, and then multiplying this amount by the reciprocal, 66.5%, of the corporate tax rate of 33.5%. There is no after tax earnings impact shown for the Shared Savings Mechanism and Deferred Rebate accounts since the treatment of these items would have been no

Witnesses: K. Culbert
N. Kishinchandani

different even in the absence of the application of rate regulated accounting. In pages following the regulatory assets and liabilities schedule within the Note 3 in the financial statement, there is a description of the recognition of each of the accounts shown in the listing. For those accounts where the CGAAP treatment is the same as that under rate regulation there is no obligation to identify a notional after tax earnings impact.

(d) Due to the variety of deferral and variance accounts and their nature, the proper treatment and impact of the accounts cannot all be easily viewed in the same manner. The Audit opinion of our financial results confirms the use of appropriate accounting and adherence to CGAAP within the development of the corporate financial results. The Utility income results are determined from there and the review process which is undertaken by the Board, stakeholders and Company is the final step in verifying the appropriate treatment of costs and expenses within those results and in relation to deferral and variance accounts. In addition to this review process, the Board receives year end utility financial results for its review as part of its RRR reporting requirements.

(e) The 11.4% Return on Equity shown in the Financial Statements is a calculation performed using the corporate consolidated results. There are elements within the corporate consolidated calculation, examples of which are, the inclusion of St. Lawrence Gas, the absence of normalization for weather impacts, the inclusion of non utility elements and amounts and the use of the average of actual opening and closing equity, which are not relevant or included within the Utility Return on Equity calculation. However, a reconciliation of the corporate consolidated income to the utility income used within the ESM return on equity calculation has been provided in response to SEC Interrogatory #1 at Exhibit I, Tab 7, Schedule 1.

Witnesses: K. Culbert
N. Kishinchandani

CME INTERROGATORY #2

INTERROGATORY

With respect to balances in various Deferral Accounts which EGD proposes to recover from customers shown in Exhibit C, Tab 1, Schedule 1, page 2, please provide the following information:

(a) With respect to the Deferred Rebate Account, please explain why the amount recorded in 2008 is some $2.1M up from about $500,000 in 2007. In particular, explain why the extent to which the inability to locate customers in 2008 appears to be materially greater than it was in 2007.

(b) With respect to the Ontario Hearing Costs Variance Account and the information shown at Exhibit C, Tab 1, Schedule 6, page 1, please provide a list of all of the Consultants included in the $993,000 shown in Column 2 at line 2, the amounts that each charged EGD in 2008, describe the services each rendered, and indicate the proceedings for which each consultant was retained.

(c) With respect to the Unbundled Rates Customer Migration Variance Account, please show how the principal amount of $485,700 has been derived by listing each migrating customer by letter, showing the bundled rate from which each customer migrated, and the methods which have been used to calculate the revenue consequence of actual migration compared to the forecast migration for the approved unbundled Rates 125 and 300.

(d) With respect to the two Open Bill Service Deferral Accounts, please describe the items of expense included in each of these accounts and the manner in which the amounts in each account have been derived.

(e) With respect to the Municipal Permit Fees Deferral Account, please provide the evidence on which the Company relies to support the proposition that this Deferral Account was intended to extend to capital expenditures.

RESPONSE

a) The primary driver which explains the difference in amounts recorded in the 2008 versus 2007 DRA accounts is the magnitude of the deferral account clearance

Witnesses: K. Culbert
A. Kacicnik

filed in each year. The $2.1 million recorded in the 2008 account was the result of $31.3 million filed for clearance that related predominantly to 2007 deferral accounts, while the $0.5 million recorded in the 2007 account was the filed amount for clearance of ($6.4) million related predominantly to 2006 deferral accounts.

b) Please refer to CCC Interrogatory #9 at Exhibit I, Tab 6, Schedule 9.

c) The amount in the 2008 Unbundled Rates Customer Migration Variance Account ("URCMVA") represents the distribution revenue shortfall from unforecast migration of a single direct purchase customer from bundled Rate 115 to unbundled Rate 125 effective July 1, 2008. Given that Section 5.3 of the *Gas Distribution Access Rule* prohibits disclosure of customer-specific information, such as contracted volumes, the Company can only provide total aggregated distribution revenues under each rate for the requested calculation.

The derivation of the amount involved taking the difference of the forecast distribution revenue for the period post migration between the bundled rate and the unbundled rate, with adjustments for (i) the cost of unaccounted for gas which the customer would have provided in kind under requirements of the unbundled contract, as well as (ii) storage given that the customer now pays for the cost of storage under R315: Unbundled Gas Storage Service.

Variable upstream costs such as load balancing costs do not need to be included in the calculation given that the Company is able to shed such costs. Hence, the variance account captures only the distribution revenue impact.

The derivation of the 2008 URCMVA balance is shown in the following page:

Rate 115		
		Total Distribution Charges
July 2008	$	177,420
August 2008	$	181,744
September 2008	$	181,398
October 2008	$	183,054
November 2008	$	182,090
December 2008	$	183,587
Forecast Distribution Revenues on R115 from Jul-Dec 2008	$	1,089,293
Less: Adjustments for Storage and Unaccounted for Gas (UFG)	$	(195,488)
Distribution Revenue Under R115	$	893,805

Rate 125		
		Total Distribution Charges
July 2008	$	68,024
August 2008	$	68,024
September 2008	$	68,024
October 2008	$	68,024
November 2008	$	68,024
December 2008	$	68,024
Distribution Revenue Under R125	$	408,144

Distribution Revenue R115	$	893,805
Less: Distribution Revenue R125	$	408,144
Variance in Distribution Revenue from Migration to Unbundled Rate	$	485,661

d) EGD no longer seeks to clear the balances in the 2008 Open Bill Service Deferral Account and 2008 Open Bill Access Variance Account as part of this proceeding. The balances, composition, and clearance of these accounts are issues being addressed in the Open Bill Application proceeding EB-2009-0043.

Witnesses: K. Culbert
A. Kacicnik

e) The 2008 Municipal Permit Fees Deferral Account ("MPFDA") was approved as part of the EB-2007-0615 proceeding. Appendix E, page 19, of the Board's Decision and Rate Order includes a description of the 2008 MPFDA which includes the following:

> *The purpose of the 2008 MPFDA is to capture Municipal permit fee costs charged for certain activities, such as road cuts, related to the Company's construction and maintenance operations.*

The Company intended and interprets this description to be indicative that municipal permit fees are being incurred as part of capital related projects.

Witnesses: K. Culbert
A. Kacicnik

VECC INTERROGATORY #1

INTERROGATORY

References: Exhibit C Tab1 Schedule 3 Pages1-2 VECC IR#14 part h (I/7/14)

Provide further explanation regarding EGDI's position in response to part h.

h) Why should the Board approve an increase in Other Revenue during the IRM period? Discuss the regulatory approach and precedents.

RESPONSE

The references quoted in this interrogatory are to an exhibit and interrogatory response within EGD's EB-2008-0219, Fiscal 2009 IR rate proceeding.

Within that proceeding, a Phase II Settlement Proposal, Exhibit N1, Tab 2, Schedule 1, which included the issue of other revenue at Issues 2, 5 and 6, was filed with the Board on May 5, 2009. On May 7, 2009, day one of the oral hearing the Phase II Settlement Proposal was approved by the Board.

Witness: K. Culbert

VECC INTERROGATORY #2

INTERROGATORY

References: D/Tab2/S5 ; VECC IRR # 11 (I/7/11); EB-2009-0055 (ExB/T1/S3) Page 2 para b)

Provide more information on LPP transactions and revenue for Board approved Base year forecast and 2008 Actuals.

a) Provide metrics
   i. # LPP transactions
   ii. Average days in arrears
   iii. Interest rates charged
   iv. Calculation of average LPP revenue per transaction
   v. Amount of Security Deposits applied to arrears
   Add Notes as necessary

b) Discuss the drivers for the increase in LPP revenues 2008 relative to historic years.

RESPONSE

a) i) The Company does not have the capability to report on the number of LPP transactions. Enbridge can, however, report on total LPP revenues and Total Bad Debt expense. The table below presents LPP revenues and bad debt for 2006 through 2008.

Year	**LPP**	**Bad Debt**
2006 Actual	$ 10,509	$ 15,450
2007 Base Year	8,011	15,105
2007Actual	11,052	17,184
2008 Actual	11,983	18,781

ii) The average Days Sales Outstanding (“DSO”), includes all of Enbridge’s customer’s payment behaviour and is presented below:

Witnesses: K. Culbert
T. Ferguson

Year	Average DSO
2006	33
2007	33
2008	34

iii) The interest charged on outstanding arrears is 1.5% on the total amount outstanding that is not paid by the Late Payment Effective Date. For additional information please see EB-2008-0219, Exhibit N1, Tab 2, Schedule 1, Issue #3.

iv) As mentioned above in (i), the Company cannot report on the number of LPP transactions and therefore cannot provide a meaningful average LPP per transaction calculation.

v) The Company is not able to report on Security Deposits relative to accounts in arrears.

b) Late Payment Penalty is an interest charge based on the principle amount outstanding (arrears) that remains unpaid by the Late Payment Effective Date. As noted above, the Board directed Enbridge to charge LPP at a monthly rate of 1.5%, which has remained the same since the implementation of the current methodology in November 2005. The response to (ii) above indicates that the outstanding amounts owed by customers were outstanding for a longer period of time in 2008 than in previous years. Also, the amounts that are in active receivables (arrears from 30 to over 90 days in arrears) as presented in the table below have also increased. The changes recorded in both of these factors would indicate increased LPP revenue.

Year	Active Receivables	
2006	$	39,040,330
2007		42,880,660
2008		46,519,798

Witnesses: K. Culbert
T. Ferguson

VECC INTERROGATORY #3

INTERROGATORY

Reference: Exhibit C, Tab 2, Schedule 3

a) Is the Allocation of deferral account balances to the Residential class changed relative to that approved by the Board in the last case? If so provide a list of all changes in allocation(s) and provide explanatory notes to support the proposed changes.

b) Provide an update to the balances for the DSM-related Deferral and Variance accounts and if possible the expected allocation(s) to the Residential class. Will the accounts be cleared under this Docket or a future application Provide details and the timing proposed for disposition.

RESPONSE

a) No, the allocation is unchanged. Also, please see the response to BOMA Interrogatory #4 at Exhibit I, Tab 3, Schedule 4, page 1, part a).

b) The allocation of DSM-related deferral and variance accounts to Rate 1 customers is detailed in Exhibit C, Tab 2, Schedule 3, page 1. Total amounts in Lines 6, 7, and 8 of the exhibit include principal amounts agreed to in the EB-2009-0271 Decision as well as interest amounts to June 30, 2009.

   As part of its updated evidence in this proceeding, on May 26, 2009, Enbridge proposed that the clearance of all Deferral and Variance accounts coincide with October 1, 2009 QRAM instead of July 1, 2009 QRAM. If approved, the DSM-related account balances to be cleared will reflect the same principal amounts from the EB-2008-0271 Decision as well as interest amounts to September 30, 2009.

   Please see the response to Board Staff Interrogatory #1 at Exhibit 1, Tab 1, Schedule 1 for more detail on the proposed timing and manner of disposition, as well as the corresponding calculation of interest that would ensue.

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

CCC INTERROGATORY #1

INTERROGATORY

(Ex. B/T1/S3/p. 2)

The evidence states that the other revenue change of $4.6 million is mainly due to increased late payment penalty revenue. Please provide a complete variance analysis of all components of other revenue. Please provide a detailed description as to why the late payment revenue increased by $4.6 million.

RESPONSE

Details of Utility Other Revenue
2008 Actual Normalized vs. 2007 Board Approved

Item No.		Col. 1 2008 Actual Normalized ($Millions)	Col. 2 2007 Board Approved ($Millions)	Col. 3 2008 Actual Over/(Under) 2007 Board Approved ($Millions)	
1.	Service charges & DPAC	12.4	11.3	1.1	a)
2.	Open Bill Access revenue	5.4	5.4	-	
3.	Rent from NGV rentals	0.9	1.3	(0.4)	b)
4.	Late payment penalties	12.0	8.0	4.0	c)
5.	Transactional services	8.0	8.0	-	
6.	Dow Moore recovery	0.2	0.3	(0.1)	
7.	Total Other Revenue	38.9	34.3	4.6	

Witnesses: K. Culbert
T. Ladanyi
R. Lei

a) Service charges and DPAC revenue is $1.1 million higher than the 2007 Board Approved level mainly due to substantially higher 2008 DPAC revenues than was forecasted in the 2007 Board Approved Budget. DPAC revenues are charged based on the number of direct purchase pools. The Company had forecasted that direct purchase marketers would consolidate more of their pools in order to reduce the direct purchase administration charges in 2008. The 2007 Board Approved Budget included DPAC revenue of approximately $1.0 million, while the 2008 Actual revenues were $2.2 million, an increase of $1.2 million over the 2007 Board Approved amount. This increase is partially offset by variances in other charges such as the new account charge, red lock charges, NSF fees, lawyer's letters charges, safety inspection charges, and the meter test charges.

b) NGV rental revenue is $0.4 million lower due to lower activity than forecasted in the 2007 Board Approved Budget.

c) Late Payment Penalty revenue is $4.0 million higher than Board Approved mainly driven by higher gas sales and higher gas prices. More customers went into arrears as a result of the worsening economy in the latter half of 2008. This is also reflected in the higher provision for uncollectibles in 2008 as shown in Exhibit B, Tab 4, Schedule 3, page 1.

Witnesses: K. Culbert
T. Ladanyi
R. Lei

CCC INTERROGATORY #2

INTERROGATORY

(Ex. B/T1/S3/p. 2)

The other income change of $4.1 million is mainly due to revenue from the management of fee for external 3rd party energy efficiency initiatives. Please provide a complete description of all activities EGD is doing with respect to 3rd party energy efficiency initiatives. Please provide a schedule setting out the costs and revenues for each specific activity. Please provide the data for 2008 and the forecast for 2009. What is the status of the EPESDA and how do these costs relate to the activities envisioned when that account was established?

RESPONSE

In 2008 the 3rd party energy efficiency initiatives consisted of non-LDC program delivery. Schedule for costs and revenues are shown below. There were no Electric LDC revenues in 2008 and therefore no impact to EPESDA. The forecast for 2009 is similar.

	2008 Actual	2009 Forecast
Revenues	$3.6 million	$5.1 million
Costs	$2.1 Million	$3.8 million
Net Revenue	$1.5 million	$1.3 million

Witnesses: M. Brophy
K. Culbert

CCC INTERROGATORY #3

INTERROGATORY

(Ex. B/T4/S3/p. 1)

The O&M cost for Business Development and Customer Strategy in 2008 was $5.7 million less than the 2007 Board approved level. Please provide a detailed explanation for this variance.

RESPONSE

The lower O&M cost for Business Development and Customer Strategy in 2008 compared to the 2007 Board Approved level is primarily due to cancelled and reduced spending on several Market Development programs, lower research studies and lower consulting costs related to Business Development projects. In addition staff efficiencies and lower employee expenses contributed to the lower O&M spend in 2008.

Witnesses: T. Ladanyi
R. Lei

CCC INTERROGATORY #4

INTERROGATORY

(Ex. B/T4/S3/p. 1)

The O&M cost for Finance in 2008 was $2.5 million less than the 2007 Board approved level. Please provide a detailed explanation for this variance.

RESPONSE

The O&M variance for Finance is primarily attributed to the restructuring of the department including the elimination of a number of positions and the mitigation of training, travel, consulting, and other expenses.

Witnesses: T. Ladanyi
R. Lei

CCC INTERROGATORY #5

INTERROGATORY

(Ex. B/T4/S3/p. 1)

The O&M cost for Non-Departmental Expenses in 2008 was $12.3 million over the 2007 Board approved amount. Please explain the nature of this category of expenses and provide a detailed explanation for the variance.

RESPONSE

Non-Departmental Expenses and the primary drivers of the variances are as follows:

(a) An increase in the Executive & Administration amounts due to realignment of positions and responsibilities.

(b) Higher STIP amounts reflecting the Company's performance in 2008 as well as the impact of annual merit increases.

(c) Amounts associated with the alignment of operating practices with the Company's strategy under IR.

Witnesses: T. Ladanyi
R. Lei

CCC INTERROGATORY #6

INTERROGATORY

(Ex. B/T4/S3/p. 1)

The Corporate Allocations for 2008 are $32.14 million. The Board approved amount was $18.1 million. Please provide a detailed explanation for this variance.

RESPONSE

The Regulatory Cost Allocation Methodology ("RCAM") calculation for 2008 was performed using the Board Approved methodology. In the summer / fall of 2008 the results of the methodology were forwarded and reviewed with stakeholders in consultative meetings at that time. The 2008 rate related results produced by the RCAM were $19.1 million.

The Corporate Allocation Methodology ("CAM") amount of $32.1 million allocated to EGD, which was not approved for rate related matters, is not derived in the same manner as the RCAM methodology. Differences between the two methodologies do not lend themselves to a direct comparison. The use of the RCAM amount within the operating and maintenance costs and the elimination of amounts in excess of that within the year end Utility results ensures alignment with the approved rate related methodology.

CCC INTERROGATORY #7

INTERROGATORY

(C/T1/S6/p. 1)

With respect to regulatory costs EGD has included $176,000 for NGEIR & Gas Storage Allocation Policy. Please explain, specifically, what these costs are related to and why these are costs that should be funded by ratepayers.

RESPONSE

The description of the 2008 Ontario Hearing Costs Variance Account ("OHCVA"), as approved by the Board in the EB-2007-0615, Final Rate Order, Appendix E, is to record the variance between actual costs incurred by the Company in relation to regulatory proceedings, stakeholder consultatives, Board costs, and related expenses, versus a budget of $5,842,500 for these types of costs.

The costs of $176,000 for the category shown as NGEIR & Gas Storage Allocation Policy consists of $149,900 of legal fees, $22,100 of intervenor costs and $4,000 of OEB costs. These costs were incurred as a result of EGDs, Unions, and intervenors required involvement in the Board initiated Storage Allocation Policy regulatory proceedings, EB-2007-0724 and EB-2007-0725.

In Procedural Order No. 1 of this proceeding, the Board noted that one of the issues addressed in its November 7, 2006 Board Decision in the Natural Gas Electricity Interface Review proceeding ("NGEIR Decision"), concerned the methodologies used by Union and EGD to allocate cost based storage. On August 28, 2007, the Board initiated the EB-2007-0724 and EB-2007-0725 regulatory proceeding to address outstanding matters on storage allocation identified in the NGEIR Decision and invited parties to participate.

As evidenced by the costs identified, EGD incurred legal, Board, and intervenor costs for those who participated in the proceeding and were awarded costs.

As outlined above, these regulatory proceeding related costs are clearly relevant for the purpose of determining the variance to be recorded and cleared to ratepayers through the OHCVA.

Witness: K. Culbert

CCC INTERROGATORY #8

INTERROGATORY

(C/T1/S6/p. 1)

With respect to regulatory costs EGD has included $105,000 for the Integrated Power System Plan. Please explain, specifically, what these costs are related to and why these are costs that should be funded by ratepayers.

RESPONSE

The description of the 2008 Ontario Hearing Costs Variance Account ("OHCVA"), as approved by the Board in the EB-2007-0615, Final Rate Order, Appendix E, is to record the variance between actual costs incurred by the Company in relation to regulatory proceedings, stakeholder consultatives, Board costs, and related expenses, versus a budget of $5,842,500 for these types of costs.

On October 22, 2007, the Board approved an IPSP review proceeding, EB-2007-0707 which the Ontario Power Authority ("OPA") filed an application for on August 29, 2007. The IPSP contained within it, a review of the use of natural gas within electricity generation in Ontario.

The costs of $105,000 for the category shown as Integrated Power System Plan in the referenced exhibit are related to legal costs incurred to date by EGD through it's attendance and involvement in the IPSP proceeding. Just as the Board approved the recovery of intervenor costs within this regulatory proceeding within Procedural Order No. 2, EGD's required costs are clearly relevant for the purpose of determining the variance to be recorded and cleared to ratepayers through the OHCVA.

Witness: K. Culbert

CCC INTERROGATORY #9

INTERROGATORY

(C/T1/S6/p. 1)

With respect to regulatory costs EGD has included $993,000 for Consultants. Please provide a detailed breakdown of these costs.

RESPONSE

The table below shows the details of the consulting costs. The services received included the Productivity study and evidence in relation to the Incentive Regulation EB-2007-0615 proceeding and management, analysis and support within the CIS and Open Bill Consultatives and Regulatory Cost Allocation Methodology process.

Consultants	2008 Regulatory Costs (Thousands)
1. The Brattle Group	$ 841.0
2. R.J. Betts Enterprises	113.0
3. Elenchus Research Assoc.	39.0
	$ 993.0

Witness: K. Culbert

SCHOOL ENERGY COALITION INTERROGATORY #1

INTERROGATORY

Ref. Exhibit B, Tab 1, Schedule 1: please provide a reconciliation of the amount of utility income used to derive the earnings sharing mechanism ($305.7 million) and the amount shown in EGD's 2008 financial statements ($300.8 million).

RESPONSE

Impact Statement No. 1, Filed: 2009-05-26, updated the ESM filing. As a result, as shown at Exhibit M, Tab 1, Schedule 2, the originally filed utility income of $305.7 is shown in Column 3 of Exhibit M-1-2 with the information from the required change resulting in an updated utility income of $305.5 as shown in Column 5.

Pages 2 through 5 of this response show all of the reconciling items and amounts that are required and recorded differently between the corporate consolidated income and utility income results.

Reconciliation of Audited EGDI Consolidated Income to Utility Income 2008 Historical Year

Line no.		Col. 1 Audited Consolidated Income ($millions)	Col. 2 Utility Income ($millions)	Col. 3 Difference ($millions)	Col. 4 Reference (pp.3 - 5)
1.	Gas commodity and distribution revenue	2,506.2	2,351.6	(154.6)	a)
2.	Transportation of gas for customers	504.8	747.3	242.5	b)
3.		3,011.0	3,098.9	87.9	
4.	Gas commodity and distribution costs	2,000.4	2,137.8	137.4	c)
5.	Gas distribution margin	1,010.6	961.1	(49.5)	
6.	Other revenue	93.9	45.0	(48.9)	d)
7.		1,104.5	1,006.1	(98.4)	
	Expenses				
8.	Operation and maintenance	373.5	323.4	(50.1)	e)
9.	Earnings sharing	5.8	-	(5.8)	f)
10.	Depreciation	239.0	236.7	(2.3)	g)
11.	Municipal and other taxes	47.3	44.8	(2.5)	h)
12.	Company share of IR agreement tax savings	-	7.4	7.4	i)
13.		665.6	612.3	(53.3)	
14.	Income before undernoted items	438.9	393.8	(45.1)	
15.	Financing income	62.7	-	(62.7)	j)
16.	Interest and financing expenses	(200.8)	(1.0)	199.8	k)
17.	Income before income taxes	300.8	392.8	92.0	
18.	Income taxes	89.4	87.3	(2.1)	l)
19.	Net Income	211.4	305.5	94.1	

Reconciliation of 2008
Audited EGDI Consolidated Income to Utility Income

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
a)	2,506.2	**Consolidated gas commodity and distribution revenue**
	(47.7)	Amounts related to St. Lawrence Gas
	(109.8)	Weather normalization adjustment
	4.8	Gazifere T-service regrouped to gas commodity and distribution revenue
	(1.8)	Adjustment to revenues to reflect required TRRCVA impact statement entry.
	(0.1)	Rounding
	2,351.6	**Utility gas commodity and distribution revenue**
b)	504.8	**Consolidated transportation of gas for customers**
	(6.8)	Amounts related to St. Lawrence Gas
	(23.3)	Weather normalization adjustment
	(4.8)	Gazifere T-service regrouped to gas commodity and distribution revenue
	277.4	Ontario and Western T-Service Credits regrouped to gas costs
	747.3	**Utility transportation of gas for customers**
c)	2,000.4	**Consolidated gas commodity and distribution costs**
	(41.8)	Elimination of amounts related to St. Lawrence Gas
	(98.3)	Weather normalization adjustment
	277.4	Ontario and Western T-Service Credits regrouped to gas costs
	0.1	Rounding
	2,137.8	**Utility gas commodity and distribution costs**

Reconciliation of 2008
Audited EGDI Consolidated Income to Utility Income

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
d)	93.9	**Consolidated other revenue**
	(8.2)	Amounts related to St. Lawrence Gas, unregulated storage and oil and gas
	(10.6)	Open Bill O&M expenses regrouped against program revenues
	(7.4)	ABC admin. and bad debt costs regrouped against program revenues from O&M
	(0.1)	ABC interest charges regrouped against program revenues
	5.1	Allowable interest during construction ("IDC") regrouped to revenues
	(0.2)	NGV merchandise cost of goods sold regrouped against program revenues from O&M
	0.5	NGV program revenue imputation
	(3.1)	Elimination of transactional services revenue above base amount included in rates
	(0.6)	Elimination of Open Bill revenues (shareholder's incentive and 50% of bill insert revenue)
	(1.2)	Elimination of affiliate and 3rd party asset use revenue which is non-utility
	(5.1)	Elimination of net ABC revenue which is non-utility
	(1.7)	Elimination of interest income from investments not included in rate base
	(5.1)	Elimination of allowable interest during construction
	(11.1)	Elimination of shareholders incentive income recorded as a result of calculating the SSM amount
	(0.1)	Rounding
	45.0	**Utility other revenue**
e)	373.5	**Consolidated operation and maintenance**
	(8.7)	Amounts related to St. Lawrence Gas, unregulated storage and oil and gas
	(0.2)	NGV merchandise cost of goods sold regrouped against program revenues
	(7.4)	ABC admin. and bad debt costs regrouped against program revenues and eliminated
	(10.6)	Open Bill expenses regrouped against program revenues
	1.7	Interest on security deposits added to utility O&M
	(0.8)	Elimination of donations
	(1.3)	Elimination of non-utility costs of supporting the ABC program
	(13.1)	Elimination of Corporate Cost Allocations above RCAM amount
	(9.8)	Elimination of CWLP CIS fees in excess of settlement agreement
	0.1	Rounding
	323.4	**Utility operation and maintenance**
f)	5.8	**Consolidated earnings sharing**
	(5.8)	Elimination of earnings sharing amount contained in year end financials from utility income calculation
	-	**Utility earnings sharing**
g)	239.0	**Consolidated depreciation**
	(1.9)	Amounts related to St. Lawrence Gas, unregulated storage and oil and gas
	(0.2)	Elimination of depreciation on disallowed Mississauga Southern Link
	(0.2)	Elimination of depreciation related to shared assets
	236.7	**Utility depreciation**

Reconciliation of 2008
Audited EGDI Consolidated Income to Utility Income

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
h)	47.3	**Consolidated municipal and other taxes**
	(2.1)	Amounts related to St. Lawrence Gas, unregulated storage and oil and gas
	(0.2)	Elimination of municipal taxes related to shared assets
	(0.2)	Adjustment to convert capital taxes to a utility "stand-alone" basis
	44.8	**Utility municipal and other taxes**
i)	-	**Consolidated IR agreement tax savings**
	7.4	Recognition of the Company's share of IR agreement tax savings on utility income, as agreed in EB-2007-0615
	7.4	**Utility IR agreement tax savings**
j)	62.7	**Consolidated financing income**
	(62.7)	Eliminate non-utility dividend income from the Board Approved financing transaction
	-	**Utility financing income**
k)	200.8	**Consolidated interest and financing expenses**
	(1.3)	Amounts related to St. Lawrence Gas, unregulated storage and oil and gas
	(26.9)	Eliminate non-utility interest expense from the Board Approved financing transaction
	5.1	Allowable interest during construction regrouped to revenues and eliminated
	(0.1)	ABC interest charges regrouped against program revenues and eliminated
	(176.6)	Elimination of interest expense and the amortization of issue and debt discount costs which are determined through the regulated capital structure
	1.0	**Utility interest and financing expenses**
l)	89.4	**Consolidated income taxes**
	(0.7)	Amounts related to St. Lawrence Gas, unregulated storage and oil and gas
	1.9	Add back income taxes on earnings sharing
	(90.7)	Elimination of corporate income taxes
	87.3	Addition of income taxes calculated on a utility "stand-alone" basis
	0.1	Rounding
	87.3	**Utility income taxes**

SCHOOL ENERGY COALITION INTERROGATORY #2

INTERROGATORY

Ref. Exhibit B, Tab 4, Schedule 2: Lines 14 (Non Departmental Expense) and 15 (Corporate Allocations (including direct costs)) show significant increases in 2008 over 2007.

(a) Please provide a detailed breakdown for the increases.

(b) With respect to Corporate Cost allocations, please explain whether a new allocation methodology has been employed and if so what the justification for the new methodology is.

RESPONSE

(a) Please refer to CCC Interrogatory #5 at Exhibit I, Tab 6, Schedule 5.

(b) The Company has not changed the Corporate Cost allocation methodology.

Witnesses: T. Ladanyi
R. Lei

SCHOOL ENERGY COALITION INTERROGATORY #3

INTERROGATORY

Exhibit C/1/1: With respect to the Ontario Hearing Costs Variance Account (2008 OHCBA) and Class Action Suit Deferral Account (2009 CASDA), please provide a breakdown of the cost recorded to this account since the last disposition.

RESPONSE

The description of the 2008 Ontario Hearing Costs Variance Account ("OHCVA"), as approved by the Board in the EB-2007-0615, Final Rate Order, Appendix E, is to record the variance between actual costs incurred by the Company in relation to regulatory proceedings, stakeholder consultatives, Board costs, and related expenses, versus a budget of $5,842,500 for these types of costs.

The amount recorded in the OHCVA is determined in reviewing the total costs incurred in relation to the above noted and approved level and description of the account. The manner in which the $2,252.1 ($000's) is arrived at is filed at Exhibit C-1-6.

The amounts shown for the CASDA account are explained in note 1 of Exhibit C-1-1, page 3. There have been no further costs recorded into the principle amounts since clearance of the account commenced in 2008 in accordance with the Boards approval in EB-2007-0731.

Witness: K. Culbert