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July 24, 2012

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")
Ontario Energy Board File No. EB-2012-0055
2011 Earnings Sharing Mechanism and Other Deferral and Variance Accounts Clearance Review
New, Updated and Corrected Interrogatory Responses**

In accordance with the Ontario Energy Board's (the "Board") Procedural Order issued for the above noted proceeding Enbridge filed its interrogatory responses on July 24, 2012. Through an inadvertent oversight Enbridge did not directly receive APPrO's interrogatories.

Attached please find Enbridge's responses to APPrO's interrogatories (Exhibit I, Tab 7, Schedules 1 to 6) as well as the following updated or corrected interrogatory responses:

Exhibit I, Tab 1, Schedule 5;
Exhibit I, Tab 2, Schedule 5;
Exhibit I, Tab 2, Schedule 7, Attachment, pages 1 to 4;
Exhibit I, Tab 4, Schedule 1, page 3; and
Exhibit I, Tab 6, Schedule 7, page 1.

This submission was filed through the Board's RESS and will be available on the Company's website at www.enbridgegas.com/ratecase .

Please contact the undersigned if you have any questions.

Yours truly,

[original signed by]

Lorraine Chiasson
Regulatory Coordinator

cc: Mr. F. Cass, Aird & Berlis LLP
All Interested Parties in EB-2011-0354

APPrO INTERROGATORY #1

INTERROGATORY

Reference: Exhibit B, Tab 1, Schedule 5, Paragraph 5 and Appendix IV

Enbridge indicates that it has accepted Black and Veatch's recommendation to use deliverability as the basis for sharing some of the O&M costs. O&M costs are usually a function of the assets installed. Please indicate if the deliverability component is based on the contracted level of deliverability actually employed by the non-utility operation, or if it is based on the level of deliverability that was designed and constructed for the utility operation. Please explain.

RESPONSE

Enbridge accepted that deliverability is a factor to be applied when determining the allocation of O&M costs. The deliverability component of the O&M cost allocation is based upon the contracted or committed maximum levels of deliverability of both the utility and non-utility businesses. In addition to the cost allocation driven by deliverability, Enbridge includes a cost allocation based on actual monthly activity. These two factors are used to ensure that any activity driven incremental O&M costs associated with non-utility operations are allocated appropriately.

Witnesses: B. Pilon
J. Sanders
K. Culbert

APPrO INTERROGATORY #2

INTERROGATORY

Reference: Exhibit C, Tab 2, Schedule 2, Page 3 of 6

Enbridge has proposed to allocate $8,642,000 to most customer rate classes using ‘number of customers’ as the allocator, resulting in $75,800 being allocated to Rate 125. Please provide:

a) The total number of customers in Enbridge’s franchise area.

b) The total number of Rate 125 customers.

c) Please explain how the allocation of $75,800 was made to Rate 125 customers, and include the calculation.

d) Please explain the nature and purpose of the ‘Mean Daily Volume D/A’ and why it is being allocated on a per customer basis.

RESPONSE

a) and b)

Clearance of 2011 Deferral and Variance account balances is based on actual customers. The total number of customers in 2011 was 1,965,538. The number of Rate 125 customers in 2011 was four.

c) The allocation of the referenced amount in Column 9 to Rate 125 customers was carried out as follows:

Witnesses: J. Collier
A. Kacicnik
M. Kirk

<u>URICDA Balance:</u>

Incremental FTE to support unbundled services	$67,200
Incremental FTE for additional upstream nom windows	$75,200
Total 2011 URICDA balance[1]	$142,400

Note[1] - Exhibit C, Tab 2, Schedule 2, Page 3, Column 1, Item 13

Rate 125 customers are allocated the entire $75,200 in additional staffing costs associated with supporting additional upstream nomination window, per the NGEIR Settlement Agreement, since the costs are to be recovered from the parties who used the service. Of the four Rate 125 customers, three used additional nomination windows in 2011. Therefore, the $75,200 was equally split between those three customers. In addition, Rate 125 customers are allocated their share of the $67,200 that supports the overall implementation of unbundled services. This cost is allocated to all large volume customers based on the number of customers in each rate class as specified in the NGEIR Settlement Agreement and consistent with Board-approved methodology. The amount allocated to Rate 125 is approximately $600.

The allocations of balances from other accounts in Column 9 to Rate 125 customers are minor.

d) The reason for allocating the Mean Daily Volume Deferral Account on a per customer basis is described at Exhibit C, Tab 2, Schedule 1, page 2. In addition, please refer to the response to Energy Probe Interrogatory #6, at Exhibit I, Tab 3, Schedule 6, page 1.

Witnesses: J. Collier
A. Kacicnik
M. Kirk

APPrO INTERROGATORY #3

INTERROGATORY

Reference: Exhibit C Tab 2 Schedule 2 page 5 of 6

The second footnote to the chart indicates:

> "The Company indicated that it incurred $75.2 k in additional staffing costs in 2011 associated with the additional upstream (such as FT-SN) nomination windows for unbundled customers. As specified in the NGEIR Settlement Agreement (EB-2005-0551 Ex S T1 S1 p13), the costs are to be recovered from the parties who availed of the service. Three customers on Rate 125 utilized the additional nomination windows in 2011 and the costs were allocated equally among the three customers."

a) Enbridge indicates that it incurred $75.2 k in additional staffing costs related to unbundled customers for additional upstream nomination windows such as FT-SN.

   i. Please provide a list of all other unbundled services that use additional nomination windows.

   ii. Please provide the number of non-utility storage customers that use nomination windows that are different than the standard NAESB nomination windows.

   iii. Please confirm that Enbridge utilizes a F24-T contract with Union that has 13 nomination windows.

   iv. Please confirm that Enbridge has multiple STS contracts with TCPL that has 4 nomination windows in excess of the standard NAESB windows.

   v. Please confirm that Enbridge is the contracting party to TCPL's contract number 37017 that is a FT-SN contract that commenced January 2009 and has a Contract Demand of 85,000 GJ/d with a receipt point of Parkway and a Delivery Point of Victoria Square 2.

   vi. Please confirm that the nomination resources that provide nominations to

Witnesses: J. Collier
A. Kacicnik
M. Kirk
J. Sanders
J. Sarnovsky
D. Small

unbundled customers are the same resources that provide nominations for the above services.

b) For each of the calendar years from 2009 to 2011, please provide a chart that separately shows the number of customers using the FT-SN services and other storage and transportation services using more than the standard NAESB nomination windows delivering gas to Enbridge's franchise area or using Enbridge storage, the total staffing or other costs associated with Enbridge accommodating the service costs, and the per customer charge actually levied for each category to recover the costs.

c) Please explain how staffing costs related to nominations for FT-SN and other services were recovered from 2009 to 2011.

d) Enbridge indicates that an additional $75.2 k was incurred in 2011 to accommodate the additional nomination windows associated with FT-SN and other services. Please explain in detail the nature of these costs. Please also detail the base costs that were being incurred to provide these nomination windows before this incremental amount was added.

e) Please explain what other duties these personnel perform in addition to accepting nominations for such customers.

f) Given that TCPL's public records only show 4 FT-SN shippers all commencing in 2009 and Enbridge has been accepting these nominations since 2009, please advise what precipitated these additional costs in 2011.

g) Please confirm that this Enbridge FT-SN contract is used to manage the balancing requirements for all customers in the GTA area and/or deliver gas to system customers in the GTA, and is not related in any way to Rate 125 customers. If not, please explain how this contract is utilized.

h) Please detail how much of the costs included in b) above were allocated to Enbridge to manage its FT-SN contract for each year from 2009 to 2011. If Enbridge has not paid its proportionate share of the expenses to accommodate FT-SN service in each of these 3 years, please explain why. If Enbridge has not picked up its share of the expenses to accommodate FT-SN services since 2009, please total the over-contribution by each customer and similarly the under-contribution by

Enbridge over the period 2009-2011.

i) Enbridge indicates that it proposes to charge each of the 3 customers in its franchise area that uses FT-SN a one-time charge of $25,075. Please confirm that if Enbridge's contract is included in the overall base of customers using FT-SN that the individual customer charge will be reduced to $18,806.

j) Please explain, in the context of an IRM, why these costs are being requested to be passed on to customers.

<u>RESPONSE</u>

a) through j)

The $75.2 K in additional staffing costs that the Company incurred in 2011 associated with the additional upstream (such as FT-SN) nomination windows for unbundled customers is part of the application to clear 2011 deferral and variance account balances. The 2011 deferral and variance accounts were established by the Board as part of the Final Rate Order for 2011 IRM Adjustment (EB-2010-0146). (Note that prior to this application the Company cleared the costs associated with the additional upstream nomination windows for unbundled customers as part of its application to dispose of 2010 deferral and variance account balances.)

The Unbundled Rate Implementation Cost Deferral Account (URICDA) was first established through the Board's Rate Order arising from the Natural Gas Electricity Interface Review (NGEIR) Decision with Reasons (EB-2005-0051) to recover incremental costs associated with unbundling implementation.

Attached to this interrogatory response are: (1) the Board's Rate Order for EGD arising from the NGEIR Decision with Reasons (EB-2005-0551) which includes the treatment for 2006 & 2007 URICDA in Appendix F, and (2) the Board's Final Rate Order for the 2011 IRM Adjustment (EB-2010-0146) and the accompanying Appendix C which includes treatment of 2011 URICDA.

The $75.2 K in additional costs are associated with one incremental FTE that was hired to facilitate the creation of the Volume Planner role. The Volume Planner is responsible

Witnesses: J. Collier
A. Kacicnik
M. Kirk
J. Sanders
J. Sarnovsky
D. Small

for processing the additional nominations arising from short notice nomination windows, as well as, other activities for unbundled large power generators. The addition of the FTE and optimization of shift schedules allowed three staff to act in the capacity of either a Volume Planner or a Gas Controller / Scheduler. As a result, incremental costs were kept to a minimum and were considerably less than the estimate ($250,000 - $750,000 per year, depending upon the number of customers) provided in the NGEIR generic proceeding.

The functions of the Volume Planner are distinct from the traditional gas control activities carried out by the Company and include the following:

- ensuring nominated volumes fall within contract allowances;
- answer customer inquiries related to operations;
- monitoring hourly flows to ensure actual consumption is not out of tolerance with nominations (this is especially critical during peak operating days and during abnormal or emergency operating conditions);
- providing reports which contribute to the invoicing process;
- helping Gas Control forecast overall daily system load based on expected Power Gen short notice service requirements.

In contrast, Gas Controllers are responsible for forecasting daily demand, monitoring of distribution system pressures, and ensuring the system is balanced at the end of the gas day. Schedulers process nominations resulting from EGD's upstream supply, transport and storage contracts, as well as, direct purchase activities, excluding short notice services for unbundled customers.

EGD uses its STS, FT-SN, and F24-T contracts in conjunction with its other upstream contracts to load balance its distribution system on a daily basis. This again is the responsibility of EGD's Gas Controllers and Schedulers (whose costs are recovered through rates), which is distinct from the function performed by the Volume Planner.

This is the reason why the incremental costs incurred are only cleared to the customers using additional nomination windows (i.e. short notice services).

In 2009, the Company did not record a balance in the URICDA associated with the additional upstream nomination windows. In 2009 the Company monitored the take up of the service and associated workload before it would hire an incremental resource.

Witnesses: J. Collier
A. Kacicnik
M. Kirk
J. Sanders
J. Sarnovsky
D. Small

One non-utility storage customer currently uses the non-standard nomination windows. Gas Control charges to non-utility storage operations are approximately $120 K a year.

In 2011, there were three Rate 125 customers who used additional nomination windows (same as in 2010). Although Rate 300 also provides / facilitates the use of additional nomination windows, no Rate 300 customers used the additional windows within the 2009 to 2011 period. Hence, the deferral account balance was cleared to Rate 125 customers only.

Witnesses: J. Collier
A. Kacicnik
M. Kirk
J. Sanders
J. Sarnovsky
D. Small

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2005-0551

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

AND IN THE MATTER OF a proceeding initiated by the Ontario Energy Board to determine whether it should order new rates for the provision of natural gas, transmission, distribution and storage services to gas-fired generators (and other qualified customers) and whether the Board should refrain from regulating the rates for storage of gas

BEFORE: Gordon Kaiser
Presiding Member and Vice Chair

Cynthia Chaplin
Member

Bill Rupert
Member

RATE ORDER FOR ENBRIDGE GAS DISTRIBUTION INC. ARISING FROM THE NATURAL GAS ELECTRICITY INTERFACE REVIEW DECISION WITH REASONS: EB-2005-0551

The Natural Gas Electricity Interface Review ("NGEIR") proceeding was commenced pursuant to sections 19, 29 and 36 of the *Ontario Energy Board Act, 1998*. On December 29, 2005, the Board issued a Notice of Proceeding on its own motion to determine: (a) whether it should order new rates for the provision of natural gas transmission, distribution and storage services to gas-fired generators (and other qualified customers); and (b) whether to refrain, in whole or part, from exercising its power to regulate the rates charged for the storage of gas in Ontario by considering whether, as a question of fact, the storage of gas in Ontario is subject to competition sufficient to protect the public interest.

Pursuant to Procedural Order No. 2, the proceeding also addressed the proposed unbundled rates for conventional large volume customers of Enbridge Gas Distribution Inc. ("Enbridge").

The hearing participants, which included gas-fired generators and consumer groups, reached settlements with Enbridge and Union Gas Limited on most of the issues related to services to gas-fired generators, including an amended Rate 125 distribution service for extra large customers. The Enbridge Settlement Proposal also contained agreements about the unbundled rates to be offered to other large volume customers (Rates 300 and 315). The Settlement Proposal indicated that these unbundled rates would be offered to customers, on a limited basis, beginning January 1, 2007. The Settlement Proposal also contained the agreement of all parties that Enbridge would establish an Unbundled Rate Implementation Cost Deferral Account to collect Enbridge's costs associated with preparing to offer unbundled rates as of January 1, 2007, as well as an Unbundled Rates Customer Migration Variance Account to capture the revenue consequences of the actual migration to the new unbundled rates being different from the forecast.

On July 14, 2006, the Board approved the Settlement Proposal related to Enbridge.

On November 7, 2006, the Board issued its EB-2005-0551 Decision with Reasons which addressed the balance of the issues in the proceeding.

In its Decision, the Board stated that:

> "As part of this proceeding, new unbundled rates have been approved for Enbridge and they are to be implemented as soon as possible. The Board therefore directs Enbridge to file a draft Rate Order within 15 days of this decision. The draft Rate Order should reflect the findings in this decision" (p. 119).

On November 22, 2006, Enbridge filed draft Rate Schedules for Rates 125, 300, 315 and 316, which are the unbundled rates that were approved in this proceeding. The Company also filed a draft Rate Rider for Enhanced Title Transfer Service and for Gas in Storage Title Transfer.

The draft Rate Schedules for Rates 125, 300, 315 and 316 all reflect a Monthly Customer Charge that has been reduced by $50 from the amount previously indicated. This reduction reflects the fact that the earlier versions of these Rate Schedules assumed that the Company would immediately proceed with an automated solution to process unbundled rate transactions. Now that parties have agreed to delay the implementation of the automated solution, the associated cost recovery of $50 per customer per month is not needed at this time.

The draft Rate Schedule for Rate 125 reflects the Board's decision that "the only aspect of Rate 125 that will be restricted to new customers is the billing contract demand feature" (EB-2005-0551 Decision with Reasons, p. 116). The amended version of Rate 125 will be available as of July 1, 2007.

The draft Rate Schedules for Rates 300 and 315 are essentially the same as agreed to in the Enbridge Settlement Proposal, and approved by the Board. Apart from the change to the Monthly Customer Charge, two other changes have been made to Rate 300 to address matters that were inadvertently omitted by Enbridge. A Direct Purchase Administration Charge of $50 has been added, to make Rate 300 consistent with Rate 125. References to Curtailment Delivered Supply, a service that bundled customers can currently receive with Rate 300, have also been added. Rates 300 and 315 will be available as of January 1, 2007.

The draft Rate Schedule for Rate 316 reflects the Board's decision that the Board will refrain from regulating the rates for new storage services, including Enbridge's high deliverability Rate 316 (EB-2005-0551 Decision with Reasons, p. 70). As a result, the draft Rate Schedule for Rate 316 reflects the fact that this regulated storage rate and service will be standard 1.2% deliverability storage, delivered at Dawn, Ontario. Rate 316 will be available as of July 1, 2007.

All customers taking service under Rate 315 or 316 are entitled to an allocation of cost-based standard 1.2% deliverability storage to be calculated in accordance with the Company's Board-approved excess over average methodology. Gas-fired generation customers also have the option to determine their allocation of cost-based standard 1.2% deliverability storage based upon the allocation methodology described at

Appendix G. In accordance with section 6.2.2 of the Board's decision, Enbridge will circulate to all parties in this proceeding and file the methodology or methodologies that it proposes to use to allocate cost based standard 1.2% deliverability storage to other unbundled customers. This will be completed by February 5, 2007.

Upon reviewing the materials, the Board finds it appropriate to issue a Rate Order in this proceeding approving the Rate Schedules for Enbridge's Rates 125, 300, 315 and 316, as well as the Rate Rider for Enhanced Title Transfer Service and for Gas in Storage Title Transfer. The Board also finds it appropriate to approve the establishment of Enbridge's 2006 and 2007 Unbundled Rate Implementation Cost Deferral Accounts, as well as Enbridge's 2007 Unbundled Rates Customer Migration Variance Account.

THE BOARD THEREFORE ORDERS THAT:

1. The Rate Schedules for Enbridge's Rates 125, 300, 315 and 316, attached as Appendices A, B, C and D to this Order are approved.

2. The Rate Rider for Enbridge's Enhanced Title Transfer Service and for Gas in Storage Title Transfer shall be in accordance with Appendix E to this Order.

3. Enbridge shall establish the 2006 and 2007 Unbundled Rate Implementation Cost Deferral Accounts and the Unbundled Rates Customer Migration Variance Account. The accounting treatment for these accounts shall be in accordance with the descriptions contained in the attached Appendix F. Enbridge shall refer to the Board directive issued in EB-2006-0117 to determine the interest rates for these accounts.

4. The storage allocation methodology for gas-fired generators is approved as described in Appendix G to this Order.

5. Enbridge shall circulate to all parties in this proceeding the methodology or methodologies that it will use to allocate cost-based standard 1.2% deliverability storage to other unbundled customers. Enbridge is directed

to circulate and file this methodology or methodologies with the Board by February 5, 2007.

ISSUED at Toronto, December 20, 2006

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary

EB-2005-0551

NATURAL GAS ELECTRICITY INTERFACE REVIEW

ENBRIDGE GAS DISTRIBUTION INC.

RATE ORDER

DECEMBER 20, 2006

APPENDIX “F”

ACCOUNTING TREATMENT FOR AN
UNBUNDLED RATE IMPLEMENTATION COST
DEFERRAL ACCOUNT
("2006 URICDA")

For the 2006 Fiscal Year
(January 1, 2006 to December 31, 2006)

The purpose of the 2006 URICDA is to record the costs associated with preparing to offer unbundled rates as of January 1, 2007. The account will collect the costs relating to a manual solution which will allow the establishment of rates 300 and 315 initially on a limited basis. Costs to be included in the account are those related to the development of spreadsheets and procedures necessary to process transactions by unbundled customers, as well as staff hiring and training costs for the personnel who will actually run the manual solution. The account will also include costs related to customer education and EnTrac changes required for a manual solution, along with necessary implementation costs.

Simple interest is to be calculated on the opening monthly balances within the account at the Board approved short-term interest rate. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

Accounting Entries

1. To record costs related to the Unbundling Rate Implementation manual solution:

Debit:	Other Income	(Account 179. 636)
Credit:	Accounts Payable	(Account 251.010)

To record the costs associated with implementing Rates 300 and 315 through a manual solution on an interim basis.

2. Interest accrual:

Debit:	Interest on 2006 URICDA	(Account 179. 646)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balances of the 2006 URICDA at the Board approved short-term interest rate.

ACCOUNTING TREATMENT FOR AN UNBUNDLED RATE IMPLEMENTATION COST DEFERRAL ACCOUNT (“2007 URICDA”)

For the 2007 Fiscal Year
(January 1, 2007 to December 31, 2007)

The purpose of the 2007 URICDA is to record any additional costs, if required, of continuing with a manual solution or the costs required of an automated solution for offering Unbundled Rates 125, 300, 315 and 316. Costs to be collected in the account are administrative, staffing and all reasonably incurred costs associated with offering these rates and the additional nomination windows required for such rates.

Simple interest is to be calculated on the opening monthly balances within the account at the Board approved short-term interest rate. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

Accounting Entries

1. To record costs related to the Unbundling Rate Implementation solution:

Debit:	Other Income	(Account 179. 637)
Credit:	Accounts Payable	(Account 251.010)

To record the costs associated with implementing Rates 300, 315 and 316 through a continuing manual solution or an automated solution.

2. Interest accrual:

Debit:	Interest on 2006 URICDA	(Account 179. 647)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balances of the 2007 URICDA at the Board approved short-term interest rate.

ACCOUNTING TREATMENT FOR AN
UNBUNDLED RATES CUSTOMER MIGRATION VARIANCE ACCOUNT
("2007 URCMVA")

For the 2007 Fiscal Year
(January 1, 2007 to December 31, 2007)

The purpose of the 2007 URCMVA is to record the revenue consequences of actual customer migration variance from forecast migration for the new NGEIR unbundled rates 125, 300, 315 and 316. The pivot point or threshold for the variance account will be the revenue related to forecast migration to new rates such that if actual migration revenue is lower or higher than forecast, there would be an associated entry to the variance account to refund or collect from customers in all applicable rate classes.

Simple interest is to be calculated on the opening monthly balances within the account at the Board approved short-term interest rate. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

Accounting Entries

1. To record the impact of customer migration to unbundled rates versus forecast:

Debit/Credit:	2007 URCMVA	(Account 179. 677)
Credit/Debit:	Revenue	(Account 300. 000)

To record the revenue variance associated with actual versus forecast migration of customers to unbundled rates.

2. Interest accrual:

Debit/Credit:	Interest on 2007 URCMVA	(Account 179. 687)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balances of the 2007 URCMVA at the Board approved short-term interest rate.

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

EB-2010-0146

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

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2011.

BEFORE: Paula Conboy
Presiding Member

Cathy Spoel
Member

FINAL RATE ORDER
2011 IRM Adjustment

Enbridge Gas Distribution Inc. ("Enbridge" or the "Applicant") filed an Application on September 1, 2010 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Sched. B, as amended, for an order of the Board approving or fixing rates for the sale, distribution, transmission and storage of natural gas, effective January 1, 2011. The Board assigned file number EB-2010-0146 to the Application and issued a Notice of Application dated September 13, 2010.

Enbridge applied for new rates for 2011 to be set under the Incentive Regulation plan approved by the Board under File No. EB-2007-0615. 2011 is the fourth year of the five year plan. The rates under the plan are adjusted each year by the application of a Distribution Revenue Requirement per Customer Formula (the "Adjustment Formula"). On October 1, 2010, Enbridge filed detailed evidence supporting the application for the Adjustment Formula and other elements underpinning the calculation of the 2011 rates.
In its Decision and Order dated November 25, 2010 the Board approved the Settlement Agreement and directed Enbridge to file a Draft Rate Order for 2011 rates and to copy all parties. The Board also outlined a process for parties to comment. On November 26, 2010

Enbridge filed draft materials for inclusion in the Board's Final Rate Order. The materials included the following:

- Financial Statement showing the total revenue applicable to the 2011 Test Year;
- Rate Handbook reflecting final 2011 rates as per the Settlement Agreement plus supporting documentation;
- Accounting treatment for all 2011 Deferral and Variance Accounts;
- Final Issues List; and
- Settlement Agreement.

None of the parties filed any comments on the Draft Rate Order.

The rates in this Final Rate Order are designed to be effective and implemented on January 1, 2011. The Board notes that there will be a natural gas commodity rate adjustment effective January 1, 2011 under the Quarterly Rate Adjustment Mechanism ("QRAM") process. The QRAM draft order is expected to be filed on or about December 10, 2010 under docket EB-2010-0347. For rate implementation purposes, it is anticipated that the rates approved under this Final Rate Order will be superceded by the January 1, 2011 QRAM rates. The Board notes that Enbridge intends to file the customer rate notices describing the rate impacts as part of the January 1, 2011 QRAM process.

Having reviewed all of the materials, the Board considers it appropriate to proceed with its Final Rate Order as proposed by Enbridge.

THE BOARD ORDERS THAT:

1. The Financial Statement, attached as Appendix "A" to this order, is accepted as the basis for the rates in this order.

2. The rates in the Rate Handbook, attached as Appendix "B" to this order, are hereby effective January 1, 2011.

3. The accounting treatment for Enbridge's fiscal 2011 deferral and variance accounts, including the applicable interest rate, shall be in accordance with the descriptions contained in the attached Appendix "C".

4. The following Deferral and Variance accounts shall be established for Enbridge's fiscal 2011 year:

Gas Related Accounts
Purchased Gas V/A ("2011 PGVA")
Transactional Services D/A ("2011 TSDA")
Unaccounted for Gas V/A ("2011 UAFVA")
Storage and Transportation D/A ("2011 S&TDA")

Non-Gas related Accounts
Carbon Dioxide Offset Credits D/A ("2011 CDOCDA")
Class Action Suit D/A ("2011 CASDA")
Deferred Rebate Account ("2011 DRA")
Electric Program Earnings Sharing D/A ("2011 EPESDA")
Gas Distribution Access Rule Costs D/A ("2011 GDARCDA")
Manufactured Gas Plant D/A ("2011 MGPDA")
Municipal Permit Fees D/A ("2011 MPFDA")
Ontario Hearing Costs V/A ("2011 OHCVA")
Unbundled Rate Implementation Cost D/A ("2011 URICDA")
Unbundled Rates Customer Migration V/A ("2011 URCMVA")
Average Use True-Up V/A ("2011 AUTUVA")
Tax Rate and Rule Change V/A ("2011 TRRCVA")
Earnings Sharing Mechanism D/A ("2011 ESMDA")
International Financial Reporting Standards Transition Costs D/A ("2011 IFRSTCDA")

Open Bill Service D/A ("2011 OBSDA")
Open Bill Access V/A ("2011 OBAVA)
Open Bill Revenue V/A ("2011 OBRVA")
Ex-Franchise Third Party Billing Services D/A ("2011 EFTPBSDA")
Mean Daily Volume Mechanism D/A ("2011 MDVMDA")

DSM Related Accounts
Demand Side Management V/A ("2011 DSMVA")
Lost Revenue Adjustment Mechanism ("2011 LRAM")
Shared Savings Mechanism V/A ("2011 SSMVA")

DATED at Toronto, December 08, 2010
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX "C" TO

FINAL RATE ORDER

BOARD FILE NO. EB-2010-0146

DATED December 8, 2010

ACCOUNTING TREATMENT FOR AN
UNBUNDLED RATE IMPLEMENTATION COST DEFERRAL ACCOUNT
("2011 URICDA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 URICDA is to record any costs, if required, of continuing with a manual solution or the costs required of an automated solution for offering Unbundled Rates 125, 300, 315 and 316. Costs to be recorded in the account include administrative, staffing, training, communication, customer education, and all other reasonably incurred costs associated with offering these rates and the additional nomination windows required for such rates.

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

Accounting Entries

1. To record costs related to the Unbundled Rate Implementation solution:

Debit:	2011 URICDA	(Account 179. 631)
Credit:	Accounts Payable	(Account 251. 010)

To record the costs associated with implementing Rates 125, 300, 315 and 316 through a continuing manual solution or an automated solution.

2. Interest accrual:

Debit:	Interest on 2011 URICDA	(Account 179. 641)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2011 URICDA using the Board approved EB-2006-0117 interest rate methodology.

APPrO INTERROGATORY #4

INTERROGATORY

Reference: Exhibit D Tab 1 Schedule 3 page 4 of 6, Paragraphs 12-16

Enbridge discusses its hybrid fuel cell plant and indicates that further development plans are not being pursued further at this time and that 2011 annual operating costs for O&M and Administrative costs are $114,159 and $78,665 respectively.

a) Please describe the nature of the administration costs being assigned to this project.

b) Please provide the 2011 electricity savings incurred at the VPC as a result of using this technology.

c) Please indicate if these costs include all fuel related costs to operate the equipment. If not, please detail the 2011 fuel costs associated with the plant.

d) Please provide Enbridge's expectations for the future operation of this facility.

e) Please provide a 5 year OM&A cost projection and electricity saving for the period 2012 - 2017.

f) Since Enbridge has no further development plans for the technology is there a business case to continue with this pilot? Please explain.

RESPONSE

a) Since Business Development and Customer Strategy ("BDCS") completed the pilot project development, and BDCS is not actively developing new projects at this time, the cost to operate and maintain the hybrid fuel cell plant was transferred to our Operations group as stated in EB-2012-0055 Exhibit D, Tab1, Schedule 3, page 4. In 2011, the miscellaneous administration costs were kept with BDCS. Example of these costs relate to legal fees, labor, fuel cell hydro costs, courier and brokerage fees. Most of these administrative costs were in support of the performance reporting, by the Company to Environment Canada, on the Hybrid Fuel Cell Technology and not related to the daily operation of the power plant. In exchange for this performance reporting, Environment Canada paid the Company

Witness: T. Maclean

$229,000 in 2011 funding support as part of the Asia Pacific Partnership Program. This funding was applied to the overall BDCS budget for the year.

b) The 2011 electricity savings are approximately $300,000. For added clarification, 2011 had partial operation of the power plant while several operational changes were completed during the year. Approximately 45% of the overall electricity budget was offset by the power plant.

c) The 2011 fuel related costs are approximately $140,000 for natural gas. These costs are not part of the O&M and Administrative costs in EB-2012-0055, Exhibit D, Tab1, Schedule 3, page 4

d) The plant will be operated as a building asset to provide energy to the VPC headquarters. Depending on electricity rates granted by the local utility or provincial government, some power that is excess to building requirements may be exported to the grid, the amount of which and extent of period, to be determined.

e) A five year projection of costs from 2013 forward is not required for the purposes of examining 2011 earnings sharing.

f) The power plant is a long-life asset and has the ability to operate beyond the pilot period. The ongoing business case includes i) generating operating savings against electricity purchases, ii) contributing to the Company's on-site generation for data centre and facilities reliability, iii) increased operational cost certainty with self-generation and favourable natural gas price forecasts, iv) maintaining operational technology so customers and policy makers can better understand how the technology can enhance the role of natural gas in a sustainable energy future, and v) provide ongoing contributions to the Company's Corporate Sustainability Results.

APPrO INTERROGATORY #5

INTERROGATORY

Reference: Exhibit D Tab 2 Schedule 1

a) Cushion gas is required by storage facilities to maintain a minimum pressure in the reservoir to enable injections and withdrawals. Please identify how cushion gas has been apportioned between utility and non-utility storage for those pools that provide both utility and no-utility services.

b) Please identify if any enhanced deliverability sold to non-utility customers is based on gas in inventory and provided by utility customers or if all enhanced deliverability is based on stand-alone assets and stand-alone gas in inventory that can operate independent of utility customers gas in inventory.

c) The B&V report has indicated that the costs for several projects such as the Seckerton #20 observation well (page 18 of the report) should be charged to the utility operation as it enhances the operation of the storage pool.

   i. Has this well been drilled? If so, has this confirmed the presence of commercial quantities of porous rich zones?

   ii. If the observation well confirms a porous zone, can the observation well be converted into an injection/withdrawal well?

   iii. If this observation well confirms a porous zone, is it Enbridge's intention to evaluate this porous zone as a possible expansion in reservoir size for the Seckerton pool or an enhancement of deliverability?

   iv. If it is Enbridge's intention to use all incremental space developed as non-utility space? If so, please explain why this this initiative is not considered a non-utility storage expense?

d) The B&V report indicates that when certain assets are being replaced at the end of the useful life, the replacement costs of assets would be charged to utility operations and the non-utility would be responsible for the incremental costs of any additional capacity added.

Witnesses: B. Pilon
J. Sanders
R. Feingold, Black & Veatch

i. Currently there is a portion of the total space and deliverability that is being used by utility and the balance is used by non-utility. B&V also acknowledge that assets usually provide both space and deliverability functions. To the extent that an asset needs to be replaced at the end of its useful life, rather than charge the like-for-like replacement costs sole to the utility operation, why would the replacement costs not be charged to the integrated operation firstly using the space and deliverability allocators and then the respective use of these by utility and non-utility operations? As Enbridge non-utility operations growth will the proportion of usage by non-utility operations grow over time?

ii. As all incremental space or deliverability is being developed for non-utility functions, it appears that to the extent that an asset is being replaced and the non-utility operation is offered the opportunity to get the economies of scale of additional capacity, then this is an asymmetric advantage to the non-utility operation. Please explain why the costs of the replacement, including the costs of adding capacity should not simply be allocated on the basis of capacity being allocated to each of the utility and non-utility operations?

<u>RESPONSE</u>

a) The cushion gas has not been apportioned between the utility and non-utility storage businesses in any of the pools to this point. The base gas volumes in the pools, and the costs associated with the base gas volumes, have not been impacted by the incremental assets or the incremental operations introduced with the non-utility business. If non-utility pools are developed as part of the integrated operations, or should other cushion gas be required for the development of unregulated storage services, the additional cushion gas will be acquired and owned by the non-utility storage business, as will the other facilities that are associated with the development of those pools.

b) The deliverability sold to non-utility customers is not derived from the working gas inventory provided by the utility. All incremental storage deliverability and capacity contracted to non-utility customers has been provided for through the addition of capital assets to the integrated storage system, by the unregulated business. These non-utility assets were designed and constructed so that the integrated operation is capable of meeting the needs of all.

c)

i. Yes it has been drilled. No commercially viable geological structures were found.

ii. It is technically possible to use this well as an injection and withdrawal well, however the well was not designed or located for this purpose and its gas flow capability would not warrant the cost of the additional facilities required to use it in that way.

iii. See i) and ii)

iv. This project was not intended to define or create incremental storage capacity. Please see the response to FRPO Interrogatory #7 at Exhibit I, Tab 4, Schedule 7.

i. Only when utility assets are being replaced at the end of their useful life, will the replacement cost be charged to the utility. And similarly, when a non-utility asset is being replaced at the end of its life, the replacement cost will be charged to the non-utility business. Given that the assets owned by each of the businesses are required for the continued operation of the integrated storage system, so as to meet the total of their respective needs, then both are responsible for the continued capabilities of their original assets. The non-utility business will be responsible for the incremental cost of any additional capacity.

i. The responsibility for asset replacement is determined by the ownership of the original asset for both the utility and the non-utility. The suggestion of sharing the costs on the basis of capacity does not provide a reasonable allocation of costs without considering the specifics of each project. For example, using the incremental increase in capacity and deliverability approach, as defined in the B&V, Schedule 5, the meter replacement project sharing resulted in the utility paying 58% of the project cost and the non-utility paying 42%. A ‘capacity-ratio’ driven sharing would have resulted in approximately 88% of the cost being charged to the utility with 12% to the non-utility. Conversely, for the replacement of the Corunna and Seckerton gathering pipelines, where the project was driven by the development of incremental capacity and deliverability, the replacement costs were allocated entirely to the non-utility. (i.e., 0% utility and 100% non-utility), notwithstanding the fact that the gathering pipelines will also be used by the utility storage business.

As the ownership of assets of the integrated facilities may continue to change, with the further development of unregulated capacities (i.e., more non-utility assets), this approach will likely result in a greater proportion of replacements costs being allocated to the non-utility business.

ii. See the response to d) i. above. The cost of all future replacements of non-utility assets will be borne by the non-utility business. This aspect of cost allocation for replacements is symmetrical. In the circumstance where capacity is added through a replacement project, all incremental costs for the additional capacity is allocated to the non-utility business.

Witnesses: B. Pilon
J. Sanders
R. Feingold, Black & Veatch

APPrO INTERROGATORY #6

INTERROGATORY

Reference Exhibit D Tab 2 Schedule 1

For non-utility transportation costs:

a) Please explain how the non-utility operation pays for costs to transport storage related gas to and from storage where Enbridge owns the pipeline assets, such as between Tecumseh and Dawn. Please explain.

b) Please indicate if the non-utility operation pays its proportionate share of any costs that Enbridge might incur under any commercial arrangements with Union related to Dawn operations, such as dehydration costs. Please explain.

RESPONSE

a) All gas volumes stored for non-utility customers are received and delivered at the custody transfer points available to Enbridge Gas storage. These are the Niagara Gas Transmission Ltd. (Corunna), Vector Pipeline (Sombra), Union Gas (Dawn) and TransCanada Pipelines (Dawn). The non-utility operation pays for these storage services through the monthly O&M allocations and through the cost of the facilities that it has installed. There is no transportation service required between the Enbridge Gas Storage and the custody points.

b) Enbridge has not passed along, to the unregulated business, any cost for Union services provided at Dawn. The only such cost that would potentially qualify is the cost for gas dehydration services at Dawn. The unregulated business has added, at its own cost, dehydration facilities at the Sombra compressor station with sufficient capacity to meet the maximum contracted flows of the unregulated business. This dehydration facility is also available to the utility as part of the integrated operations.

Witnesses: B. Pilon
J. Sanders
R. Feingold, Black & Veatch

BOARD STAFF INTERROGATORY #5

INTERROGATORY

Ref: ExB/Tab 4/S2/page 1

Please provide (more) detailed explanations for the following changes

a. Provision for uncollectibles (Line 5)

b. Pipeline integrity and safety (Line 13)

c. Public and government affairs (Line 14)

d. Non-departmental expenses (Line 15)

RESPONSE

a. The 2011 Provision for Uncollectibles increased by $10 million mainly due to adjustments required to correct deficiencies in accounts receivable reporting that were recognized in 2011. There are two categories of the deficiencies in accounts receivable reporting.

   i. First, is the impact of adjustments in 2010 and 2011 related to the true-up of the General Ledger and Accounts Receivable subledger stemming from the Company's new CIS implementation. This accounts for $7 million of the $10 million increase from 2010 to 2011.

   ii. Second, mass market arrears balances, which are used in the determination of uncollectible accounts, had been understated. This understatement related to sales for 2009 and 2010; and up to the time it was corrected in 2011. The Company recognizes bad debt in the month of sale. However, the Company follows a 27 month write-off cycle i.e., approximate time from sale to write-off is 27 months. Therefore, at any point in time, the Company's Allowance for Doubtful Accounts ("ADA") covers expected write-offs for approximately the previous 27 months of sales. Where it is determined that some of those previous months are over or under provided, then adjustments are made in subsequent months. The arrears balances were understated for sales related to the latter part of 2009 to 2011. Deterioration in collectability of mass

Witnesses: R. Lei
S. McGill

market accounts is partly offset by improvements in collections for large accounts and sundry AR, resulting in a net increase in the Provision of $3 million from 2010 to 2011.

Please refer to the response to CME Interrogatory #4 at Exhibit I, Tab 2, Schedule 4.

b. Higher damage prevention costs were driven by higher locates which increased significantly from 2010 to 2011 due to higher customer requests as a result of the increased awareness of people on “Call before you dig” and through the sewer safety program. Higher Environment, Health, and Safety (“EHS”) costs are primarily due to activities related to the Path to Zero initiative (focus on enhancing worker and contractor safety) as well as other EHS training and safety challenge initiatives.

c. The $0.8 million variance between the 2011 and 2010 actuals reflects a number of new initiatives including the Fire Marshal’s Public Safety Council Project Assist sponsorships, administration for the Low Income Assistance Program (“LEAP”), and also the increased costs for customer communications.

d. Non-departmental expenses increased by $5.3 million mainly due to Short Term Incentive Program cost increases of $5.5 million driven by higher performance multiplier and higher salary base.

Witnesses: R. Lei
S. McGill

CME INTERROGATORY #5

INTERROGATORY

Ref: Exhibit B, Tab 4, Schedule 2, Page 2 of 3

EGD states that the Legal and Corporate Security has increased by $2.7 million because of the centralization of legal expenses in the Legal Department. Please explain where legal expenses were incurred prior to the centralization in the Legal Department. Further, please explain why legal expenses were centralized in the Legal Department if the result is an increase rather than a decrease in overall legal expenses.

RESPONSE

Prior to 2011, some of the business specific external legal work used to be managed and paid by each individual department rather than by the Legal department, which was not viewed as the best practice anymore. As a result, starting in 2011 Enbridge Gas Distribution switched from the decentralized process to the new centralized process for legal expenses to enhance efficiency, governance, and transparency. Under the new process, the Legal department is responsible for managing all external legal engagement and consolidating all legal fees across the Company except for legal fees incurred for capital projects, and legal costs recorded in the Ontario Hearings Cost Variance Account and Manufactured Gas Plant Deferral Account. There are a number of anticipated benefits to the centralized approach:

- Single point of contact for internal users and external law firms
- Greater oversight of all legal services used by the Company
- Maximizing the use of internal resources where appropriate
- Ensure the most appropriate selection of external law firm (in terms of cost and expertise)
- Ensure the consistency of accounting for legal fees

Witness: R. Lei

A summary of Enbridge's actual external legal spend for the years 2007 to 2011 follows, with the possible exception of a small number of legal invoices that may have been paid without Legal department review.

Year	2007	2008	2009	2010	2011
Total EGD External Legal Spend	$6,395,630	$4,492,052	$3,668,113	$4,262,638	$3,944,139

The Table indicates that in 2011, there was a decrease rather than an increase in overall external legal expenses.

Witness: R. Lei

FRPO INTERROGATORY #1

INTERROGATORY

B - Rate Base
Issue 6: Is the allocation of the cost and use of capital assets between utility and non-utility ("unregulated") operations appropriate?

Ref: Exhibit B1, Tab 2, Schedule 2, Lines 100-117

We require additional information about EGD's utility and non-utility storage capital expenditures.

a) For each storage plant project, for each year, provide the total project cost, the project cost allocated to utility storage, and the cost allocated to non-utility ("unregulated") storage. Provide a detailed explanation of how EGD has allocated the costs between utility and non-utility storage for each project.

b) For each storage plant project, identify the portion of the total project cost (in dollars) that is a like-for-like replacement of existing equipment.

c) Please provide the same information requested in (a) and (b) for each utility and non-utility storage plant capital expenditure project exceeding $500,000 for the years 2007, 2008, 2009 and 2010.

d) Please complete the table below.

Storage Capital Expenditures ($ Millions)

	Utility	Non-Utility
2007		
2008		
2009	4.6	
2010	14.7	
2011	30.1	
2012 (estimate)	26.0	
2013 (budget)	20.1	

Witnesses: L. Au
D. Kelly
R. Lei
B. Pilon
J. Sanders

RESPONSE

a) For all but one of the projects included on pages 7 and 8 of Exhibit B1, Tab 2, Schedule 2, the costs have been or will be charged entirely to the regulated gas storage business. The one exception, the KVT Compressor Upgrade project shown on line 107, will not be after further consideration of the project. It will be charged to unregulated storage.

The cost of the project shown on line 110 of this exhibit, the Replacement/Upgrade of Storage Pool Metering, already reflects the regulated/unregulated split and the figures shown on this table are only the portion charged to regulated storage. A discussion of the allocation of those costs can be found in the response to Exhibit I, Issue B6, Schedule 8.11.

The basis for determining the allocation of capital project costs is depicted on Schedule 5 of the Black & Veatch Report that is filed as Exhibit D2, Tab 5, Schedule 1.

b) Of the storage projects included on pages 7 and 8 of this exhibit, the following are intended as like- for- like replacements of assets that, for reasons of either wear or obsolescence, were at the end of their useful life. In most cases the replacement is driven by the need to bring the asset up to an acceptable regulatory or corporate standard.

Line 100	Tecumseh Office Facilities
Line 102	MCC#1 Generator and Boiler
Line 108	Control Room Equipment Changes
Line 110	Replace/Upgrade Storage Pool Metering
Line 113	Mid/South Kimball (Pipeline) Road Crossing

In only one of these cases, was it necessary to identify a portion of the cost that was required to replace an original asset, and that was for the Storage Metering project. And that is discussed in the response to Exhibit I, Issue B4, Schedule 8.1.

There have been a number of other significant utility asset replacements projects done but, because they were done to bring the assets to a standard required for

Witnesses: L. Au
D. Kelly
R. Lei
B. Pilon
J. Sanders

unregulated storage needs, all of the costs were charged to the unregulated business. Examples are the replacement of wellheads on all wells in several storage pools and the replacement of the Corunna and Seckerton pool gathering pipelines.

c) The table below shows all of the capital projects over $500 K for both utility and non-utility storage over the period from 2007 through 2010 and indicates which would be considered 'replacement'.

Project Name	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Total Cost	Total Regulated	Total Unreg	Replace? (Y/N)
70.5223.06 KVTR Lean Burn Upgrade	713	208			921	921		N
70.5248.08 KVTR Lean Burn Upgrade	174	1,340	504		2,018	2,018		N
70.5260.08 Warehouse Construction		750	(748)	2,769	2,771	2,771		Y
70.5268.08 Dow-Moore Inline Inspection		679			679	679		N
70.5275.09 Dow Cavern Workovers			933	(11)	922	922		N
70.5302.10 TW#14 Drilling				2,206	2,206	2,206		Y
70.5320.10 Meter Run Upgrade				342	342	342		Y
70.5321.10 C of A Air & Noise Emissions				366	366	366		N
70.5330.10 DM/Cov/Bcreek/ChatD 3D Seismic				455	455	455		N
70.5333.10 3D Seismic KC & Ladysmith				3,297	3,297	3,297		N
70.5334.10 PhaseII Reservoir Simulation				119	119	119		N
74.0450.09 Unregulated Land Purchase			1,090	58	1,147		1,147	N
74.5200.07 Sombra Station - Gas Dehydrator	5,594	3,085	110	249	9,038		9,038	N
74.5201.07 Sombra Station - Compressor Addition	1,066	6,379	(269)	163	7,338		7,338	N
74.5202.07 Ladysmith NPS20 Pipeline loop	201	6,593	338	14	7,146		7,146	N
74.5203.07 Vector Pipeline-Sombra Interconnect	1,107	2,355	(19)		3,443		3,443	N
74.5204.07 Storage Reservoir Simulation	384	477	45		905		905	N
74.5206.08 TW#13h Drilling		551	1,560	29	2,139		2,139	N
74.5207.08 TKC#61H Drilling		1,837	322	25	2,183		2,183	N
74.5208.08 TKC#62H Drilling		2,206	49	27	2,282		2,282	N
74.5209.08 Sombra Extension to Dawn		4,338	364		4,702		4,702	N
74.5214.09 Growth Phase II - Vector AFE			1,385	2,951	4,337		4,337	N
74.5215.09 Integrity Testing & Upgrading			2,861	136	2,997		2,997	N
MP01 Major Projects [1]				3,131	3,131		3,131	N

(1) MPO1 includes well upgrade, pipeline and pool meter upgrade costs

Witnesses: L. Au
D. Kelly
R. Lei
B. Pilon
J. Sanders

d)

Storage Capital Expenditures ($ Millions)

	Utility	Non-Utility
2007	4.5	8.4
2008	5.9	28.2
2009	4.6	11.4
2010	14.7	4.0
2011	30.1	32.3
2012 (estimate)	26.0	2.1
2013 (estimate)	20.1	5.5

Witnesses: L. Au
D. Kelly
R. Lei
B. Pilon
J. Sanders

FRPO INTERROGATORY #1

INTERROGATORY

Reference: Ex. B, Tab 4, Schedule 2, page 1

Please provide the main drivers behind the substantial 2011 increase in Human Resources cost.

a. For each driver, please provide if this factor is a one year phenomenon or the trend is expected into 2012 and beyond.
b. To the extent possible, please explain what EGD is doing to mitigate these increases in 2012 and beyond.
c. Please break out from each of the respective years from 2007 Board-approved to 2011, the actual amount of performance based incentives.
    i. Please provide the details on any significant change to EGD performance based incentive programs during the Incentive Regulation term.

RESPONSE

a) The main drivers of the $4.9M increase are:

$1.6M	Severances
$0.4M	Salaries & Wages
$1.8M	Relocation
$0.3M	Employee Recognition Awards (service awards)
$0.2M	Training
<u>$0.6M</u>	CPP, EI, Employer's Health Tax
$4.9M	

Severances – The Company is placing a greater emphasis on performance management ensuring employees are achieving the required results. Employees are expected to achieve their performance objectives, which assists the Company in achieving operational and financial results. As the performance management process continues to be refined and implemented, the Company expects severances to increase over the next 2 or 3 years, and then stabilize afterwards.

Witnesses: R. Lei
S. Trozzi

Salaries & Wages – result of a merit salary increase of 3.5% plus five FTE's. Merit increases are not a one-time phenomenon. Enbridge expects salaries will continue to be adjusted as required to maintain competitiveness in the market.

Relocation – Enbridge is committed to employee development, which in some circumstances requires employees to move to new locations. These moves ensure that Enbridge is developing the required skills for the future, and also promotes employee engagement and retention. There has been a greater emphasis placed upon leadership development, this will increase the need for additional relocation funds to move employees to locations that will allow their continued development. Enbridge does not expect relocation costs to increase each year, however the Company believes they will remain stable.

Employee Recognition Awards – Employee recognition awards will continue as a greater number of employees who will be celebrating milestones as their years of service grow, and more employees are expected to retire. Enbridge anticipates employee recognition awards will remain constant.

Training & Development – Enbridge is increasing its focus on leadership development which will require a continued financial contribution to ensure we are delivering the required learning and development programs. As Enbridge enhances its leadership development programs, this focus will require additional funds for 2013.

CPP, EI, Employer's Health Tax – this is an uncontrollable expense driven by increases in salaries and wages for the Company. These expenses will continue to grow as salaries are adjusted.

c) Below is the breakdown of all performance based incentive programs at Enbridge. There have been no significant changes in the program during the IR term.

Performance Based Incentive Program	**2007 Board Approved**	**2007**	**2008**	**2009**	**2010**	**2011**
Short Term Incentive Program	$15M	$20M	$19M	$25M	$20M	$25M
Restricted Stock Units	N/A	85,300 grants	109,200 grants	134,200 grants	121,800 grants	112,900 grants
Performance Stock Units	N/A	9,600 grants	10,000 grants	13,600 grants	17,200 grants	18,000 grants
Incentive Stock Units	N/A	242,000 grants	415,600 grants	501,200 grants	359,000 grants	556,400 grants

/c

Witnesses: R. Lei
S. Trozzi

VECC INTERROGATORY #7

INTERROGATORY

Ref: Exhibit B, Tab 4, Schedule 2, Page 1

a) Provide (more) explanations for the following material changes
   i. Provision for Uncollectables (line 5)
   ii. Human Resources (line 11)
   iii. Public and Government Affairs (line 14)
   iv. Corporate Allocations (line 16)

   For each variance indicate the 2012 estimate and indicate whether the 2012 level of expense is continued in 2013.

b) Show the following for 2007-2011:
   i. CAM amounts
   ii. RCAM amounts
   iii. RCAM Amount Recovered from Ratepayers(Residual after Eliminations)

RESPONSE

a)

i. Please refer to the response to Board Staff Interrogatory 5, at Exhibit I, Tab 1, Schedule 5 . /u

ii. Please refer to the response to FRPO Interrogatory 1, at Exhibit I, Tab 4, Schedule 1.

iii. Please refer to the response to Board Staff Interrogatory 5, at Exhibit I, Tab 1, Schedule 5.

iv. The increase is primarily due to higher stock based compensation, insurance premium, general expenses, and IT shared services.

With respect to 2012 and 2013 level of expense, please refer to EB-2011-0354.

Witnesses: R. Lei
B. Yuzwa

b)

$ Millions	Actuals 2011	Actuals 2010	Actuals 2009	Actuals 2008	Actuals 2007
(i) CAM	43.4	36.7	34.3	32.2	27.7
(ii) RCAM	26.7	24.3	21.1	19.1	18.1

iii) There was no discrete/separate amount recovered in rates from 2008 to 2011 for RCAM (or any other particular item that is part of the Company's overall revenue requirement).

Witnesses: R. Lei
B. Yuzwa