Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2011-0354

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, 2013.

DECISION ON REVISED SETTLEMENT AGREEMENT AND PROCEDURAL ORDER NO. 6

November 2, 2012

Enbridge Gas Distribution Inc. ("Enbridge") filed an application on January 31, 2012 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Schedule B 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, 2013. The Board assigned file number EB-2011-0354 to the application and issued a Notice of Application dated March 2, 2012 (the "Notice"). The application was filed on the basis of US Generally Accepted Accounting Principles.

The Board issued its Decision on Preliminary Issue and Procedural Order No. 2 on May 16, 2012 which provided for, among other things, a settlement conference to be held between September 11 and 21, 2012. The Board directed that any settlement proposal arising from the settlement conference be filed on September 28, 2012. Enbridge advised the Board on September 28, 2012 and again on October 2, 2012 that the parties would need additional time to complete the settlement agreement. The Board received a settlement agreement dated October 3, 2012. The Board issued its Decision on Settlement Agreement and Procedural Order No. 5 on October 15, 2012. In that decision, the Board accepted the settlement agreement with the exception of one settled item, that being the matter of the Pension True-up Variance Account (the "PTUVA"). The Board indicated it would accept the settlement agreement if certain wording related to pension costs beyond 2013 was removed. The Board directed Enbridge to file a revised settlement agreement by October 26, 2012 incorporating new wording for the PTUVA, and allowed parties the option to consider other changes to the settlement agreement.

The revised Settlement Agreement dated October 26, 2012

The Board received a revised settlement agreement on October 26, 2012 (the "Settlement Agreement") together with a covering letter and appendices containing financial statements, submitted on behalf of Enbridge and all other parties to the Settlement Agreement. The Settlement Agreement, including the financial statement appendices, is attached as Appendix "A".

The Settlement Agreement included new wording on Issue D1, "Is the 2013 O&M budget appropriate?" but was otherwise unchanged from the original settlement agreement filed on October 3, 2012. The Settlement Agreement also indicated that there was a complete settlement on Issue D1. A key feature of the revised settlement is a new variance account, the Post-Retirement True-up Variance Account (the "PTUVA")[1], that would function to true-up both pension and other post-employment benefits ("OPEBs") in 2013 and successive years, throughout the term of Enbridge's upcoming Incentive Regulation Plan.

The covering letter explained the rationale underpinning the parties' approach to addressing the Board's Decision on Issue D1, including the reasons why the on-going true-up of post-retirement expenses is supported by all the parties, and why OPEBs is now included in the PTUVA.

[1] The Board acknowledges that the "PTUVA" acronym used in the revised settlement is the same as that which appears in the original settlement agreement, but now represents "post-retirement" amounts as opposed to only "pension" amounts.

The language in the Settlement Agreement addressed the Board's concerns about the on-going nature of the pension true-up feature and its concerns about the broad implications of pension recoverability.

The Board notes that for a number of issues the parties have agreed that they will make no objection should another party seek to raise the issue in the 2014 proceeding. In all cases the parties also acknowledge that the 2014 proceeding is anticipated to be an application for approval of an IR methodology during which such issues would not ordinarily be raised. The Board cautions parties that although they may not object if another party seeks to raise a particular issue within the context of such a proceeding, the Board panel in that proceeding will retain the discretion to determine the appropriate scope of that proceeding, and will not be bound by that aspect of this Settlement Agreement.

The Board has considered the Settlement Agreement and the context provided in the covering letter and finds that it adequately addresses the concerns raised in its October 15, 2012 Decision. The Board therefore accepts the Settlement Agreement.

Open Bill Access ADR Discussions

The Board is in receipt of a letter from Enbridge dated October 31, 2012 concerning the ADR discussions on the Open Bill Access agreement. The letter requested an extension to November 9, 2012 to allow parties to continue their discussions and raised the possibility of filing a Supplementary Settlement Agreement in respect of the outstanding issues on Issue D11 (the Open Bill Access Program issue). The Board grants the extension request.

Experts' Conference

The Board is in receipt of a letter from Enbridge dated October 31, 2012 concerning the filing of the experts' Joint Written Statement which was required on October 31, 2012. The letter requested an extension to November 9, 2012 to file the statement. The Board grants the extension request.

The Board also understands that parties may wish an extension to file submissions with respect to the process for the oral hearing of the evidence of the concurrent experts witness panel. The Board will extend the submissions deadline to November 13, 2012.

Draft Rate Order

The Board notes that the Settlement Agreement proposes that interim rates be established for January 1, 2013 on the basis that final rates would be set once the Board hears and determines cost of debt and capital structure issues (Issues E1 and E2). The Settlement Agreement refers to a Draft Rate Order (the "Draft Rate Order") for circulation by October 26, 2012. The Board notes that the circulation of this document is being withheld pending the Board's direction on the revised Settlement Agreement. The Draft Rate Order shall be circulated forthwith. As previously noted in Procedural Order No. 5, the Board will consider the appropriateness of the Draft Rate Order with a view to issuing an Interim Rate Order to allow for new rates commencing January 1, 2013.

The dates for the oral hearing announced in Procedural Order No. 5 shall remain.

THE BOARD ORDERS THAT:

1. The Joint Written Statement of the experts shall be filed with the Board and delivered to all parties on or before **November 9, 2012**.

2. Parties participating in the Open Bill Access Program ADR may continue their discussions until **November 9, 2012**.

3. Parties may file submissions with respect to process for the oral hearing of the evidence of the concurrent experts witness panel by **November 13, 2012**.

4. The oral hearing will commence at 9:30 a.m. in the Board's hearing room at 2300 Yonge Street Toronto on **November 19, 2012** and will continue on **November 20, 2012.**

5. An updated case timetable is attached as Appendix "B".

All filings to the Board must quote file number **EB-2011-0354**, be made through the Board's web portal at www.pes.ontarioenergyboard.ca/eservice/, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address, telephone number, fax number and e-mail address.

All filings shall use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available the document may be emailed to BoardSec@ontarioenergyboard.ca. Persons who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Persons who do not have computer access are required to file seven paper copies. If a document has been submitted through the Board's web portal an e-mail is not required. For all electronic correspondence and materials related to this proceeding, parties must include in their distribution the Case Manager, Colin Schuch at colin.schuch@ontarioenergyboard.ca and Senior Legal Counsel, Kristi Sebalj at kristi.sebalj@ontarioenergyboard.ca.

All communications should be directed to the attention of the Board Secretary and be received no later than 4:45 p.m. on the required date.

ADDRESS

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Toronto ON M4P 1E4
Attention: Board Secretary

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DATED at Toronto November 2, 2012

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX "A"
Enbridge Gas Distribution Inc.

EB-2011-0354

Settlement Agreement dated October 26, 2012

SETTLEMENT AGREEMENT

Enbridge Gas Distribution 2013 Rate Application

October 26, 2012

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PREAMBLE

This Settlement Agreement is filed with the Ontario Energy Board (the “OEB” or the “Board") in connection with the Application of Enbridge Gas Distribution Inc. (“Enbridge” or the “Company”), 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, 2013.

In Procedural Order No. 2, the Board established the process to address the application, and in a Decision and Order dated June 15, 2012, the Board established the Issues List for this application.

A Settlement Conference was held between September 11 and 20, 2012. Ken Rosenberg acted as the OEB-appointed facilitator for the Settlement Conference. This Settlement Agreement arises from the Settlement Conference.

Enbridge and the following intervenors, as well as Ontario Energy Board technical staff (“Board Staff”), participated in the Settlement Conference:

ASSOCIATION OF POWER PRODUCERS OF ONTARIO (APPrO)
BUILDING OWNERS AND MANAGERS ASSOCIATION TORONTO (BOMA)
CANADIAN MANUFACTURERS & EXPORTERS (CME)
CONSUMERS COUNCIL OF CANADA (CCC)
DIRECT ENERGY MANAGEMENT LIMITED (Direct Energy)
ENERCARE INC. (EnerCare)
ENERGY PROBE RESEARCH FOUNDATION (Energy Probe)
FEDERATION OF RENTAL-HOUSING PROVIDERS OF ONTARIO (FRPO)
GREEN ENERGY COALITION (GEC)
HEATING, VENTILATION, AND AIR CONDITIONING COALITION (HVAC)
JUST ENERGY ONTARIO LP (Just Energy)
LOW-INCOME ENERGY NETWORK (LIEN)
POLLUTION PROBE (Pollution Probe)
SCHOOL ENERGY COALITION (SEC)
SUMMITT ENERGY (Summit)
VISTA CREDIT CORP. (Vista)
VULNERABLE ENERGY CONSUMERS COALITION (VECC)

The Settlement Agreement deals with all of the issues on the Issues List. Each of these issues from the Issues List is listed in the Table of Contents, above.

All intervenors listed above participated in part or all of the Settlement Conference and subsequent discussions. Certain of the intervenors participated only in the “open bill” issue (Issue D11) and not in discussions on any other issues. Those intervenors are referred to herein as the “open bill issue participants”. The “open bill issue participants” are Direct Energy, EnerCare, GEC, HVAC, Just Energy, LIEN, Pollution Probe, Summitt and Vista. (As noted in Issue D11, other intervenors also participated in Issue D11. Those other intervenors also participated in the other issues, and are therefore not listed as “open bill issue participants”.)

Any reference to "parties" in this Settlement Agreement is intended to refer to Enbridge and the intervenors listed above, with one exception. That exception relates to the fact that the "open bill issue participants" only participated in the negotiation of Issue D11, and did not participate in the negotiation of any other issue. Therefore, within the "Issues" section of this Settlement Agreement (Issues B1 to O6), references to "all parties" are intended to refer to Enbridge and all intervenors listed above, except for (and not including) the open bill issue participants. .

Board Staff takes no position on any issue and, as a result, is not a party to the Settlement Agreement. Enbridge and all intervenors listed above have agreed to the settlement of the issues as described on the following pages. The open bill issue participants have only participated in the negotiation of Issue D11, and take no position on any other issue.

Best efforts have been made to identify all of the evidence that relates to each issue. The supporting evidence for each issue is identified individually by reference to its exhibit number in an abbreviated format; for example, Exhibit B1, Tab 3, Schedule 1 is referred to as B1-3-1. The identification and listing of the evidence that relates to each settled issue is provided to assist the Board.

The Settlement Agreement describes the agreements reached on the issues. The Settlement Agreement provides a direct link between each settled issue and the supporting evidence in the record to date. In this regard, the parties are of the view that the evidence provided is sufficient to support the Settlement Agreement in relation to the settled issues and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make findings agreeing with the proposed resolution of the settled issues. In the event that the Board does not accept the proposed settlement of any issue, then subject to the parties' agreement on non-severability set out in the final paragraph below, further evidence may be required on the issue for the Board to consider it fully.

According to the Board's *Settlement Conference Guidelines* (p. 3), the parties must consider whether a settlement proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. Enbridge and the other parties who participated in the Settlement Conference consider that no settled issue requires an adjustment mechanism other than those expressly set forth herein.

None of the parties can withdraw from the Settlement Agreement except in accordance with Rule 32 of the *Ontario Energy Board Rules of Practice and Procedure*. Finally, unless stated otherwise, a settlement of any particular issue in this proceeding is without prejudice to the positions parties might take with respect to the same issue in future proceedings, unless explicitly stated otherwise.

The parties agree that all positions, negotiations and discussion of any kind whatsoever that took place during the Settlement Conference and all documents exchanged during the conference that were prepared to facilitate settlement discussions are strictly confidential and without prejudice, and inadmissible unless relevant to the resolution of any ambiguity that subsequently arises with respect to the interpretation of any provision of this Settlement Agreement.

It is fundamental to the agreement of the parties that none of the provisions of this Settlement Agreement are severable. If the Board does not, prior to the commencement of the hearing of the evidence in this proceeding, accept the provisions of the Settlement Agreement in their entirety, there is no Settlement Agreement (unless the parties agree that any portion of the Settlement Agreement that the Board does accept may continue as a valid Settlement Agreement).

OVERVIEW

Through the Settlement Conference, and as set out in this Settlement Agreement, the parties (except for the open bill issue participants, who take no position on any issue except for D11) have reached agreement on 53 of the 56 issues in Enbridge's 2013 rate rebasing application (referred to herein as the "Settled Issues").

The overall impact of the Settled Issues is to reduce the revenue deficiency from the as-filed amount of $92.9 million (Exhibit M2, Tab 1, Schedule 2) to an amount of approximately $17.9 million. The revenue requirement and deficiency impact of the Settled Issues are set out in the ADR Financial Statements attached to this Settlement Agreement as Appendix A (Exhibit N1, Tab1, Schedule 1, Appendix A, part 1).

As noted above, all parties agree that the Settled Issues are a package. This means that none of the components of the Settlement Agreement should be considered in isolation, but instead they should be considered as a complete package. All parties agree that the package of Settled Issues represents a fair and reasonable agreement that is in the public interest.

There are three outstanding issues (the "Unsettled Issues").

One of these Unsettled Issues, relating to the Open Bill Access Program (Issue D11), is listed as "Partially Settled" because the aspects of the issue with ratemaking implications are settled, while one aspect of the issue with no ratemaking impact remains unsettled (related to the terms of the Open Bill Agreement for 2013).

The other two Unsettled Issues, related to equity thickness and cost of capital under a new thickness (Issues E1 and E2), have a potential revenue deficiency impact of up to $21.9 million. This means that if Enbridge is successful in its request for an increase in equity thickness from the current 36% level to the requested 42% level, then the final 2013 revenue deficiency will be approximately $17.9 million. If Enbridge is not completely successful in this regard, then the 2013 revenue deficiency will be reduced by up to $21.9 million, depending on the level of equity thickness and associated capital structure approved by the Board.

All parties agree that Enbridge should implement interim rates on January 1, 2013 that reflect the impact of the Settled Issues. For the purpose of interim rate implementation, all parties have agreed that Enbridge will use the current level of equity thickness (36%). All parties agree that the agreement to use the current level of equity thickness (36%) and associated capital structure ratios for implementation of interim rates is not intended as an indication or suggestion to the Board that 36% is the appropriate level of equity thickness for Enbridge in 2013. That issue is to be determined by the Board based upon the evidence and argument presented.

The revenue requirement and deficiency impact of the agreement for interim rates is set out in the ADR Financial Statements attached to this Settlement Agreement as Appendix A (Exhibit N1, Tab1, Schedule 1, Appendix A, part 2). The overall result of the implementation of the Settled Issues is a revenue sufficiency of approximately $4.0 million (using the current 36% level of equity thickness). This Agreement also includes Appendix B (Gas Costs) and Appendix C (Average Use Forecasts). All of the Appendices are incorporated into and form part of this Settlement Agreement.

The Appendices were prepared by Enbridge for the assistance of the Board and the other parties. The parties to this Agreement, other than Enbridge, are relying on the accuracy and completeness of the Appendices in entering into this Settlement Agreement.

All parties agree that any financial impact of the determination of the Unsettled Issues (Issues E1 and E2) should be implemented as part of Enbridge's first QRAM Application following the Board's decision on those matters.

THE ISSUES

B: RATE BASE

1. Is Enbridge's forecast level of capital spending in 2013 appropriate?

[Complete Settlement]

All parties agree that Enbridge's capital budget for 2013 is appropriately set at $387 million. Amounts to be spent in relation to the GTA Reinforcement and Ottawa Reinforcement projects, which projects will be considered by the Board in separate Leave to Construct Applications, will, if approved, be in addition to the $387 million capital budget. Those two projects have no rate impact in 2013.

This 2013 capital budget is approximately $97 million less than the as-filed budget of $483.9 million, to take account of the assumed $46 million impact from the agreed-upon $23 million property, plant and equipment related reduction to 2013 rate base (set out in Issue B2 below), as well as the fact that the forecast $51 million to be spent in 2013 on the GTA and Ottawa Reinforcement projects (Exhibit B1, Tab 3, Schedule 3) is outside of the $387 million budget.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
A2-1-2	Benchmarking Study
A2-2-1	2013 Regulatory Budget Assumptions and Guidelines Directive
B1-2-1	Rate Base – Capital Budget
B1-2-2	Details of Capital Budget Expenditures and Justification for Projects over $500,000
B1-2-3	Comparison of Capital Expenditures 2007 to 2013
B1-3-1	Asset Plan
B1-3-2	Asset Plan and 2013 Capital Budget
B1-3-3	Leave to Construct Projects

B1-4-1	Information Technology Capital Budget
B1-5-1	Storage Capital Expenditure
B2-2-1	EGD Asset Plan 2012 to 2021
B3-2-1	Utility Capital Expenditures Comparison 2013 Test Year and 2012 Estimate
B3-2-2	2013 Capital Expenditures by Project (Projects Exceeding $500,000)
B3-2-4	System Expansion Monitoring - 2013 Test Year
B4-2-1	Utility Capital Expenditures Comparison 2012 Bridge Year and 2011 Historical Year
B4-2-2	2012 Capital Expenditures by Project (Projects Exceeding $500,000)
B4-2-4	System Expansion Monitoring - 2012 Bridge Year
B5-2-1	Utility Capital Expenditures Comparison 2011 Historic and 2007 Board Approved
B5-2-2	2011 Capital Expenditures by Project (Projects Exceeding $500,000)
B5-2-4	System Expansion Portfolio - 2011 Historic Year
I-B1-1.1 to 20.4	Interrogatories on Issue B1
I-B2-4.4 and 4.5	CME Interrogatories #4 and 5
I-B2-8.1	FRPO Interrogatory #1
I-B3-1.1 to 14.1	Interrogatories on Issue B3
I-B4-1.1 to 14.1	Interrogatories on Issue B4
I-B5-1.1 to 20.1	Interrogatories on Issue B5
I-B6-8.1 to 14.1	Interrogatories on Issue B6
I-B7-5.1 to 20.1	Interrogatories on Issue B7
I TR 5 to 80	Evidence at Technical Conference (September 5, 2012)
JT1.1 to 1.9	Undertakings from Technical Conference (September 5, 2012)

2. Is the proposed Test Year Rate Base appropriate?

[Complete Settlement]

All parties agree that Enbridge's 2013 utility rate base, on an average of averages basis, is appropriately set at $4,162.0 million, as compared to the amount of $4,174.2 million set out at Exhibit M2, Tab 1, Schedule 3). This amount is derived as follows.

First, it reflects an agreed-upon reduction of $23 million in the average of averages 2013 rate base related to property, plant and equipment (i.e. $3,935.1 million, as compared to the amount of $3,958.1 million set out at Exhibit M2, Tab 1, Schedule 3, which was part of an overall rate base of $4,174.2 million).

Second, it reflects an increase in rate base of $10.2 million that results from the agreed-upon changes to depreciation rates set out at Issue D7 below.

Third, it reflects an increase in rate base of $0.6 million that results from a change in working capital, as discussed at Issue B7 below.

The updated Test Year Rate Base, reflecting the impact of these changes, is seen in the attached ADR Financial Statements (Exhibit N, Tab 1, Schedule 1, Appendix A, parts 1 and 2) at pages 2 through 5.

Evidence: The evidence in relation to this issue includes the following:

B1-1-1	Rate Base Evidence and Summaries
B1-2-2	Details of Capital Budget Expenditures and Justification for Projects over $500,000
B1-2-3	Comparison of Capital Expenditures 2007 to 2013

B3-1-1	Ontario Utility Rate Base – Comparison of 2013 Test Year to 2012 Bridge Year
B3-1-2	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2013 Test Year
B4-1-1	Ontario Utility Rate Base – Comparison of 2012 Bridge Year to 2011 Historical Year
B4-1-2	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2012 Bridge Year
B5-1-1	Ontario Utility Rate Base – Comparison of 2011 Historic to 2007 Board Approved
B5-1-2	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2011 Historic Year
I-B1-1.4 and 1.6	Board Staff Interrogatories #4 and 6
I-B1-2.1	APPrO Interrogatory #1
I-B1-3.1	BOMA Interrogatory #1
I-B1-4.1 to 4.2	CME Interrogatories #1 and 2
I-B1-5.3- 5.4 and 5.11-5.14 and 5.16	CCC Interrogatories #3 and 4 and 11 to 14 and 16
I-B1-7.1to 7.2 and 7.4	Energy Probe Interrogatories #1, 2 and 4
I-B1-14.1	SEC Interrogatory #1
I-B1-20.1	VECC Interrogatory #1
I-B2-1.1 to 8.1	Interrogatories on Issue B2
I-B4-5.1	CME Interrogatory #1
I-B6-8.1 to 14.1	Interrogatories on Issue B6

3. Is the proposed Information Technology Capital Budget appropriate?

[Complete Settlement]

See Issue B1, above. The Information Technology Capital Budget is part of the overall agreed-upon capital budget of $387 million for 2013.

Evidence: The evidence in relation to this issue includes the following:

B1-2-2	Details of Capital Budget Expenditures and Justification for Projects over $500,000
B1-4-1	Information Technology Capital Budget
I-B1-20.2	VECC Interrogatory #2
I-B2-1.14 to 1.16	Board Staff Interrogatories #14 to 16
I-B3-1.1 to 14.1	Interrogatories on Issue B3
I-B6-8.1 to 14.1	Interrogatories on Issue B6
I TR 66 to 71	Evidence at Technical Conference (September 5, 2012)
JT1.8	Undertaking from Technical Conference (September 5, 2012)

4. Is the proposed budget for Storage Capital Expenditure appropriate?

[Complete Settlement]

See Issue B1, above. The Storage Capital Expenditure Budget is part of the overall agreed-upon capital budget of $387 million for 2013.

Evidence: The evidence in relation to this issue includes the following:

B1-2-2	Details of Capital Budget Expenditures and Justification for Projects over $500,000

B1-5-1	Storage Capital Expenditure
I-B4-1.1 to 14.1	Interrogatories on Issue B4
I TR 5 to 43	Evidence at Technical Conference (September 5, 2012)
JT1.1 to 1.5	Undertakings from Technical Conference (September 5, 2012)

5. Is the forecast of Customer Additions appropriate?

[Complete Settlement]

All parties agree that Enbridge's forecast of 38,896 customer additions for 2013, as set out at Exhibit B3, Tab 2, Schedule 3, is appropriate for capital budget purposes.

Evidence: The evidence in relation to this issue includes the following:

B2-1-1	Economic Feasibility Procedure and Policy
B3-2-3	Gross Customer Additions and Average Cost per Customer Addition Budget 2013 and 2012 Estimate
B4-2-3	Gross Customer Additions and Average Cost per Customer Addition 2012 Estimate and 2011 Historic
B5-2-3	Gross Customer Additions and Average Cost per Customer Addition Actual 2011 and 2011 Board Approved
I-B5-1.1 to 20.1	Interrogatories on Issue B5

6. Is the allocation of the cost and use of capital assets between utility and non-utility ("unregulated") operations appropriate?

[Complete Settlement]

All parties agree to the overall 2013 capital and O&M budgets (as set out at Issues B1 and D1), which include the impact of allocations of costs between utility and non-utility ("unregulated") storage operations.

In relation to the EB-2012-0055 case (Enbridge's 2011 ESM case), all parties agree that because this Settlement Agreement does not result in any change to Enbridge's approach to the allocation of costs between regulated and unregulated storage activities that, when applied to the 2011 allocations would affect the 2011 ESMDA, there is no need for any adjustment to the 2011 ESMDA in relation to allocation of storage costs. (Reference, OEB Decision and Order on Settlement Agreement in EB-2012-0055, dated September 17, 2012 at page 2).

It is agreed that EGD will not raise any procedural objection if any party seeks approval of different methodologies for allocation of the cost and use of capital assets or O&M allocations between utility and non-utility storage operations in the 2014 rates proceeding (which is anticipated to be an application for approval of an IR methodology, which is not the type of case where such issues would ordinarily be raised). All parties are free to take whatever positions they determine with respect to this issue at that time.

Evidence: The evidence in relation to this issue includes the following:

B1-2-2	Details of Capital Budget Expenditures and Justification for Projects over $500,000
B1-5-1	Storage Capital Expenditure
D2-5-1	Regulated Unregulated Storage Cost Allocation – Black & Veatch
I-B4-5.1	CCC Interrogatory #1
I-B5-5.3	CCC Interrogatory #3
I-B6-8.1 to 14.1	Interrogatories on Issue B6
C1-1.2-1	Board Staff Interrogatory #2
I TR 5 to 43	Evidence at Technical Conference (September 5, 2012)
JT1.1 to 1.5	Undertakings from Technical Conference (September 5, 2012)
2 TR 25 to 39 and 197 to 202	Evidence at Technical Conference (September 6, 2012)
JT2.1 and 30	Undertakings from Technical Conference (September 6, 2012)

7. Is the proposed working capital allowance appropriate?

[Complete Settlement]

All parties agree that the proposed 2013 working capital allowance of $216.1 million (as set out at Exhibit M2, Tab 1, Schedule 3, page 1) will be increased by $0.6 million, to take account of two settled items.

First, there is an increase in working cash allowance of $1.5 million that results from the agreed-upon changes to the overall O&M budget amount, as discussed at Issue D1 below. This outcome results from the fact that the net lag day credit within the working cash calculation will be applied to a lower level of O&M budget as compared to the pre-filed evidence.

Second, there is a decrease in gas in storage of $0.9 million to take account of the agreed-upon changes to the gas volume budget, as discussed at Issue C2 below.

Evidence: The evidence in relation to this issue includes the following:

B1-1-1	Rate Base Evidence and Summaries
B3-1-3	Working Capital Components of Average of Monthly Averages 2013 Test Year
B4-1-3	Working Capital Components of Average of Monthly Averages 2012 Bridge Year
B4-1-3	Working Capital Components of Average of Monthly Averages 2013 Historic Year
I TR 72 to 74	Evidence at Technical Conference (September 5, 2012)
JT1.9	Undertaking from Technical Conference (September 5, 2012)

C: OPERATING REVENUE

1. Is Enbridge's revenue forecast appropriate?

[Complete Settlement]

Subject to changes set out below related to Gas Volume Forecast (Issue C2) and Transactional Services (Issue C6), all parties agree that Enbridge's revenue forecast is appropriate. The updated revenue forecast, reflecting the impact of these changes, is seen in the attached ADR Financial Statements (Exhibit N, Tab 1, Schedule 1, Appendix A, parts 1 and 2) at page 6.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
A2-2-1	2013 Regulatory Budget Assumptions and Guidelines Directive
C1-1-1	Operating Revenue Summary
C1-2-1	Revenue Forecast
C1-4-1	Transactional Services
C1-5-1	Other Service and Late Payment Penalty Revenue
C3-1-1	Utility Operating Revenue 2013 Test Year
C3-1-2	Comparison of Utility Operating Revenue Budget 2013 and Estimate 2012
C3-2-1	Customers, Volumes and Revenues by Rate Class - 2013 Budget
C3-2-2	Comparison of Average Customer Numbers by Rate Class 2013 Budget and 2012 Estimate
C3-3-1	Details of Other Revenue Budget 2013 and Estimate 2012
C3-4-1	Transactional Services 2013 Test Year Budget Revenue and Cost Components
C3-5-1	NGV Rate of Return 2013 Test Year
C4-1-1	Utility Operating Revenue 2012 Bridge Year
C4-1-2	Comparison of Utility Operating Revenue 2012 Estimate and 2011 Historic
C4-1-3	Comparison of Utility Operating Revenue 2012 Estimate and Board 2007 Budget Approved
C4-2-1	Customers, Volumes and Revenues by Rate Class - 2012 Estimate
C4-2-2	Comparison of Average Customer Numbers by Rate Class 2012 Estimate and 2011 Historic
C4-3-1	Details of Other Revenue 2012 Estimate and 2011 Historic
C4-3-2	Details of Other Revenue 2012 Estimate and 2007 Board Approved
C4-4-1	Transactional Services 2012 Bridge Year Estimate vs. 2007 Board Approved Budget Revenue and Cost Components
C4-5-1	NGV Rate of Return 2012 Bridge Year
C5-1-1	Utility Operating Revenue 2011 Historic (Estimate)
C5-1-2	Comparison of Utility Operating Revenue 2011 Historic Year and 2007 Board Approved
C5-2-1	Customers, Volumes and Revenues by Rate Class –2011 Historic
C5-3-1	Details of Other Revenue 2011 Historic vs. 2007 Board Approved
C5-4-1	Transactional Services 2011 Historic vs. 2007 Board Approved Budget Revenue and Cost Components
C5-5-1	NGV Rate of Return 2011 Historic Year
I-C1-1.1 to 5.1	Interrogatories on Issue C1
I-C5-1.1 to 20.1	Interrogatories on Issue C6
I-C5-1.1 to 20.1	Interrogatories on Issue C7

2. Is Enbridge's gas volume forecast appropriate?

[Complete Settlement]

All parties agree that Enbridge will increase its forecast number of customers (active customer meters, or "unlocks") for 2013 by 4,500 from the estimate set out at Exhibit C1, Tab 3, Schedule 2 (page 1), such that the forecast total customers for 2013 will be 2,025,462. This change arises from the agreement of all parties that Enbridge's forecast of customers for 2012 was understated by 4,500, which agreement results in an increase to the forecast starting number of customers for 2013. This change has no impact on the customer additions forecast for 2013, which is settled under Issue B5 above.

All parties also agree that Enbridge's gas volume forecast for 2013 will be updated to take account of the changes to degree day forecasts in Issue C3 (below).

Enbridge's updated gas volume forecast reflecting the changes noted above is seen in the updated Summary of Gas Costs to Operations attached as Appendix B (Exhibit N1, Tab 1, Schedule 1, Appendix B).

Evidence: The evidence in relation to this issue includes the following:

C1-3-1	Gas Volume Budget
C1-3-2	2013 Gas Volume Budget Update
C2-3-1	Budget Degree Days
C2-3-2	Updated 2013 Budget Degree Days
C4-2-3	Comparison of Gas Sales and Transportation Volume by Rate Class 2012 Estimate and 2011 Historic
C4-2-4	Comparison of Gas Sales and Transportation Revenue by Rate Class 2012 Estimate and 2011 Historic
C4-2-5	Comparison of Gas Sales and Transportation Volume by Rate Class 2012 Estimate and 2007 Board Approved
C5-2-2	Comparison of Gas Sales and Transportation Volume by Rate Class 2011 Historic and 2010 Historic
C5-2-3	General Service System-Wide Normalized Average Use
C5-2-4	Comparison of Gas Sales and Transportation Volume by Rate Class 2011 Historic and 2007 Board Approved
C5-2-5	General Service Average Uses Historical Normalized Actual and Board Approved Fiscal and Calendar Years
C5-2-6	Large Volume (Contract) Customer Demand Historical Normalized Actual and Board Approved Fiscal and Calendar Years
D2-6-1	Unaccounted For Gas Study
D3-4-1	Unbilled and Unaccounted-for Gas Volumes
D4-4-1	Unbilled and Unaccounted-for Gas Volumes
D5-4-1	Unbilled and Unaccounted-for Volumes 2011 Historic vs. 2007 Board Approved
I-C1-4.1	CME Interrogatory #1
I-C2-5.1 to 11.1	Interrogatories on Issue C2
I-C3-7.1 to 20.1	Interrogatories on Issue C3
I-C4-1.1 to 20.2	Interrogatories on Issue C4
I-C5-1.1 to 20.2	Interrogatories on Issue C5
I-C5-1.1 to 20.2	Interrogatories on Issue C5

3. Is Enbridge's degree day forecast for each of the Company's delivery areas (EDA, CDA, and Niagara) appropriate?

[Complete Settlement]

All parties agree that Enbridge's degree day forecasts for 2013 for the Eastern Delivery Area and the Niagara Delivery Area, as set out in the Company's updated evidence at Exhibit C2, Tab 3, Schedule 2 (page 2), are appropriate.

All parties agree that for 2013, Enbridge will use the 10 year moving average model to forecast degree days for the Central Delivery Area. That agreement is based upon the Company's evidence in response to Exhibit I, Issue C3, Schedule 7.1 which indicates that the 10 year moving average model is currently the highest ranked forecasting model (using data up to and including 2011) for the Central Delivery Area. As set out in response to Exhibit I, Issue C3, Schedule 7.1 (page 3), this will result in a 2013 Environment Canada degree day forecast of 3,713 for the Central Delivery Area, which is 201 degree days higher than had been indicated the Company's updated evidence, which used the 20 year trend model.

It is agreed that no party will raise any procedural objection if Enbridge seeks approval of different degree day methodologies for any of its delivery areas in its 2014 rates proceeding (which is anticipated to be an application for approval of an IR methodology, which is not the type of case where such issues would ordinarily be raised). All parties are free to take whatever positions they determine with respect to this issue at that time.

Evidence: The evidence in relation to this issue includes the following:

C2-3-1	Budget Degree Days
I-C3-7.1 to 20.1	Interrogatories on Issue C3
JT2.28 and 2.33 to 2.34	Undertakings from Technical Conference (September 6, 2012)
JT2-EP1	Supplementary Undertaking from Technical Conference (September 6, 2012)
2 TR 189 to 196 and 207 to 211	Evidence at Technical Conference (September 6, 2012)
JT2.28, 2.33 and 2.34	Undertaking from Technical Conference (September 6, 2012)

4. Is the Average Use forecast appropriate?

[Complete Settlement]

All parties agree that Enbridge's average use forecast for 2013, which has been updated to take account of the changes in degree day forecast as set out at Issue C3 above, is appropriate. The updated average use forecast is set out at Appendix C (Exhibit N1, Tab 1, Schedule 1, Appendix C).

Evidence: The evidence in relation to this issue includes the following:

C1-3-1	Gas Volume Budget
C5-2-6	Large Volume (Contract) Customer Demand Historical Normalized Actual and Board Approved Fiscal and Calendar Years
I-C4-1.1 to 20.2	Interrogatories on Issue C4
2 TR 202 to 206	Evidence at Technical Conference (September 6, 2012)
JT2.32	Undertaking from Technical Conference (September 6, 2012)

5. Is the forecast level of Unaccounted For (UAF) gas volumes appropriate?

[Complete Settlement]

For the purpose of settlement, all parties accept the level of UAF forecast by Enbridge.

Evidence: The evidence in relation to this issue includes the following:

D2-6-1	Unaccounted For Gas Study
D3-4-1	Unbilled and Unaccounted-for Gas Volumes
D4-4-1	Unbilled and Unaccounted-for Gas Volumes
D5-4-1	Unbilled and Unaccounted-for Volumes 2011 Historic vs. 2007 Board Approved
I-C5-1.1 to 20.2	Interrogatories on Issue C5
2 TR 155 to 189 and 196 to 197	Evidence at Technical Conference (September 6, 2012)
JT2.21 to 2.23; 2.25 to 2.26; and 2.29	Undertakings from Technical Conference (September 6, 2012)
	Supplementary Undertakings from Technical Conference (September 6, 2012)

6. Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

[Complete Settlement]

All parties agree to a change in Enbridge's Transactional Services (TS) sharing methodology for 2013. The changes are the following:

a. All TS net revenues (total storage and transportation TS revenues less associated costs) will be shared 90/10 between ratepayers and Enbridge's shareholder.

b. Enbridge will include a credit of $12 million in revenue requirement for 2013 related to an anticipated ratepayer share of TS net revenues, with a guarantee of $8 in ratepayer share.

c. The ratepayer share of 2013 TS net revenues will be tracked in the 2013 Transactional Services Deferral Account. In the event that the ratepayer share of 2013 TS net revenues exceeds $12 million, then such amounts over $12 million will be credited to ratepayers along with the clearance of the Company's other 2013 deferral and variance accounts. In the event that the ratepayer share of 2013 TS net revenues is less than $12 million, then Enbridge will be credited with the difference between the actual ratepayer share of 2013 TS net revenues and $12 million, to a maximum credit to Enbridge of $4 million.

It is agreed that no party will raise any procedural objection if Enbridge or any other party requests a different TS sharing methodology in Enbridge's 2014 rates proceeding (which is anticipated to be an application for approval of an IR methodology, which is not the type of case where such issues would ordinarily be raised). All parties are free to take whatever positions they determine with respect to this issue at that time.

All parties agree that the acceptance of the inclusion of TS revenues related to FT long haul optimization in the determination of Enbridge's net TS revenues for 2013 is without prejudice to the position that any party may take on any issues related to the determination of Enbridge's net TS revenues within the 2011 and 2012 ESM proceedings, or in Enbridge's 2014 rate proceeding.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
C1-4-1	Transactional Services
C3-4-1	Transactional Services 2013 Test Year Budget Revenue and Cost Components
C4-4-1	Transactional Services 2012 Bridge Year Estimate vs. 2007 Board Approved Budget Revenue and Cost Components
C5-4-1	Transactional Services 2011 Historic vs. 2007 Board Approved Budget Revenue and Cost Components
I-C5-1.1 to 20.1	Interrogatories on Issue C6
I-DV1-8.2	FRPO Interrogatory #2

7. Is Enbridge's forecast of other service and late payment penalty revenues, including the methodologies used to cost and price those services, appropriate?

[Complete Settlement]

For the purposes of settlement, all parties accept Enbridge's forecast of other service and late payment penalty revenues, as set out at Exhibit C1, Tab 5, Schedule 1, including the methodologies used to cost and price those services.

Evidence: The evidence in relation to this issue includes the following:

C1-5-1	Other Service and Late Payment Penalty Revenue
C3-3-1	Details of Other Revenue Budget 2013 and Estimate 2012
C4-3-1	Details of Other Revenue 2012 Estimate and 2011 Historic
C4-3-2	Details of Other Revenue 2012 Estimate and 2007 Board Approved
C5-3-1	Details of Other Revenue 2011 Historic vs. 2007 Board Approved
I-C5-1.1 to 20.1	Interrogatories on Issue C7

D: OPERATING COSTS

1. Is the 2013 O&M budget appropriate?

[Complete Settlement]

In its prefiled evidence, Enbridge requested a total O&M budget of $438.1 million, comprised of five elements as set out below (Exhibit D1, Tab 3, Schedule 1):

Customer Care service charges	$89.4 million
DSM	$31.4 million
Pension costs	$37.3 million
RCAM	$32.1 million
All other O&M	$247.8 million
	$438.1 million

As set out below (Issues D9 and D13), the DSM and Customer Care costs have already been approved in separate proceedings. All parties agree that the amounts for the RCAM and "All other O&M" budgets will be combined, that Enbridge will include its OPEB costs of $5.5 million with pension costs (and not with the "All other O&M" costs) and that Enbridge will reduce the resulting combined "All other O&M" budget for 2013 by $22.8 million. All parties agree, for the purposes of settlement, that Enbridge's O&M budget for pension costs and OPEB costs is accepted as filed, subject to the variance account treatment described below.

As a result, parties agree, for the purposes of settlement, that Enbridge's 2013 O&M budget is appropriately set at $414.9 million, which represents a reduction of $22.8 million from the as-filed budget as set out in Impact Statement #2 (Exhibit M2). The budget is comprised of the following:

Customer Care service charges	$89.4 million
DSM	$31.4 million
Pension and OPEB costs	$42.8 million
All other O&M	$251.3 million
	$414.9 million

The "All other O&M" amount is an envelope amount, and is not specifically allocated to any particular O&M expenses.

The updated O&M budget, reflecting the impact of these changes, is seen in the attached ADR Financial Statements (Exhibit N, Tab 1, Schedule 1, Appendix A, parts 1 and 2) at page 6.

The parties acknowledge that issues related to pension and OPEBs expenses, including the volatility of such expenses (the "Pensions Issue") affect many entities regulated by the Board, and that the Board may determine at the appropriate time to institute a generic review of the Pensions Issue. Unless and until the Board issues a generic decision or other policy determination on the Pensions Issue, applicable to regulated entities that would include Enbridge during the term of its upcoming IR plan, the parties have agreed to a variance account that will function so as to effect a true-up of pension and OPEBs expenses, as well as a smoothing of pension and OPEBs differences over future years. All parties agree that if the Board does undertake a generic review of the Pensions Issue, then all parties will support Enbridge's continuing recovery of its pension and OPEB expenses throughout the term of Enbridge's upcoming IR plan, provided that such recovery is designed in a manner to ensure that Enbridge recovers no more or less than its actual pension and OPEB expenses during each year of the IR plan.

To effect this result, all parties agree that the 2013 pension expenses and OPEBs expenses, totalling $42.8 million ($37.3 million in pension expenses plus $5.5 million in OPEBs expenses, both determined on an accrual basis) are to be trued-up, such that Enbridge ultimately recovers in rates only the actual amounts of its 2013 pension and OPEBs expense. All parties agree to the creation of a Post-Retirement True-Up Variance Account (PTUVA) which will record any differences between the Company's forecast pension and OPEBs expense and the actual pension and OPEBs expense (both determined on an accrual basis). In future years, and in the absence of any new Board decision or policy on the Pensions Issue that is made to apply to Enbridge during the term of its upcoming IR plan, the PTUVA will include any uncleared balances from previous years, as well as the difference between the amount otherwise included in that year's rates, and actual pension and OPEBs expenses for that year (again, on an accrual basis). For the Test Year, the 2013 PTUVA will record differences between the forecast 2013 pension and OPEBs expense of $42.8 million and the actual 2013 pension and OPEBs expense. To be clear, the OPEBs expenses that are subject to the true-up approach described in this paragraph are the current year OPEBs expenses. This true-up approach does not apply to the $90 million of OPEBs costs allowed for recovery commencing in 2013, which is addressed in Issues D4 and DV2, below.

The parties agree that the 2013 PTUVA will be cleared in a manner that will allow for all variances between $42.8 million and actual pension and OPEBs expenses to be recorded and cleared, subject to the condition that any amounts in excess of $5 million (credit or debit) will be transferred into the next year's account, so that large variances can be cleared over time (smoothed). Under this approach, the maximum amount (debit or credit) that will be cleared from the 2013 PTUVA will be $5 million, and any remaining amounts will be transferred to the 2014 PTUVA for future clearance.

There is no agreement as to the clearance methodology that will be applied to the PTUVA in future years beyond 2013. No party will raise any procedural objection if Enbridge or any other party seeks approval of a different clearance methodology for the PTUVA as part of Enbridge's 2014 rates proceeding (which is anticipated to be an application for approval of an IR methodology, which is not the type of case where such issues would ordinarily be raised). All parties are free to take whatever positions they determine with respect to the PTUVA clearance methodology at that time.

The parties agree that this approach will continue until the earlier of a) a decision by the Board to implement a policy respecting the Pensions Issue that is applicable to Enbridge during the term of its upcoming IR plan, and b) the next rebasing application for Enbridge.

The parties further agree that their commitment to support Enbridge's recovery of pension and OPEB expenses on an actual basis during the term of its upcoming IR plan should not be interpreted as any broad precedent or endorsement of that approach. To the contrary, the parties are agreeing to this approach in the specific circumstances of the overall settlement of this case, which include tradeoffs and compromises on a variety of items to arrive at an overall resolution in the interest of ratepayers and the Company.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
A2-1-2	Benchmarking Study
A2-2-1	2013 Regulatory Budget Assumptions and Guidelines Directive
D1-1-1	Operating Cost Summary
D1-3-1	Operating Maintenance Costs
D1-3-2	Employee Expenses and Workforce Demographics
D1-4-1	Corporate Cost Allocation ("CAM")
D1-4-2	Updated Corporate Cost Allocation ("CAM")
D1-24-1	Regulatory Adjustments and Eliminations – CAM Elimination to Adjust for RCAM
D1-24-2	Updated Regulatory Adjustments and Eliminations - CAM Elimination to Adjust for RCAM
D1-7-1	Demand Side Management Budget
D1-9-1	Open Bill Access
D1-10-1	Finance Department - O&M Budget
D1-12-1	CIS / Customer Care – A Review of the Treatment of CIS/Customer Care Costs as a Result of the

	ADR Settlement in EB-2011-0226
D1-13-1	Energy Supply, Storage Development and Regulatory – O&M Budget
D1-14-1	Law Department – O&M Budget
D1-15-1	Operations – O&M Budget
D1-16-1	Information Technology – O&M Budget
D1-17-1	Business Development and Corporate Strategy
D1-18-1	Human Resources – O&M Budget
D1-20-1	Pipeline Integrity and Safety – O&M Budget
D1-21-1	Public and Government Affairs – O&M Budget
D1-22-1	Non Departmental Expenses – O&M Budget
D2-3-1	Compensation Study – A Comparison of the EGDI Compensation Program
D3-1-1	Cost of Service 2013 Test Year
D3-2-1	Cost of Service Comparison of Utility Cost and Expenses Budget 2013 and Estimate 2012
D3-2-2	Operating and Maintenance Expense by Department 2013 Test Year
D3-2-3	Operating and Maintenance Expense by Cost Type - 2013 Test Year vs. 2012 Bridge Year
D3-2-4	Salaries and Wages and FTE Forecast 2013 Test Year
D4-1-1	Cost of Service 2012 Bridge Year
D4-2-1	Cost of Service Comparison of Utility Cost and Expenses 2012 Estimate and 2011 Historic
D4-2-3	Operating and Maintenance Expense by Department 2012 Estimate
D4-2-4	Operating and Maintenance Expense by Cost Type 2012 Estimate and 2011 Historic
D4-2-5	Salaries and Wages and FTE Estimate 2012 Bridge Year
D5-1-1	Cost of Service 2011 Historic
D5-2-1	Cost of Service Comparison of Utility Costs and Expenses Actual 2011 and 2007 Board Approved
D5-2-2	Operating and Maintenance Expense by Department 2011 Historic
D5-2-3	Operating and Maintenance Expense by Cost Type 2011 Historic and 2007 Board Approved
D5-2-4	Salaries and Wages and FTE 2011 Historic
D5-2-5	O&M Variances 2007 - 2011
I-D1-1.1 to 20.5	Interrogatories on Issue D1
I-D2 to D26	Other Interrogatories on D series issues
I TR 82 to 160	Evidence at Technical Conference (September 5, 2012)
JT1.11 to 1.22	Undertakings from Technical Conference (September 5, 2012)
2 TR 182 to 184	Evidence at Technical Conference (September 6, 2012)
JT2.27	Undertaking from Technical Conference (September 6, 2012)

2. Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

[Complete Settlement]

For the purposes of settlement, all parties accept Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs, when updated to take account of the updated gas volume budget (Issue C2).

The impact of the updated gas volume budget on Enbridge's gas supply requirements can be seen in the updated Summary of Gas Costs to Operations (Exhibit N1, Tab 1, Schedule 1, Appendix B) and the impact to Enbridge's gas costs are seen in the ADR Financial Statements (Exhibit N1, Tab 1, Schedule 1, Appendix A, parts 1 and 2) at page 6.

All parties agree that the acceptance of Enbridge's 2013 gas supply plan is without prejudice to the position that parties may take in Enbridge's 2014 rates proceeding, or in Enbridge's 2011 and 2012 ESM proceedings, in relation to the issue described above at Issue C6 related to FT long haul optimization in the determination of Enbridge's net TS revenues.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Operating Cost Summary
D1-2-1	Gas Costs, Transportation and Storage
D1-2-2	Status of Transportation Contracts
D1-2-4	Curtailment Compliance Report
D3-1-1	Cost of Service 2013 Test Year
D3-2-1	Cost of Service Comparison of Utility Cost and Expenses Budget 2013 and Estimate 2012
D3-3-1	Summary of Gas Cost to Operations
D3-3-2	Summary of Storage and Transportation Costs Fiscal 2013
D3-3-3	Peak Day Supply Mix
D3-3-4	Monthly Pricing Information
D3-3-5	Gas Supply/Demand
D4-1-1	Cost of Service 2012 Bridge Year
D4-2-1	Cost of Service Comparison of Utility Cost and Expenses 2012 Estimate and 2011 Historic
D4-3-1	Summary of Gas Cost to Operations 2012 Bridge Year
D4-3-2	Summary of Storage & Transportation Costs Fiscal 2012
D4-3-3	Peak Day Supply Mix – 2012 Forecast
D5-1-1	Cost of Service 2011 Historic
D5-2-1	Cost of Service Comparison of Utility Costs and Expenses Actual 2011 and 2007 Board Approved
D5-3-1	Summary of Gas Cost to Operations 2011 Historic Year
D5-3-2	Summary of Storage & Transportation Costs Fiscal 2011 Historic
D5-3-3	Canadian Peak Day Supply Mix 2011 Historic
I-D2-1.1 to 8.10	Interrogatories on Issue D2
I-D6-20.2	VECC Interrogatory #2
I-DV1-7.2	Energy Probe Interrogatory #2
2 TR8 to 91	Evidence at Technical Conference (September 6, 2012)
JT2.2 to 2.11	Undertakings from Technical Conference (September 6, 2012)

3. Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

[Complete Settlement]

In its prefiled evidence (at Exhibit D1, Tab 2, Schedule 3), Enbridge applied to increase its peak gas day design criteria (PGDDC) to utilize updated design criteria using a 1 in 10 recurrence interval. For the purposes of settlement, all parties agree that Enbridge will increase its PGDDC to utilize the updated design criteria set out at Exhibit D1, Tab 2, Schedule 3 using a 1 in 5 recurrence interval. As set out at Tables 1 and 5 (pages 7 and 16) to Exhibit D1, Tab 2, Schedule 3, this will result in an increase of heating degree days (HDDs) for the Company's three weather zones as follows:

	Current Design Criteria	Updated Design Criteria
Central Weather Zone	39.5	41.4
Eastern Weather Zone	45.1	48.2
Niagara Weather Zone	36.3	38.8

All parties agree that Enbridge will phase in the change to HDDs equally over the 2013 and 2014 years, as follows:

	Current	1st 'Step'	2013	2nd 'Step'	2014
Central Weather Zone	39.5	0.9	40.4	1.0	41.4
Eastern Weather Zone	45.1	1.6	46.7	1.5	48.2
Niagara Weather Zone	36.3	1.3	37.6	1.2	38.8

In order to meet the increased requirements resulting from the 2013 and 2014 increases to PGDDC, the Company will have to acquire increased transportation capacity. All parties agree that the cost consequences of unutilized transportation capacity related to this incremental transportation capacity will be recorded in the 2013 and 2014 Design Day Criteria Transportation Deferral Account (DDCTDA). Enbridge estimates that the cost consequences of unutilized transportation capacity will be approximately $5 million in 2013 and $15 million in 2014. The balances in the 2013 and 2014 DDCTDAs , together with carrying charges, will be disposed of in a manner determined by the Board in a future rate hearing.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
D1-2-3	Design Criteria Evidence
D2-4-1	Gas System Design Criteria Analysis For Enbridge Gas Distribution
D2-4-2	Analysis of Peak Gas Day Design Criteria
I-D2-4.1	CME Interrogatory #1
I-D2-8.5 to 8.9	FRPO Interrogatory #5 to 9
I-D3-1.1 to 20.1	Interrogatories on Issue D3
2 TR 4 to 8; 39 to 63; 67 to 72 ;and 76 to 91	Evidence at Technical Conference (September 6, 2012)
JT2.2 to 2.5 and 2.10 to 2.11	Undertakings from Technical Conference (September 6, 2012)

4. Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

[Complete Settlement]

All parties agree that the recovery of Pension and Other Post-Employment Benefits expense on an accrual basis commencing January 1, 2013 is appropriate. All parties further agree that Enbridge shall recover the Other Post-Employment Benefits (OPEB) expenses described at Exhibit A2, Tab 3, Schedule 1 equally over a twenty year period commencing January 1, 2013. The OPEB expenses of $90 million will be recorded in the Transition Impact of Accounting Changes Deferral Account (TIACDA), and will be cleared to the credit of Enbridge at the rate of $4.5 million per year (no interest will be applicable to the amounts recorded in the TIACDA).

Evidence: The evidence in relation to this issue includes the following:

A2-3-1	Change in Accounting Methodology – Other Post Employment Benefits (“OPEB”)
A2-3-2	Change in Accounting Methodology – Pension Expense
I-D1-1.6	Board Staff Interrogatory #6
I-D4-1.1 to 14.2	Interrogatories on Issue D4
I-DV2-1.1 to 4.1	Interrogatories on Issue DV2
I TR 138 to 153	Evidence at Technical Conference (September 5, 2012)
T1.23	Undertaking from Technical Conference (September 5, 2012)

5. Is the corporate cost allocation (“RCAM”) appropriate?

[Complete Settlement]

See Issue D1, above. The RCAM corporate cost allocation for 2013 is part of the overall agreed-upon “All other O&M budget” of $256.8 million. It is agreed that no party will raise any procedural objection if any party requests changes to RCAM in Enbridge’s 2014 rates proceeding (which is anticipated to be an application for approval of an IR methodology, which is not the type of case where such issues would ordinarily be raised). All parties are free to take whatever positions they determine with respect to this issue at that time.

Evidence: The evidence in relation to this issue includes the following:

D1-4-1	Corporate Cost Allocation (“CAM”)
D1-4-2	Updated Corporate Cost Allocation (“CAM”)
D1-24-1	Regulatory Adjustments and Eliminations – CAM Elimination to Adjust for RCAM
D1-24-2	Updated Regulatory Adjustments and Eliminations - CAM Elimination to Adjust for RCAM
D2-1-1	Regulatory Corporate Cost Allocation (“RCAM”) Update - MNP
I-D1-1.12	Board Staff Interrogatory #12
I-D1-1-20.5	VECC Interrogatory #5
I-D5-1.1 to 20.5	Interrogatories on Issue D5
I-D12-14.2	SEC Interrogatory #2
I-D15-14.3 and 14.4	SEC Interrogatories #3 and 4
I TR 108 to 117 and 121 to 123	Evidence at Technical Conference (September 5, 2012)
JT1.17 to 1.19	Undertakings from Technical Conference (September 5, 2012)

6. Are the affiliate charges appropriate?

[Complete Settlement]

See Issue D1 above. The financial impact of affiliate charges for 2013 is part of the overall agreed-upon “All other O&M budget” of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

A1-9-1	List of Affiliate Charges
I-D6-20.1 to 20.2	Interrogatories on Issue D6

I-D14-5.3	CCC Interrogatory #3
I-D14-7.1	Energy Probe Interrogatory #1
I-D14-14.1	SEC Interrogatory #1
I-D18-5.1 to 5.2	CCC Interrogatories #1 and 2
I-D19-14.2	SEC Interrogatory #2
I TR 135 to 138	Evidence at Technical Conference (September 5, 2012)
JT1.21	Undertaking from Technical Conference (September 5, 2012)

7. Are the proposed depreciation rate changes appropriate?

[Complete Settlement]

All parties accept Enbridge's proposed depreciation rates for 2013, as set out at Exhibit D2, Tab 5, Schedule 1 and Exhibit D2, Tab 2, Schedule 1 (Gannett Fleming Depreciation Study), with two exceptions.

First, the service lives for 475.20 Distribution Mains – Plastic will be increased from 55 to 65 years.

Second, the service lives for 473/474 Distribution Services & Meter Installations will be increased from 40 to 45 years.

All parties agree that the use of the depreciation rates set out in the Gannett Fleming Depreciation Study, as modified for the two adjustments set out above, is appropriate for ratemaking purposes for 2013 (including for determination of rate base) and that Enbridge shall be entitled to adopt such adjusted depreciation rates for purposes of financial accounting. The impact of this change for 2013 is to reduce depreciation expense by $20.3 million.

It is agreed that no party will raise any procedural objection if Enbridge files a new depreciation study, and seeks approval of updated depreciation rates based upon such new study, in its 2014 rates proceeding (which is anticipated to be an application for approval of an IR methodology, which is not the type of case where such issues would ordinarily be raised). All parties are free to take whatever positions they determine with respect to this issue at that time.

Evidence: The evidence in relation to this issue includes the following:

D1-5-1	Depreciation Rate Change
D2-2-1	Depreciation Study – Gannett Fleming
D2-2-2	Schedule Depreciation Rates
D3-1-1	Cost of Service 2013 Test Year
D3-2-1	Cost of Service Comparison of Utility Cost and Expenses Budget 2013 and Estimate 2012
D4-1-1	Cost of Service 2012 Bridge Year
D4-2-1	Cost of Service Comparison of Utility Cost and Expenses 2012 Estimate and 2011 Historic
D5-1-1	Cost of Service 2011 Historic
D5-2-1	Cost of Service Comparison of Utility Costs and Expenses Actual 2011 and 2007 Board Approved
I-D1-1.2	Board Staff Interrogatory #2
I-D5-2.1 to 5.1	Interrogatories on Issue D7
I TR 103 to 108	Evidence at Technical Conference (September 5, 2012)
JT1.13 to 1.14	Undertakings from Technical Conference (September 5, 2012)

8. Is the municipal taxes expense appropriate?

[Complete Settlement]

All parties agree that Enbridge will reduce its municipal taxes forecast by $800,000, such that the 2013 municipal tax amount to be included in operating costs is $39.3 million.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Operating Cost Summary
D1-6-1	Municipal Taxes
D3-1-1	Cost of Service 2013 Test Year
D3-2-1	Cost of Service Comparison of Utility Cost and Expenses Budget 2013 and Estimate 2012
D4-1-1	Cost of Service 2012 Bridge Year
D4-2-1	Cost of Service Comparison of Utility Cost and Expenses 2012 Estimate and 2011 Historic
D5-1-1	Cost of Service 2011 Historic
D5-2-1	Cost of Service Comparison of Utility Costs and Expenses Actual 2011 and 2007 Board Approved
I-D8-1.1 to 20.1	Interrogatories on Issue D8

9. Is the demand side management budget appropriate?

[Complete Settlement]

All parties agree that Enbridge's demand side management budget for 2013 is $31.4 million, as set out in the Board-approved Settlement Agreement in the EB-2011-0295 proceeding. This amount is part of the overall O&M budget set out at Issue D1.

Evidence: The evidence in relation to this issue includes the following:

D1-7-1	Demand Side Management Budget
I-D1-1.12	Board Staff Interrogatory #12
I-D9-1.1	Board Staff Interrogatory #1

10. Is the income tax expense forecast appropriate?

[Complete Settlement]

All parties agree that Enbridge's income tax expense forecast is appropriate, subject to adjustments to be made to reflect the changes between Enbridge's pre-filed evidence (as set out in Impact Statement #2 at Exhibit M2) and the Settled Issues in this Settlement Agreement. The revised income tax expense is reflected in the ADR Financial Statements (Exhibit N1, Tab 1, Schedule 1, Appendix A, parts A and B at page 8).

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Operating Cost Summary
D3-1-1	Cost of Service 2013 Test Year
D3-2-1	Cost of Service Comparison of Utility Cost and Expenses Budget 2013 and Estimate 2012
D4-1-1	Cost of Service 2012 Bridge Year
D4-2-1	Cost of Service Comparison of Utility Cost and Expenses 2012 Estimate and 2011 Historic
D5-1-1	Cost of Service 2011 Historic
D5-2-1	Cost of Service Comparison of Utility Costs and Expenses Actual 2011 and 2007 Board Approved
I-D10-1.1 to 1.4	Interrogatories on Issue D10
I TR 123 to 132	Evidence at Technical Conference (September 5, 2012)
JT1.20	Undertaking from Technical Conference (September 5, 2012)

11. Is the proposal for the Open Bill Access Program appropriate?

[Partial Settlement]

All parties, as well as the open bill issue participants, agree to the resolution of the Open Bill Access issue on the following terms.

Enbridge will continue to offer open bill services in 2013, under the terms of the Board-approved Settlement Agreement in EB-2009-0043 subject to the following two changes:

a. The Fees to be charged for Billing Services will be updated as set out at Table 4 of Exhibit D1, Tab 9, Schedule 14.

b. The Costs to be used for determining net income amounts for the purpose of sharing between Enbridge and ratepayers will be updated as set out at Table 4 of Exhibit D1, Tab 9, Schedule 14.

The terms of the OBA Agreement that governs the relationship between Enbridge and Billers are being discussed between Enbridge and the open bill issue participants. These parties hope to be able to reach resolution on the terms of contract by the end of October 2012, and will advise the Board in that regard. In the event that no agreement can be reached, then these parties may ask the Board to consider and determine issues related to the terms of the OBA Agreement, as contemplated in Procedural Order No. 4.

All parties, as well as the open bill issue participants, agree that as of January 1, 2013 Enbridge will continue to use the current form of OBA Agreement until such time as either: (i) Enbridge and the open bill issue participants agree on an updated form of OBA Agreement; or (ii) the Board makes a determination on any outstanding issues related to the OBA Agreement.

All parties, as well as the open bill issue participants, agree that if Enbridge wishes to continue to offer open bill services beyond December 31, 2013, then Enbridge must make application to the Board to do so. It is expected that such application (which might be part of a rates application, or might be a stand-alone application), will set out the terms upon which Enbridge proposes to continue the open bill program over a longer term or the terms upon which Enbridge proposes to wind down the program. Enbridge agrees that it will meet with all interested parties (including open bill issue participants) at least one month before it files the application contemplated in this paragraph. The purpose of such meeting is to provide information about Enbridge's plans and intentions to interested parties and to allow Enbridge to receive comments from those parties that may be relevant in the preparation of Enbridge's application.

In response to a proposal made by certain open bill issue participants to have Enbridge initiate an on-bill financing program for DSM measures (such as energy efficient equipment and building envelope upgrades), all parties, as well as the open bill issue participants, agree to the following next steps to work towards the possibility of offering on-bill financing for DSM measures with the intention of starting in January 2014:

a. By November 15, 2012, a consultative group will be formed to further consider the proposal. Any intervenor participating in this EB-2011-0354 case or in the ongoing DSM consultative would be eligible to participate in the consultative group.

   The consultative group will have at least three meetings in 2012, with the stated goal of creating a project plan setting out how Enbridge would offer on-bill financing for DSM measures at the lowest feasible interest rates.

b. In creating a project plan, the consultative group will consider the appropriate program design for an on-bill financing program for DSM measures to allow for such a program to be feasible, viable and effective. Items that may be considered include, but are not limited to, the following items which have been proposed by certain open bill issue participants:

   a. Whether and, if appropriate, how to issue an RFP seeking one or more financiers to offer financing to underpin the on-bill financing program activities involving the on-bill financing DSM consultative.

   b. Whether and, if appropriate, how to ensure that the DSM on-bill financing program will only provide financing for DSM measures, with the goal of having such products sold and installed by reputable professionals.

   c. Whether and, if appropriate, how to ensure that an accurate energy rating system (e.g., NRCan's EnerGuide Rating system) is used to: a) forecast; and b) measure the post-installation actual savings of DSM measures that are financed by the DSM on-bill financing program.

   d. Whether and, if appropriate, how to ensure that DSM on-bill financing charges can be transferred to a new homeowner or tenant.

c. Once the project plan is completed, which is anticipated by early 2013, Enbridge will then lead the execution of the project plan.

All parties, as well as the open bill issue participants, acknowledge that Enbridge has not yet made any determination as to whether it plans to continue open bill services beyond 2013 or whether Enbridge will seek to wind down the program at that time. All parties, as well as the open bill issue participants further acknowledge that while the continuation of Enbridge's open bill services is not a pre-requisite to offering DSM on-bill financing, the question of whether open bill services continue in 2014 may impact on the feasibility and viability of offering DSM on-bill financing. In that regard all parties, as well as the open bill issue participants, acknowledge that Enbridge has not yet made any determination about whether it will proceed with on-bill financing for DSM measures in 2014 and acknowledge that such determination is contingent, at least in part, on the DSM on-bill financing program being feasible and viable to implement. If the decision is made to proceed with on-bill financing for DSM measures, Enbridge will aim to launch the DSM on-bill financing program in January 2014.

Evidence: The evidence in relation to this issue includes the following:

D1-9-1	Open Bill Access
I-D11-1.1 to 20.11	Interrogatories on Issue D11
I-D11-23.1 to 24.17	Supplementary Interrogatories on Issue D11

12. Is the proposed O&M budget for Finance appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Finance is part of the overall agreed-upon “All other O&M budget” of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-10-1	Finance Department - O&M Budget
I-D12-5.1 to 14.3	Interrogatories on Issue D12

13. Has Enbridge properly implemented the revenue requirement associated with the Customer Care and CIS Settlement Agreement (per EB-2011-0226)?

[Complete Settlement]

All parties agree that Enbridge has properly implemented the revenue requirement associated with the Customer Care and CIS (“CC/CIS”) Settlement Agreement (per EB-2011-0226).

All parties agree that the 2013 Customer Care O&M component of $89.4 million within the total CC/CIS revenue requirement is part of the overall O&M budget set out at Issue D1.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
D1-12-1	CIS / Customer Care – A Review of the Treatment of CIS/Customer Care Costs as a Result of the ADR Settlement in EB-2011-0226
D1-12-2	EB-2011-0226 Settlement Agreement Enbridge Customer Care and CIS Costs 2013 to 2018 - September 2, 2011
I-D1-1.12	Board Staff Interrogatory #12
I-D13-1.1	Board Staff Interrogatory #1

14. Is the proposed O&M budget for Energy Supply, Storage Development and Regulatory appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Energy Supply, Storage Development and Regulatory is part of the overall agreed-upon "All other O&M budget" of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-13-1	Energy Supply, Storage Development and Regulatory – O&M Budget
I-D14-1.1 to 20.1	Interrogatories on Issue D14
1 TR 116 to 120	Evidence at Technical Conference (September 5, 2012)

15. Is the proposed O&M budget for Law appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Law is part of the overall agreed-upon "All other O&M budget" of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-14-1	Law Department – O&M Budget
I-D15-1.1 to 14.4	Interrogatories in Issue D25

16. Is the proposed O&M budget for Operations appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Operations is part of the overall agreed-upon "All other O&M budget" of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-15-1	Operations – O&M Budget
I-D16-1.1 to 14.4	Interrogatories on Issue D16

17. Is the proposed O&M budget for Information Technology appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Information Technology is part of the overall agreed-upon "All other O&M budget" of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-16-1	Information Technology – O&M Budget
I-D17-1.1 to 14.3	Interrogatories on Issue D17

18. Is the proposed O&M budget for Business Development & Customer Strategy, including Energy Technology Innovation Canada (“ETIC”) related amounts, appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Business Development & Customer Strategy, including Energy Technology Innovation Canada (“ETIC”) related amounts, is part of the overall agreed-upon “All other O&M budget” of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-17-1	Business Development and Corporate Strategy
I-D18-1.1 to 20.1	Interrogatories on Issue D18

19. Is the proposed O&M budget for Human Resources appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Human Resources is part of the overall agreed-upon “All other O&M budget” of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-18-1	Human Resources – O&M Budget
I-D19-1.1 to 20.1	Interrogatories on Issue D19

20. Is the proposed O&M budget for Pipeline Integrity & Safety appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Pipeline Integrity & Safety is part of the overall agreed-upon “All other O&M budget” of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-20-1	Pipeline Integrity and Safety – O&M Budget
I-D20-1.1 to 14.5	Interrogatories on Issue D20

21. Is the proposed O&M budget for Public and Government Affairs appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Public and Government Affairs is part of the overall agreed-upon "All other O&M budget" of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-21-1	Public and Government Affairs – O&M Budget
I-D1-1-14.9	SEC Interrogatory #9
I-D21-5.1 to 14.2	Interrogatories on Issue D21

22. Is the proposed O&M budget for Non-Departmental O&M Expenses appropriate?

[Complete Settlement]

See Issue D1, above. The O&M budget for Non-Departmental O&M Expenses is part of the overall agreed-upon "All other O&M budget" of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-22-1	Non Departmental Expenses – O&M Budget
I-D22-1.1 to 14.1	Interrogatories on Issue D22

23. Is the forecast of Provision for Uncollectable Amounts for 2013 appropriate?

[Complete Settlement]

See Issue D1, above. The Provision for Uncollectable Amounts for 2013 is part of the overall agreed-upon "All other O&M budget" of $256.8 million.

Evidence: The evidence in relation to this issue includes the following:

D1-3-1	Operating Maintenance Costs
I-D1-1.9	Board Staff Interrogatory #9
I-D1-1-14.3	SEC Interrogatory #3

24. Is the allocation of O&M costs between utility and non-utility ("unregulated") operations appropriate?

[Complete Settlement]

See Issue B6, above.

Evidence: The evidence in relation to this issue includes the following:

A1-9-1	List of Affiliate Transactions for the 2013 Test Year, 2012 Bridge Year and 2011 Historic Year
I-D18-1.1	Board Staff Interrogatory #1
I-D24-1.1 to 5.1	Interrogatories on Issue D24
1 TR 132 to 135	Evidence at Technical Conference (September 5, 2012)

DV: DEFERRAL AND VARIANCE ACCOUNTS

1. Are Enbridge's existing and proposed deferral and variance accounts appropriate?

[Complete Settlement]

Subject to the exceptions set out below, all parties agree to the establishment of Enbridge's deferral and variance accounts, on the basis as described in evidence at Exhibit D1, Tab 8, Schedule 1.

Within the Purchased Gas Variance Account (PGVA), all parties have agreed to one methodology change. With respect to dispositions of long Banked Gas Account (BGA) balances, all parties agree that when a long BGA balance is purchased by Enbridge from a customer, Enbridge will credit the difference between the purchase price and the Empress price embedded in the PGVA to a load balancing component of the PGVA (rather than to the commodity component of the PGVA, which is the current methodology).

As set out in Issue C6 above, all parties agree to the changes described in determining amounts to be included in the 2013 Transactional Services Deferral Account (TSDA).

As set out in Issue D1 above, all parties agree to the creation of a 2013 Pension True-Up Variance Account (PTUVA).

As set out in Issue D3 above, all parties agree to the parameters described in determining amounts to be included in the 2013 and 2014 Design Day Criteria Transportation Deferral Account (DDCTDA).

Evidence: The evidence in relation to this issue includes the following:

A1-6-1	Accounting Orders
D1-8-1	Deferral and Variance Accounts
D1-8-3	Deferral and Variance Account Forecast Balances
I-DV1-5.1 to 20.1	Interrogatories on Issue DV1

2. Is Enbridge's request to recover from ratepayers an approximate $90 million forecasted balance as at December 31, 2012 in the 2012 Transition Impact of Accounting Changes Deferral Account ("TIACDA") appropriate?

[Complete Settlement]

See Issue D4, above.

Evidence: The evidence in relation to this issue includes the following:

D1-8-1	Deferral and Variance Accounts
D1-8-3	Deferral and Variance Account Forecast Balances
I-DV2-1.1 to 4.1	Interrogatories on Issue DV2
2 TR 138 to 153	Evidence at Technical Conference (September 6, 2012)

E: COST OF CAPITAL

1. Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

[Partial Settlement]

All parties agree with Enbridge's forecasts of the cost rates for 2013 long and medium term debt, short term debt and preference shares.

All parties also agree with the forecast of the cost of debt for the Test Year, based upon Enbridge's current 36% level of deemed common equity (as set out in the attached ADR Financial Statements (Exhibit N, Tab 1, Schedule 1, Appendix A, part 2 at page 9). In that regard, if the OEB were to determine that no change to Enbridge's current 36% level of deemed common equity is appropriate, then it is agreed that the long term debt component of Enbridge's capital structure will increase to $2,461.9 million as a result of a required $400 million debt issuance, to occur in August 2013, at agreed upon forecast coupon and effective interest rates of 4.10% and 4.18%. As a result of the new debt issuance with interest rates that are lower than the average interest rate for Enbridge's existing outstanding debt, Enbridge's average long term debt cost rate is reduced to 5.80% from the forecast 5.90%.

In the event that the Board approves a different level of common equity from the current 36%, in response to Issue E2, then there is no agreement on the appropriate capital structure. This issue is to be heard by the Board. In particular, there is no agreement as to the mix of short and long term debt and preference shares, and the resulting cost of capital, in the event that the Board approves a different level of deemed common equity from the current 36%, in response to Issue E2. All parties are free to take whatever position they deem appropriate in relation to this question when Issue E2 is considered by the Board.

Evidence: The evidence in relation to this issue includes the following:

E1-1-1	Cost of Capital Summary
E1-2-1	Cost of Capital
E3-1-2	Summary Statement of Principal and Carrying Costs of Term Debt 2013 Test Year
E3-1-3	Unamortized Debt Discount and Expense Average of Monthly Averages 2013 Test Year
E3-1-4	Preference Shares Summary Statement of Principal and Carrying Cost 2013 Test Year
E3-1-5	Unamortized Preference Share Issue Expense Average of Monthly Averages 2013 Test Year
E4-1-1	Cost of Capital 2012 Bridge Year
E4-1-2	Summary Statement of Principal and Carrying Cost of Term Debt 2012 Bridge Year
E4-1-3	Unamortized Debt Discount and Expense Average of Monthly Averages 2012 Bridge Year
E4-1-4	Preference Shares Summary Statement of Principal and Carrying Cost 2012 Bridge Year
E4-1-5	Unamortized Preference Shares Issue Expense Average of Monthly Averages 2012 Bridge Year
E5-1-2	Summary Statement of Principal and Carrying Cost of Term Debt 2011 Historic
E5-1-3	Unamortized Debt Discount and Expense Average of Monthly Averages 2011 Historic
E5-1-4	Preference Shares Summary Statement of Principal and Carrying Cost 2011 Historic
E5-1-5	Unamortized Preference Share Issue Expense Average of Monthly Averages 2011 Historic
F3-1-1	Cost of Capital 2013 Test Year
I-E1-1.1 to 21.2	Interrogatories on Issue E1
I-E2-2.1	APPrO Interrogatory #1
2 TR 118 to 121 and 137 to 145	Evidence at Technical Conference (September 6, 2012)
JT2.15 to 2.17	Undertakings from Technical Conference (September 6, 2012)

2. Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

[No settlement]

All parties agree that this issue shall proceed to hearing. The attached ADR Financial Statements show the impact of this Settlement Agreement based upon a 42% equity thickness and a 36% equity thickness (Exhibit N, Tab 1, Schedule 1, Appendix A, parts 1 and 2) at pages 1 and 9.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
A3-9-1	DBRS and S&P Reports
E1-2-1	Cost of Capital
E2-1-2	Capital Structure: Equity Ratio
E2-2-1	Concentric Energy Advisors : Equity Thickness Evaluation & Recommendation
L1-1-1	Business Risk And Capital Structure For Enbridge Gas Distribution Inc (EGDI) – Dr. Booth
I-E1-7.1 and 7.5	Energy Probe Interrogatories #1 and 5
I-E1-20.1 and 20.3	VECC Interrogatories #1 and 3
I-E1-21.1 and 21.2	CME et al Interrogatories #1 and 2
I-E2-1.1 to 21.12	Interrogatories on Issue E2
I-E2-22.1 to 22.52	EGD Interrogatories to Dr. Booth
2 TR91 to 155	Evidence at Technical Conference (September 6, 2012)
JT2.12 to 2.20	Undertakings from Technical Conference (September 6, 2012)

3. Is the proposal to use the Board's formula to calculate return on equity appropriate?

[Complete Settlement]

All parties agree that Enbridge will use the Board's formula from the December 2009 Report of the Board on the Cost of Capital for Ontario's Regulated Utilities to calculate return on equity (ROE). All parties agree that, as set out in that Report, the calculation of ROE to be used for the purpose of setting rates for 2013 shall be determined using Consensus October 2012 inputs, which are based on September data, once such information is available in October 2012. As set out at Issue O6 below, if timing permits Enbridge will implement the updated ROE as part of the draft Rate Order process in November 2012, so that this becomes part of the interim rates to be implemented on January 1, 2013. If that timing is not possible, then the updated ROE will be implemented as part of final rates.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
E2-1-1	Return on Equity Calculation for 2013
I-E3-1.1 to 21.3	Interrogatories on Issue E3

F: REVENUE SUFFICIENCY / DEFICIENCY

1. Is the revenue requirement and revenue deficiency or sufficiency for the Test Year calculated correctly?

[Complete Settlement]

All parties agree that the revenue deficiency for the Test Year arising from the Settled Issues, as set out in the attached ADR Financial Statements (Exhibit N, Tab 1, Schedule 1, Appendix A, parts 1 and 2), is calculated correctly.

Evidence: The evidence in relation to this issue includes the following:

A2-4-1	Drivers of Deficiency / (Sufficiency)
E3-1-1	Revenue Deficiency Calculation And Required Rate Of Return 2013 Test Year
E5-1-1	Revenue Sufficiency Calculation And Required Rate Of Return 2011 Historical Year (Estimate)
F1-1-1	Revenue (Deficiency) / Sufficiency Summary
F3-1-1	Cost of Capital 2013 Test Year
F3-1-2	Utility Income 2013 Test Year
F3-1-3	Utility Rate Base 2013 Test Year
F4-1-1	Revenue Sufficiency Calculation and Required Rate of Return 2012 Bridge Year
F4-1-2	Utility Income 2012 Bridge Year
F4-1-3	Utility Rate Base 2012 Bridge Year
F5-1-1	Revenue Sufficiency and Recalculated Rate of Return 2011 Historic
F5-1-2	Utility Income 2011 Historic
F5-1-3	Utility Rate Base 2011 Historic
M1-1-1	Impact Statement No. 1
M1-1-2	Change in Revenue Requirement 2013 Test Year

M1-1-3	Utility Rate Base 2013 Test Year
M1-1-4	Utility Income 2013 Test Year
M1-1-5	Ontario Utility Capital Structure 2013 Test Year
I-F1-5.1 to 20.1	Interrogatories on Issue F1

2. Is the overall change in revenue requirement reasonable given the impact on consumers?

[Complete Settlement]

The overall changes in revenue requirement arising from the Settled Issues assuming a 36% and a 42% equity thickness is set out in the attached ADR Financial Statements (Exhibit N, Tab 1, Schedule 1, Appendix A, parts 1 and 2). All parties agree that the overall change in revenue requirement is reasonable given the impact on consumers.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
I-F2-4.1 to 20.1	Interrogatories on Issue F2

G: COST ALLOCATION

1. Is Enbridge's utility Cost Allocation Study, including the methodologies and judgements used and the proposed application of that study with respect to Test Year rates, appropriate?

[Complete Settlement]

For the purposes of settlement, all parties accept Enbridge's utility Cost Allocation Study, including the methodologies and judgements used and the proposed application of that study with respect to Test Year rates.

Evidence: The evidence in relation to this issue includes the following:

G1-1-1	2013 Cost Allocation Methodology
G2-1-1	Fully Allocated Cost Study - 2013 Test Year
G2-2-1	Revenue to Cost/Rate of Return Comparisons
G2-2-2	Revenue to Cost/Rate of Return Comparisons Excluding Gas Supply Commodity
G2-3-1	Functionalization of Utility Rate Base
G2-3-2	Functionalization of Utility Working Capital
G2-3-3	Functionalization of Utility Net Investments
G2-3-4	Functionalization of Utility O&M
G2-4-1	Classification of Rate Base
G2-4-2	Classification of Net Investment
G2-4-3	Classification of O&M Costs
G2-5-1	Allocation of Rate Base
G2-5-2	Allocation of Return & Taxes
G2-5-3	Allocation of Total Cost of Service
G2-6-1	Rate Base Functionalization Factors

G2-6-2	Classification of Gas Costs to Operations
G2-6-3	Allocation Factors
G2-6-4	Allocation of DSM Program Costs General Costs Including Fringe Benefits and A&G
G2-7-1	Tecumseh – Functionalization and Classification of Rate Base
G2-7-2	Tecumseh – Functional Allocation of Cost of Service - 2013 Test Year
G2-7-3	Tecumseh – Classification of Cost of Service 2013 Test Year
G2-7-4	Tecumseh Gas Rate Derivation 2013 Test Year
G2-7-5	Tecumseh Gas Isolation of Transmission Related Rate Base 2013 Test Year
G2-7-6	Tecumseh Gas Isolation of Transmission Related Operating Cost 2013 Test Year
G2-7-7	Functionalization of Short Cycle Net Revenues to In/Ex Franchise Customers 2013 Test Year
I-G1-2.1 to 20.1	Interrogatories on Issue G1

2. Are the Cost Allocation Study methodology relating to Customer Care and CIS costs appropriate?

[Complete Settlement]

For the purposes of settlement, all parties accept the Cost Allocation methodology relating to Customer Care and CIS costs.

Evidence: The evidence in relation to this issue includes the following:

G1-1-1	2013 Cost Allocation Methodology
G2-1-1	Fully Allocated Cost Study - 2013 Test Year

3. Are the principles applied in the utility Cost Allocation Study consistent where appropriate with the principles applied in allocating costs between utility and non-utility (“unregulated”) businesses?

[Complete settlement]

See Issue B6, above.

Evidence: The evidence in relation to this issue includes the following:

G1-1-1	2013 Cost Allocation Methodology
G2-1-1	Fully Allocated Cost Study - 2013 Test Year
D2-5-1	Regulated Unregulated Storage Cost Allocation – Black & Veatch
G2-7-1	Tecumseh – Functionalization and Classification of Rate Base
G2-7-2	Tecumseh – Functional Allocation of Cost of Service - 2013 Test Year
G2-7-3	Tecumseh – Classification of Cost of Service 2013 Test Year
G2-7-4	Tecumseh Gas Rate Derivation 2013 Test Year
G2-7-5	Tecumseh Gas Isolation of Transmission Related Rate Base 2013 Test Year
G2-7-6	Tecumseh Gas Isolation of Transmission Related Operating Cost 2013 Test Year
G2-7-7	Functionalization of Short Cycle Net Revenues to In/Ex Franchise Customers 2013 Test Year

H: RATE DESIGN

1. Are the rates proposed for implementation effective January 1, 2013 and appearing in Exhibit H just and reasonable?

[Complete Settlement]

See Issue O6, below.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	2013 Proposed Rates
H2-1-1	Revenue Comparison – Current Revenue vs. Proposed Revenue
H2-2-1	Proposed Revenue Recovery by Rate Class
H2-3-1	Summary of Proposed Rate Change by Rate Class
H2-4-1	Calculation of Gas Supply Charges by Rate Class
H2-5-1	Detailed Revenue Calculations by Rate Class
H2-6-1	Rate Handbook
H2-7-1	Annual Bill Comparison

2. Are the proposed levels of customer charges, including the fixed/variable split, appropriate?

[Complete Settlement]

For the purposes of settlement, all parties accept the fixed/variable split of customer charges, and agree with the process set out in response to Issue O6 for the implementation of interim rates as of January 1, 2013.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	2013 Proposed Rates
H2-6-1	Rate Handbook
H2-7-1	Annual Bill Comparison

O: OTHER ISSUES

1. Has Enbridge responded appropriately to all relevant Board directions from previous proceedings, including any commitments from prior settlement agreements?

[Complete Settlement]

All parties accept Enbridge's evidence that it has responded appropriately to all relevant Board directions from previous proceedings.

Evidence: The evidence in relation to this issue includes the following:

A1-13-1	Status of Board Directives from Previous Board Decisions and/or Board Orders
I-O1-8.1	FRPO Interrogatory #1

2. Are Enbridge's economic and business planning assumptions for the Test Year appropriate?

[Complete Settlement]

In relation to the Settled Issues, no party takes issue with whether Enbridge's economic and business planning assumptions for the Test Year are appropriate.

Any party is free to take whatever position they deem appropriate about the economic and business planning assumptions applied by Enbridge in relation to Issues E1 and E2.

Evidence: The evidence in relation to this issue includes the following:

A2-2-1	2013 Regulatory Budget Assumptions and Guidelines Directive
B2-1-1	Economic Feasibility Procedure and Policy
C2-1-1	Key Economic Assumptions
I-B1-5.15	CCC Interrogatory #15
I-C2-11.2	Energy Probe Interrogatory #2
I-O2-5.1 to 5.2	CCC Interrogatories #1 and 2

3. Are sustainable productivity and efficiency gains achieved under incentive regulation appropriately reflected in Enbridge's Cost of Service estimates?

[Complete Settlement]

All parties agree that Enbridge's 2013 cost of service rates, as agreed through the Settled Issues in this Settlement Agreement, reflect productivity and efficiency gains that have been achieved from the incentive regulation term. The parties accept the estimates of productivity and efficiency gains prepared by Enbridge in response to JT1.28. Enbridge agrees that, as part of its 2014 rates proceeding (which is anticipated to be an application for approval of an IR methodology), it will address ways to establish and maintain records of productivity and efficiency initiatives that would be useful for the Board in a subsequent rebasing application or other proceeding where such information would be useful.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Introductory Evidence
A2-1-2	Benchmarking Study (Concentric)
A2-1-3	Analytical Review of the September 2011 PEG-R Report (PSE)
I-O3-1.1 to 20.1	Interrogatories on Issue O3
I TR 160 to 200	Evidence at Technical Conference (September 5, 2012)
JT1.25 to 1.28	Undertakings from Technical Conference (September 5, 2012)

4. Are Enbridge's Conditions of Service (i.e. customer service policies including security deposits, late payment penalty, etc.) compatible with Board directives?

[Complete Settlement]

No party takes issue with whether Enbridge's Conditions of Service are compatible with Board directives. As indicated in response to JT1.24, Enbridge will update its Conditions of Service to address low-income customer service policy amendments, as required in the EB-2010-0280 proceeding.

Evidence: The evidence in relation to this issue includes the following:

A1-14-1	Conditions of Service
I-O4-5.1 to 5.2	Interrogatories on Issue O4
I TR 156 to 158	Evidence at Technical Conference (September 5, 2012)
JT1.24	Undertaking from Technical Conference (September 5, 2012)

5. Have all impacts of the conversion of regulatory and financial accounting from CGAAP to USGAAP been identified, and reflected in the appropriate manner in the application, the revenue requirement for the Test Year, and the proposed rates?

[Complete Settlement]

See Issue B4 above.

Evidence: The evidence in relation to this issue includes the following:

Procedural Order #2	Decision on Preliminary Issue, May 16, 2012
A1-6-2	Accounting for Rate Regulated Operations Current and Future Changes
I-O5-1.1 to 1.4	Clearance of Deferral and Variance Account Balances

6. How should the Board implement the rates relevant to this proceeding if they cannot be implemented on or before January 1, 2013?

[Complete Settlement]

All parties agree that the revenue requirement and rate impact of the Settled Issues should be implemented into rates as of January 1, 2013, using an assumed 36% equity thickness. The overall change in revenue requirement arising from the Settled Issues assuming a 36% equity thickness is set out in the attached ADR Financial Statements (Exhibit N, Tab 1, Schedule 1, Appendix A, part 2). As noted in the Overview, all parties agree that the agreement to use the current level of equity thickness (36%) and associated capital structure ratios for implementation of interim rates is not intended as an indication or suggestion to the Board that 36% is the appropriate level of equity thickness for Enbridge in 2013. That issue is to be determined by the Board based upon the evidence and argument presented.

Enbridge will provide a draft Rate Order (setting out the interim rates reflecting the Settled Issues) to all parties on or before Friday, October 26, 2012. Parties will provide comments on the draft Rate Order by Wednesday, November 7, 2012. Enbridge will then provide any required response and updates, in order to allow the Board to consider the draft Rate Order shortly thereafter. Assuming that the Board approves the draft Rate Order before the end of November 2012, then the interim rates reflecting the Settled Issues will be implemented in conjunction with Enbridge's January 1, 2013 QRAM Application. If timing permits, Enbridge will implement the updated ROE (see issue E3, above) as part of the draft Rate Order process in November 2012. That would allow for the updated ROE to become part of the interim rates to be implemented on January 1, 2013. If that timing is not possible, then the impact of the updated ROE will be implemented as part of final rates, as described below.

The rates to be implemented on January 1, 2013 will be interim rates, to be adjusted subsequently to take account of the full year effect of the determination of Issue E2 (Enbridge's request to increase deemed common equity component from 36% to 42%), and any related impacts from Issue E1 (cost of debt). If necessary, the interim rates will also be adjusted to reflect the updated ROE that will be determined in November 2011 in accordance with process described at Issue E3, above). All parties agree that any financial impact of the determination of Issues E1 and E2 (and Issue E3, if necessary) shall be implemented as part of Enbridge's first QRAM Application following the Board's decision (or if time does not permit, as part of the following QRAM Application).

Evidence: The evidence in relation to this issue includes the following:

N1-1-1, App. A to C	Appendices to Settlement Agreement

CHANGE IN REVENUE REQUIREMENT
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 2 (Note 1)	Col. 2 ADR Adjustments	Col. 3 Excl. CIS Adjusted ADR Impact Statement	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 ADR Impact Statement EGD Total
		($Millions)		($Millions)	($Millions)	($Millions)
	Cost of capital					
1.	Rate base	4,103.7	(12.2)	4,091.5	70.5	4,162.0
2.	Required rate of return	7.19	-	7.19	6.44	7.18
3.		295.1	(0.9)	294.2	4.6	298.8
	Cost of service					
4.	Gas costs	1,307.9	34.9	1,342.8	-	1,342.8
5.	Operation and maintenance	348.3	(22.8)	325.5	89.4	414.9
6.	Depreciation and amortization	288.1	(21.5)	266.6	12.7	279.3
7.	Fixed financing costs	2.3	-	2.3	-	2.3
8.	Debt redemption premium amortization	-	-	-	-	-
9.	Company share of IR agreement tax savings	-	-	-	-	-
10.	Municipal and other taxes	40.1	(0.8)	39.3	-	39.3
11.		1,986.7	(10.2)	1,976.5	102.1	2,078.6
	Miscellaneous operating and non-operating revenue					
12.	Other operating revenue	(38.3)	(6.0)	(44.3)	-	(44.3)
13.	Interest and property rental	-	-	-	-	-
14.	Other income	(0.7)	-	(0.7)	-	(0.7)
15.		(39.0)	(6.0)	(45.0)	-	(45.0)
	Income taxes on earnings					
16.	Excluding tax shield	73.7	12.8	86.5	9.0	95.5
17.	Tax shield provided by interest expense	(35.8)	(0.2)	(36.0)	(0.9)	(36.9)
18.		37.9	12.6	50.5	8.1	58.6
	Taxes on sufficiency / (deficiency)					
19.	Gross sufficiency / (deficiency)	(81.9)	75.0	(6.9)	-	(6.9)
20.	Net sufficiency / (deficiency)	(60.2)	55.1	(5.1)	-	(5.1)
21.		21.7	(19.9)	1.8	-	1.8
22.	**Sub-total revenue requirement**	2,302.4	(24.4)	2,278.0	114.8	2,392.8
23.	Customer Care Rate Smoothing V/A Adjustment	-	-	-	(4.6)	(4.6)
24.	**Total revenue requirement**	2,302.4	(24.4)	2,278.0	110.2	2,388.2
	Revenue at existing Rates					
25.	Gas sales	1,923.9	45.6	1,969.5	80.2	2,049.7
26.	Transportation service	294.9	4.9	299.8	19.0	318.8
27.	Transmission, compression and storage	1.7	-	1.7	-	1.7
28.	Rounding adjustment	-	0.1	0.1	-	0.1
29.	Revenue at existing rates	2,220.5	50.6	2,271.1	99.2	2,370.3
30.	**Gross revenue sufficiency / (deficiency)**	(81.9)	75.0	(6.9)	(11.0)	(17.9)

Note 1: Information from Col. 3 of Exhibit M2, Tab 1, Schedule 2, Page 1, Filed: 2012-09-12.
Note 2: Information from Col. 3 of Exhibit F3, Tab 1, Schedule 1, Page 2, Filed: 2012-01-31.

UTILITY RATE BASE
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 2 (Note 1)	Col. 2 ADR Adjustments	Col. 3 Excl. CIS Adjusted Impact Statement Number 2	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Total Adjusted ADR Impact Statement Rate Base Including CIS
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment					
1.	Cost or redetermined value	6,645.6	(23.3)	6,622.3	127.1	6,749.4
2.	Accumulated depreciation	(2,758.0)	10.5	(2,747.5)	(56.6)	(2,804.1)
3.		3,887.6	(12.8)	3,874.8	70.5	3,945.3
	Allowance for Working Capital					
4.	Accounts receivable merchandise finance plan	-	-	-	-	-
5.	Accounts receivable rebillable projects	1.3	-	1.3	-	1.3
6.	Materials and supplies	31.9	-	31.9	-	31.9
7.	Mortgages receivable	0.2	-	0.2	-	0.2
8.	Customer security deposits	(68.7)	-	(68.7)	-	(68.7)
9.	Prepaid expenses	1.8	-	1.8	-	1.8
10.	Gas in storage	249.3	(0.9)	248.4	-	248.4
11.	Working cash allowance	0.3	1.5	1.8	-	1.8
12.	Total Working Capital	216.1	0.6	216.7	-	216.7
13.	Utility Rate Base	4,103.7	(12.2)	4,091.5	70.5	4,162.0

Note 1: Information from Col. 3 of Exhibit M2, Tab 1, Schedule 3, Page 1, Filed: 2012-09-12.
Note 2: Information from Col. 2 of Exhibit F3, Tab 1, Schedule 3, page 1, Filed: 2012-01-31.

EXPLANATION OF ADJUSTMENTS TO UTILITY RATE BASE
2013 TEST YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	(23.3)	Cost or redetermined value Change is the result of the settlement of issues B1 through B7 and related descriptions contained within the Agreement.
2.	10.5	Accumulated depreciation Change is the result of the settlement of issue D7 and the related description contained within the Agreement.
10.	(0.9)	Gas in storage Change is the result of the settlement of issue B7 and the related description contained within the Agreement.
11.	1.5	Working cash allowance Change is the result of the settlement of issue B7 and the related description contained within the Agreement.

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2013 TEST YEAR

		Col. 1	Col. 2	Col. 3	Col. 4
Line No.		Reference	Disburs-ements	Net Lag-Days	Allowance
			($Millions)	(Days)	($Millions)
1.	Gas purchase and storage and transportation charges		1,350.9	4.0	14.8
2.	Items not subject to working cash allowance (Note 1)		(8.1)		
3.	Gas costs charged to operations	M2.T1.S4.P1.Col.3	1,342.8		
4.	Operation and Maintenance	M2.T1.S4.P1.Col.3	325.5		
5.	Less: Storage costs		(7.9)		
6.	Operation and maintenance costs subject to working cash		317.6		
7.	Ancillary customer services		-		
8.			317.6	(18.7)	(16.3)
9.	Sub-total				(1.5)
10.	Storage costs		7.9	62.5	1.4
11.	Storage municipal and capital taxes		2.2	24.4	0.1
12.	Sub-total				1.5
13.	Harmonized sales tax				1.8
14.	Total working cash allowance				1.8

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

GAS IN STORAGE
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2013 TEST YEAR

Line No.		Volume	Col. 1 Impact Statement Number 2	ADR Adjustments	Col. 2 ADR Adjustments	Adjusted Volume	Col. 3 Adjusted ADR Impact Statement
		10*6 M*3	($Millions)	10*6 M*3	($Millions)	10*6 M*3	($Millions)
1.	January 1	1,425.1	328.4	(0.1)	(0.1)	1,425.0	328.3
2.	January 31	872.6	211.7	(33.0)	(7.3)	839.6	204.4
3.	February	446.8	120.1	(8.2)	(3.9)	438.6	116.2
4.	March	95.9	51.7	30.8	2.3	126.7	54.0
5.	April	44.4	50.2	25.2	1.8	69.6	52.0
6.	May	330.9	105.4	19.4	1.4	350.3	106.8
7.	June	720.0	178.2	13.9	0.9	733.9	179.1
8.	July	1,241.2	272.1	8.2	0.6	1,249.4	272.7
9.	August	1,763.8	366.3	2.3	0.1	1,766.1	366.4
10.	September	2,141.1	437.3	(3.2)	(0.4)	2,137.9	436.9
11.	October	2,246.7	462.6	(9.0)	(0.8)	2,237.7	461.8
12.	November	1,957.2	412.2	(36.1)	(5.2)	1,921.1	407.0
13.	December	1,478.4	318.6	(2.6)	(0.6)	1,475.8	318.0
14.	Avg. of monthly avgs.	1,109.4	249.3	0.7	(0.9)	1,110.1	248.4

UTILITY INCOME
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 2 (Note 1)	Col. 2 ADR Adjustments	Col. 3 Excl. CIS Adjusted Impact Statement Number 2	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Total Adjusted ADR Impact Statement Utility Income
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Gas sales	1,923.9	45.6	1,969.5	80.2	2,049.7
2.	Transportation of gas	294.9	4.9	299.8	19.0	318.8
3.	Transmission, compression and storage revenue	1.7	-	1.7	-	1.7
4.	Other operating revenue	38.3	6.0	44.3	-	44.3
5.	Interest and property rental	-	-	-	-	-
6.	Other income	0.7	-	0.7	-	0.7
7.	Total operating revenue	2,259.5	56.5	2,316.0	99.2	2,415.2
8.	Gas costs	1,307.9	34.9	1,342.8	-	1,342.8
9.	Operation and maintenance	348.3	(22.8)	325.5	89.4	414.9
10.	Depreciation and amortization expense	288.1	(21.5)	266.6	12.7	279.3
11.	Fixed financing costs	2.3	-	2.3	-	2.3
12.	Debt redemption premium amortization	-	-	-	-	-
13.	Company share of IR agreement tax savings	-	-	-	-	-
14.	Municipal and other taxes	40.1	(0.8)	39.3	-	39.3
15.	Interest and financing amortization expense	-	-	-	-	-
16.	Other interest expense	-	-	-	-	-
17.	Total costs and expenses	1,986.7	(10.2)	1,976.5	102.1	2,078.6
18.	Ontario utility income before income taxes	272.8	66.7	339.5	(2.9)	336.6
19.	Income tax expense	37.9	12.6	50.5	8.1	58.6
20.	Utility net income	234.9	54.1	289.0	(11.0)	278.0

Note 1: Information from Col. 3 of Exhibit M2, Tab 1, Schedule 4, Page 1, Filed: 2012-09-12.
Note 2: Information from Col. 2 of Exhibit F3, Tab 1, Schedule 2, page 1, Filed: 2012-01-31.

EXPLANATION OF ADJUSTMENTS TO UTILITY INCOME
2013 TEST YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	45.6	Gas sales Change is the result of the settlement of issues C1 through C5 and related descriptions contained within the Agreement.
2.	4.9	Transportation of gas Change is the result of the settlement of issues C1 through C5 and related descriptions contained within the Agreement.
4.	6.0	Other operating revenue Change is the result of the settlement of issues C6 and C7 and related descriptions contained within the Agreement.
8.	34.9	Gas costs Change is the result of the settlement of issues C1 through C5 and D2 & D3 and related descriptions contained within the Agreement.
9.	(22.8)	Operation and maintenance Change is the result of the settlement of issues C1 through C5 and D2 & D3 and related descriptions contained within the Agreement.
10.	(21.5)	Depreciation and amortization expense Change is due to the settlement of issues D1, D5, D9, D11 through D24 and related descriptions contained within the Agreement.
14.	(0.8)	Municipal and other taxes Change is the result of the settlement of issues D8 and the related description contained within the Agreement.
19.	12.6	Income tax expense Change is due to the impact on taxable income as a result of the settlement of all the issues identified above.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 2 (Note 1) ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 Excl. CIS Adjusted ADR Impact Statement Utility Tax ($Millions)
1.	Utility income before income taxes (M2, T1, S3, P1)	272.8	66.7	339.5
	Add			
2.	Depreciation and amortization	288.1	(21.5)	266.6
3.	Accrual based pension and OPEB costs	42.1	-	42.1
4.	Other non-deductible items	2.2	-	2.2
5.	Total Add Back	332.4	(21.5)	310.9
6.	Sub total	605.2	45.2	650.4
	Deduct			
7.	Capital cost allowance - Federal	234.8	(3.1)	231.7
8.	Capital cost allowance - Provincial	234.8	(3.1)	231.7
9.	Items capitalized for regulatory purposes	46.3	-	46.3
10.	Deduction for "grossed up" Part VI.1 tax	5.0	-	5.0
11.	Amortization of share/debenture issue expense	3.6	-	3.6
12.	Amortization of cumulative eligible capital	0.4	-	0.4
13.	Amortization of C.D.E. and C.O.G.P.E	0.4	-	0.4
14.	Cash based pension and OPEB costs	42.6	-	42.6
15.	Total Deduction - Federal	333.1	(3.1)	330.0
16.	Total Deduction - Provincial	333.1	(3.1)	330.0
17.	Taxable income - Federal	272.1	48.3	320.4
18.	Taxable income - Provincial	272.1	48.3	320.4
19.	Income tax rate - Federal	15.00%	0.00%	15.00%
20.	Income tax rate - Provincial	11.50%	0.00%	11.50%
21.	Income tax provision - Federal	40.8	7.3	48.1
22.	Income tax provision - Provincial	31.3	5.5	36.8
23.	Income tax provision - combined	72.1	12.8	84.9
24.	Part V1.1 tax			1.7
25.	Investment tax credit			(0.1)
26.	Total taxes excluding tax shield on interest expense			86.5
	Tax shield on interest expense			
27.	Rate base (M2.T1.S2.P1)			4,091.5
28.	Return component of debt (M2.T1.S4.P1)			3.32%
29.	Interest expense			135.7
30.	Combined tax rate			26.50%
31.	Income tax credit			(36.0)
32.	Total income taxes			50.5

Note 1: Information from Col. 3 of Exhibit M2, Tab 1, Schedule 4, page 3, Filed: 2012-09-12.

UTILITY CAPITAL STRUCTURE
2013 TEST YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Indicated Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long and medium term debt	2,312.8	56.53	5.90	3.335
2.	Short term debt/(investment)	(39.7)	-0.97	2.00	(0.019)
3.		2,273.1	55.56		3.316
4.	Preference shares	100.0	2.44	3.20	0.078
5.	Common equity	1,718.4	42.00	9.03	3.793
6.		4,091.5	100.00		7.187
7.	Utility income	($Millions)			289.0
8.	Rate base	($Millions)			4,091.5
9.	Indicated rate of return				7.063%
10.	(Deficiency) in rate of return				(0.124)%
11.	Net (deficiency)	($Millions)			(5.1)
12.	Gross (deficiency)	($Millions)			(6.9)
13.	Customer Care/CIS deficiency	($Millions)			(11.0)
14.	Total gross (deficiency)	($Millions)			(17.9)
15.	Revenue at existing rates	($Millions)			2,370.3
16.	Revenue requirement	($Millions)			2,388.2
17.	Total gross revenue (deficiency)	($Millions)			(17.9)

CHANGE IN REVENUE REQUIREMENT
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 2 (Note 1)	Col. 2 ADR Adjustments	Col. 3 Excl. CIS Adjusted ADR Impact Statement	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 ADR Impact Statement EGD Total
		($Millions)		($Millions)	($Millions)	($Millions)
	Cost of capital					
1.	Rate base	4,103.7	(12.2)	4,091.5	70.5	4,162.0
2.	Required rate of return	7.19	(0.34)	6.85	6.44	6.85
3.		295.1	(14.8)	280.3	4.6	284.9
	Cost of service					
4.	Gas costs	1,307.9	34.9	1,342.8	-	1,342.8
5.	Operation and maintenance	348.3	(22.8)	325.5	89.4	414.9
6.	Depreciation and amortization	288.1	(21.5)	266.6	12.7	279.3
7.	Fixed financing costs	2.3	-	2.3	-	2.3
8.	Debt redemption premium amortization	-	-	-	-	-
9.	Company share of IR agreement tax savings	-	-	-	-	-
10.	Municipal and other taxes	40.1	(0.8)	39.3	-	39.3
11.		1,986.7	(10.2)	1,976.5	102.1	2,078.6
	Miscellaneous operating and non-operating revenue					
12.	Other operating revenue	(38.3)	(6.0)	(44.3)	-	(44.3)
13.	Interest and property rental	-	-	-	-	-
14.	Other income	(0.7)	-	(0.7)	-	(0.7)
15.		(39.0)	(6.0)	(45.0)	-	(45.0)
	Income taxes on earnings					
16.	Excluding tax shield	73.7	12.7	86.4	9.0	95.4
17.	Tax shield provided by interest expense	(35.8)	(2.3)	(38.1)	(0.9)	(39.0)
18.		37.9	10.4	48.3	8.1	56.4
	Taxes on sufficiency / (deficiency)					
19.	Gross sufficiency / (deficiency)	(81.9)	96.9	15.0	-	15.0
20.	Net sufficiency / (deficiency)	(60.2)	71.2	11.0	-	11.0
21.		21.7	(25.7)	(4.0)	-	(4.0)
22.	**Sub-total revenue requirement**	2,302.4	(46.3)	2,256.1	114.8	2,370.9
23.	Customer Care Rate Smoothing V/A Adjustment	-	-	-	(4.6)	(4.6)
24.	**Total revenue requirement**	2,302.4	(46.3)	2,256.1	110.2	2,366.3
	Revenue at existing Rates					
25.	Gas sales	1,923.9	45.6	1,969.5	80.2	2,049.7
26.	Transportation service	294.9	4.9	299.8	19.0	318.8
27.	Transmission, compression and storage	1.7	-	1.7	-	1.7
28.	Rounding adjustment	-	0.1	0.1	-	0.1
29.	Revenue at existing rates	2,220.5	50.6	2,271.1	99.2	2,370.3
30.	**Gross revenue sufficiency / (deficiency)**	(81.9)	96.9	15.0	(11.0)	4.0

Note 1: Information from Col. 3 of Exhibit M2, Tab 1, Schedule 2, Page 1, Filed: 2012-09-12.
Note 2: Information from Col. 3 of Exhibit F3, Tab 1, Schedule 1, Page 2, Filed: 2012-01-31.

UTILITY RATE BASE
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 2 (Note 1) ($Millions)	Col. 2 ADR Adjustments ($Millions)	Col. 3 Excl. CIS Adjusted Impact Statement Number 2 ($Millions)	Col. 4 Cust. Care / CIS (Note 2) ($Millions)	Col. 5 Total Adjusted ADR Impact Statement Rate Base Including CIS ($Millions)
	Property, Plant, and Equipment					
1.	Cost or redetermined value	6,645.6	(23.3)	6,622.3	127.1	6,749.4
2.	Accumulated depreciation	(2,758.0)	10.5	(2,747.5)	(56.6)	(2,804.1)
3.		3,887.6	(12.8)	3,874.8	70.5	3,945.3
	Allowance for Working Capital					
4.	Accounts receivable merchandise finance plan	-	-	-	-	-
5.	Accounts receivable rebillable projects	1.3	-	1.3	-	1.3
6.	Materials and supplies	31.9	-	31.9	-	31.9
7.	Mortgages receivable	0.2	-	0.2	-	0.2
8.	Customer security deposits	(68.7)	-	(68.7)	-	(68.7)
9.	Prepaid expenses	1.8	-	1.8	-	1.8
10.	Gas in storage	249.3	(0.9)	248.4	-	248.4
11.	Working cash allowance	0.3	1.5	1.8	-	1.8
12.	Total Working Capital	216.1	0.6	216.7	-	216.7
13.	Utility Rate Base	4,103.7	(12.2)	4,091.5	70.5	4,162.0

Note 1: Information from Col. 3 of Exhibit M2, Tab 1, Schedule 3, Page 1, Filed: 2012-09-12.
Note 2: Information from Col. 2 of Exhibit F3, Tab 1, Schedule 3, page 1, Filed: 2012-01-31.

EXPLANATION OF ADJUSTMENTS TO UTILITY RATE BASE
2013 TEST YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	(23.3)	Cost or redetermined value Change is the result of the settlement of issues B1 through B7 and related descriptions contained within the Agreement.
2.	10.5	Accumulated depreciation Change is the result of the settlement of issue D7 and the related description contained within the Agreement.
10.	(0.9)	Gas in storage Change is the result of the settlement of issue B7 and the related description contained within the Agreement.
11.	1.5	Working cash allowance Change is the result of the settlement of issue B7 and the related description contained within the Agreement.

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2013 TEST YEAR

		Col. 1	Col. 2	Col. 3	Col. 4
Line No.		Reference	Disburs-ements	Net Lag-Days	Allowance
			($Millions)	(Days)	($Millions)
1.	Gas purchase and storage and transportation charges		1,350.9	4.0	14.8
2.	Items not subject to working cash allowance (Note 1)		(8.1)		
3.	Gas costs charged to operations	M2.T1.S4.P1.Col.3	1,342.8		
4.	Operation and Maintenance	M2.T1.S4.P1.Col.3	325.5		
5.	Less: Storage costs		(7.9)		
6.	Operation and maintenance costs subject to working cash		317.6		
7.	Ancillary customer services		-		
8.			317.6	(18.7)	(16.3)
9.	Sub-total				(1.5)
10.	Storage costs		7.9	62.5	1.4
11.	Storage municipal and capital taxes		2.2	24.4	0.1
12.	Sub-total				1.5
13.	Harmonized sales tax				1.8
14.	Total working cash allowance				1.8

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

GAS IN STORAGE
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2013 TEST YEAR

			Col. 1		Col. 2		Col. 3
Line No.		Volume	Impact Statement Number 2	ADR Adjustments	ADR Adjustments	Adjusted Volume	Adjusted ADR Impact Statement
		10*6 M*3	($Millions)	10*6 M*3	($Millions)	10*6 M*3	($Millions)
1.	January 1	1,425.1	328.4	(0.1)	(0.1)	1,425.0	328.3
2.	January 31	872.6	211.7	(33.0)	(7.3)	839.6	204.4
3.	February	446.8	120.1	(8.2)	(3.9)	438.6	116.2
4.	March	95.9	51.7	30.8	2.3	126.7	54.0
5.	April	44.4	50.2	25.2	1.8	69.6	52.0
6.	May	330.9	105.4	19.4	1.4	350.3	106.8
7.	June	720.0	178.2	13.9	0.9	733.9	179.1
8.	July	1,241.2	272.1	8.2	0.6	1,249.4	272.7
9.	August	1,763.8	366.3	2.3	0.1	1,766.1	366.4
10.	September	2,141.1	437.3	(3.2)	(0.4)	2,137.9	436.9
11.	October	2,246.7	462.6	(9.0)	(0.8)	2,237.7	461.8
12.	November	1,957.2	412.2	(36.1)	(5.2)	1,921.1	407.0
13.	December	1,478.4	318.6	(2.6)	(0.6)	1,475.8	318.0
14.	Avg. of monthly avgs.	1,109.4	249.3	0.7	(0.9)	1,110.1	248.4

UTILITY INCOME
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 2 (Note 1) ($Millions)	Col. 2 ADR Adjustments ($Millions)	Col. 3 Excl. CIS Adjusted Impact Statement Number 2 ($Millions)	Col. 4 Cust. Care / CIS (Note 2) ($Millions)	Col. 5 Total Adjusted ADR Impact Statement Utility Income ($Millions)
1.	Gas sales	1,923.9	45.6	1,969.5	80.2	2,049.7
2.	Transportation of gas	294.9	4.9	299.8	19.0	318.8
3.	Transmission, compression and storage revenue	1.7	-	1.7	-	1.7
4.	Other operating revenue	38.3	6.0	44.3	-	44.3
5.	Interest and property rental	-	-	-	-	-
6.	Other income	0.7	-	0.7	-	0.7
7.	Total operating revenue	2,259.5	56.5	2,316.0	99.2	2,415.2
8.	Gas costs	1,307.9	34.9	1,342.8	-	1,342.8
9.	Operation and maintenance	348.3	(22.8)	325.5	89.4	414.9
10.	Depreciation and amortization expense	288.1	(21.5)	266.6	12.7	279.3
11.	Fixed financing costs	2.3	-	2.3	-	2.3
12.	Debt redemption premium amortization	-	-	-	-	-
13.	Company share of IR agreement tax savings	-	-	-	-	-
14.	Municipal and other taxes	40.1	(0.8)	39.3	-	39.3
15.	Interest and financing amortization expense	-	-	-	-	-
16.	Other interest expense	-	-	-	-	-
17.	Total costs and expenses	1,986.7	(10.2)	1,976.5	102.1	2,078.6
18.	Ontario utility income before income taxes	272.8	66.7	339.5	(2.9)	336.6
19.	Income tax expense	37.9	10.4	48.3	8.1	56.4
20.	Utility net income	234.9	56.3	291.2	(11.0)	280.2

Note 1: Information from Col. 3 of Exhibit M2, Tab 1, Schedule 4, Page 1, Filed: 2012-09-12.
Note 2: Information from Col. 2 of Exhibit F3, Tab 1, Schedule 2, page 1, Filed: 2012-01-31.

EXPLANATION OF ADJUSTMENTS TO UTILITY INCOME
2013 TEST YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	45.6	Gas sales Change is the result of the settlement of issues C1 through C5 and related descriptions contained within the Agreement.
2.	4.9	Transportation of gas Change is the result of the settlement of issues C1 through C5 and related descriptions contained within the Agreement.
4.	6.0	Other operating revenue Change is the result of the settlement of issues C6 and C7 and related descriptions contained within the Agreement.
8.	34.9	Gas costs Change is the result of the settlement of issues C1 through C5 and D2 & D3 and related descriptions contained within the Agreement.
9.	(22.8)	Operation and maintenance Change is the result of the settlement of issues C1 through C5 and D2 & D3 and related descriptions contained within the Agreement.
10.	(21.5)	Depreciation and amortization expense Change is due to the settlement of issues D1, D5, D9, D11 through D24 and related descriptions contained within the Agreement.
14.	(0.8)	Municipal and other taxes Change is the result of the settlement of issues D8 and the related description contained within the Agreement.
19.	10.4	Income tax expense Change is due to the impact on taxable income as a result of the settlement of all the issues identified above.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 2 (Note 1) ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 Excl. CIS Adjusted ADR Impact Statement Utility Tax ($Millions)
1.	Utility income before income taxes (M2, T1, S3, P1)	272.8	66.7	339.5
	Add			
2.	Depreciation and amortization	288.1	(21.5)	266.6
3.	Accrual based pension and OPEB costs	42.1	-	42.1
4.	Other non-deductible items	2.2	-	2.2
5.	Total Add Back	332.4	(21.5)	310.9
6.	Sub total	605.2	45.2	650.4
	Deduct			
7.	Capital cost allowance - Federal	234.8	(3.1)	231.7
8.	Capital cost allowance - Provincial	234.8	(3.1)	231.7
9.	Items capitalized for regulatory purposes	46.3	-	46.3
10.	Deduction for "grossed up" Part VI.1 tax	5.0	-	5.0
11.	Amortization of share/debenture issue expense	3.6	0.2	3.8
12.	Amortization of cumulative eligible capital	0.4	-	0.4
13.	Amortization of C.D.E. and C.O.G.P.E	0.4	-	0.4
14.	Cash based pension and OPEB costs	42.6	-	42.6
15.	Total Deduction - Federal	333.1	(2.9)	330.2
16.	Total Deduction - Provincial	333.1	(2.9)	330.2
17.	Taxable income - Federal	272.1	48.1	320.2
18.	Taxable income - Provincial	272.1	48.1	320.2
19.	Income tax rate - Federal	15.00%	0.00%	15.00%
20.	Income tax rate - Provincial	11.50%	0.00%	11.50%
21.	Income tax provision - Federal	40.8	7.2	48.0
22.	Income tax provision - Provincial	31.3	5.5	36.8
23.	Income tax provision - combined	72.1	12.7	84.8
24.	Part V1.1 tax			1.7
25.	Investment tax credit			(0.1)
26.	Total taxes excluding tax shield on interest expense			86.4
	Tax shield on interest expense			
27.	Rate base (M2.T1.S2.P1)			4,091.5
28.	Return component of debt (M2.T1.S4.P1)			3.52%
29.	Interest expense			143.9
30.	Combined tax rate			26.50%
31.	Income tax credit			(38.1)
32.	Total income taxes			48.3

Note 1: Information from Col. 3 of Exhibit M2, Tab 1, Schedule 4, page 3, Filed: 2012-09-12.

UTILITY CAPITAL STRUCTURE
2013 TEST YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Indicated Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long and medium term debt	2,461.9	60.17	5.80	3.490
2.	Short term debt/(investment)	56.7	1.39	2.00	0.028
3.		2,518.6	61.56		3.518
4.	Preference shares	100.0	2.44	3.20	0.078
5.	Common equity	1,472.9	36.00	9.03	3.251
6.		4,091.5	100.00		6.847
7.	Utility income	($Millions)			291.2
8.	Rate base	($Millions)			4,091.5
9.	Indicated rate of return				7.117%
10.	Sufficiency in rate of return				0.270 %
11.	Net sufficiency	($Millions)			11.0
12.	Gross sufficiency	($Millions)			15.0
13.	Customer Care/CIS deficiency	($Millions)			(11.0)
14.	Total gross sufficiency	($Millions)			4.0
15.	Revenue at existing rates	($Millions)			2,370.3
16.	Revenue requirement	($Millions)			2,366.3
17.	Total gross revenue sufficiency	($Millions)			4.0

Summary of Gas Cost to Operations
Year ended December 31, 2013

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
	Western Canadian Supplies				
1.1	Alberta Production	0.0	0.0	0.000	0.000
1.2	Western - @ Empress - TCPL	2,062,200.2	232,482.7	112.735	2.991
1.3	Western - @ Nova - TCPL	938,105.2	112,398.0	119.814	3.179
1.4	Western Buy/Sell - with Fuel	1,849.7	225.9	122.138	3.241
1.5	Western - @ Alliance	954,694.8	119,568.5	125.243	3.323
1.6	Less TCPL Fuel Requirement	(70,759.0)	0.0		
1.	Total Western Canadian Supplies	3,886,090.9	464,675.1	119.574	3.173
2.	Peaking Supplies	37,998.7	9,406.9	247.560	6.568
3.	Ontario Production	730.0	144.4	197.809	5.248
4.	Chicago Supplies	1,832,109.7	253,812.3	138.536	3.676
5.	Delivered Supplies	1,553,462.5	221,208.9	142.397	3.778
6.	Total Supply Costs	7,310,391.8	949,247.6	129.849	3.445
	Transportation Costs				
7.1	TCPL - FT - Demand		232,978.8		
7.2	- FT - Commodity	2,931,396.1	15,884.3	5.419	0.144
7.3	- Parkway to CDA		3,238.4		
7.4	- STS - CDA		5,793.8		
7.5	- STS - EDA		4,687.0		
7.6	- Dawn to CDA		9,471.0		
7.7	- Dawn to EDA		22,582.0		
7.8	- Dawn to Iroquois		7,063.3		
7.9	Other Charges		0.0		
7.10	Nova Transmission		7,039.6		
7.11	Alliance Pipeline		42,819.4		
7.12	Vector Pipeline		24,970.4		
7.	Total Transportation Costs		376,528.0		
8.	Total Before PGVA Adjustment	7,310,391.8	1,325,775.6	181.355	4.812
9.	PGVA Adjustment		(175,419.3)		
10.	Total Purchases & Receipt	7,310,391.8	1,150,356.3	157.359	4.175

Summary of Gas Cost to Operations
Year ended December 31, 2013

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
10.	Total Purchases & Receipt	7,310,391.8	1,150,356.3	157.359	4.175
11.	Storage Fluctuation	(50,729.1)	(7,982.7)		
12.	Commodity Cost to Operations	7,259,662.7	1,142,373.6	157.359	
13.	Storage and Transportation Costs		107,679.1		
14.	Gas Cost to Operations	7,259,662.7	1,250,052.7	172.192	4.569
15.	Ontario T-Service Credits		0.0		
16.	Western T-Service		92,706.0		
17.	Forecasted Gas Costs	7,259,662.7	1,342,758.8	184.962	4.907

Reconciliation Of Natural Gas Sendout Volumes
To Sales Volumes
Year ended December 31, 2013

Item #		
1.	Sendout To Operations	7,259,662.7
2.	T-Service Volumes	4,316,708.5
3.	Total Sendout	11,576,371.2
4.1	Residential Sales	4,095,952.3
4.2	Commercial Sales	2,499,322.9
4.3	Industrial Sales	437,628.5
4.4	T-Service	4,277,267.2
4.5	Rate 200 T-Service (Gazifere)	38,849.3
4.6	Rate 200 Sales (Gazifere)	124,230.8
4.7	Company Use	5,176.3
4.8	Unaccounted For (UAF)	73,092.0
4.9	Unbilled Forecast - Sales	496.3
4.10	Unbilled Forecast - T-Service	592.0
4.11	Lost and Unaccounted For (LUF)	23,763.6
4.	Total System Requirements	11,576,371.2

Summary of Storage & Transportion Costs
Fiscal 2013

Item #	Units - $(000)	Col. 1 Storage & Transportation Charges Incurred in Fiscal 2013	Col. 2 Fiscal 2013 Storage Charges Recovered in Fiscal 2013	Col. 3 Fiscal 2012 Storage Charges Recovered in Fiscal 2013	Col. 4 Total Storage & Transportation Charges Recovered in Fiscal 2013
	Storage				
1.1	Chatham D	132.3	74.6	57.3	131.9
1.2	Injection	122.7	38.1	87.8	126.0
1.3	Withdrawal	121.2	121.2	0.0	121.2
1.4	Market Based Storage	19,592.0	10,691.8	8,747.6	19,439.4
1.5	Unutilized Transportation Costs	0.0	0.0	0.0	0.0
1.6	Other	827.2	827.2	0.0	827.2
1.	Total Storage	20,795.4	11,752.9	8,892.8	20,645.7
2.	Total Transportation	65,550.7	35,832.5	29,496.5	65,328.9
	Dehydration				
3.1	Demand	1,001.1	547.2	450.5	997.7
3.2	Commodity	189.5	189.5	0.0	189.5
3.	Total Dehydration	1,190.6	736.8	450.5	1,187.2
4.	Total Storage & Other Costs	87,536.8	48,322.1	38,839.7	87,161.9
	Fuel Costs				
5.1	Tecumseh	3,411.2	2,235.0	1,349.4	3,584.4
5.2	Union Storage	1,074.3	696.0	413.6	1,109.6
5.3	Union Transportation	15,815.1	15,508.8	314.5	15,823.2
5.	Total Fuel Costs	20,300.6	18,439.9	2,077.4	20,517.3
6.	Total Storage & Transportation	107,837.3	66,762.0	40,917.1	107,679.1
8.	Storage and Transportation Costs Charged to Gas Cost to Operations				107,679.1

GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED AVERAGE USE*

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011 Historic Year	2012 Bridge Year Estimate	2013 As Filed	2013 ADR
Residential	2,975	2,869	2,844	2,831	2,786	2,716	2,680	2,670	2,640	2,593	2,562	2,523	2,492	2,491	2,568
Change		-106	-25	-13	-45	-70	-36	-10	-30	-47	-31	-39	-31	-1	77
% Change		-3.56%	-0.87%	-0.46%	-1.59%	-2.51%	-1.33%	-0.37%	-1.12%	-1.78%	-1.20%	-1.52%	-1.23%	-0.04%	3.09%
Apartment	79,237	79,588	80,512	81,828	81,783	78,307	85,577	99,377	123,734	141,644	161,844	150,684	159,642	151,222	154,877
Change		351	924	1,316	-45	-3,476	7,270	13,800	24,357	17,910	20,200	-11,160	8,958	-8,420	3,655
% Change		0.44%	1.16%	1.63%	-0.05%	-4.25%	9.28%	16.13%	24.51%	14.47%	14.26%	-6.90%	5.94%	-5.27%	2.42%
Commercial	17,249	17,042	17,001	17,000	16,877	16,470	16,614	17,066	17,931	18,530	19,203	19,461	19,772	19,648	20,230
Change		-207	-41	-1	-123	-407	144	452	865	599	673	258	311	-124	582
% Change		-1.20%	-0.24%	-0.01%	-0.72%	-2.41%	0.87%	2.72%	5.07%	3.34%	3.63%	1.34%	1.60%	-0.63%	2.96%
Industrial	57,075	54,320	51,791	54,856	50,563	51,424	53,620	58,779	73,938	88,264	106,163	108,872	113,866	108,350	109,481
Change		-2,755	-2,529	3,065	-4,293	861	2,196	5,159	15,159	14,326	17,899	2,709	4,994	-5,516	1,131
% Change		-4.83%	-4.66%	5.92%	-7.83%	1.70%	4.27%	9.62%	25.79%	19.38%	20.28%	2.55%	4.59%	-4.84%	1.04%

* All historical average uses are on a calendar-year basis and have been normalized to the 2013 Budget degree days as filed.

GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED AVERAGE USE*

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011 Historic Year	2012 Bridge Year Estimate	2013 As Filed	2013 ADR
Rate 1		2,975	2,869	2,844	2,831	2,786	2,716	2,680	2,670	2,640	2,593	2,562	2,523	2,492	2,491	2,568
	Change		-106	-25	-13	-45	-70	-36	-10	-30	-47	-31	-39	-31	-1	77
	% Change		-3.56%	-0.87%	-0.46%	-1.59%	-2.51%	-1.33%	-0.37%	-1.12%	-1.78%	-1.20%	-1.52%	-1.23%	-0.04%	3.09%
Rate 6		21,565	21,221	21,093	21,275	20,970	20,447	20,960	22,243	24,871	26,685	28,873	29,007	29,941	29,132	29,878
	Change		-344	-128	182	-305	-523	513	1,283	2,628	1,814	2,188	134	934	-809	746
	% Change		-1.60%	-0.60%	0.86%	-1.43%	-2.49%	2.51%	6.12%	11.81%	7.29%	8.20%	0.46%	3.22%	-2.70%	2.56%

* All historical average uses are on a calendar-year basis and have been normalized to the 2013 Budget degree days as filed.

APPENDIX "B"
Enbridge Gas Distribution Inc.

EB-2011-0354

Case Timetable
Date: November 2, 2012

	Event	**Date**
1.	File experts' Joint Written Statement	November 9
2.	Final day for Open Bill Access ADR discussions	November 9
3.	File proposals on concurrent experts' hearing process	November 13
4.	Oral Hearing	November 19 and 20